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MARYLAND
DEPARTMENT OF
NATURAL RESOURCES

PPRP

Maryland Power Plants and the Environment

A review of the impacts of power plants and transmission lines on Maryland's natural resources

August 2024

MARYLAND POWER PLANT
RESEARCH PROGRAM

Wes Moore, Governor ◊ **Aruna Miller, Lt. Governor**

The Maryland Department of Natural Resources (DNR) seeks to preserve, protect and enhance the living resources of the state. Working in partnership with the citizens of Maryland, this worthwhile goal will become a reality. This publication provides information that will increase your understanding of how DNR strives to reach that goal through its many diverse programs.

Joshua E. Kurtz, Secretary
Maryland Department of Natural Resources

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Chapter 1 – Background

The Maryland Department of Natural Resources (DNR) Power Plant Research Program (PPRP) evaluates how the design, construction, and operation of power plants and transmission lines affect Maryland's environmental, socioeconomic, and cultural resources. PPRP's legislative mandate seeks to ensure that the citizens of Maryland can continue to enjoy reliable electricity supplies at a reasonable cost while minimizing impacts to Maryland's natural resources. The program plays a key role in the licensing process for power plants and transmission lines by coordinating the state agencies' review of new or modified facilities and developing recommendations for license conditions.

The Maryland Power Plant Siting Act of 1971 directs PPRP to prepare a biennial Cumulative Environmental Impact Report (CEIR). The intent of the CEIR is to assemble and summarize information regarding the impacts of electric power generation and transmission on Maryland's natural resources, cultural foundation, and economic situation. A listing of key PPRP projects and reports, as well as a complete program bibliography, is available at dnr.maryland.gov/pprp.

General background information on environmental, socioeconomic, and cultural impacts on generation and transmission can also be found on PPRP's website under the Supplemental CEIR Information section located here: https://dnr.maryland.gov/pprp/Pages/ceir.aspx. Specific topics covered in this background information are referenced within this document, with links provided to direct the reader to the specified discussion.

This twenty-second edition of CEIR (CEIR-22) is divided into the following chapters:

- Chapter 1 provides background on PPRP and the Certificate of Public Convenience and Necessity process.
    - The Role of PPRP
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- Chapter 2 discusses evolving energy topics in Maryland.
    - Transforming Maryland's Electric Grid
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    - Retail Electricity Markets and Billing
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    - The Role of Federal Entities

- Chapter 5 identifies issues around and effects of power generation and transmission on Maryland's air, water, land, and socioeconomic resources.
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  - Impacts on Terrestrial Resources
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  - Power Plant Coal Combustion Byproducts (CCBs)

1.1 The Role of PPRP

The Maryland legislature passed the Power Plant Siting Act in 1971 as a result of extensive public debate over the potential effects of the Calvert Cliffs Nuclear Power Plant during its approval and design stage, and the legislature's desire that the State of Maryland play a significant role in the decision-making process. At that time, Calvert Cliffs was a source of concern mainly due to its once-through cooling system, designed to withdraw up to 3.5 billion gallons of water per day from the Chesapeake Bay and then discharge it back into the Bay with a temperature increase of up to 12°F. This and other issues prompted the creation of PPRP to ensure a comprehensive, integrated, objective evaluation based on sound science to investigate environmental and economic issues.

Today, PPRP continues this role by coordinating a comprehensive review of proposals for the construction or modification of power generation and transmission facilities and by developing technically based licensing recommendations for submission to the Maryland Public Service Commission (PSC). Consistent with the original statute, PPRP also conducts research on power plant impacts to Maryland's natural resources, including the Chesapeake Bay. In addition to surface water concerns, PPRP evaluates impacts to Maryland's groundwater, air, land, and socioeconomics for proposed power generation facilities and transmission lines.

1.2 Power Plant and Transmission Line Licensing

The PSC is the regulating entity whose jurisdiction includes licensing power generating facilities and overhead transmission lines greater than 69 kilovolts (kV) within the state. The PSC is an independent commission created by the state legislature with commissioners appointed by the governor for set terms.

An applicant that is planning to construct or modify a generating facility or a transmission line must receive a permit, the Certificate of Public Convenience and Necessity (CPCN),[1] from the PSC before the start of construction. The applicant must provide notification of the CPCN application to each county or

[1] Not all projects are subject to CPCN review. Projects under 2 megawatts (MW) in capacity are excluded from the regulatory definition of a "generating station." Several types of projects can receive CPCN exemptions from the PSC. These include (1) land-based wind projects, under 70 MW in capacity, whose energy is solely on the wholesale market, pursuant to an agreement with the local electric company; (2) projects under 70 MW in capacity that export less than 20% of the energy generated on an annual basis; and (3) projects under 25 MW that use at least 10% of the energy generated annually on site. In addition, the Federal Energy Regulatory Commission (FERC) has licensing jurisdiction over non-federal hydroelectric projects located on navigable waters in the United States. Thus, Conowingo Dam's license is from FERC, while certain permits necessary for this license, such as the water quality certification, are issued by Maryland (see Public Utility Commission (PUC) Article 7-207.1).

municipality in which the proposed facility or transmission line is located. The approved CPCN constitutes permission to construct the facility and incorporates several, but not all, additional permits required prior to construction, such as air quality and water appropriation (see Appendix A).

The PSC, or a delegated Public Utility Law Judge (PULJ), reviews applications for a CPCN in a formal adjudicatory process that includes written and oral testimony, cross-examination, and the opportunity for public participation. Parties to a CPCN licensing case include the applicant, the PSC Staff, the Office of People's Counsel (acting on behalf of the Maryland residential ratepayers) and PPRP (acting on behalf of DNR and six other state agencies). Other groups, such as federal agencies, county and municipal governments, and consumer and environmental organizations, as well as individuals with a specified interest, also have a right to participate as intervenors in these hearings. The broad authority of the PSC allows for comprehensive review of all pertinent issues related to power plant licensing.

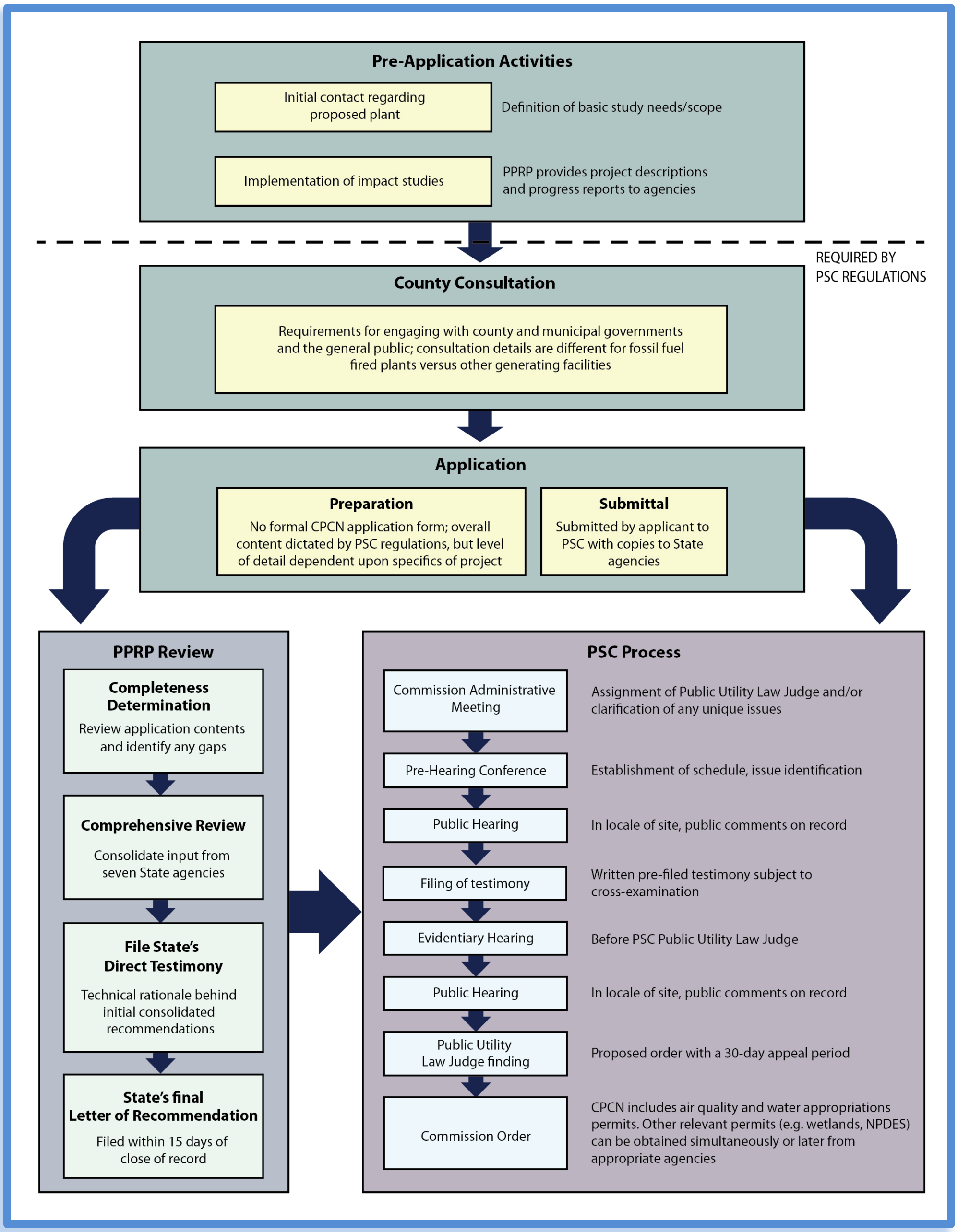
The CPCN licensing process provides an opportunity for the PSC to examine all of the significant aspects and potential impacts of a proposed power facility or transmission line, including the cumulative effects, interrelations between various impacts, and county and municipality input. This is a unique process within the state's regulatory framework. The CPCN mechanism recognizes that electricity is a vital public need, but its generation and transport can result in impacts on the state's natural, social, and cultural resources. A distinguishing feature of PPRP's role in the CPCN process is the high degree of interagency coordination involved. PPRP coordinates the project review and consolidates comments from the Departments of Natural Resources, Environment, Agriculture, Commerce, Planning, and Transportation, and the Maryland Energy Administration (MEA).

The Maryland Code, Natural Resources Article §3-306(b) requires the reviewing state agencies to forward to the PSC the results of their analysis and investigation of a CPCN application, "together with a recommendation that the certificate be granted, denied, or granted with any condition deemed necessary." For those projects that the reviewing state agencies recommend granting a CPCN, PPRP develops a consolidated set of scientifically supported recommended license conditions, unique to each facility's CPCN, and submits these recommendations to the PSC on behalf of the state agencies. In many instances, conditions go beyond regulatory requirements to incorporate innovative measures for mitigating potential facility impacts, often as stipulations agreed to by the applicant and other parties to the case prior to the conclusion of the adjudicatory process.

When multiple facilities are within proximity to each other or existing plants, or when proposed transmission lines span multiple regions and resource areas, PPRP considers cumulative impacts within the consolidated review process. In such cases, impacts to air, water, terrestrial, socioeconomic, and other resources are evaluated and compared with any identified thresholds of acceptability.

In 2020, the PSC proposed to revise the regulations concerning the CPCN application process for generating stations and transmission lines. This action was taken largely in response to concerns that the process of reviewing and licensing solar facilities was causing delays that threaten Maryland's ability to meet its goal of 14.5% of purchased electricity coming from instate solar resources by the year 2030, established in the 2019 Clean Energy Jobs Act (see further discussion in Section 3.5.1). The regulatory revisions clarified aspects of the CPCN application requirements to help applicants, and the PSC, in determining when an application is considered complete. The new regulations also lay out requirements for CPCN applicants to demonstrate that they have coordinated with appropriate county and municipal governments. After the rulemaking process was complete, the PSC adopted the revisions on August 10, 2021. More discussion of the revisions is included in Section 2.2. Figure 1-1 illustrates the elements of the CPCN licensing process.

Figure 1-1 CPCN Licensing Process



The primary steps in the CPCN licensing process are described as follows.

Pre-application. The PSC revised its CPCN regulations in 2021 to clarify several aspects of the CPCN application process. For proposed solar facilities, the applicant must contact any county or municipality in which a portion of the project is located, at least 90 days prior to submitting an application. The applicant must show the PSC a good-faith effort regarding their communication with the county or municipality prior to submission of the application to the PSC. Additionally, at least 45 days prior to the submittal of the application, the applicant must meet with PPRP to provide an overview of the proposed project. Through a diligent and thorough pre-application process, a prospective developer can limit the risk of submitting an incomplete CPCN application by making changes during the preliminary design phase to minimize negative impacts.

Application. PSC regulations require the CPCN applicant to summarize the proposed project and its potential environmental, social, cultural, and economic impacts. The application is often accompanied by an environmental review document that presents the applicant's supporting environmental and socioeconomic studies. Once the applicant has submitted a CPCN application to the PSC, PPRP coordinates with other state agencies to evaluate the potential impacts of the proposed project on Maryland's resources, including water (surface and groundwater), air, land, ecology, and socioeconomics (e.g., visual and noise-related impacts). In the case of transmission line projects, the need for the project is evaluated and a review of alternative routes is conducted as part of the review process. The demonstration of need for new electric generation was eliminated when Maryland adopted retail electric competition, also known as electric restructuring, in 1999. Instead, the development of new electric generation is left to the competitive market; applicants seeking a CPCN for a generating unit do not have to show that the state has a need for the power.

PSC Process and PPRP Review. The PSC typically assigns a PULJ to the licensing case at a preliminary administrative meeting after an application for a CPCN has been received.[2] Within 45 days of assignment to a PULJ, PPRP must provide a summary of the completeness of the application. If the application is deemed complete by all parties, the PULJ then schedules a prehearing conference to establish an overall procedural schedule, including dates for evidentiary and public hearings. The adjudicatory process commences with a discovery phase. The applicant files direct testimony to summarize the impact analyses that have been completed and provide the basis for the applicant's request for a CPCN. During the PSC evidentiary hearing, all the parties to the proceeding may actively participate and file their findings as formal testimony. PPRP and any other parties that have intervened in the process may cross-examine applicant testimony and present their analyses in direct testimony. PPRP's testimony, presented on behalf of the various state agencies, typically includes initial recommended license conditions along with supporting analyses (in the form of testimony and an independent project assessment report), which can be subject to vigorous cross-examination by all parties. Other intervening parties can prepare direct testimony and present their opinions and arguments in turn and are likewise subject to cross-examination. The PULJ also presides over public hearings to accept comments on a project from the general public.

The PULJ takes into consideration the briefs filed by the applicant, the state, and any other parties; reviews the recommended license conditions and public comments; and issues a decision in the form of a Proposed Order on whether or not the CPCN should be granted and under what conditions. After a prescribed appeal period, a Final Order is released granting or denying the CPCN.

[2] The PSC may also choose to conduct *en banc* hearings before all five commissioners.

Chapter 2 – Evolving Energy Topics in Maryland

Systems for generating electricity and supplying it to customers have changed significantly over the past 20 years, and they continue to evolve. With the rise of digital technology, distributed generation, and demands for decarbonization, the traditional electric utility framework and regulatory structures are being transformed. This chapter provides an overview of key energy topics and how they are affecting the state's electricity infrastructure.

2.1 Transforming Maryland's Electric Grid

In December 2016, the Maryland Public Service Commission (PSC) initiated Public Conference 44 (PC44) with the intent of ensuring that Maryland's electric grid is customer-centered, affordable, reliable, and environmentally sustainable. The PSC reviewed Maryland's electricity distribution system to explore opportunities to maximize benefits and choice to Maryland electric customers, and, in particular, assess how the evolving electric grid impacts low- and moderate-income (LMI) ratepayers. In January 2017, after reviewing public comment on its initial scoping, the PSC settled on six specific issues, for which it set up individual workgroups:

1. Rate Design
2. Electric Vehicles
3. Competitive Markets and Customer Choice
4. Interconnection Process
5. Energy Storage
6. Distribution System Planning[3]

2.1.1 Rate Design

The Rate Design Workgroup is responsible for developing two time-of-use (TOU) pilot programs, one for customers who receive electric supply from standard offer service (SOS) and another for customers who receive electric supply service from a retail supplier. See Section 2.4.1 of Cumulative Environmental Impact Report 2021 (CEIR-21) for background information on the Rate Design Workgroup.

Ultimately, the PSC approved a voluntary, opt-in residential time-varying rate pilot program for Baltimore Gas and Electric Company (BGE), Potomac Electric Power Company (Pepco) and Delmarva Power & Light Company (DPL), collectively the "Participating Utilities."[4] The TOU pilot programs' time-varying rates became effective as of April 1, 2019. Originally intended to end May 2021, they have been extended pending transition to permanent TOU programs, discussed in the following paragraphs.

Approximately 3,800 customers across the Participating Utilities' service territories participated in the PC44 TOU pilot programs. In addition, a separate sampling for LMI customers (defined as earning 80%

[3] The PSC lists Distribution System Planning as a sixth issue, but exploration of this issue is dependent upon available funding. To date, the PSC has not undertaken this issue.

[4] Maryland Public Service Commission, Mail Log No. 220322.

or less of the area median income) was established. The pilot program produced generally encouraging results:[5]

- Customers reduced summer peaks between 9.3% to 13.7% and non-summer peaks between 4.9% and 5.4%.

- LMI customers responded to the rate with statistical significance in the majority of the analyses in a manner similar to non-LMI customers.

- Customers experienced bill savings averaging 5.3% to 9.7% in year one and 2.3% to 7.5% in year two.

- Customer satisfaction rates were very high (90% for both BGE and Pepco, 95% for DPL).

By Orders dated July 26, 2022[6] and June 15, 2023,[7] the PSC addressed the recommendations specified by the Rate Design Workgroup in its report filed June 3, 2022, and updated March 31, 2023, for a permanent TOU program. By Order No. 90298, the PSC ordered expansion of TOU program enrollment; continued the rate design methodology for the TOU rates adopted for the pilot programs; accepted the Workgroup's consensus for each of the Participating Utilities' on-peak and off-peak hours; and accepted the consensus recommendation to allow expansion of TOU rates to customers participating in other pilot programs and retail supply choice. The PSC directed the Workgroup to provide a more thorough explanation of the challenges and risks to expanding TOU distribution rate eligibility to customers with flat SOS supply rates in its first quadrennial review.

In Order No. 90673, the PSC addressed unresolved issues arising in Order No. 90298. Regarding net-metered customers participating in TOU programs (currently closed to new net-metered customers after October 1, 2022), the PSC accepted the Participating Utilities' methodology to calculate separately on-peak and off-peak consumption and generation as "standard metering practice" under Public Utilities Articles (PUA) §7-306 and directed the Workgroup to develop and present proposed regulations for implementation. The PSC further directed the Workgroup to monitor TOU enrollment and notify the PSC when the TOU class reaches 50 MW for evaluating the possibility of separately soliciting an SOS rate for TOU customers; to continue work on the issue of estimating reductions in energy, capacity, and transmission costs associated with TOU and provide an update in its next report; to monitor utility TOU recruitment and outreach efforts and provide an update in its next report; and to provide a progress update in its next report on a review of whether the TOU rate class should be its own cost-of-service class in the future.

[5] Maryland Public Service Commission, 2022 Annual Report. 2022 MD PSC Annual Report (state.md.us).

[6] *In the Matter of Transforming Maryland's Electric Distribution Systems to Ensure that Electric Service is Customer-centered, Affordable, Reliable, and Environmentally Sustainable in Maryland*, MD PSC Order No. 90298; Administrative Docket PC44, July 26, 2022.

[7] *In the Matter of Transforming Maryland's Electric Distribution Systems to Ensure that Electric Service is Customer-centered, Affordable, Reliable, and Environmentally Sustainable in Maryland*, MD PSC Order No. 90673; Administrative Docket PC44, June 15, 2023.

2.1.2 Electric Vehicles

The Maryland PSC created and charged the Electric Vehicles (EV) Workgroup with the following goals:

- Making currently available EV tariffs applicable in other utility territories.
- Allowing retail choice for EV tariffs in all utility territories.
- Considering additional rate structures for customers with EVs, including EV-only time-varying rates.
- Planning a limited utility infrastructure investment in EV supply equipment (EVSE), working with private industry, and identifying locations at which it is difficult to attract private capital for EVSE investment.
- Developing a strategy in partnership with other state agencies and in consultation with Maryland utilities to address grid-related costs associated with vehicle fleet electrification.
- Considering unique tariffs for corporate fleets and workplace and commercial EVSE.
- Partnering with Maryland Department of Transportation and the auto industry to promote the cost savings and other benefits of EV rate structures.[8]

See Section 2.4.2 of CEIR-21 for background information on the EV Workgroup.

In March 2023, the Federal Highway Administration published regulations outlining reliability and reporting standards for EV chargers. Subsequently, in May 2023, the Maryland General Assembly enacted the Electric Vehicle Charging Reliability Act (EVCR Act), thereby establishing reporting standards for utility-owned charging stations. The EVCR Act requires an electric utility that operates an EV charging network to maintain uptime standards for each EV charging station.

The EV Workgroup devoted part of 2023 to devising reliability and reporting requirements for utility-owned charging stations. The EV Workgroup filed a report on July 28, 2023 and a supplemental report on September 29, 2023, identifying consensus and non-consensus issues regarding EV charging station reliability and reporting requirements. The EV Workgroup reached consensus on the following issues:

- Uptime measurements should be applied at the port level when each port has one connector.
- 97% average annual uptime should be the minimum reliability standard.
- Reporting exemptions should be allowed when downtime results from issues that are outside of the operator's control.
- Uptime should be measured in minutes or the most granular time increment available to the utility.

In Order No. 090971, dated January 10, 2024,[9] the PSC decided that:

[8] Maryland Public Service Commission, Mail Log No. 212176, pp. 8–9.

[9] Order-90971-EV-Charging-Reliability-and-Reporting-Standards.pdf (state.md.us)

1. All connectors connected to a port should be in operating order, regardless of type for the port, for the charging station to be considered "up" for reliability reporting purposes.
2. Pilot utilities should define in their business plans whether the "down" period for reliability reporting purposes begins from when the utility inspects and confirms that a charger is not working or when an outage is communicated to the utility.
3. Chargers unable to connect to the payment network shall be considered "down" for reliability reporting purposes.
4. Chargers with broken screens or other features should be considered "down" for reliability reporting purposes.
5. The EV Workgroup should develop a metric for the cost of electricity supplied to EV charging stations.
6. The EV Workgroup should develop standard contract language regarding charging station reliability and reporting.

As of February 1, 2023, 2,286 residential EV chargers were rebated, 231 multifamily EV charging ports were installed, 16 utility-owned multifamily EV chargers were installed, and 552 utility-owned public chargers were installed in the state.[10]

Potential Grid Impact of Electric Vehicle Charging

The North American Electric Reliability Council (NERC) projects that grid impacts from significantly increased EV charging demand could include:[11]

- Costly and rapid distribution system upgrades if EV charger load causes operating problems.
- Resource adequacy shortfalls and planned, rolling blackouts due to unmanaged EV charging, TOU rates, and deployment of distributed renewable energy resources.
- Compromised capacity and energy resource planning efforts because changes in demand profiles increase the need for flexible ramping generation resources and reserves.
- Unplanned power interruptions if increasingly variable distribution and transmission system demand patterns from EV charging negatively affect distribution and transmission protection systems.
- Cascading blackouts if the power electronics used in EV charging systems adversely impact grid dynamics, controls, and system stability.

NERC recommended collaboration between electric utilities, EV manufacturers, and EVSE manufacturers to develop strategies that will enhance power grid reliability, resilience, and security.

[10] Maryland Public Service Commission, 2022 Annual Report. 2022 MD PSC Annual Report (state.md.us).

[11] Grid_Friendly_EV_Charging_Recommendations.pdf (nerc.com)

A 2019 study[12] conducted by U.S. Drive, a partnership between the U.S. automobile industry and the U.S. Department of Energy (DOE) , used three models (low, medium, and high EV adoption) to predict the ability of the U.S. electric power system to accommodate the growing fleet of light-duty EVs. The study found that:

- By 2030, new EV sales would increase by 320,000 (2%), 2.2 million (12%), and 6.8 million (40%) in the low, medium, and high adoption scenarios, respectively.
- On average, each additional EV will require 3.8 megawatt hours (MWh) per year of energy generation. This translates to approximately 1 billion, 8 billion, and 26 billion kilowatt hours (kWh) annually of energy generation needed for the low, medium, and high scenarios, respectively.
- The average annual growth in energy generation in the past decade was approximately 5 billion kWh/year; however, the average annual energy generation growth for the past 20 years was around 30 billion kWh/year.
- Each EV has a charging demand of approximately 2.05 kilowatts (kW).
- By 2030, the low, medium, and high EV adoption scenarios will require 0.7, 4.5, and 14 gigawatts (GW) annually of added generation capacity respectively.

Based on these findings, the study concluded that increased EV adoption does not pose a threat to the U.S. electric power system as long as proper planning for EV adoption is performed.

2.1.3 Competitive Markets and Customer Choice

The Competitive Markets and Customer Choice (CMCC) Workgroup is charged with considering revisions to Maryland's retail choice electric and natural gas markets to promote competition. See Section 2.4.3 of CEIR-21 for background information on the CMCC Workgroup.

Passage of Senate Bill (SB) 1 by the Maryland General Assembly in 2024[13]

The enactment of SB 1 by the Maryland General Assembly in 2024 made sweeping changes to Maryland's competitive retail electricity market. Beginning in July 2025, SB 1 requires separate licenses by the Maryland PSC for both energy salespersons and for energy vendors. Energy salespeople must provide proof of association with a licensed electricity or natural gas supplier; documented compliance with training requirements; and proof of financial integrity, which may require the posting of a bond or comparable financial instrument at the discretion of the Maryland PSC. Energy vendors must hold a license from the Maryland PSC to operate in the state and pay a licensing fee. The term of the license for both energy salespeople and energy vendors is three years and can be renewed.

Suppliers of electricity to residential customers, except for green power, are limited to charging no more than the trailing 12-month average of the electric utility's SOS rate, and for a term of no longer than 12 months. Variable electricity rates are prohibited, other than for seasonal variations that can change

[12] Summary Report on EVs at Scale and the U.S. Electric Power System. USDRIVE. (2019), https://www.energy.gov/eere/vehicles/articles/summary-report-evs-scale-and-us-electric-power-system-2019

[13] All information in this section is sourced from Stephen M. Ross, *Fiscal and Policy Note for Senate Bill 1,* Maryland Department of Legislative Services, May 6, 2024, https://mgaleg.maryland.gov/2024RS/fnotes/bil_0001/sb0001.pdf.

twice per year. Electricity suppliers can renew a contract only after providing notices to customers 90 days and 30 days before renewal.

The Maryland PSC is required to hold an annual proceeding to set the price per MWh for green power that electricity suppliers serving residential customers cannot exceed, unless documentation is provided that shows the actual cost exceeds the green power price set by the Maryland PSC. Electricity suppliers cannot market green power unless the percentage of electricity or renewable energy credits exceeds the greater of 51% or 1% higher than the Maryland Renewable Energy Portfolio Standard (RPS) for a specific year.

2.1.4 Interconnection Process

The PSC tasked the Interconnection Workgroup with "implementing rules and policies to promote competitive, efficient, and predictable distributed energy resources (DERs) markets that maximize customers' choices."[14] The PSC, with assistance from the Interconnection Workgroup, has implemented five different rulemaking phases focused on improving interconnection of DERs, addressing interconnection costs and cost recovery, and adopting new smart inverter regulations. A detailed description of past efforts of the PSC and Interconnection Workgroup is available on Power Plant Research Program's (PPRP's) website.

In January 2024, the PSC adopted in regulation the Interconnection Workgroup's recommendations for Phase V:

- Adopt definitions for hosting capacity upgrade plan and rightsizing. A hosting capacity upgrade plan is a utility proposal to promote interconnection of clean energy facilities through proactive distribution investments. Rightsizing, in contrast, is more reactive and is focused on increasing the size, scope, and cost of a utility hosting capacity upgrade project in response to interconnection requests of distributed energy resources.
- Within one year, electric utilities must file, for PSC review and approval, a proposed primary voltage hosting capacity cost sharing and allocation methodology for interconnection customers.[15] The default methodology is based on locational pricing to encourage interconnection in areas with more available hosting capacity. Utilities can propose a hosting capacity cost sharing and allocation methodology that is not locational-based for "good cause."
- Similarly, utilities are required to submit, for PSC review and approval, a proposed hosting capacity cost sharing and allocation methodology for both residential and commercial interconnection customers operating on secondary voltage. There is not a location-based requirement for hosting capacity cost sharing and allocation for secondary voltage customers.
- Should there not be enough hosting capacity for either primary or secondary voltage interconnection customers, a utility may propose a hosting capacity upgrade project to the interconnection customer. For primary voltage interconnection customers, a utility can charge a hosting capacity fee equal to the interconnection customer's utilization of hosting capacity. Any

[14] Maryland Public Service Commission, Mail Log No. 199669, p. 3.

[15] Under Maryland PSC regulations for interconnection, primary voltage is defined as a distribution line or interconnection point rated greater than 600 kV. Secondary voltage interconnection customers have a point of interconnection at less than or equal to 600 kV.

unallocated hosting capacity upgrade costs for either primary or secondary voltage customers will be shared under a cost allocation methodology in the utility's tariff, as reviewed and approved by the PSC.

- Interconnection customers and utilities can enter into limited export agreements for managing the ramp rates and generation levels under specified operating conditions.
- Interconnection customers can also request a limited export agreement if they do not wish to pay any needed distribution system upgrade costs. Utilities are required to determine that an interconnection customer has the appropriate controls to prevent power exports. Utilities are also required to publish on their interconnection websites a description of their limited export agreement policies. Inadvertent exports from generators are limited to the generator's nameplate capacity multiplied by one hour per billing cycle.
- Meter collar adapters are permitted as long as they are approved or listed by a nationally recognized testing laboratory, that installations and service are performed by qualified entities agreed to between the utility and the meter collar manufacturer, and that the meter collar adapter does not obstruct access to the meter. Utilities can deny requests to install a meter collar adapter but must provide a written explanation as to why the request was denied. The meter collar adapter manufacturer may appeal a utility's decision to the PSC.[16]

Also in January 2024, the Workgroup launched Phase VI, which will address several issues such as implementation of FERC Order 222, interconnection process improvements, greater use of cluster studies, and improved reporting of curtailment of distributed energy resources.

Impact of PJM Generation Interconnection Queue on Development of Renewable Energy Projects

Before generators can be connected to the PJM Interconnection LLC (PJM) grid and begin operating, PJM conducts a series of studies to determine whether the generator can be interconnected reliably and to assess the cost responsibility if system upgrades are required. In all, PJM performs three studies:

1. A feasibility study that makes preliminary estimates of the type, scope, cost, and lead time for the development of any facilities needed to interconnect the project;
2. A system impact study that identifies system constraints resulting from the prospective addition of a new generating facility and the required local upgrades and network upgrades, as well as costs and construction lead time, for interconnecting the generator; and
3. A facilities study where a system stability analysis is conducted and the system impact study is amended as needed to account for changes to other projects in the PJM queue.

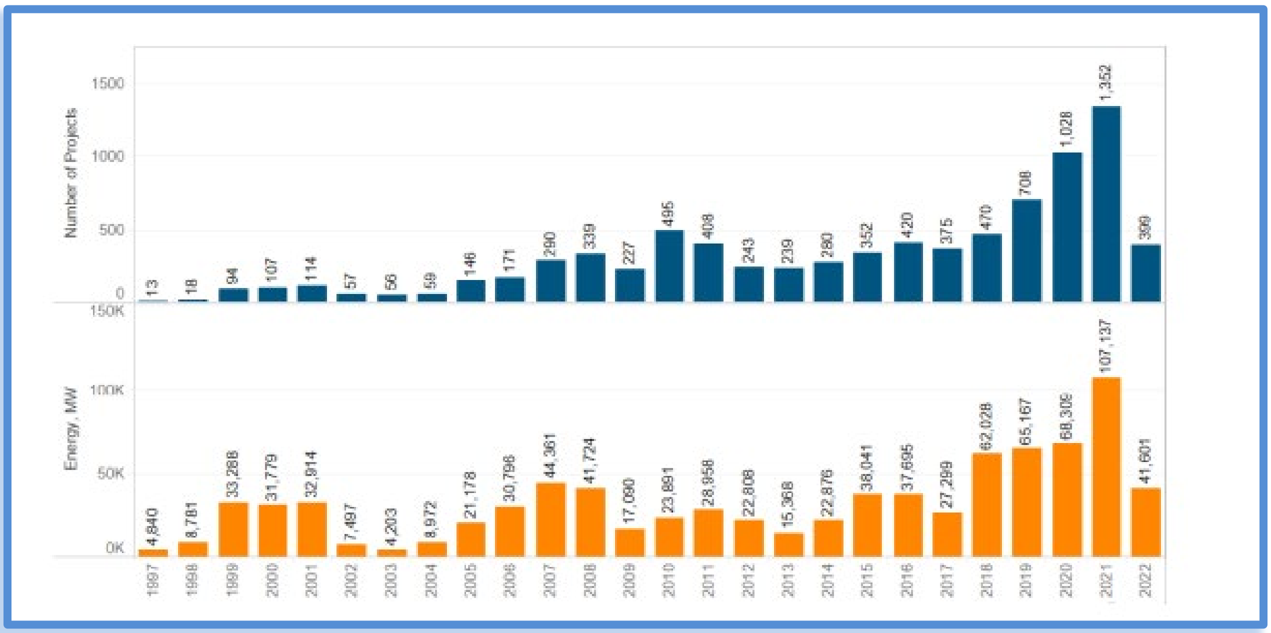
Should the studies find that a generator can be reliably interconnected, and there is agreement with PJM and the generator on the needed system upgrades and who pays, then the two parties enter into an

[16] Maryland Public Service Commission, Small Generator Interconnection Standards, Code of Maryland Regulations (COMAR) 20.50.09.02 through 20.50.09.14. To access, go to https://www.psc.state.md.us/ and click on "COMAR Title 20" under the "Quick Links" section. Meter collar adaptors are electronic devices installed between a residential electric meter and the meter socket for the purpose of facilitating the deployment and interconnection of an onsite electricity generation source or for the purpose of isolating a customer's electrical load to enable the provision of backup power.

interconnection service agreement (ISA). The ISA also defines any capacity interconnection rights a generator may have.

The declining costs of renewable energy and energy storage technologies, the expansion of state RPS policies (10 states in PJM have such policies), and federal policies such as the Inflation Reduction Act have all combined to lead to a sharp rise in interconnection applications at PJM, particularly among renewable energy and energy storage technologies, as indicated in Figure 2-1. The upper level of the figure represents the number of projects, while the bottom level represents capacity. The volume of interconnection requests caused PJM to fall behind in processing interconnection studies. That, in turn, forced PJM to seek waivers of deadlines and to be the recipient of multiple complaints filed at FERC.[17]

Figure 2-1 PJM Generation Queue by Capacity and Number of Projects, 1997–2022



Source: PJM, FERC Docket No. ER22-2110-000 and ER-2110-001, *Tariff Revisions for Interconnection Process Reform*, June 14, 2022.

Historically, PJM accepted interconnection requests during two six-month windows, from April 1st to September 30th of each year and from October 1st to March 31st of the following year. Interconnection customers were required to document site control only once when they submitted their interconnection service request. PJM would evaluate each interconnection application serially, and if proposed generating projects withdrew from the queue, then PJM would restudy the other proposed projects in the queue to determine whether there are any needed changes to system upgrades or cost responsibility because of that withdrawal. PJM asserted the relatively low study deposit and minimal site control requirements resulted in a large number of speculative projects to enter the interconnection queue and to stay in the queue with the hope that a higher-queued project would withdraw and, therefore, make their project more economically viable.

[17] PJM, FERC Docket No. ER22-2110-000 and ER-2110-001, Tariff Revisions for Interconnection Process Reform, June 14, 2022.

In 2020, PJM began a stakeholder process to overhaul PJM's generation interconnection process. Stakeholders reached consensus on a plan in April 2022, and by order issued November 29, 2022, FERC accepted for filing PJM's tariff revisions implementing the interconnection process reforms.[18] Beginning in 2026, PJM will transition to a cluster study process, allowing it to study multiple interconnection requests at a time instead of studying each project sequentially. Interconnection applicants will have three off-ramps to decide whether to stay in the interconnection queue or withdraw. Should they stay in the queue, then interconnection applicants will have steadily increasing security deposits equal to a percentage of the potential network upgrade costs. Another 450 projects are on a faster schedule as they require $5 million or less in network upgrades and consequently have relatively simple study requirements. Interconnection queue applications filed with PJM after October 2021 will not be evaluated until at least 2026. PJM will use the time before 2026 as a transition period to clear the backlog of existing interconnection requests, specifically applications that entered the PJM queue between April 2018 and September 2021. PJM had 229,538 MW of generating projects in the queue as of December 31, 2023, including 7,361 MW located in Maryland.[19]

PJM's issues with its interconnection queue have drawn national attention. The Natural Resources Defense Council (NRDC) completed an analysis[20] in 2023 of the impact of queue delays in PJM states on meeting RPS goals. The NRDC concluded that PJM queue reforms will narrowly provide enough renewable energy to meet RPS requirements by 2027 but are unlikely to meet total regional demand for new renewable energy capacity through 2030. In response to criticism of its interconnection review practices, PJM states that it expects to process about 72,000 MW in projects by mid-2025 and 230,000 MW over the next three years, with 90% of those projects powered by renewable energy or energy storage.[21]

FERC Order 2023

In July 2023, FERC issued Order 2023, a sweeping revamp of FERC's interconnection policies and requirements. The provisions in Order 2023 largely mirror what FERC approved in PJM's interconnection reform proposal. Specifically, Order 2023 requires transmission providers to study interconnection requests in a group (cluster) over a 150-day period. Any costs for upgrading the network identified during the cluster study are assigned to interconnection customers proportionally by how much each interconnection customer contributes to the need for an upgrade.

Order 2023 also calls for increased financial deposits and proof of site control. For deposits, interconnection customers must pay a deposit to transmission providers to cover the interconnection study costs and a commercial readiness deposit for each phase (feasibility, system impact, and facilities impact) of the cluster study. As the cluster study proceeds, the deposit transitions from capacity-based to one based on the interconnection customer's documented network upgrade costs. Transmission

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[18] FERC, *Order Accepting Tariff Revisions Subject to Condition*, Docket Nos. ER22-2110-000, ER22-2110-001, 181 FERC ¶ 61,162, November 29, 2022.

[19] https://www2.pjm.com/-/media/library/reports-notices/testimony/2024/20240111-haque-maryland-senate-energy-education-environment-committee-presentation.ashx

[20] https://www.nrdc.org/press-releases/pjm-interconnection-delays-threaten-state-renewable-goals

[21] Ethan Howland, "ERCOT, CAISO offer best grid interconnection processes; PJM, ISO-NE the worst, report finds," *Utility Dive,* February 26, 2024, https://www.utilitydive.com/news/ercot-caiso-pjm-grid-interconnection-queue-scorecard-advanced-energy-aeu/708450/.

providers can levy a withdrawal penalty if it can be shown that the withdrawal has a material impact on the cost or timing of any interconnection requests with an equal or lower queue position.

A notable difference between Order 2023 and FERC's order approving the PJM Interconnection Reforms is the imposition of penalties on transmission providers if they do not complete interconnection studies on time. Previously, transmission providers were held to a "reasonable effort" standard, but Order 2023 eliminates that standard. Additionally, transmission providers must notify other nearby transmission providers, or "affected systems," of interconnection service requests, and the affected system must announce its plans to do (or not do) its own cluster study. Finally, Order 2023 requires transmission providers to consider alternative transmission technologies when conducting a cluster study, such as advanced conductors or advanced power flow control, and strengthens modeling requirements for non-synchronous generating facilities such as wind or solar.[22]

2.1.5 Energy Storage

The Energy Storage Workgroup was tasked with (1) facilitating increased understanding of energy storage; (2) exploring how energy storage may be used by individual customers and as a distribution grid asset; and (3) evaluating the criteria to be used when determining whether a utility should use energy storage as a distribution asset, and if so, how the utility should be compensated for the investment. See Section 2.4.5 of CEIR-21 for background information on the initial Energy Storage Workgroup.

Maryland's largest grid-scale battery is the 10 MW Warrior Run Battery Facility. The facility is co-located with the 205 MW, coal-fired Warrior Run Plant in Cumberland, Maryland. The lithium-ion battery facility, owned by AES Corporation, became operational in November 2015. The project is interconnected at the transmission level and provides frequency regulation services to PJM. The modular design is considered to be unique as it can be separated into various configurations. The facility is considered to be a 20 MW flexible resource because the batteries can absorb a total of 10 MW of excess power from the grid or supply up to 10 MW to the grid. Depending on the configuration, the facility can provide output ranging from 15 minutes to four hours.

Energy Storage Pilots

The Maryland General Assembly enacted SB 573 during the 2019 legislative session. The bill required the PSC to establish an energy storage pilot program with pilot projects ranging between 5 MW and 10 MW. Additionally, SB 573 required each investor-owned utility (IOU) to solicit offers for each of the ownership models: utility only, utility and third party, and third-party ownership. SB 573 required the energy storage pilot projects to come online by February 28, 2022 but gave the PSC authority to grant extensions based on good cause.

In all, the PSC has approved 29.6 MWh of energy storage pilot projects. The status of each Pilot Program storage project is as follows:

- BGE Fairhaven Energy Storage Project: In Operation

[22] FERC, "Explainer on the Interconnection Final Rule," https://www.ferc.gov/explainer-interconnection-final-rule. Accessed March 14, 2024.

- BGE Chesapeake Energy Storage Project: In Operation
- DPL Ocean City battery energy storage system (BESS) Project: Request submitted to the PSC on January 5, 2024, to extend the operational deadline to December 30, 2024
- DPL Elk Neck Project: In Operation
- Potomac Edison (PE) Myersville BESS Project: In Operation
- Pepco Bus Depot Project: In Operation
- PE Town Hill: Request submitted to the PSC on January 10, 2024, to extend the operational deadline to July 1, 2024
- Pepco National Harbor/Livingston Road: A request to amend a PSC Order (No. 89664) to reject the project is pending before the PSC.

Maryland Energy Storage Program Working Group

On May 8, 2023, the Maryland General Assembly enacted House Bill 910, amending §7-216 and promulgating §7-216.1, directing the PSC to establish a Maryland Energy Storage Program (MESP) that provides a competitive energy storage procurement program. The statute sets goals for cost-effective energy storage of 750 MW by the end of the 2027 PJM delivery year; 1,500 MW by the end of the 2030 PJM delivery year; and 3,000 MW by the end of the 2033 PJM delivery year.[23] If the goals cannot be met cost-effectively, then the PSC is charged with reducing the goal to the maximum cost-effective amount for the particular PJM delivery year. The PSC may adopt the following:

- A system of energy storage credits and market-based incentives.
- A requirement that investor-owned electric companies install or contract for energy storage devices or contract for energy storage credits from an energy storage project under the MESP.
- A requirement that program participants make reasonable efforts to apply for all applicable State and federal grants, rebates, tax credits, loan guarantees, and other similar benefits as the benefits become available, or
- Any other mechanism or policy that PSC determines is appropriate to achieve the goal of a robust cost-effective energy storage system in Maryland.

The MESP Workgroup was established on October 2, 2023, to develop a consensus proposal for the establishment of the MESP that aligns with the requirements of §7-216.1. The Workgroup submitted an interim report to the PSC on December 15, 2023[24], that covered 46 MESP design questions and the general architecture of the MESP. The Workgroup did not reach consensus on several design issues and referred the following questions to the PSC for further guidance:

1. Does the definition of "energy storage device" include thermal storage and hydrogen-based storage?

[23] The PJM delivery year is from June 1 through May 30 of the following year. PJM sometimes also calls the delivery year the "planning year."

[24] https://webpsc.psc.state.md.us/DMS/case/9715

2. Will only new-build energy storage resources be eligible to contribute toward the statutory deployment goals?
3. What criteria will be used to define "deployed" or "installed" energy storage assets?
4. What is the appropriate term and definition for "EV V2G" or "mobile batteries"?
5. How will "Pumped Hydro" be defined and will it be eligible to contribute to the statutory energy storage goals?
6. What's the vision that fully describes the role that energy storage will play in the Maryland electrical system by 2033 and how will the MESP achieve that vision?
7. Should incremental maintenance and construction requirements be imposed by the MESP on applicants, beyond those needed for adherence to standards, local permitting requirements, and CPCN conditions?

Additionally, the MESP Workgroup is considering three different mechanisms for promoting energy storage. The mechanisms are competitive solicitations, grid services programs, and deployment incentives. The MESP Workgroup is considering these mechanisms for three different market segments defined as behind-the-meter, front-of-the-meter distribution, and front-of-the-meter transmission energy storage facilities. The MESP Workgroup believes any energy storage program launched by the PSC should be organized by market segment, with each segment having its own mix of mechanisms to achieve deployment. This includes funding sources, rules regarding ownership models, rules regarding safety and environmental standards, methodology for evaluating cost-effectiveness, and equity considerations that are built into the program. The MESP Workgroup further believes that multiple mechanisms should be offered for each market segment and plan to rely upon program performance evaluations and market data to judge the impact of each mechanism.[25]

The Workgroup is charged with providing a report to the PSC containing MESP designs and a proposed petition for rulemaking by October 1, 2024. By statute, the PSC must launch an energy storage program by July 1, 2025.

2.1.6 Distribution System Planning

The Distribution System Planning (DSP) Workgroup discusses the components of distribution planning and identifies key topics the PSC should focus on. The PSC convened the DSP Workgroup in response to a Task Force on Comprehensive Electricity Planning (Task Force) formed by the National Association of Regulatory Utility Commissioners (NARUC) and the National Association of State Energy Officials (NASEO), This Task Force developed recommendations for states to both increase involvement in distribution system planning and to further align planning processes with state goals and the proliferation of distributed energy resources. In June 2021, the PSC initiated Case No. 9665, authorizing the DSP Workgroup to conduct a comprehensive examination of Maryland utility planning practices (PSC Order 89865). Subsequently, with the passage of the Climate Solutions Now Act in 2022, the PSC was charged with developing specific policies for distribution system planning and

[25] Maryland Public Service Commission, *Maryland Energy Storage Program 2023 Status Report*, Submitted to the Maryland General Assembly Annapolis, Maryland. In compliance with HB 910 of Public Utilities Article, Annotated Code of Maryland, December 27, 2023. Available under the "MESPWG" folder at https://www.psc.state.md.us/electricity/working-groups/.

improvements to facilitate electrification across Maryland, improve distribution resilience and reliability, and enhance stakeholder involvement. (PSC Order 90777, Maillog 304701) As a result of further legislative activity in 2024, the Maryland General Assembly broadened its charge to the PSC from a focus on distribution system planning to overall electric system planning. The DSP Workgroup filed its final report in April 2024 in Case 9665, and the PSC issued subsequent analysis and findings (Order No. 91256, July 30, 2024). The PSC Order requires Maryland utilities to report annually on actions taken to support the State's clean energy policies through electric system improvements, and for the DSP Workgroup to develop a consistent framework for such utility reporting.

2.2 Recent Federal Legislation

The Bipartisan Infrastructure Law

The Bipartisan Infrastructure Law (BIL) was passed in November 2021, to help fund projects that strengthen resilience to extreme weather and climate change while reducing greenhouse gas emissions. The BIL includes funding for the following categories of energy investments[26]:

- **Clean Energy Transmission:** A new Grid Deployment Authority at DOE will invest in research and development for advanced transmission and electricity distribution technologies. The Authority will also invest in demonstration projects and research hubs for advanced nuclear reactors, carbon capture, and clean hydrogen.
- **Electric Vehicle Infrastructure:** The BIL invests $7.5 billion to build out a national network of EV chargers to accelerate the adoption of EVs.
- **Clean School Buses:** The BIL will deliver thousands of electric school buses nationwide, including in rural communities.
- **Zero-emission Buses:** The BIL invests in zero- and low-emission school buses, in addition to more than $5 billion in funding for public transit agencies to adopt low- and no-emissions buses.
- **Transmission Facilitation Program:** The BIL will invest $2.5 billion to support the construction of nationally significant transmission lines, increase grid resilience, and improve access to clean energy sources.
- **National Interest Electric Transmission Corridors:** The Secretary of Energy is also authorized to designate geographic areas as National Interest Electric Transmission Corridors (NIETCs) based on recommendations from DOE's National Transmission Needs Study; public comment from states, tribes, industry, and stakeholders; transmission capacity constraints or congestion that are (or could be) detrimental to consumers; and existing or planned transmission projects in the area. Such a designation can make an area eligible for funding from the Transmission Facilitation Program and DOE's $2 billion Transmission Facility Financing Loan Program. A NIETC designation also gives FERC authority to issue permits for siting transmission lines where state siting authorities do not have the authority to site a transmission

[26] FACT SHEET: The Bipartisan Infrastructure Deal Boosts Clean Energy Jobs, Strengthens Resilience, and Advances Environmental Justice | The White House

line, have not acted on an application for over one year, or have denied a transmission siting application.[27]

- **Smart Grid Investment Matching Grant Program:** The BIL invests $3 billion in expanding this program, focusing on investments that improve the grid's flexibility.[28]
- **Hydroelectric Incentives Program:** The BIL allocates $754 million to support a comprehensive hydroelectric incentive program. The program includes $125 million for hydroelectric production incentives, $75 million for hydroelectric efficiency improvement incentives, and $554 million for maintaining and enhancing hydroelectricity incentives.[29]
- **Civilian Nuclear Credit Program:** The BIL allocates $6 billion to prevent the premature retirement of existing nuclear power plants. Owners or operators of commercial U.S. reactors can apply for certification to bid on financial credits to support their continued operations. Credits are dispersed over four years and can be distributed through September 30, 2031, if funds are still available. Applicants must show that the nuclear plant is expected to retire because of economic reasons and that closure will lead to an increase in air pollutants.[30]
- **Clean Energy Demonstrations and Research Hubs:** The BIL provides $21.5 billion in funding to help develop the next generation of technologies needed to achieve the goal of a net-zero-carbon economy by 2050. The funding includes $8 billion for clean hydrogen; $10 billion for carbon capture, direct air capture, and industrial emissions reduction; $2.5 billion for advanced nuclear; and $1.5 billion for demonstration projects in rural/economically hard-hit areas.[31]

The Inflation Reduction Act

The Inflation Reduction Act (IRA) was passed in 2022 and is frequently characterized as the most ambitious climate legislation in U.S. history. The IRA offers a myriad of federal tax incentives, guaranteed loans, and direct payments to governmental entities for investments in clean energy projects such as wind, solar combined heat and power, energy storage, and hydrogen energy and related infrastructure. In all, the IRA is projected to provide $369 billion in spending for clean energy technologies and climate protection investments.[32] A non-exhaustive list is provided following.

[27] National Interest Electric Transmission Corridor Designation Process | Department of Energy

[28] DOE Fact Sheet: The Bipartisan Infrastructure Deal Will Deliver For American Workers, Families and Usher in the Clean Energy Future | Department of Energy

[29] Biden-Harris Administration Opens Hydroelectric Production Incentives Application Period to Support Hydropower Facilities Across the Country | Department of Energy

[30] U.S. Department of Energy, Grid Deployment Office, "Civilian Nuclear Credit Program," https://www.energy.gov/gdo/civil-nuclear-credit-program. Accessed March 18, 2024.

[31] DOE Fact Sheet: The Bipartisan Infrastructure Deal Will Deliver For American Workers, Families and Usher in the Clean Energy Future | Department of Energy

[32] White House Fact Sheet: One Year In, President Biden's Inflation Reduction Act is Driving Historic Climate Action and Investing in America to Create Good Paying Jobs and Reduce Costs, August 16, 2023, https://www.whitehouse.gov/briefing-room/statements-releases/2023/08/16/fact-sheet-one-year-in-president-bidens-inflation-reduction-act-is-driving-historic-climate-action-and-investing-in-america-to-create-good-paying-jobs-and-reduce-costs/.

- The IRA extends the production tax credit (PTC) and investment tax credit (ITC) for eligible technologies through 2024, after which a clean electricity PTC and a clean electricity ITC take effect.
- For both the PTC and ITC, the IRA offers a base ITC of 6% that increases up to 30% if the project meets prevailing wage and apprenticeship requirements. Energy storage projects under 1 MW of storage capacity qualify for the 30% bonus rate regardless of compliance with the prevailing wage and apprenticeship requirements.[33] The following additional bonus credits are also available[34]:
    - If the project meets the 40% minimum domestic content requirement (i.e., defined as any steel, iron, or manufactured product that is a component of the project and was produced in the United States), a 10% bonus credit would increase the total tax credit to 40%.[35]
    - If the project is sited in an Energy Community (defined as a census tract where a coal mine was closed or a coal-fired electric generation unit was retired after December 31, 2009),[36] an additional 10% bonus credit would increase the total tax credit to 50%.
    - The IRA added a provision to allow taxable entities to transfer the ITC to an unrelated third party in exchange for cash that will not be included in the entity's gross income. This will create a new tax credit transfer market and potentially impact project financing if sponsors elect to simply monetize the ITC.37
    - The IRA also includes a tax credit of up to $3 per kilogram (kg) for clean hydrogen and up to $85/ton of carbon dioxide (CO_2) captured and sequestered.
    - The IRA also authorized an additional $40 billion to the DOE Loan Programs Office for issuing new loan guarantees in support of innovative energy or supply chain projects.
    - EPA is providing $27 billion in funding for grants to support clean energy and climate projects that reduce greenhouse gas emissions, with a focus on projects that benefit low-income and disadvantaged communities.

DOE estimates that the IRA and the BIL are projected to result in 2030 economy-wide greenhouse gas (GHG) emissions 40% below 2005 levels. Specifically, DOE projects that the two laws could help decrease GHG emissions by about 1,150 million metric tons of carbon dioxide equivalent (CO_2e) in 2030, in comparison to a business-as-usual scenario.[38] Researchers at Princeton University calculated

[33] Inflation Reduction Act Creates New Tax Credit Opportunities for Energy Storage Projects | McGuireWoods

[34] Summary of Inflation Reduction Act provisions related to renewable energy | US EPA

[35] IRS Releases Highly Anticipated Guidance on Domestic Content IRA Tax Credit 'Adder' – Publications (morganlewis.com)

[36] https://www.sierraclub.org/sites/default/files/2023-08/2675%20IRA-EnergyCommunities_FactSheet.pdf

[37] Inflation Reduction Act Creates New Tax Credit Opportunities for Energy Storage Projects | McGuireWoods

[38] U.S. Department of Energy, Office of Policy, The Inflation Reduction Act Drives Significant Emissions Reductions and Positions America to Reach Our Climate Goals, August 2022, https://www.energy.gov/sites/default/files/2022-08/8.18%20InflationReductionAct_Factsheet_Final.pdf

that the IRA would reduce economy-wide carbon emissions by 43% to 48% below 2005 levels by 2035.[39]

The Section 45Q Tax Credit for Carbon Sequestration[40]

Carbon capture and sequestration (CCS) technologies capture CO_2 emissions from fossil fuel–fired combustion sources or from the atmosphere using direct air capture technology. The captured CO_2 is either injected into underground geological formations, where it is permanently trapped or used as a feedstock in commercial products[41]. The tax credit for carbon sequestration or utilization is referred to using its Internal Revenue Code (IRC) section, Section 45Q. It is intended to incentivize investment in carbon capture, sequestration, and utilization technologies. The amount that a taxpayer may claim as a Section 45Q tax credit is computed per metric ton of qualified carbon dioxide captured or used and can range from a base credit of $45 per ton up to $180 per ton from CO_2 from direct air capture facilities.

2.3 Environmental Justice

At the federal level, environmental justice is defined as "the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies".[42] President Clinton's Executive Order (EO) 12898 "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations" is still the primary guidance at the federal level for addressing environmental justice. In April 2023, President Biden released EO 14096 "Revitalizing our Nation's Commitment to Environmental Justice for All," which reaffirmed the federal government's commitment to environmental justice, particularly meaningful engagement with communities facing environmental justice concerns.

Maryland state law defines environmental justice as "equal protection from environmental and public health hazards for all people regardless of race, income, culture, and social status".[43] DNR has a commitment to diversity, equity, inclusion, and justice that in part focuses the department on building relationships with underrepresented groups, including communities of color and low-income neighborhoods, and incorporating their knowledge into decision making.[44]

Historically, throughout the United States, industrial infrastructure and hazardous pollutant emitting facilities have been located, either intentionally or through neglect, within minority, low-income, and other marginalized communities. By conducting an environmental justice analysis, PPRP aims to ensure

[39] Bistline, J., et. al, "Emissions and energy impacts of the Inflation Reduction Act," Science, June 29, 2023, https://www.science.org/doi/full/10.1126/science.adg3781.

[40] IF11455 (congress.gov)

[41] See Section 45Q(f)(5), 2021-00302.pdf (govinfo.gov)

[42] https://www.epa.gov/environmentaljustice#:~:text=Environmental%20justice%20is%20the%20fair,laws%2C%20regulations%2C%20and%20policies

[43] https://mde.maryland.gov/Environmental_Justice/Pages/Landing%20Page.aspx

[44] https://dnr.maryland.gov/education/Pages/Environmental-Justice.aspx

that future power plant and transmission projects do not exacerbate conditions in communities already facing outsized burdens to their environment or health.

An environmental justice analysis for a proposed project firstly identifies groups located near a project site that are vulnerable because of their background, race, income, cultural, or social status. Secondly, the analysis seeks to determine whether negative environmental consequences resulting from the project would disproportionately affect any of these groups. Finally, a robust environmental justice analysis also promotes meaningful involvement with the communities with environmental justice concerns in the decision-making process that could affect their environment and health.

Under Code of Maryland Regulations (COMAR) 20.79.01.04 "Pre-Application Requirements for a Qualifying Generating Station," prior to filing an application for a Certificate of Public Convenience and Necessity for the construction of a new qualifying generating station, the applicant should engage with affected communities and use EJSCREEN, an environmental justice mapping and screening tool developed by EPA. A copy of the EJSCREEN report is required as part of the qualifying generating station CPCN application, under COMAR 20.79.03.05. "Qualifying generation station" is defined as a fossil fuel generator with nameplate capacity greater than 70 MW.

However, as a conservative best practice, PPRP assesses environmental justice impacts from all projects under their purview, regardless of whether they are qualifying generating stations. As such, PPRP has used COMAR guidelines to assess environmental justice on proposed transmission lines and generation projects less than 70 MW, including solar projects.

In its assessment of applications, PPRP uses EJSCREEN data to understand the community makeup within a 3-mile radius of the proposed project, including the presence of minority and low-income populations at the census block group (CBG) level. CBG is the smallest unit of community makeup the U.S. Census Bureau measures and typically includes between 600 and 3,000 people.[45] Using EJSCREEN, a typical environmental justice assessment also considers existing conditions, such as whether the area is historically a site of industrial development or if there are pre-existing heavy polluters in the area. To determine this, PPRP uses EJSCREEN's pollution and sources variables to see how the area around the proposed project compares to the rest of the state in terms of existing pollution burden. The assessment also addresses other vulnerable populations, such as proximity to hospitals and incarcerated individuals, to best inform project impacts on communities with environmental concerns.

After using EJSREEN to establish a baseline of the surrounding community and understand the presence, or lack thereof, of communities with environmental justice concerns, PPRP assesses whether the proposed project would have an effect on those communities. This effect can be beneficial or adverse and can range from insignificant to significant.

Recent environmental justice policy advances in Maryland include the development of a state-level screening tool by the Maryland Department of Environment (MDE) . The MDE EJ Screening tool uses MDE-specific variables (such as proximity to active high-emission facilities) in addition to demographic and socioeconomic data. The tool uses the definition of an overburdened community to calculate pollution burden exposure, pollution burden environmental effects, and sensitive populations, whereas the definition of an underserved community is used to calculate socioeconomic/demographic indicators.

[45] https://www.census.gov/programs-surveys/geography/about/glossary.html#par_textimage_4

The state-level tool may be used in addition to the Environmental Protection Agency's (EPA's) EJSCREEN to identify vulnerable populations. Recognizing where environmental justice populations may overlap with other forms of vulnerability—whether categorized as disadvantaged, underserved, or overburdened—is helpful to understand the context of potential impacts to a community.

Chapter 3 – Power Generation, Transmission, and Use in Maryland

As a basis for discussing the impacts of power plants in Maryland, it is helpful to understand how electricity is generated, transmitted, and used within the state. This chapter provides information on the electric industry in Maryland, from generation to final consumption.

Maryland's electricity industry is functionally separated into three lines of business: generation and supply, transmission, and distribution (see sidebar). While customers are billed for each of these three separate functions, most only receive one consolidated electric bill. The generation and supply of electricity are not price-regulated in Maryland; prices are established by the competitive wholesale and retail electricity markets. Retail competition for power supply provides Maryland consumers with an opportunity to choose their own electricity suppliers. For more information about electric choice, visit the Maryland Public Service Commission (PSC) website.

The high-voltage bulk electric transmission system is a monopoly function, regulated by the Federal Energy Regulatory Commission (FERC), and the distribution of electricity is a monopoly function provided by local utilities. It is therefore subject to price and quality-of-service regulation by the PSC.

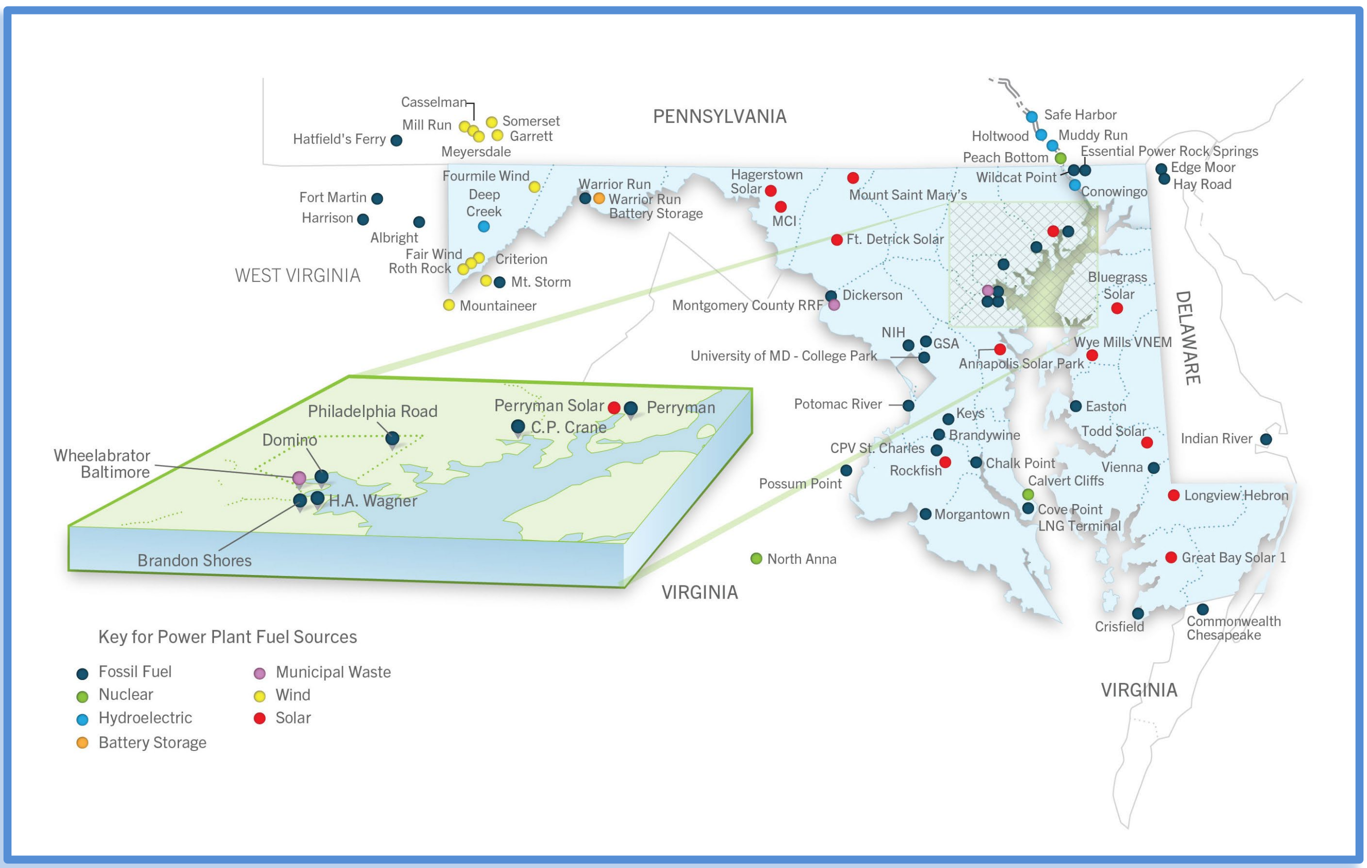
Maryland's Electricity Market

- **Generation** companies produce power to be sold in the wholesale marketplace. Generation of electricity is a competitive industry in Maryland (i.e., It is not subject to price regulation). Retail power supply to end–use customers is also competitive, allowing consumers to choose their own supplier.
- **Transmission** is the high–voltage, long–distance movement of power, while **distribution** is the low–voltage, local delivery of power.
- **Transmission** and **distribution** of electricity continue to be provided by local utilities within their various franchised service territories

3.1 Electricity Generation in Maryland

Currently in Maryland, 43 power plants with generation capacities greater than 10 megawatts (MW) are interconnected to the regional transmission grid. Table 3-1 lists the individual power plant sites. Figure 3-1 shows the plant locations. In aggregate, these 43 Maryland power plants represent just over 15,000 MW of operational capacity. The largest portion of Maryland's generating capacity comes from fossil fuels (see Figure 3-2), with the remainder attributed to nuclear and renewables. With the addition of 3,464 MW of natural gas capacity in 2017 and 2018, and the retirement of coal plants throughout the decade, there has been a significant shift between coal and natural gas generation within the state, as noted in Figure 3-2. Since 2016, natural gas capacity increased approximately 58% and natural gas generation increased 160%, while the capacity of coal has decreased almost 23% and generation has declined by 76%.

Figure 3-1 Power Plants in Maryland



Note: The coal-fired C.P. Crane facility in Baltimore County ceased operation in May 2018; the owner has received a Certificate of Public Convenience and Necessity (CPCN) to construct and operate a new 160 MW natural gas-fired facility at the existing site. Coal-fired units Dickerson and Chalk Point were decommissioned in August 2020, and June 2021, respectively.

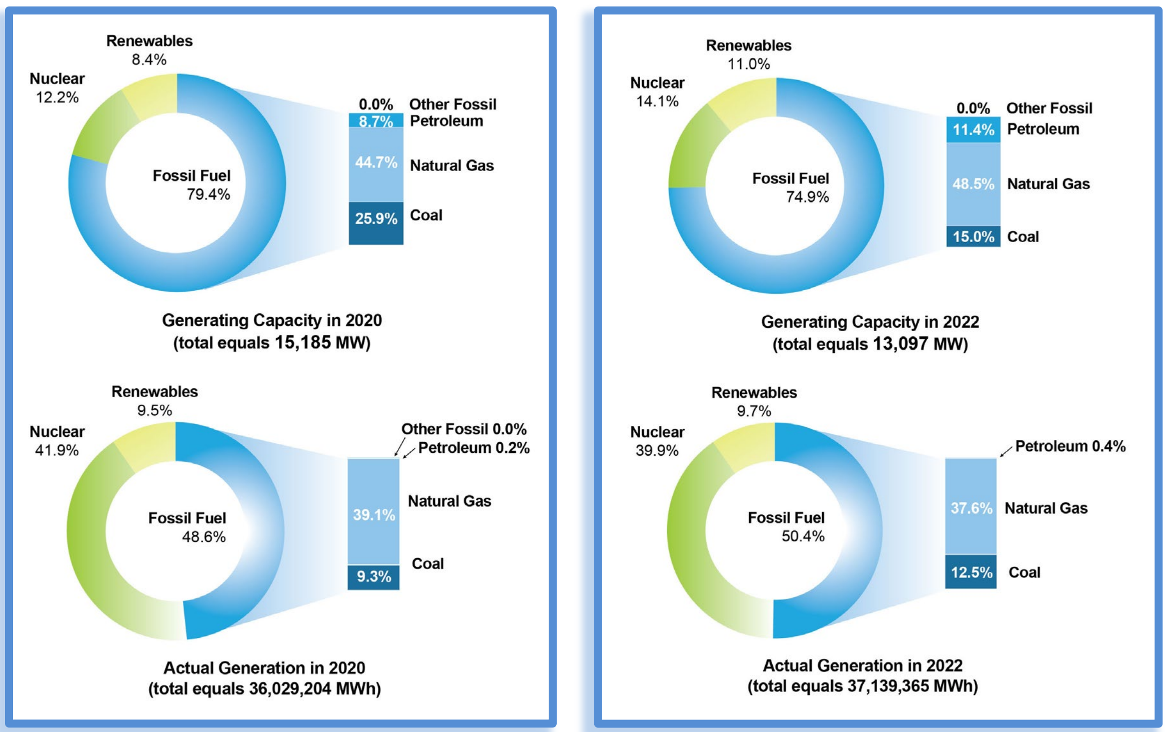
Table 3-1 Operational Generating Capacity in Maryland, December 2022 (10 MW or greater)

Owner	Plant Name	Fuel Type	Nameplate Capacity (MW)
INDEPENDENT POWER PRODUCERS			
AES Enterprise	Warrior Run	Coal	229
AES Tait LLC	AES Warrior Run Energy Storage Project	Batteries	11
Annapolis Solar Park, LLC	Annapolis Solar Park LLC	Solar	12
Berkshire Hathaway's Dominion Cove Point LNG, LP	Cove Point LNG Terminal	Natural Gas/Oil/other	229
Bluegrass Solar, LLC	Bluegrass Solar	Solar	80
BP Piney & Deep Creek, LLC	Deep Creek	Hydroelectric	20
Brandon Shores LLC	Brandon Shores	Coal	1,370
Calpine Corporation	Crisfield	Oil	12
CD Arevon USA, Inc.	Maryland Solar, Located at Maryland Correctional Institute (MCI)	Solar	27
Constellation Energy Corporation*	Calvert Cliffs Nuclear Power Plant	Nuclear	1,850
	Conowingo	Hydroelectric	531
	Criterion Wind Park	Wind	70
	Fair Wind Power Partners	Wind	30
	Fourmile Ridge	Wind	40
	Mount Saint Mary's	Solar	14
	Perryman	Oil/Natural Gas	492
	Perryman Solar	Solar	17
	Philadelphia Road	Oil	83
Covanta	Montgomery County Resource Recovery Facility (RRF)	Waste	68
CPV Maryland LLC	CPV St. Charles Energy Center	Natural Gas	775
Essential Power Rock Springs LLC (Carlyle Group LP)	Essential Power Rock Springs LLC	Natural Gas	773
GenOn Chalk Point, LLC***	Chalk Point LLC	Coal/Oil/Natural Gas	2,647
GenOn Mid-Atlantic LLC***	Dickerson**	Oil/Natural Gas	345
	Morgantown Generating Plant	Coal/Oil	1,548
Gestamp Wind	Roth Rock Wind Facility	Wind	50
Great Bay Solar 1 LLC	Great Bay Solar 1	Solar	75

Owner	Plant Name	Fuel Type	Nameplate Capacity (MW)
H.A. Wagner LLC	Herbert A Wagner	Coal/Oil/Natural Gas	923
Invenergy Services, LLC	Todd Solar	Solar	20
KMC Thermo LLC	Brandywine	Natural Gas	289
LaFarge Holcim	Hagerstown Solar	Solar	10
Marina Energy LLC	Longview Solar – Hebron	Solar	14
Maryland Economic Development Corporation	University of Maryland – College Park	Natural Gas	27
Montevue Lane Solar, LLC	Fort Detrick Solar PV	Solar	16
NRG Energy	Vienna	Oil	181
Pepco Energy Services	National Institutes of Health (NIH)	Natural Gas	28
PSEG Keys Energy Center, LLC	Keys Energy Center	Natural Gas	831
Rockfish Solar LLC	Rockfish Solar LLC	Solar	10
Tesla, Inc.	Wye Mills VNEM	Solar	10
Wheelabrator Technologies	Wheelabrator Incinerator	Waste	65
PUBLICLY OWNED ELECTRIC COMPANIES			
Easton Utilities	Easton	Oil/Biodiesel	72
Old Dominion Electric Cooperative and Essential Power	Wildcat Point Generation Facility	Natural Gas	1,114
SELF-GENERATORS			
American Sugar Refining Co.	Domino Sugar	Natural Gas	10
GSA Metropolitan Service Center	Central Utility Plant	Oil/Natural Gas	54
Total:			**15,072**

* Capacity figures for Exelon-owned facilities were provided by Exelon Generation. Note that Exelon Corporation separated into two publicly traded companies in early 2022, with the power plant business (including nuclear) operating under the name Constellation Energy Corporation.
** Dickerson decommissioned its coal units in August 2020.
***GenOn is a subsidiary of NRG.
Source: U.S. Energy Information Administration, Form EIA-860, 2020 Final Release.

Figure 3-2 Power Plant Capacity and Generation in Maryland by Fuel Category, 2020 compared to 2022



Source: 2020 data "Existing Nameplate and Net Summer Capacity by Energy Source, Producer Type, and State (EIA-860)," U.S. Energy Information Administration (EIA), 2020 Final Release; "Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923)," U.S. Energy Information Administration, 2020 Final Release.
2022 data: "Existing Nameplate and Net Summer Capacity by Energy Source, Producer Type, and State (EIA-860)," U.S. Energy Information Administration, 2022 Final Release; "Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923)," U.S. Energy Information Administration, 2022 Final Release

Note: EIA data for generation contain the fossil fuel category, "Other," which is not included in EIA data for capacity.

3.1.1 Fossil Fuels

In Maryland, coal, natural gas, and petroleum are the fossil fuels used to produce electricity. Due to the steep price declines in recent years, the primary fuel used for electricity in Maryland is natural gas.

Coal

In 2022, Maryland consumed 1.8 million tons of coal for electricity generation, which was a decrease of 24% compared to 2021. Most Maryland power plants cannot efficiently burn coal mined in the state because they were designed for coal with higher volatility characteristics, which allows for it to ignite more easily. Based on 2022 data, 100% of the coal received by Maryland plants was mined in the Appalachia region of the United States. Table 3-2 lists the amount of coal received at each power plant in 2022. According to the U.S. Energy Information Administration (EIA), the average cost of coal delivered for electricity generation in the South Atlantic region of U.S. was $3.12 per million British thermal units (MMBtu) for 2022, a 29% increase over 2021.[46]

Table 3-2 Tons of Coal Purchased at Maryland Power Plants in 2022

Origin of Coal	Brandon Shores	Morgantown	Warrior Run	Total by Source
Appalachia	886,274	273,563	659,437	1,819,274
Percentage of Total	49%	15%	36%	100%

Source: U.S. Energy Information Administration, Fuel Receipts and Cost Time Series File, 2022 Final Data.

Natural Gas

In 2022, approximately 99.1 billion cubic feet (Bcf) of natural gas was used for electricity generation in Maryland, representing 33% of the total statewide consumption of natural gas for all uses.[47] Slightly more natural gas was used for electricity generation in Maryland in 2022 than in 2021 (98.6 Bcf), but the percentage share of natural gas for power generation was a little higher at 37% in 2021, as total natural gas consumption in Maryland was higher in 2022 (301 Bcf) versus 2021 (288 Bcf).

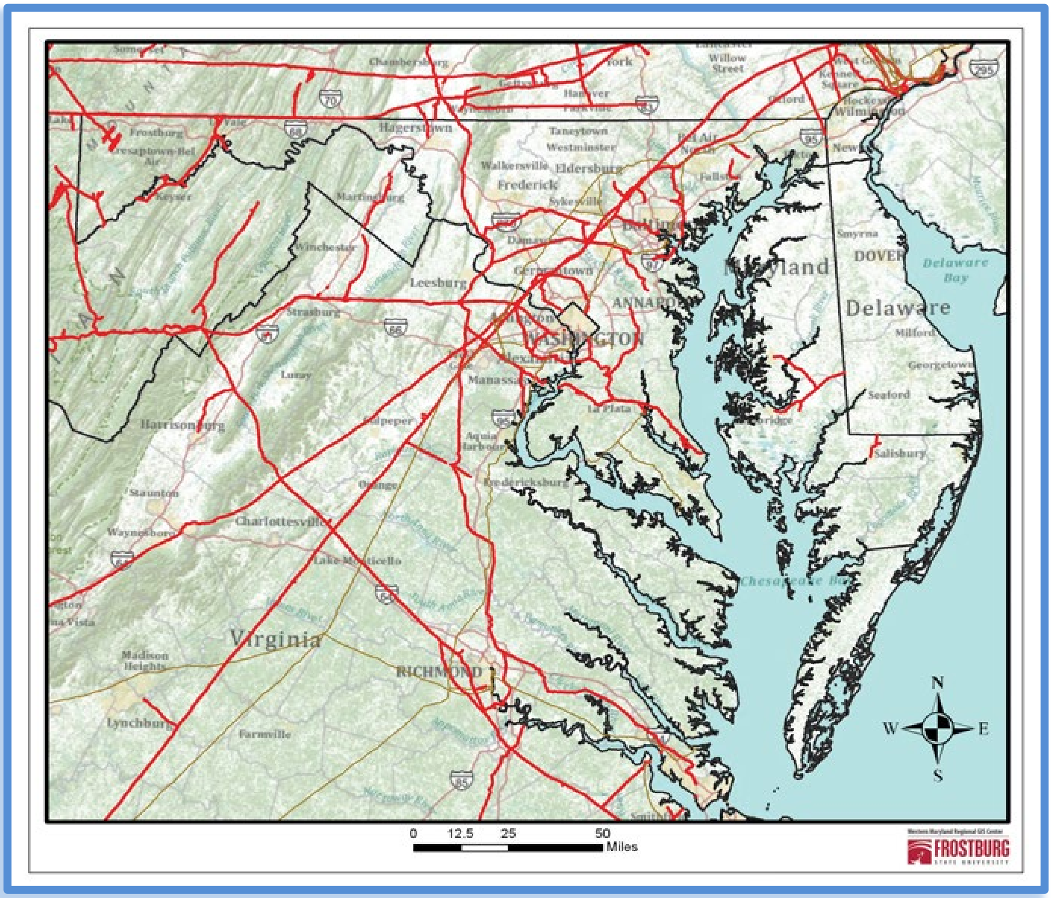
Currently, Maryland receives natural gas from several interstate pipelines that traverse the state (see Figure 3-3). Interstate gas suppliers operate storage areas, usually in depleted production fields, where natural gas can be accumulated during low demand periods and released during high demand periods. Maryland has one such storage area, Accident Dome in Garrett County, with a storage capacity representing 2% of the underground gas storage capacity in the region (which includes Maryland, New Jersey, Pennsylvania, Virginia, and West Virginia). Other potentially suitable storage sites may also exist in Western Maryland.

See PPRP's website Electricity Generation in Maryland section for additional information on natural gas.

[46] U.S. Energy Information Administration, "Table 7.17. Average Cost of Coal Delivered for Electricity Generation by State, 2022 and 2021," *Electric Power Annual 2022*, October 19, 2023, https://www.eia.gov/electricity/annual/html/epa_07_17.html.

[47] U.S. Energy Information Administration, "Natural Gas Consumption by End Use" for Maryland, eia.gov/dnav/ng/NG_CONS_SUM_DCU_SMD_A.htm, accessed on February 28, 2024.

Figure 3-3 Interstate Natural Gas Pipelines in Maryland



Petroleum

A small amount of electricity—less than 1% of the state's total—is generated by combusting distillate or residual fuel oil. According to EIA, fuel oil consumption for electric power in Maryland totaled 10 million gallons in 2022.[48] Because there are no crude oil reserves or refineries in Maryland, all supplies of petroleum necessary to meet the state's consumption needs are imported. Petroleum is transported via barge to the Port of Baltimore and via the Colonial Pipeline, a major petroleum products pipeline that traverses the state on its way to New York.

3.1.2 Nuclear

Maryland is home to one nuclear power facility, Constellation Energy Corporation's Calvert Cliffs plant. This 1,850 MW facility represents 12% of the state's total electricity generation capacity and accounted for 40% of the state's total generation in 2022. More information on Calvert Cliffs is included in Section 5.5.2.

[48] Form EIA-923 detailed data with previous form data (EIA-906/920) - U.S. Energy Information Administration (EIA).

Small Nuclear Reactors

Small modular reactors (SMRs) typically have generating capacities up to 300 MW per unit and are small enough to be constructed on a 35-acre site. By comparison, conventional nuclear power plants can be over 1,000 MW capacity per unit and require over 800 acres.

Small modular reactors offer the following advantages versus conventional nuclear power plants:

- **Lower Capital Investment:** Major components of an SMR are fabricated offsite in controlled factory environments and shipped to the plant site for installation. Less onsite fabrication work and shorter construction periods are expected to reduce the total capital investment for SMRs.
- **Siting Flexibility:** SMRs can be installed in locations that are too small to accommodate conventional nuclear plants.
- **Safety:** Most SMRs would be built below grade for enhanced safety and security.

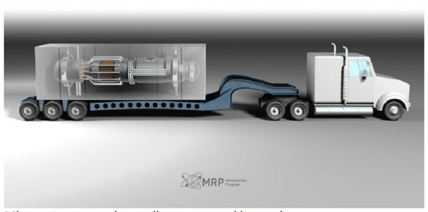
SMR technology development is facing challenging economics. A DOE-funded SMR project in Utah was cancelled in November 2023 when customers pulled out of the project after the projected cost of power increased from $58/MWh to $89/MWh. Overall, DOE has contributed $600 million since 2014 to supporting the commercialization of SMR technologies.

Microreactors are smaller versions of SMRs with capacities that range from 1 MW to 20 MW. They can be small enough for transport by truck or train and occupy less than two acres. Like SMRs, microreactors are scalable, adaptable to different locations, and can be rapidly transported.

Small Modular Reactor Building Illustration

Source: https://www.energy.gov/ne/advanced-small-modular-reactors-smrs

Microreactor Illustration



Microreactors can be easily transported by truck.

Source: New study examines U.S. markets for microreactors - Idaho National Laboratory (inl.gov)

References:
https://www.iaea.org/newscenter/news/what-are-small-modular-reactors-smrs
https://inl.gov/trending-topic/small-modular-reactors/
https://www.nei.org/news/2022/nuclear-brings-more-electricity-with-less-land
https://www.energy.gov/ne/benefits-small-modular-reactors-smrs
https://ieefa.org/resources/eye-popping-new-cost-estimates-released-nuscale-small-modular-reactor#:~:text=Key%20Findings,(SMR)%20have%20risen%20dramatically.&text=As%20recently%20as%20mid%2D2021,MWh%2C%20a%2053%25%20increase
NuScale ends Utah project, in blow to US nuclear power ambitions | Reuters
https://www.tandfonline.com/doi/full/10.1080/00295450.2022.2118626
https://www.westinghousenuclear.com/energy-systems/evinci-microreactor

3.1.3 Distributed Generation

Distributed generation (DG) refers to those generating resources located close to, or on the same site as, the facility using power. DG is typically installed on the customer side of the meter and used to serve onsite power needs; because of this, distributed generators are not centrally dispatched by the regional grid operator. Types of DG technologies include internal combustion engines, small wind, solar, small hydroelectric, micro gas turbines, and fuel cells. Some of these technologies can be used to provide electricity to the grid during times of peak demand.

Distributed Generation and PJM Interconnection LLC's (PJM's) Proposed Implementation of FERC Order 2222

The FERC issued Order 2222 in September 2020, which directed PJM and all Regional Transmission Organizations to allow groups of distributed energy resources (DERs), such as rooftop solar, battery storage, and electric vehicle chargers, to be combined to provide services to the grid for compensation.

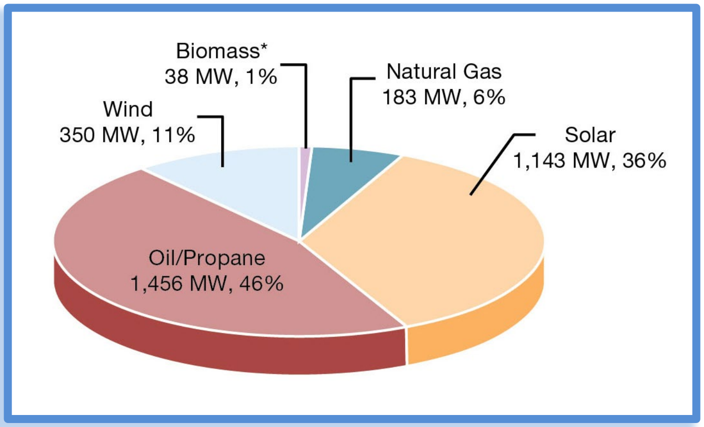
DERs are typically small and widely dispersed; therefore, DER output must be combined by a third-party aggregator that directly participates in the PJM markets on behalf of the DER owners. The aggregator shares compensation with the DER owners. Individual customers, businesses, or municipalities install and operate DERs to reduce electricity costs. The DER aggregator controls or monitors DER operation and shares compensation with the DER owners.

Order 2222 requires PJM to submit a plan to allow aggregated DERs to participate in the wholesale markets. PJM submitted its initial plan in February 2022 and a revised plan September 2023. The revised plan was filed in response to FERC and stakeholder questions regarding:

- Opt-in and op-out provisions for small utilities;
- Provisions to prevent DER compensation for providing the same service in PJM markets and retail markets;
- DER locational constraints; and
- A process for distribution utilities to review and approve DER interconnections, operating protocols, and coordination.

DG units are often used to provide emergency backup power in the event that large and essential loads, such as government offices, hospitals, colleges and universities, commercial and industrial facilities, telecommunications installations, and farming operations, lose electricity service. By fuel type, Maryland's distributed generators (see Figure 3-4) are mostly fossil-fueled, consistent with their use for backup power. A large share of DG capacity is solar, which is predominantly grid-tied for purposes of net metering and generating solar Renewable Energy Credit (RECs) (SRECs) for sale or trade. Between 2022 and 2023, for example, statewide net metered solar system capacity increased 6%. The solar energy requirement in the Maryland Renewable Energy Portfolio Standard (RPS) will also continue to provide an incentive to add distributed solar generation to the Maryland grid.

Figure 3-4 Distributed Generation by Fuel Type, as of June 30, 2022



Source: PSC CPCN Database and Maryland Public Service Commission, "Report on the Status of Net Energy Metering in the State of Maryland," November 2023, https://www.psc.state.md.us/wp-content/uploads/2023-Net-Metering-Report.pdf.
Note: This figure only includes solar from net metered systems and CPCN-exempted systems.
*Biomass includes digester and landfill gas units.

3.1.4 Demand Response

Demand response (DR) serves as a tool for bolstering energy efficiency and conservation efforts in Maryland. DR allows end-use customers to reduce their energy consumption during periods of high demand (and high prices). DR occurs when a customer reduces electricity use in response to either a change in the price of electricity or an incentive payment. Customers who reduce electricity consumption in response to high real-time electricity prices or when called on by the system operator or utility are used as an alternative to generation resources as a means of meeting load requirements. Voluntary usage reductions can come from customers of all sizes. Large industrial customers may choose to shift some high-energy intensity processes to lower-cost hours. Through these voluntary, opt-in programs, utilities can cycle residential consumers' air conditioning and electric water heaters. When aggregated across thousands of customers, these residential energy use reductions can create significant savings during times of peak demand.

See Cumulative Environmental Impact Report 2021 (CEIR-21), Section 3.1.4 and also PPRP's website for additional information on Demand Response in the Electricity Generation in Maryland discussion.

3.1.5 Maryland Renewable Energy Portfolio Standard

The Maryland Renewable Energy Portfolio Standard (RPS) was enacted in May 2004. The RPS requires retail electrical suppliers to provide a specified percentage of their electricity sales from Maryland-certified Tier 1 and Tier 2 renewable resources. Currently, the Maryland RPS requires 52.5% of electricity sales to come from Tier 1 and Tier 2 resources by 2030. Every MWh generated by qualified renewable energy resources is eligible to be registered as one Maryland-certified Renewable Energy Credit (REC). Eligible RECs may come from a PSC-certified renewable energy facility that is either located within PJM or for the electricity the facility delivers into PJM from an adjacent control area outside of PJM. The 2004 RPS law has been modified by legislation 15 times from 2007 through 2023, mainly to increase the requirement and to change the eligibility of renewable energy resources. Figure 3-5 illustrates the RPS requirements over time.

The current version of the Maryland RPS contains the following provisions:

- Tier 1 renewable resources include fuel cells that produce electricity from other Tier 1 renewable fuel resources, geothermal, hydroelectric facilities under 30 MW, methane, ocean, poultry litter-to-energy, qualifying biomass, solar, wind, waste-to-energy (WTE), refuse-derived fuel, and offshore wind.

- Including the geothermal and solar carve-outs, the Tier 1 requirement began at 1% and increases annually; in 2023, it was 29.87% and will reach its 50% maximum in 2030. Senate Bill 65 of 2021 (Chapter 673) removed black liquor as an eligible renewable resource. Existing obligations or contract rights may not be impaired; therefore, black liquor RECs will remain eligible until certain still-existing contracts expire.[49]

- The solar energy carve-out requires that a specified percentage of energy supply must come from instate solar facilities. The solar carve-out began in 2008 at 0.005% and will reach its maximum of 14.5% in 2030. The 14.5% solar requirement is part of the Tier 1 overall 50% requirement.

- The Maryland Offshore Wind Energy Act, which was passed in 2013, created a separate carve-out for offshore wind facilities. The offshore wind energy carve-out requires that a specified percentage of energy in the state must come from offshore wind facilities located between 10 miles and 80 miles off the coast of Maryland. Each year, the PSC will set the percentage of required offshore energy to be no less than 400 MW of offshore wind by 2026, 800 MW by 2028, and 1,200 MW by 2030. This is in addition to the 368 MW of offshore wind approved by the PSC to receive Offshore Renewable Energy Credits (ORECs) in 2017.[50]

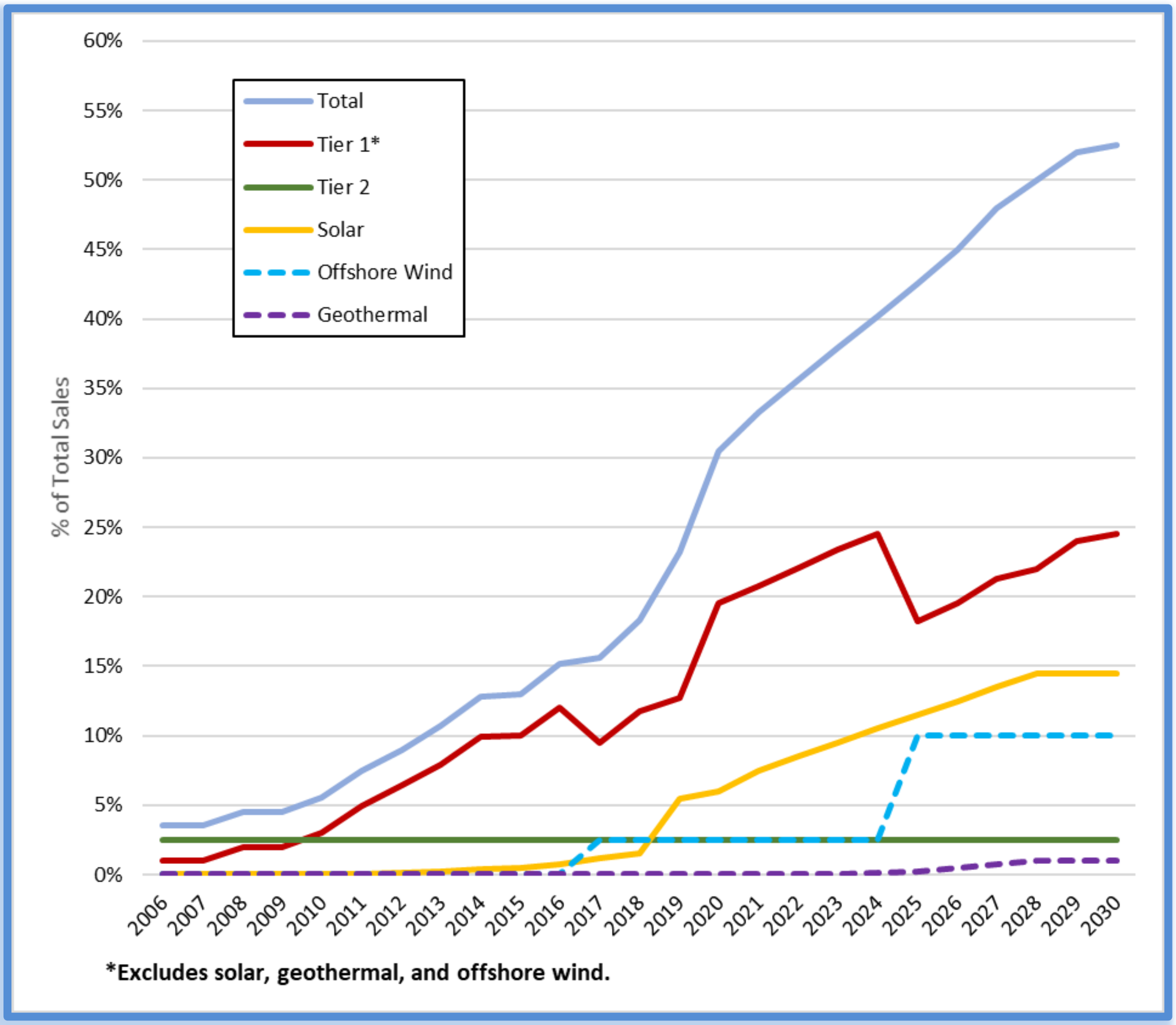
- A new carve-out of Tier 1 for geothermal began in 2023, starting at 0.05% and increasing to 1% by 2028.

- Existing hydroelectric facilities that are not pump-storage and are over 30 MW qualify to meet the Tier 2 standard as long as the facilities were operational as of January 1, 2004. Tier 1 resources may also be used to meet the 2.5% Tier 2 standard.

[49] RPS Report of 2010 (state.md.us), 2022 RPS Report, Footnote 23, p. 16.

[50] Maryland General Assembly, Maryland Public Utilities Articles §7-701 – §7-713.

Figure 3-5 Maryland RPS Requirements Summary, 2006–2030



Source: Maryland Senate Bill 516; 2019 and the Annotated Code of Maryland, PUA §7-703.

Electricity suppliers have the option to make an Alternative Compliance Payment (ACP) in place of RECs. As summarized following, the ACP varies based upon tier and carve-out.

- **Tier 1 ACP:** $0.0375 for each kilowatt hour (kWh) (i.e., $37.50/MWh) in 2017 and 2018. Decreases to $0.03/kWh ($30/MWh) from 2019 to 2023, then gradually decreases each year until 2030 when it is set at $0.02235/kWh ($22.35/MWh) and remains constant thereafter.

- **Tier 1 Solar Carve-out ACP:** Began at $0.45/kWh ($450/MWh) in 2006 but has since decreased to $0.1/kWh ($100/MWh) in 2020. The ACP will continue to decrease, reaching $0.055/kWh ($55/MWh) by 2025, and finally reaching $0.0225/kWh ($22.5/MWh) in 2030.

- **Tier 1 Geothermal Carve-out ACP:** Begins at $0.1/kWh ($100/MWh) from 2023 through 2025, decreases to $0.09/kWh ($90/MWh) in 2026 and $0.08/kWh ($80/MWh) in 2027, and reaches a fixed $0.065/kWh ($65/MWh) in 2028.

- **Tier 2 ACP:** $0.015/kWh ($15/MWh).[51]

At the conclusion of 2022, there were 77,222 renewable energy facilities certified by the Maryland PSC,[52] providing approximately 34,439 MW of renewable energy capacity in PJM (see Table 3-3).

Table 3-3 Maryland RPS-certified Capacity as of December 2022 (MW)

	Tier 1										Tier 2	
State	Solar	Solar Thermal	Wind	Hydro	Landfill Gas	Other Biomass Gas	Black Liquor	Municipal Solid Waste	Wood Waste	Geothermal	Hydro	Total
Maryland	1,805	4	190	20	31	-	65	138	4	2	474	2,733
Delaware	-	-	2	-	12	-	-	-	-	-	-	14
Illinois	-	-	5,125	20	88	-	-	-	-	-	-	5,233
Indiana	-	-	2,530	8	8	-	-	-	-	-	-	2,546
Kentucky	-	-	-	2	18	-	-	-	5	-	229	254
Michigan	-	-	58	15	4	-	-	-	31	-	20	128
Missouri	-	-	839	-	-	-	-	-	-	-	-	839
New Jersey	-	-	8	11	45	15	-	152	-	-	-	231
North Carolina	-	-	208	-	-	-	152	-	-	-	755	1,115
North Dakota	-	-	360	-	-	-	-	-	-	-	-	360
Ohio	-	-	1,099	-	50	6	93	-	-	-	125	1,373
Pennsylvania	-	-	1,460	95	96	1	164	-	-	-	501	2,317
Tennessee	-	-	-	-	-	-	50	-	-	-	206	256
Virginia	-	-	12	69	134	3	288	143	241	-	266	1,156
West Virginia	-	-	856	54	-	-	-	-	-	-	159	1,069
Washington, D.C.	-	4	-	-	-	49	-	-	-	-	-	53
TOTAL	1,805	8	12,747	294	486	74	812	433	281	2	2,735	19,677

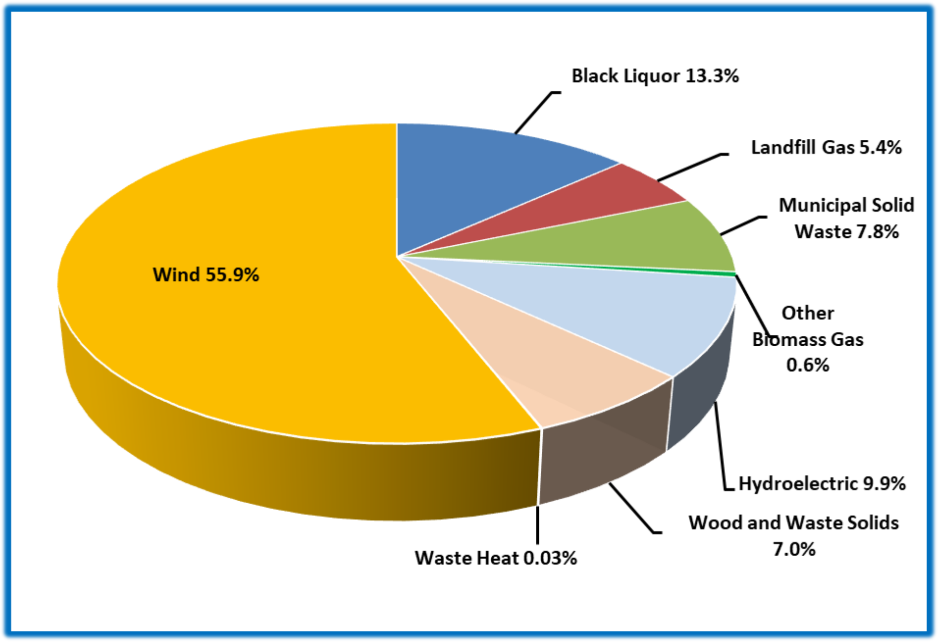
Source: PJM Generation Attribute Tracking System (GATS), nameplate capacities, as of December 31, 2022.
Note: The capacity values are based on the estimate of renewable energy capacity for each facility, which does not necessarily equal the total nameplate capacity at that facility.

[51] ACPs are different for industrial process load customers. For Tier 1, the ACP is 0.2 cents/kWh ($2/MWh). There is no ACP for Tier 2 resources. The ACP drops further to 0.1 cents/kWh ($1/MWh) in years where suppliers are required to buy ORECs, and nothing at all if the net rate impact of OREC purchases exceeds $1.65/MWh, in 2012$.

[52] RPS Report of 2010 (state.md.us), 2022 RPS Report, Appendix B.

As depicted in Figure 3-6, wind power is the leading fuel source for compliance with the Tier 1 Maryland RPS, followed by black liquor, small-scale hydro, municipal solid waste, wood waste, and landfill gas.

Figure 3-6 Tier 1 Non-solar Retired RECs by Fuel Source, 2022



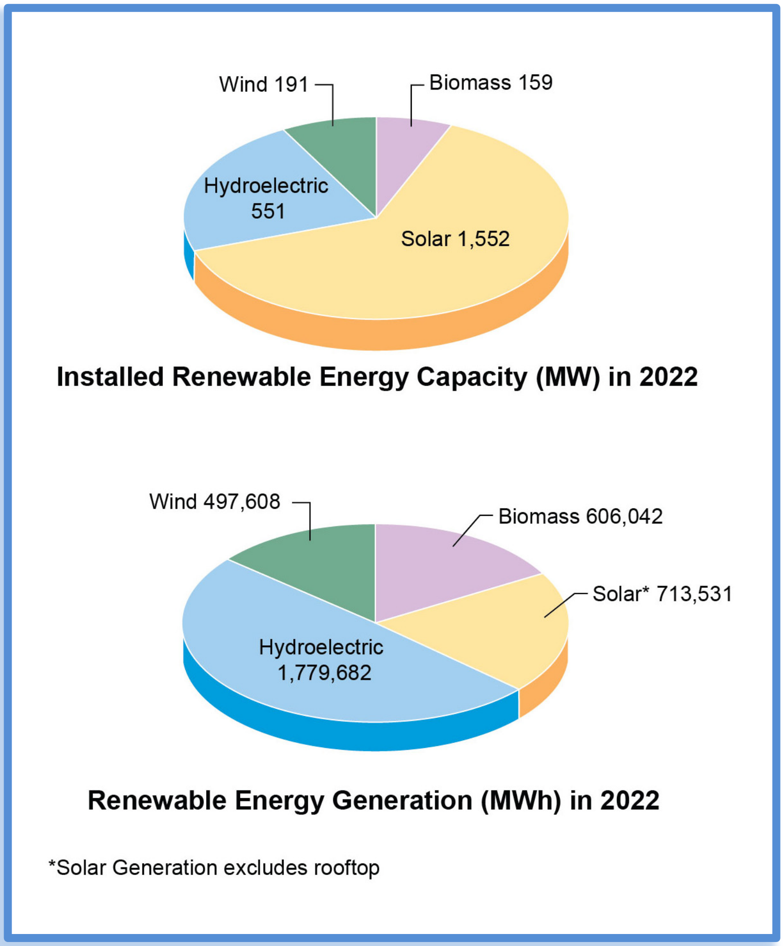
Source: Maryland Public Service Commission, Renewable Energy Portfolio Standard Report with Data for Calendar Year 2022, November 2023, , https://www.psc.state.md.us/wp-content/uploads/CY22-RPS-Annual-Report_Final-w-Corrected-Appdx-A.pdf

The PSC is charged with ensuring compliance with the RPS and certifying eligible facilities. Additional information about RPS compliance can be found on the PPRP website in the Policy Initiatives and Energy Programs discussion.

3.1.6 Renewable Resources

Presently, there are four main types of renewable energy resources in use in Maryland: solar, hydroelectric, wind, and biomass (which is composed of wood waste, landfill gas, and municipal waste-to-energy (WTE)). Approximately 2,453 MW of generation capacity in Maryland comes from these resources (see Figure 3-7).

Figure 3-7 Renewable Energy in Maryland, as of 2020



Source: EIA-860 PJM for capacity, and EIA-923 for generation. Solar capacity includes both utility-scale and rooftop solar. Hydroelectric capacity includes 531 MW nameplate capacity for Conowingo Dam. Solar generation excludes rooftop.

Wind

The conversion of wind power to electricity is typically accomplished by constructing an array of wind turbines in a suitable location. Wind turbines range in size from 20-watt microturbines (used for small-scale residential or institutional applications) to new 10 MW prototypes, with manufacturers now researching the possibility of 20 MW turbines for offshore facilities. Land-based, utility-scale wind turbines typically have a rated capacity between 1.5 MW and 3 MW, with some as large as 5 MW.

At the conclusion of 2022, there were 144 gigawatts (GW) of land-based wind in operation throughout the United States, making the country the second-leading installer of wind capacity in the world after China.[53] Texas is the leading state in land-based wind, with 40.6 GW of capacity.[54]

Offshore Wind

According to a National Renewable Energy Laboratory (NREL) study, the United States may have a usable offshore wind resource capacity of over 4,000 GW, with approximately 480 GW to 570 GW of that potential in the Mid-Atlantic region. NREL estimates that Maryland alone has an unrestricted (not accounting for siting or possible conflicts with freight ships) offshore wind power capacity in excess of 130 GW, with a potential generation of 603 terawatt hours (TWh). Using existing offshore wind turbine technology and limiting development to shallow waters reduces the offshore wind potential to 23.8 GW and 80 TWh, respectively.[55] Still, if fully developed, offshore wind would far exceed the state's electric demand.

See CEIR-21, Section 3.1.5 for additional information on offshore wind permitting issues, research and development, and environmental and socioeconomic risks.

The United States has three operating offshore wind energy projects, a 30 MW project at Block Island, Rhode Island, a 130 MW project off Long Island in New York, and a 12 MW project off Virginia Beach, Virginia. As of 2022, there were over 40 GW of offshore wind capacity under various stages of development (see Figure 3-8). States have announced goals or mandates to acquire over 42 GW of offshore wind capacity by 2040, while the Biden Administration set a nationwide goal of 30 GW of offshore wind by 2030.[56]

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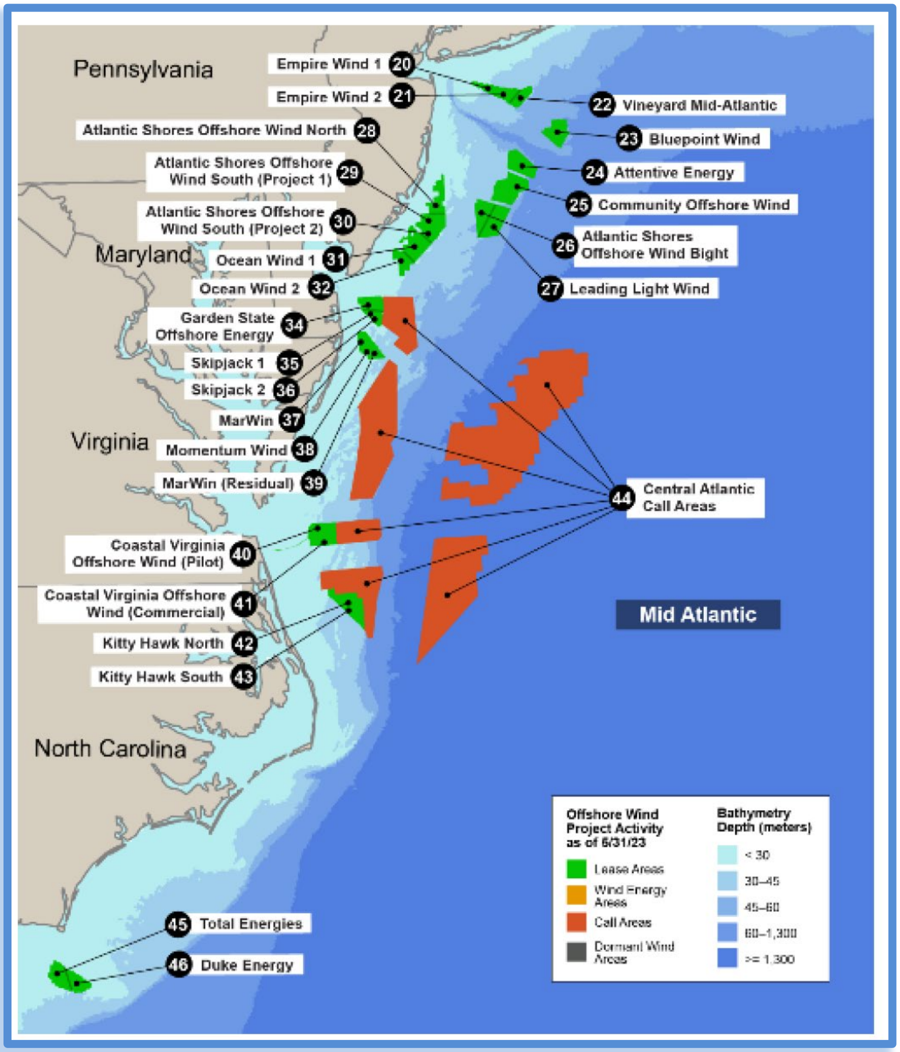
[53] https://www.energy.gov/sites/default/files/2023-08/land-based-wind-market-report-2023-edition.pdf.

[54] https://comptroller.texas.gov/economy/economic-data/energy/2023/wind.php#:~:text=Wind%20Energy%20in%20Texas&text=In%202022%2C%20Texas%20had%2040%2C556,the%20first%20time%20in%202020..

[55] Walt Musial, Donna Heimiller, Philipp Beiter, George Scott, and Caroline Draxl, 2016 Offshore Wind Energy Resource Assessment for the United States, National Renewable Energy Laboratory, September 2016, nrel.gov/docs/fy16osti/66599.pdf.

[56] U.S. Department of Energy, Offshore Wind Market Report: 2023 Edition, https://www.energy.gov/sites/default/files/2023-09/doe-offshore-wind-market-report-2023-edition.pdf.

Figure 3-8 Mid-Atlantic Offshore Wind Pipeline—Project Locations



Source: U.S. Department of Energy, Offshore Wind Market Report: 2023 Edition, https://www.energy.gov/sites/default/files/2023-09/doe-offshore-wind-market-report-2023-edition.pdf.

Floating Offshore Wind Turbines

Floating Offshore Wind Turbines are a solution to the challenge of harnessing wind energy in deep waters, where about two-thirds of the U.S. offshore wind energy potential resides. These deep regions have long been inaccessible due to the economic impracticality of traditional fixed-bottom wind farms.

The U.S. Department of Energy's Floating Offshore Wind Shot initiative aims to reduce the total expenses of floating wind turbines by over 70%, targeting $45/MWh by 2035. This initiative stands as a cornerstone in the transition to clean energy, with the potential to power over five million American homes.

The U.S. Department of the Interior announced a goal to deploy 15 GW of installed capacity by 2035, supporting the commercialization of floating wind turbines. This supplements broader plans to deploy 30 GW of offshore wind by 2030. Key to this support is nearly $50 million in research, development, and demonstration funding, as well as a planned lease auction off the coast of California. Achieving these targets will create billions of dollars of economic opportunities and avoid an estimated 26 million metric tons of carbon emissions annually.

As shown in the following table, the Department of Energy estimates that floating wind technology is needed to capture 51% of the offshore wind generation technical potential off the Mid-Atlantic coast.

Offshore Wind Energy Technology Technical Potential

Region	Fixed-Bottom (GW)	Floating (GW)	Fixed-Bottom (%)	Floating (%)
California	4	88	4	96
Great Lakes	160	415	28	72
Gulf	696	867	45	55
Mid-Atlantic	157	166	49	51
North Atlantic	264	442	37	63
Oregon	2	150	1	99
South Atlantic	188	586	24	76
Washington	5	59	8	92
CONUS Total	**1,476**	**2,773**	35	65

CONUS = Contiguous United States

Source: https://www.nrel.gov/docs/fy22osti/83650.pdf.

Sources:
https://www.energy.gov/eere/articles/wind-waves-floating-wind-power-becoming-reality
https://www.energy.gov/energy-earthshots-initiative
https://www.whitehouse.gov/briefing-room/statements-releases/2022/09/15/fact-sheet-biden-harris-administration-announces-new-actions-to-expand-u-s-offshore-wind-energy/

Whether these projects will ever come online will depend on the ability of developers to secure financing and power purchase agreements (PPAs), as well as navigating federal and state permitting requirements. In 2020, the U.S. Congress enacted a 30% investment tax credit (ITC) for offshore wind projects that begin construction by 2025. Existing law and Internal Revenue Service (IRS) "safe harbor" regulations allow the ITC to be used up to 10 years after construction begins, meaning an offshore wind project could go into service as late as 2035 and still take advantage of the ITC.

The Inflation Reduction Act (IRA), which was enacted in 2022, extends and increases wind energy investment and production tax credits through 2024 for projects that begin construction prior to January 1, 2025. In 2025, the tax credits for onshore and offshore wind will be replaced with technology-neutral credits. These credits will phase out in 2032, or when U.S. power sector greenhouse gas (GHG) emissions decline to 25% of 2022 levels, whichever is later.[57]

Offshore Wind Manufacturing at Sparrows Point

In November 2023, Sparrows Point Steel, LLC won a major new federal grant of over $47 million for upgrades needed to fabricate wind turbine monopile foundations and towers at Tradepoint Atlantic in Baltimore County. Marshaling of wind turbine components will also take place at Sparrows Point for transport to project sites along the East Coast.

Sparrows Point Steel is wholly owned and operated by Baltimore-based U.S. Wind, Inc. In March 2023, U.S. Wind announced a partnership with Haizea Wind Group to manage and operate Sparrows Point Steel.

U.S. Wind plans to construct a 300 MW wind project off the Maryland coast. Fabrication of monopile foundations and towers for the project will take place at Sparrows Point Steel and is expected to support 1,300 jobs in Maryland.

Danish wind developer Ørsted also committed to fabricate wind turbine components at Sparrows Point Steel for a planned 966 MW off the Maryland coast. In January 2024, the company paused all spending on the project and withdrew from a contract with the Maryland Public Service Commission to sell power from the project. Ørsted stated that the contracted power prices were not sufficient to cover project costs that have escalated because of inflation, high interest rates, and supply-chain issues. Ørsted will continue development and permitting activities as they await an opportunity to rebid.

Rendering of Sparrows Point Steel Monopile and Tower Fabrication Facility

Source: https://www.marinelink.com/news/new-monopile-tower-fabrication-facility-503965

U.S. Maritime Administration Awards $47 Million to Baltimore County and Sparrows Point Steel – U.S. Wind (uswindinc.com)
U.S. Wind and Haizea Wind Group Team Up for New Monopile and Tower Fabrication Facility – U.S. Wind (uswindinc.com)
https://uswindinc.com/marwin/
Ørsted withdraws from contract for Maryland offshore wind farm | Wind Energy News (wind-watch.org)

57 https://windexchange.energy.gov/projects/tax-credits.

Land-based Wind Projects in Maryland

Currently, there are four operating utility-scale wind facilities in Maryland, all located in Garrett County. Their combined power capacity of 190 MW is estimated to represent about 12% of Maryland's land-based wind resource potential. One other project, representing about 70 MW, is currently in the planning and development stage. See CEIR-21, Section 3.1.5 for additional information on land-based wind projects in Maryland.

Vineyard Wind

Vineyard Wind 1, developed by Avangrid Renewables and Copenhagen Infrastructure Partners, will be the first commercial scale offshore wind project in the U.S. when it is fully operational in 2024.

There are currently two offshore wind projects operating in the United States:

1. The 30 MW Block Island project off the coast of Rhode Island, and
2. The 12 MW Coastal Virginia Offshore Wind Pilot Project.

Vineyard Wind 1 will have 62 turbines totaling 800 MW and will be located 15 miles off Martha's Vineyard. At full capacity, the project would be capable of powering over 400,000 Massachusetts households. Vineyard Wind 1 is projected to generate 3,600 full-time jobs and save ratepayers $1.4 billion over the first 20 years of operation.

The project will employ protective measures during construction such as using marine mammal observers on vessels, setting vessel speed restrictions, and restricting pile-driving operations to daylight hours. Concerns of fishing communities will be addressed by establishing a compensation fund and minimizing disruption to traditional fishing areas. Archaeological surveys will also be conducted to ensure that historical sites are not disturbed during construction.

The permitting process for Vineyard Wind 1 commenced with a federal lease obtained in 2015. A detailed Construction and Operations Plan (COP) was proposed to the Bureau of Ocean Energy Management (BOEM) in 2017. Following this, BOEM released the Draft Environmental Impact Statement (DEIS) in 2018, initiating a public comment period. A supplement to the DEIS was published in the summer of 2019, with the final Environmental Impact Statement given the green light in 2020. The project successfully passed state review by the Massachusetts Executive Office of Energy and Environmental Affairs and received certification of its final Environmental Impact Report in 2019. Vineyard Wind 1 then secured approvals from the Cape Cod Commission and the Martha's Vineyard Commission in 2019. Local endorsements from the Towns of Barnstable and Edgartown Conservation Commissions in 2019 marked the final steps in the project's comprehensive approach to secure all necessary permits. As of February 2024, five turbines are in operation, representing about 68 MW of capacity.

Source: https://www.vineyardwind.com/press-releases/2021/5/11/vineyard-wind-receives-record-of-decision
https://www.vineyardwind.com/vw1-permitting
Riley, Neil. "5 Vineyard Wind turbines now providing enough power for 30,000 Massachusetts homes," CBS News, February 23, 2024, https://www.msn.com/en-us/news/us/5-vineyard-wind-turbines-now-providing-enough-power-for-30000-massachusetts-homes/ar-BB1iJ1W9

Solar

At the end of 2023, there were 90,824 solar facilities in Maryland representing 2,001 MW of generating capacity, according to the PJM Generation Attribute Tracking System (GATS). GATS tracks SRECs that are eligible for use in complying with the Maryland RPS. While most of the facilities are smaller than 10 kilowatts (kW), 248 systems larger than 1 MW have come online representing 963 MW of solar generating capacity. Table 3-4 lists the GATS-registered solar facilities by system size. In 2020, the 118 MW Great Bay Solar Phase I project in Somerset County became the largest operational solar facility in Maryland. From 2016 to April 2024, the PSC issued CPCNs to 46 solar facilities with a combined capacity of 1,391 MW, and there are 10 cases pending before the PSC with a combined capacity of 141 MW. The largest CPCN approved as of December 2023 is for Cherrywood Solar, a 202 MW solar facility located in Caroline County.

See CEIR-21, Section 3.1.5 for additional information on solar facilities in Maryland.

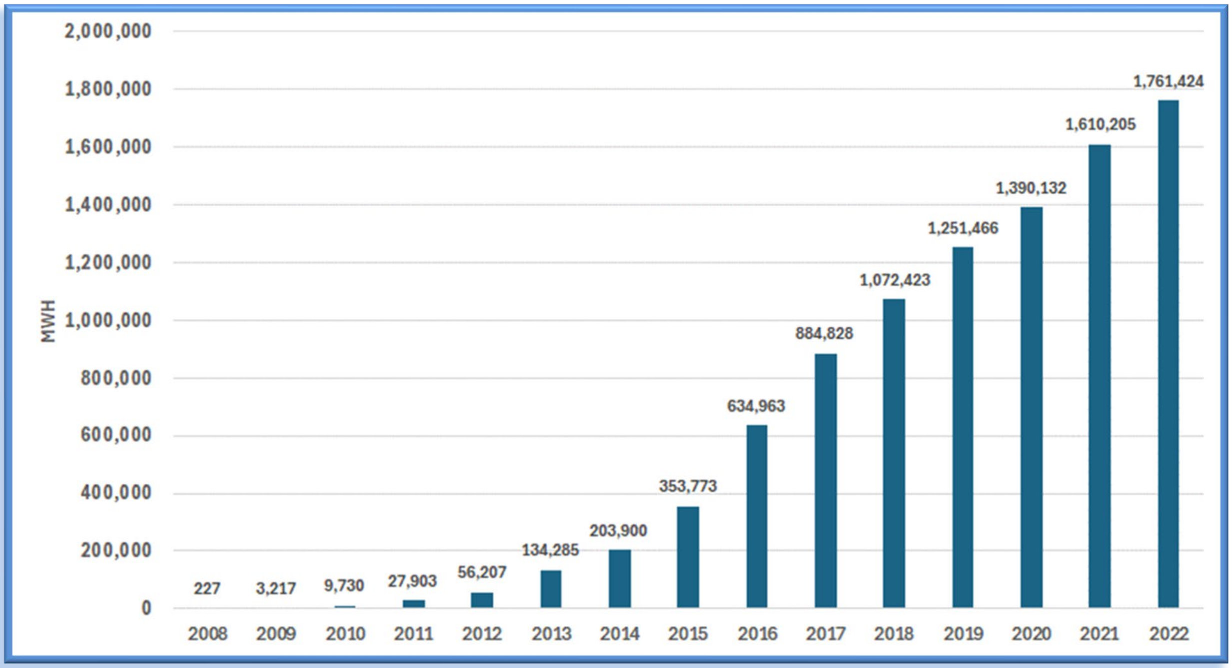
Table 3-4 Maryland's Solar Facilities Listed in PJM GATS, 2023

System Size (kW)	Number of Projects	Total Capacity (MW)
0 to ≤ 3	2,567	6
> 3 to 6	19,921	95
> 6 to 10	33,433	267
> 10 to 50	33,923	486
> 50 to 100	267	19
> 100	713	1,128
Total	90,824	2,001

Source: PJM Generation Attribute Tracking System.

Solar energy generation capacity in Maryland went from 0.1 MW in 2007 to 2,001 MW in 2023 due in large part to Maryland's implementation of a solar carve-out under the Maryland RPS. The General Assembly passed a bill in 2019 that further increased the percentage of the solar carve-out in the Maryland RPS from 2.5% by 2020 to 14.5% by 2030. Prior to that, in 2017, the solar carve-out had increased from 2% to 2.5%. Overall, solar generation in Maryland increased 1,212%, or approximately 1,627,139 MWh, between 2013 and 2022 (see Figure 3-9). For more information on the Maryland RPS solar carve-out, see Section 3.1.5. See also Section 3.5.2 for a discussion of Maryland's community solar program and its role in driving solar power growth.

Figure 3-9 Solar Generation in Maryland, 2008–2022



Source: Maryland Public Service Commission, Renewable Energy Portfolio Standard Reports. Solar Photovoltaic (PV) RECs Generated in Maryland, Appendix B in the 2021 report and Appendix C in the 2022 report.

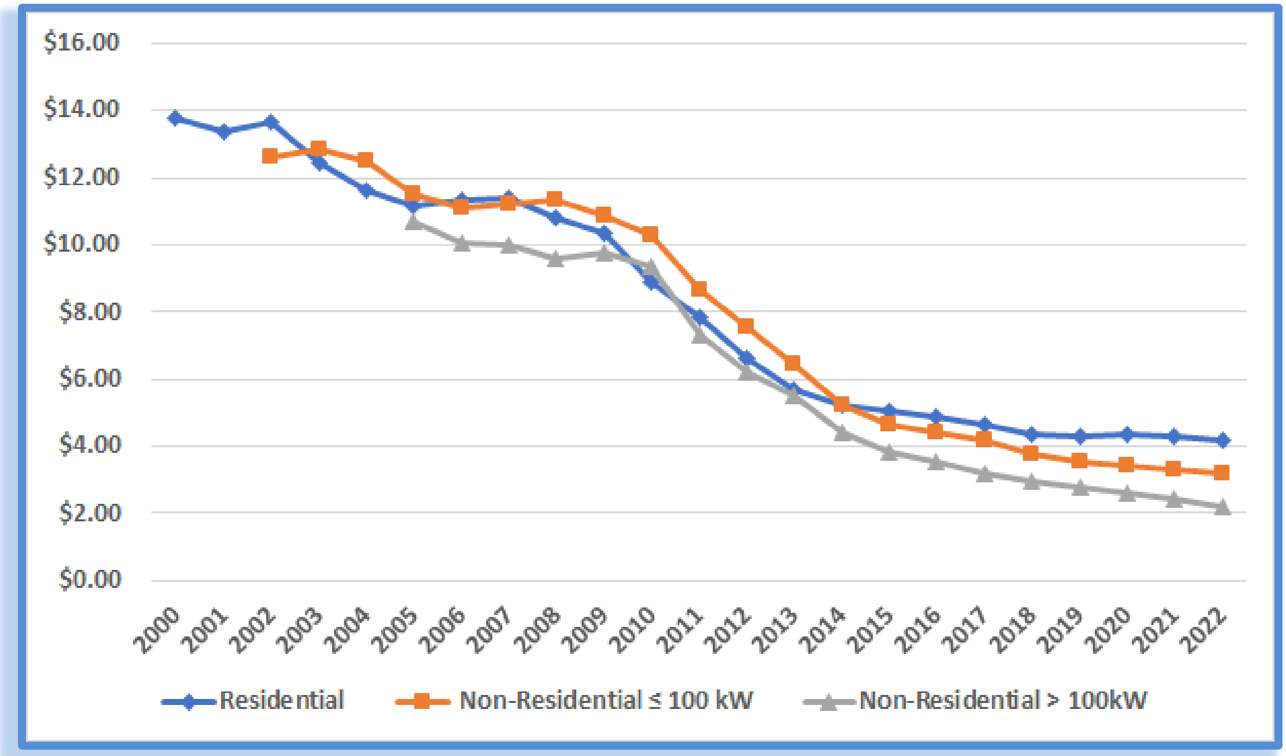
Nationally, installed solar costs for systems up to 5 MW have declined, on average, by 5% to 9% per year since 2000, depending on customer class (residential or nonresidential). Cost declines, however, have not occurred at a steady pace. In fact, installed costs have declined markedly since 2009. National median costs of solar systems dropped by 74% for residential systems, 70% for nonresidential systems below 100 kW and 80% for nonresidential systems over 100 kW (see Figure 3-10) in 2022, as compared to 2009.[58] Costs for utility-scale solar systems (5 MW and higher) have also dropped sharply, from over \$5.81/watt$_{AC}$ to \$1.32/watt$_{AC}$ in 2022 versus 2009.[59]

Certain incentive policies, like the Maryland and New Jersey RPS policies, have assumptions of declining photovoltaic (PV) installation costs built into the enforcement mechanisms. In the case of state RPS policies, the ACP effectively places a ceiling on SREC costs and generally moves lower year to year. If the solar industry cannot match these downward cost profiles, utilities may opt to pay the ACP in lieu of installing solar facilities.

[58] Year-End 2022 Summary Data Tables in LBNL annual Tracking the Sun Report; https://emp.lbl.gov/tracking-the-sun.

[59] LBNL Utility-Scale Solar, 2023 Edition: Empirical Trends in Deployment, Technology, Cost, Performance, PPA Pricing, and Value in the United States; https://emp.lbl.gov/publications/utility-scale-solar-2023-edition.

Figure 3-10 Cost of Solar PV in the United States ($/watt), 2000–2022



Source: Year-End 2022 Summary Data Tables in LBNL Annual Tracking the Sun Report; https://emp.lbl.gov/tracking-the-sun.

Hydroelectric

Maryland has two large-scale (greater than 10 MW capacity) hydroelectric dam projects and four additional small-scale facilities that are currently in operation. Conowingo Dam is the state's largest hydro facility. In October 2019, Exelon, the then owner and operator of Conowingo Dam, proposed a settlement with Maryland Department of Environment (MDE) to FERC, where Exelon will spend over $200 million over 50 years on several protection, mitigation, and enhancement measures, including fish passage attraction flows, eel passage, invasive species management, a revised downstream operating flow regime, trash and debris removal, dissolved oxygen monitoring, shoreline management, turtle management, a waterfowl nest plan, sturgeon monitoring, mussel restoration, water quality project funding, and other measures.[60] In March 2021, FERC approved relicensing, granting Exelon a new 50-year license to operate the dam.[61] Exelon transferred the Conowingo project to Constellation in early 2022. Section 5.2.2 includes further discussion about hydroelectricity and its potential impacts.

See CEIR-21, Section 3.1.5 for additional information on hydroelectric power.

[60] Exelon Corporation, "Exelon Generation and State of Maryland Reach Agreement to Restore and Sustain Chesapeake Bay," October 29, 2019, https://www.constellationenergy.com/newsroom/2019/conowingo-announcement.html.

[61] ferc.gov/news-events/news/ferc-relicenses-conowingo-hydroelectric-project.

Biomass

In the energy production sector, biomass refers to biological material that can be used as fuel for transportation, steam heat, and electricity generation. Biomass fuels are most commonly created from wood and agricultural wastes, alcohol fuels, animal waste, and municipal solid waste. Biomass can be combusted to produce heat and electricity; transformed into a liquid fuel such as biodiesel, ethanol, or methanol; or transformed into a gaseous fuel such as methane.

Waste-to-Energy

Waste-to-energy (WTE) facilities generate energy from municipal solid waste. While the precise details of the processes may vary, the general method involves combusting the waste to heat boilers and create high-pressure steam, which is used to turn a turbine and generate electricity. In addition to the energy produced, WTE plants typically reduce the volume of incoming waste by about 90% and the weight of incoming waste by about 75%.

WTE was classified as a Tier 2 resource under the Maryland RPS until 2011, but the Maryland General Assembly enacted legislation that made WTE a Tier 1 resource and added refuse-derived fuel as a Tier 1 resource. See Section 3.1.5 for information on the Maryland RPS Tier 1 and Tier 2 requirements.

As of 2023, there are 75 WTE facilities currently operating nationwide according to the EPA, including two facilities in Maryland that are certified under Maryland's RPS.[62] WTE facilities are heavily regulated due to various environmental impacts. As an energy source, WTE is similar to coal and oil electricity generators in terms of carbon dioxide (CO_2), sulfur dioxide (SO_2), and nitric oxide (NO) emissions. However, WTE facilities can also contribute to the environmental deposition of (Hg), dioxin, furan, and other toxic metals and organic compounds unless adequate pollution controls are installed.

See CEIR-21, Section 3.1.5 for additional information on WTE.

Landfill Gas

Landfill gas (LFG) is created when organic solid wastes decompose in a landfill. The amount of gas produced in a landfill depends upon the characteristics of the waste, the climate, the residence time of the waste, and operating practices at the landfill. LFG can contain as much as 45% CO_2 and 55% methane by volume. If no capture or extraction measures are employed, LFG will be released into the atmosphere as a combination of methane and CO_2, with small amounts of non-methane organic components. If the LFG is extracted and combusted (e.g., flared or used for energy), then the methane produced in the landfill is converted entirely to CO_2, and the CO_2 in the LFG is released directly into the atmosphere. Both CO_2 and methane are GHGs; however, methane has 25 times the global warming potential of CO_2, thus converting methane to CO_2 provides an important benefit.

Many landfills capture LFG and simply burn it off in a flare to prevent a potentially explosive buildup of gas. Combusting LFG to generate power makes use of this otherwise wasted energy and also reduces odors, contaminants, and GHGs. The 3.2 MW Millersville LFG project collects LFG and sells it directly to the Army's Fort Meade installation to fuel operations at the installation.

[62] Energy Recovery from the Combustion of Municipal Solid Waste (MSW) | U.S. EPA.

LFG can be upgraded to renewable natural gas (RNG) by removing the CO_2 and other contaminants such as siloxanes, volatile organic compounds, and hydrogen sulfide. RNG can be injected directly into natural gas pipelines and used as a substitute for natural gas for space heating, power generation, vehicle fuel or in industrial processes.[63]

The steam-methane reforming process is widely used to convert natural gas into hydrogen. The steam-methane reforming process can extract hydrogen from RNG and rejects the remaining carbon into the atmosphere in the form of CO_2. If the rejected CO_2 is recovered and either sequestered or used as in industrial processes, the hydrogen would be considered clean and potentially eligible for production tax credits pursuant to the IRA.[64]

See CEIR-21, Section 3.1.5 for additional information on LFG.

[63] An Overview of Renewable Natural Gas from Biogas (epa.gov).

[64] Treasury, IRS issue guidance on the tax credit for the production of clean hydrogen | Internal Revenue Service.

Hydrogen

Hydrogen is a colorless, odorless gas that exists only in compound form with other elements. For example, water is composed of hydrogen and oxygen, and natural gas is composed of hydrogen and carbon. Nearly all of the hydrogen consumed in the U.S. is used in petroleum refining, metal treating, ammonia production, and food processing.

Hydrogen Production Processes

- Steam-methane reforming is the predominant process used to produce hydrogen. This process extracts hydrogen from natural gas and releases the remaining carbon into the atmosphere in the form of CO_2.
- Steam-methane reforming emits nine tons of CO_2 for every ton of hydrogen produced,[1] making it one of the most carbon-intensive industrial processes. Hydrogen from steam-methane reforming is not considered clean unless the CO_2 emissions are captured and sequestered.
- Electrolysis a process in which an electrolyzer produces hydrogen from water. Hydrogen is considered "clean" when the electricity supplied to the electrolyzer is generated from renewable sources such as solar or wind.

Use of Hydrogen in the Power Sector[1]

- **Fuel Cell Power Generation:** Stationary hydrogen fuel cell generators produce electricity for buildings by combining hydrogen fuel with oxygen from the air. An electrochemical reaction produces electricity without combustion, and pure water and heat are the only byproducts. Fuel cell electric vehicles (FCEVs) use hydrogen fuel cell generators in cars, trucks, and buses supply power to electric motors for vehicle propulsion with zero tailpipe emissions.
- **Engines and Gas Turbine Generators:** Hydrogen can be used as fuel in internal combustion engines for stationary power generation or for vehicle propulsion. Gas turbine generators can also use hydrogen fuel. It is typical for engines and gas turbines to use hydrogen–natural gas blends, of 5% to 15% hydrogen, as most would require modifications to operate on 100% hydrogen. Engines and gas turbines that use 100% hydrogen fuel must be designed or retrofitted for exposure to high temperatures and equipped to control NO_x emissions associated with combustion of hydrogen.
- **Energy Storage:** Solar and wind power can be curtailed when generation exceeds demand. Excess renewable generation can be used to produce hydrogen via electrolysis. The hydrogen can be stored and supplied to fuel cells to generate power at times when demand exceeds renewable generation. However, the required infrastructure for electrolysis and hydrogen transportation and storage is often expensive because it is not yet pervasive in the market.

Federal Incentives for Clean Hydrogen Production

- In October 2023, the Department of Energy's Regional Clean Hydrogen Hubs Program[1] selected seven regional clean hydrogen hubs[1] to be funded from a $7 billion appropriation in the 2021 Bipartisan Infrastructure Law. The hydrogen hubs program is aimed at facilitating the formation of a network of clean hydrogen producers, consumers, and connective infrastructure to decarbonize multiple sectors of the economy.
- The IRA added Section 45V to the federal tax code to provide a production tax credit of up to $3 per kilogram for hydrogen depending on the GHG emissions intensity of the hydrogen production process. Hydrogen produced using electrolysis with renewable electricity would qualify for the greatest tax credit, assuming certain conditions are met. Hydrogen produced using steam-methane reforming with CO_2 recovery and sequestration would receive a lower tax credit. In December 2023, the IRS issued draft regulations that would require that to receive the maximum tax credit, the renewable energy sources must be incremental to existing power sources. In addition, the renewable energy generation must be located in the same grid region, and the generation must be time matched to the time the electrolyzer operates.

Sources:

Reality-Check-on-CO2-Emissions-Capture-at-Hydrogen-From-Gas-Plants_February-2022.pdf (ieefa.org)
https://www.eia.gov/energyexplained/hydrogen/use-of-hydrogen.php
Regional Clean Hydrogen Hubs | Department of Energy
DOE New Regional Clean Hydrogen Hubs (natlawreview.com)
Federal Register, *Section 45V Credit for Production of Clean Hydrogen; Section 48(a)(15) Election To Treat Clean Hydrogen Production Facilities as Energy Property*, December 26, 2023, https://www.federalregister.gov/documents/2023/12/26/2023-28359/section-45v-credit-for-production-of-clean-hydrogen-section-48a15-election-to-treat-clean-hydrogen

3.1.7 Energy Storage

Overview

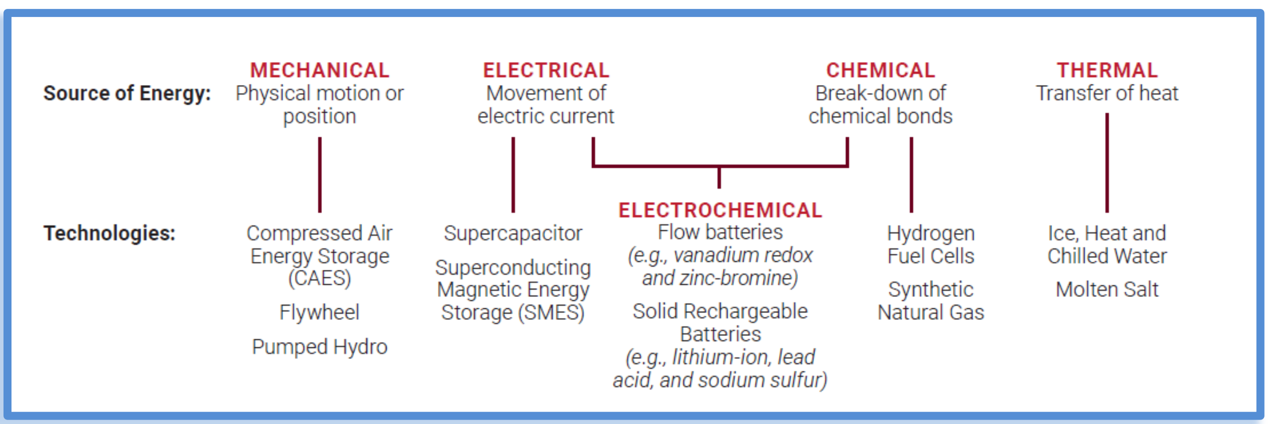
Energy storage allows energy produced at one point in time to be used at a later time. Storage systems are unique in that they can be in various forms and satisfy multiple functions, such as being able to serve as a generator, transmission asset, and/or distribution asset. Examples of energy storage technologies include pumped hydroelectric, compressed air energy storage (CAES), flywheels, and various types of batteries (e.g., lead-acid batteries, lithium-ion batteries, and zinc-bromide batteries). Each of the various technologies has different benefits, economics, and operational characteristics. Hence, the various technologies can be used to serve multiple end-uses.

See PPRP's website for additional information on energy storage in the Electricity Generation in Maryland discussion.

Energy Storage Technologies

Energy for storage systems can come from four sources: mechanical, electrical, chemical, and thermal. As noted in Figure 3-11, there is a wide variety of electricity storage devices currently in use, including pumped hydroelectric power, chilled water, batteries, and flywheels.

Figure 3-11 Energy Storage Sources of Energy and Common Technologies



Source: Maryland Department of Natural Resources Power Plant Research Program, "Energy Storage in Maryland," dnr.maryland.gov/pprp/Documents/Energy-Storage-In-Maryland.pdf, pp. 1–2.

Pumped hydro is the most widespread energy storage system in use today. With an efficiency rate of more than 80%, pumped storage provides for approximately 22 GW of energy storage in the United States. Water is pumped into an upper reservoir when electricity prices are low, generally during nighttime and off-peak periods, and then used to generate electricity for sale to the grid during peak hours. The Muddy Run pumped storage facility on the Susquehanna River in Pennsylvania has been in operation since 1966 and has a capacity of 1,070 MW.

Compressed air energy storage (CAES) makes use of natural and manmade (abandoned gas and oil wells) caverns to store compressed air and recover it for use in a turbine. Excess and inexpensive electricity is used to compress and pump high-pressure air into an underground cavern. When electricity is needed, the air is released, mixed with natural gas, and combusted via a turbine to generate electricity.

Lithium-ion batteries and sodium sulfur batteries are already being used to provide 15 minutes to 60 minutes of energy storage as regulation service. Some energy companies are also testing the use of

Brookville Bus Depot Battery Energy Storage System

The Montgomery County Department of Transportation plans to phase out fossil-fueled buses and transition to a battery electric bus (BEB) fleet. The County is developing a microgrid facility at the Brookville Bus Depot to support charging requirements for up to 44 BEBs. The microgrid scope is composed of:

- 4 MW of Battery Energy Storage System (BESS)
- Electric bus charging system (chargers, dispensers, and charge management)
- 2 MW of solar PV panels
- Natural gas generators

The Brookville Bus Depot is in the Potomac Electric Power Company (Pepco) service territory. The BESS participated in Maryland's Energy Storage Pilot Program and will provide peak-shaving services. Pepco has the contractual right to use 3 MW of the project's battery capacity over a 3-hour period up to 10 days per year over a 10-year period for peak shaving and to enhance grid reliability.

The microgrid project was developed, owned, and operated by AlphaStruxure, a joint venture of Schneider Electric and the Carlyle Global Infrastructure Opportunity Fund. The BESS was placed into service on October 18, 2022.

Montgomery County Completes Nation's Largest Bus Microgrid and Charging Infrastructure Project in Silver Spring (montgomerycountymd.gov)

Sources:

Brookville Smart Energy (Microgrids) Depot (montgomerycountymd.gov)
Microsoft Word - Order No. 89664 - Case No. 9619 - Energy Storage Pilot Proposal Order.docx (state.md.us)
https://www2.montgomerycountymd.gov/mcgportalapps/Press_Detail.aspx?Item_ID=42341&Dept=50

batteries for grid management and energy storage. The largest facility in the United States is the Vistra Energy's Moss Power Plant in Monterey County, California, that came on line in three phases between 2020 and 2023 with a capacity of 750 MW/3,000 MWh.

Flow batteries use liquid chemicals to store energy. Total energy storage is limited only by the size of tank used to hold the liquid. These systems are being targeted for peak shaving and utility-scale storage of solar and wind power. The technology has moved beyond the prototype phase. Recent commercial deployments include:[65]

- A 100 MW/400 MWh vanadium flow battery began operations in Dalian in northeast China in 2023 by Rongke Power Company.
- A 7 MW/30 MWh vanadium flow battery will be installed by Invinity Energy Systems in the United Kingdom.
- Wilsonville, Oregon,-based ESS, Inc. ended 2022 with just under 800 MWh of annual production capacity for its iron flow battery.
- China's megawatt iron-chromium flow battery with 6,000 kWh of energy capacity was approved for commercial use in 2023.
- Australia-based Redflow Limited installed 2 MWh zinc-bromine redox flow batteries at Anaergia's Rialto Bioenergy Facility in San Bernardino County, California.

Flywheel systems use large rotating masses and are a good fit for providing regulation services. This technology can be used as a short-term buffer to smooth local output fluctuations from a wind facility or PV array. Flywheels are commercially available for development as "regulation power plants" providing up to 25 MW of regulation capacity. A flywheel storage regulation power plant has been shown to be capable of providing full power within four seconds of receiving a control signal.

See PPRP's website for additional information on other emerging battery storage technologies, the energy storage tax credit, and Maryland's energy storage goals in the Electricity Generation in Maryland discussion.

3.2 New and Proposed Power Plant Construction

From 2015 to 2023, the PSC received 57 CPCN applications for proposed new generating facilities. While the majority of these proposed plants obtained a CPCN, only 16 are now in operation. The remainder are under construction or have been delayed or abandoned for various financial or commercial reasons.

Maryland has seen a sharp increase in both community-scale and utility-scale solar projects in recent years. Developers are proposing these solar projects to capitalize on federal tax incentives, support the Maryland RPS, and meet electricity generation demand growth (see solar discussion in Section 3.1.5).

As of October 2023, a total of 61 solar cases had filed for CPCNs since 2010 and 45 have been granted a CPCN. Among the cases that have not been granted a CPCN:

- Five are currently under review,

[65] Technology Strategy Assessment - Flow Batteries (energy.gov).

- One is suspended,
- One is being held in abeyance,
- Seven were withdrawn from the CPCN process by the applicant, and
- One CPCN was denied.

Of the 45 projects that have been granted CPCNs, 17 are operational as of October 2023. These 17 facilities have an aggregate licensed generating capacity of just over 400 MW.

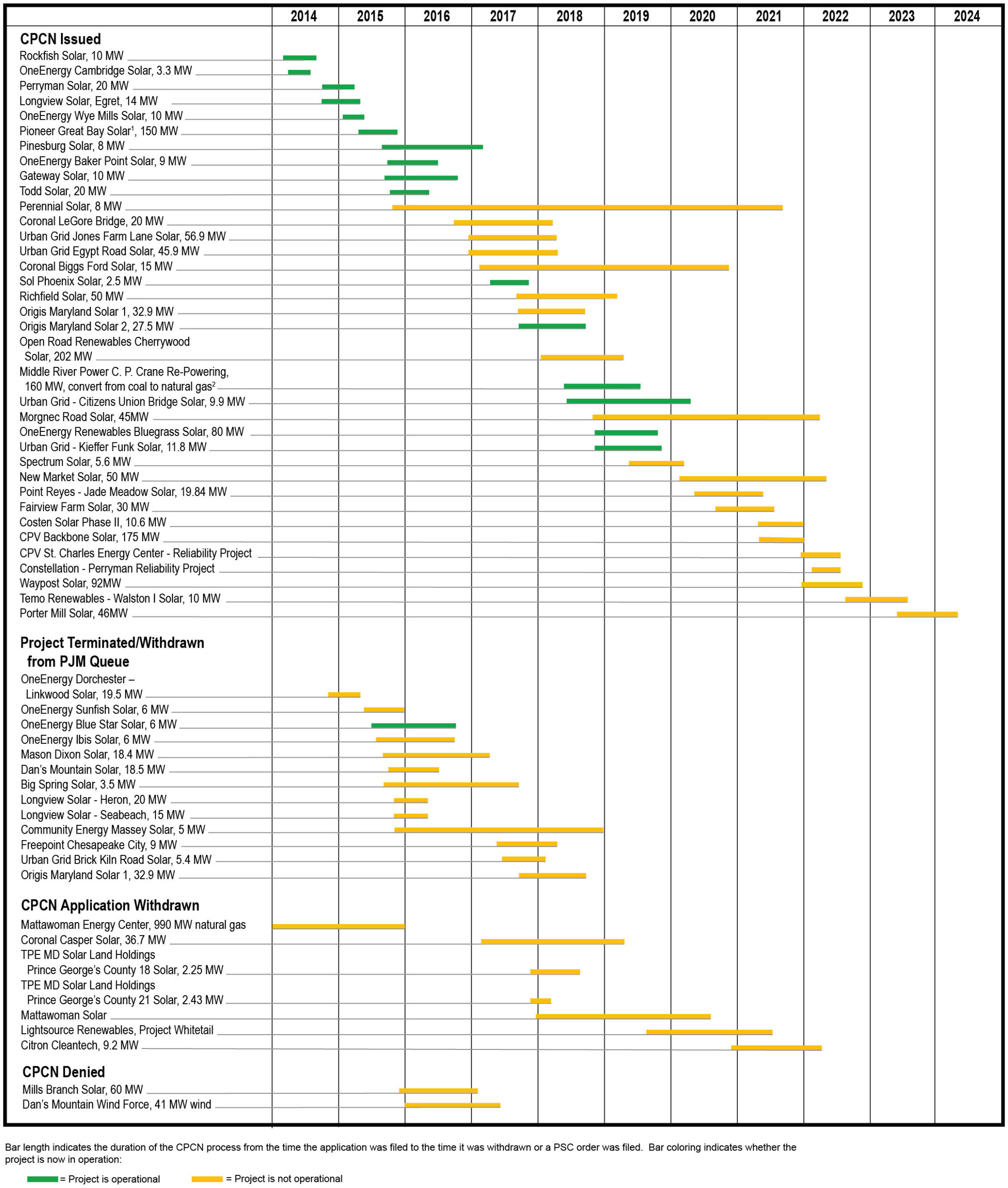
In July 2023, PPRP undertook a study to determine the reason why the remaining proposed solar projects with CPCNs were not yet operational. PPRP used the CPCN discovery process to issue data requests to developers of these proposed projects. The data requests asked for information about the current status, the reasons for any delays in project construction, and feedback on what are the primary causes of delays in the construction of utility-scale solar projects. PPRP received 27 responses. Five of the respondents indicated they had not encountered any delays. The remaining respondents reported either delays to construction or reasons why project construction was ultimately abandoned. Reasons given for delay or abandonment of construction included:

- Difficulties with county permitting,
- Local interconnection costs and timelines,
- Decrease in the value of the proposed project,
- Supply chain disruptions,
- PJM interconnection delays,
- MDE permitting delays, and
- Lack of a power purchase agreement.

Figure 3-12 provides a snapshot of all projects that requested a CPCN during the period 2014 to 2024. Those that were granted a CPCN are listed either under CPCN Issued or Project Terminated/Withdrawn from PJM Queue, depending on the project's response to PPRP's July 2023 study.

In addition, from the renewable energy project perspective, Competitive Power Ventures (CPV) Backbone Solar, LLC received a CPCN in January 2022 to construct a large, utility-scale, 175 MW alternating current (AC) generating capacity solar PV facility in Garrett County, Maryland. The project is currently under construction and will be the first utility solar facility of this size to be constructed to effectively reuse reclaimed underground coal mine property with minimal impacts to neighboring properties. One other smaller solar PV facility to be constructed on reclaimed surface coal mine property was also granted a CPCN in May 2021.

Figure 3-12 CPCN Requests, 2014 through May 2024



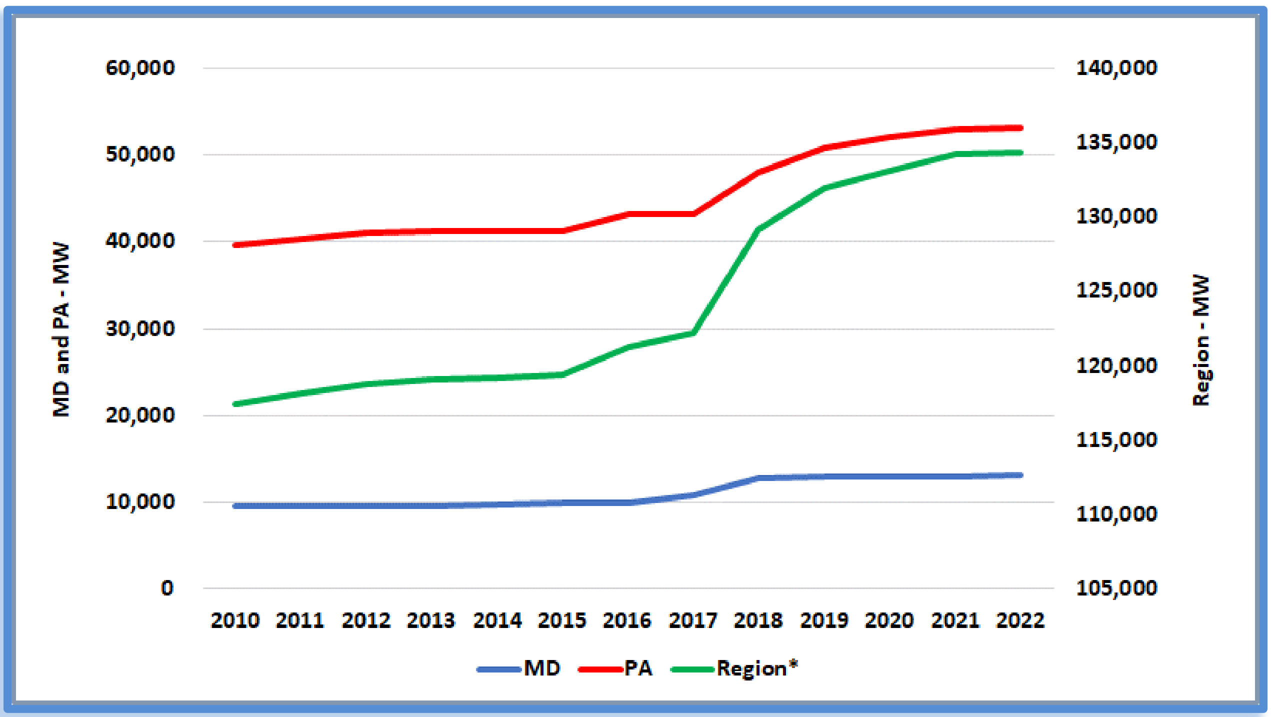
Bar length indicates the duration of the CPCN process from the time the application was filed to the time it was withdrawn or a PSC order was filed. Bar coloring indicates whether the project is now in operation:

[1] The CPCN is for 150 MW solar array; only 75 MW of the project are in operation as of October 2019.
[2] CP Crane Generating Station was demolished in 2022.

Chart does not reflect the following CPCN cases ongoing as of May 2024: Flownium Power Rosehip Solar, Community Power Group Hidden Meadows Solar, Kumquat & Citron Cleantech Citron 2 Solar, and Porter Mill Solar.

Over the last decade, capacity in Maryland increased 34% from 9,575 MW in 2012 to 13,079 MW in 2022. Over the same period, capacity in Pennsylvania increased 29% from 41,018 MW to 53,085 MW. Regionally, capacity increased 12.1% from 118,801 MW in 2012 to 134,372 MW in 2022. The increase in capacity is due almost entirely to natural gas plants, with renewable energy resources contributing a small portion of the total capacity growth. Figure 3-13 shows the amount of capacity online for Maryland, Pennsylvania, and the region.

Figure 3-13 Maryland and Regional Capacity, 2010–2022

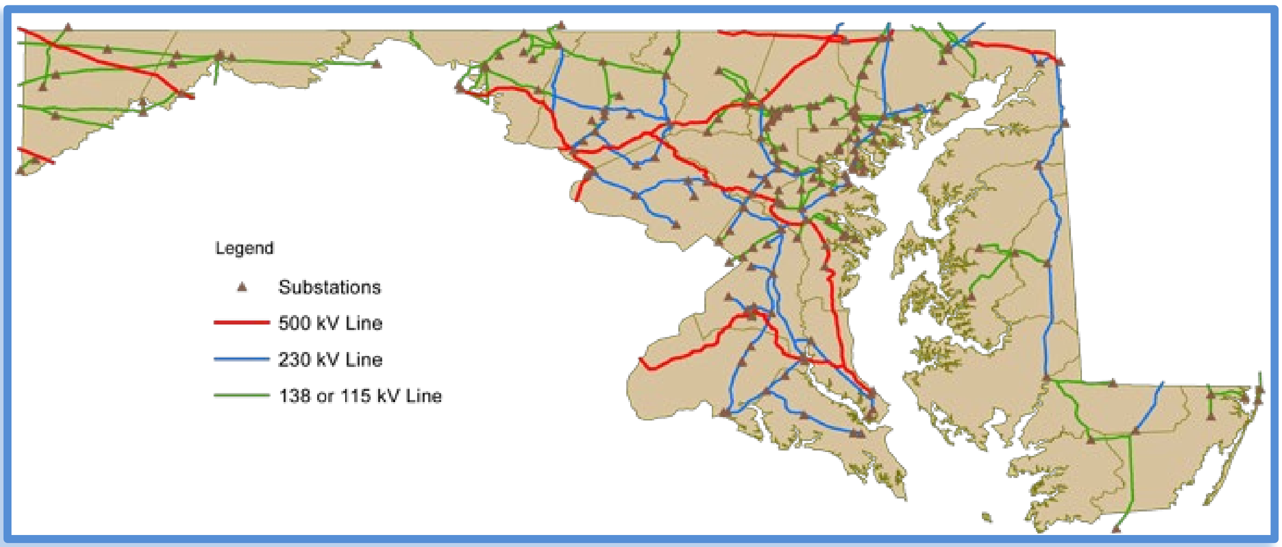


*Region includes Delaware, Maryland, New Jersey, Pennsylvania, Virginia, the District of Columbia, and West Virginia.
Source: U.S. Energy Information Administration, EIA-860, 2022 Final Release.

3.3 Electric Transmission

The network of high-voltage lines, transformers, and other equipment that connects power-generating facilities to distribution systems is part of an expansive electric transmission system. In Maryland, there are more than 2,000 miles of transmission lines operating at voltages between 115 kilovolts (kV) and 500 kV. Figure 3-14 shows a map of this high-voltage transmission grid in Maryland.

Figure 3-14 Transmission Lines in Maryland (>115 kV)

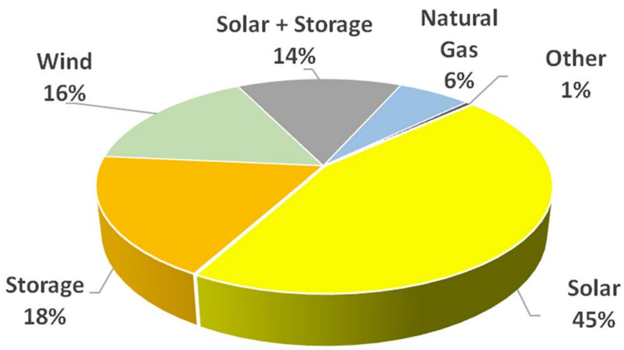


While the economic and environmental effects of generation can be substantial, transmission also has major environmental and socioeconomic implications in Maryland, particularly because Maryland is a net importer of electricity. Building new transmission facilities is costly, often with significant environmental impacts and ratepayer costs. Upgrading existing heavily used facilities must be done quickly, often within short windows of time, while minimizing environmental impacts. Shortages of transmission capacity or congestion can lead to higher-priced, out-of-merit generation dispatch and extremely high energy and capacity prices.

PJM has operational control over and planning responsibility for the high-voltage transmission facilities in Maryland. As part of its transmission planning responsibilities, PJM routinely examines projections of generation, transmission, and loads to determine whether additional transmission facilities are needed to comply with applicable transmission planning standards and associated reliability criteria. The PJM Generation Interconnection Queue is described in a sidebar shown on the PPRP website. PJM also periodically examines whether certain new transmission lines will produce economic benefits, usually in the form of market efficiency projects that may relieve congestion and provide the lowest electric costs for consumers in the region, even if they are not needed for reliability reasons. To the extent PJM determines a need for a transmission project and includes it in the Regional Transmission Expansion Plan (RTEP), there is an expectation that the transmission owner will file for a CPCN seeking permission to construct the proposed transmission line. More details on the RTEP process are discussed in Section 4.3.3. Typical transmission line design and construction techniques are provided on the PPRP website.

PJM Generation Interconnection Queue

New generation projects seeking to connect to the PJM grid must submit a generator interconnection request. PJM performs the requisite studies for generator interconnection in clusters grouped together based on a six-month queue cycle. The aggregate list of dated interconnection requests is referred to as the generation interconnection queue. As of December 2022, the PJM interconnection queue consisted of projects totaling 287 GW of capacity (stated as winter net capacity). Solar is the dominant resource, followed by storage. The breakdown by fuel type is shown in the following pie chart. Renewable energy projects (e.g., wind, solar, and solar + storage) accounted for 75% of the total capacity in the PJM interconnection queue. Although most generation projects in the interconnection queue are not ultimately constructed, the interconnection queue provides an initial estimate of the potential new generation capacity in PJM.



	MW	
Solar	128,529	45%
Storage	52,926	18%
Wind	46,633	16%
Solar + Storage	40,179	14%
Natural Gas	17,789	6%
Other	1,436	1%
Total	**287,493**	**100%**

On July 10, 2022, PJM implemented a new interconnection process, moving to a "first-ready, first-served" cycle where developers submit readiness deposits and proof of site control for PJM to begin the interconnection. PJM has also released a new Queue Scope tool for developers to access location impacts of future generators before formal interconnection to PJM.

Sources:

FERC approves PJM's "first-ready, first-served" interconnection reform plan, steps to clear backlog | Utility Dive
Transition to New Interconnection Process Begins July 10 | PJM Inside Lines
PJM Launches Public Tool To Assess Potential Impacts of New Generation on the Grid | PJM Inside Lines

3.3.1 New and Proposed Transmission Projects

On January 2, 2022, the PSC granted a CPCN to Baltimore Gas and Electric Company (BGE) to build the Five Forks to Windy Edge Reliability Project. Once constructed, this overhead transmission line rebuild will replace the existing double-circuit 115 kV line and its associated lattice structures with new weathering steel monopole towers. The approximately 20-mile line runs from the Five Forks substation in northern Harford County to the Windy Edge substation located in northern Baltimore County and was placed into service approximately 100 years ago. The new transmission line will replace more than 400 existing lattice structures with 219 new monopole structures. The project will address aging infrastructure and avian interactions and will reduce tower strike risk by reducing structure foundation size. This project has a target in-service date of December 21, 2025.

Potomac Edison's Doubs to Goose Creek overhead transmission line rebuild will replace the existing 500 kV line located in Frederick and Montgomery counties, Maryland. The approximately 18-mile, extra-high-voltage line will connect with an extra-high-voltage line that continues into Virginia. The new line will replace facilities that have been in service for 40 years and are reaching the anticipated end of life. The maximum operating capacity will increase from 2,442 megavolt-amperes (MVA) to 4,330 MVA. The PSC issued a proposed order on March 23, 2023; however, the Office of People's Counsel (OPC) filed a Notice of Appeal on April 24, 2023. OPC filed a Memorandum on Appeal, and PE filed a Reply Memorandum on May 23, 2023. The PSC denied the appeal and granted the CPCN on June 27, 2023.

As reported in CEIR-21, Transource Energy, LLC (Transource) was granted a CPCN on June 30, 2020, to build two new 230 kV overhead transmission lines, one in Frederick County, Maryland (Independence Energy Connection (IEC) West) and one in the reconfigured IEC East portion in Harford County, Maryland. However, on May 24, 2021, the Pennsylvania Public Utility Commission (PA PUC) denied the siting applications of the IEC East project for the portions located in York County, Pennsylvania, and the IEC West project in Franklin County, Pennsylvania, because Transource failed to establish the need for the proposed transmission lines.[66] As of October 2023, the future of this transmission project is undecided as Transource has appealed the PA PUC decision.

Delmarva Power & Light Company's (DPL's) Vienna to Nelson Transmission Reliability Project extends from the Vienna Substation in Dorchester County, Maryland, to the Nelson Substation in Sussex County, Delaware. The Project crosses the Nanticoke River east of the Vienna Substation. The entire project length is 13.7 miles— 7.6 miles in Maryland and 6.1 miles in Delaware—with all work occurring within the existing right-of-way (ROW). The rebuild project will include replacing two existing steel lattice towers and 57 existing wood H-frame structures, installed in the late 1950s, with 59 galvanized steel monopoles. This project will include an upgrade of existing conductors and shield wire to 230 kV construction standards, although the project will be energized to 138 kV for the near term. The PSC granted a CPCN to DPL on December 19, 2023. The planned in-service date is late 2025.

Potomac Electric Power Company's (Pepco) Oak Grove to Talbert Rebuild Project extends approximately 10.2 miles from the Oak Grove Substation to the Talbert Substation all within Prince George's County. Pepco plans to rebuild an existing 10.2 mile, 230 kV, double circuit tower line (DCTL) originating at Pepco's Oak Grove Substation and running to Pepco's Talbert Substation. The project will include the replacement of 62 lattice structures with 62 new double-circuit single steel pole structures on the West Line. There are currently two sets of 230 kV circuits located within the ROW, the East Line and West Line, both constructed in 1968. The PSC granted a CPCN to Pepco on March 14, 2024. The planned in-service date is May 2025.

BGE's Fitzell Substation 3rd and 4th Circuits Reconfiguration Project extends approximately 2.5 miles from the proposed Bear Creek Terminal Station along Dundalk Avenue to the Fitzell Substation in Edgemere, Baltimore County. BGE is proposing to reconfigure 2.5 miles of existing 115 kV Circuit 110503 and Circuit 110504. The project would intercept the existing Windy Edge to Riverside overhead transmission line and reroute the circuits to the Fitzell Substation located within the Trade Point Atlantic property on Sparrow's Point. The reconfiguration includes both overhead and underground segments and multiple underground installation techniques are proposed, including duct-bank, horizontal

[66] Pennsylvania Public Utility Commission, Docket Nos. A-2017-2640195 and A-2017-2640200.

directional drilling, and jack and bore installation. Project components include the New Bear Creek Terminal Station with eight new transmission structures and ancillary structures on property to be acquired, approximately 1.6 miles of new underground transmission segments, and underground crossings of Bear Creek, Riverside Drive, I-695, and Bethlehem Boulevard. The PSC granted a CPCN to BGE on March 28, 2024. The planned in-service date is Fall 2025.

As of August 2024, PPRP has one ongoing transmission project under CPCN Review:

- BGE's Brandon Shores Retirement Mitigation Project includes five project segments involving modifying and constructing overhead transmission lines in Harford, Baltimore, and Anne Arundel counties. The Graceton to MD-PA Segment will involve upgrading 2.2 miles of 23 kV transmission line to 500 kV starting from the MD-PA state line and ending at the Graceton Substation. The Graceton Connections Segment will involve the reconfiguration of an existing 500 kV overhead transmission line and relocation of a 230 kV circuit termination point. The Graceton to Batavia Segment will involve the installation of a new 230 kV double circuit line along 29 miles of an unoccupied side of BGE's existing ROW. The Batavia to Riverside Segment will involve reconductoring six miles of an existing 230 kV transmission line from the Batavia Substation to the Riverside Substation. The Solley Road Segment will involve work on an existing 230 kV overhead transmission line and the addition of two new 230 kV overhead transmission lines needed to connect a new substation and STATic synchronous COMpensator (STATCOM). BGE filed its CPCN application on July 11, 2024. The planned in-service date is December 2028.

Transmission planning and regulatory drivers, as well as oversight, are described in Section 4.3.

The Maryland Power Act

The Promoting Offshore Wind Energy Resources Act (the Power Act) was signed into law on April 21, 2003, and took effect on June 1, 2023. It establishes a target for offshore wind generation of 8,500 MW by 2031. The Power Act requires the PSC to request that PJM conduct an analysis of transmission system upgrades and expansion options that would be needed to accommodate at least 8,500 MW of offshore wind energy. The new law also requires that PSC or PJM issue competitive solicitations for proposals for offshore wind transmission facilities and related onshore facilities by July 1, 2025. The Department of General Services, in consultation with PSC, must issue a competitive solicitation by July 31, 2024, to procure up to 5.0 million MWhs of offshore wind energy annually for a minimum term of 20 years.

3.3.2 Transmission Line Designs

Transmission lines can be designed and constructed in a variety of ways to accommodate site-specific conditions, such as topography, soil types, proximity to existing infrastructure, sensitive resources, and urban areas. While traditional overhead alternating current (AC) transmission lines are the most common, alternative transmission line types, such as underground, submarine, and direct current (DC), are becoming more prevalent. These types of technologies are discussed in the following sections.

Underground Transmission Cables

Underground transmission lines are typically installed in locations where overhead lines are difficult to place or would create aesthetic or environmental issues. In this type of construction, underground transmission cables are typically placed three to five feet below the ground surface in conduits or reinforced duct banks or are directly buried in specially prepared soil. Instead of wide spacing between conductors, as is required for overhead transmission lines, underground cables are typically placed close together and insulated to protect the cables from one another. Frequently, the individual cables required to make up a circuit are placed in polyethylene, polyvinyl chloride (PVC), or fiberglass conduits and installed as a group. Please refer to CEIR-21 for images and additional discussions of underground transmission line installations, including the advantages and disadvantages of this practice. CEIR-21 also describes the Southern Maryland Electric Cooperative (SMECO) project from the Holland Cliff in Calvert County to the Hewitt Road Switching Station in St. Mary's County, where an underground construction component of the new 230 kV transmission line was included. This technology is proposed for BGE's Fitzell Substation 3rd and 4th Circuits Reconfiguration Project described in CEIR-22, Section 3.3.1.

Submarine Transmission Cables

Submarine cables are installed beneath a river bottom or seabed via trenching or (for shorter lengths) horizontal directional drilling or are laid on the river bottom or seabed. These cables are becoming more common for higher-voltage transmission lines, as the reliability of the technology is being proven and for offshore transmission systems where submarine installations are necessary. Offshore wind projects will require the installation of submarine cables to connect the offshore to onshore components (i.e., inter-array submarine cables from the wind turbines to offshore substations, and submarine offshore export cables to the onshore substation).

Submarine cables are typically manufactured and installed as one line to provide the greatest reliability and can stretch up to 10 miles in one segment for AC cables, or several times longer for DC cables. Submarine cables are similar in design to underground cables with additional shielding layers. Like underground cables, submarine cables can be designed for both AC and DC systems and can be bundled and installed together in the same trench or conduit. Trenching techniques typically involve fluidizing the seabed using a jet plow pulled along the seabed to allow the cable to sink down to the desired installation depth of approximately six feet to 15 feet, depending on specific site conditions.

The benefits of implementing a submarine system are a limited disruption to navigation and minimized visual impacts once the cables are installed as compared to the use of an overhead waterway crossing. Impacts from submarine cables are typically associated with disruption of the seabed, sedimentation, and release of nutrients sequestered in the sediments, as well as heat dissipation during operation.

The previously mentioned SMECO 230 kV transmission line from Holland Cliff in Calvert County to the Hewitt Road Switching Station in St. Mary's County includes an approximately one-mile submarine crossing of the Patuxent River near Solomons, achieved with horizontal directional drilling. The construction of this project, monitored by PPRP, was completed in 2014.

Direct Current Transmission Lines

According to the U.S. Department of Energy (DOE), several thousand miles of high-voltage direct current (HVDC) transmission lines are presently installed in the U.S., which is only a fraction of the more than 200,000 miles of total installed high-voltage transmission lines (including hybrid AC and DC) in the United States. However, the implementation of DC technology into project design is becoming increasingly common. DC systems are most often implemented for large-scale bulk power transfers over long distances, such as undersea cables, or to connect different transmission networks between countries. In some applications, HVDC systems can be more cost-effective at long transport distances compared to high-voltage alternating current (HVAC) systems. DC technology allows for the use of fewer conductors or cables (two versus three for AC), allowing for typically more compact installations than a comparable AC system. However, DC systems require large conversion stations at each interconnection with the traditional AC grid. Precise, fast, and flexible control of energy flows at any level within the capacity limit of the line is another significant advantage of a DC system. This technology is becoming more widely used across the industry; however, there are no projects within Maryland proposing the use of HVDC transmission. This technology could be used to support future offshore wind projects to meet the recent increases in the amended Maryland RPS (see Section 3.1.5).

3.3.3 Transmission Line Impacts

Recognizing the ever-changing landscape of the nation's electric transmission grid, there are federal and state initiatives to study the current and anticipated future capacity constraints and congestions. The DOE has proposed the 2023 National Transmission Needs Study,[67] formerly known as the National Electric Transmission Congestion Study. This study will be based on findings that there is a demand for additional electric transmission infrastructure, as is demonstrated by the projects described in Section 3.3.1, particularly for projects on Maryland's eastern shore and projects to support the growing localized demand (i.e., data centers) on the U.S. East Coast. The study will also focus on interregional transfer capacity by connecting transmission across larger regions. There is also the recognition that the electrical grid will need to be reinforced to shift to clean energy while accommodating rapid changes in regional demand and increased extreme weather events.

3.3.4 Electricity Distribution

There are 13 utilities distributing electricity to customers in Maryland (see Table 3-5). Four of these are large, investor-owned electric companies organized as for-profit, tax-paying businesses: Potomac Edison (formerly Allegheny Power), BGE, DPL, and Pepco. They are owned by two holding companies—FirstEnergy (which owns Potomac Edison) and Exelon (which owns BGE, DPL, and Pepco). Maryland's investor-owned utilities serve approximately 90% of the customers in the state.

Five utilities are owned and operated by municipalities providing local electric distribution service to a specific area. Four utilities are electric cooperatives, serving generally less populated rural areas. The service territories for the state's distribution companies are illustrated in Figure 3-15.

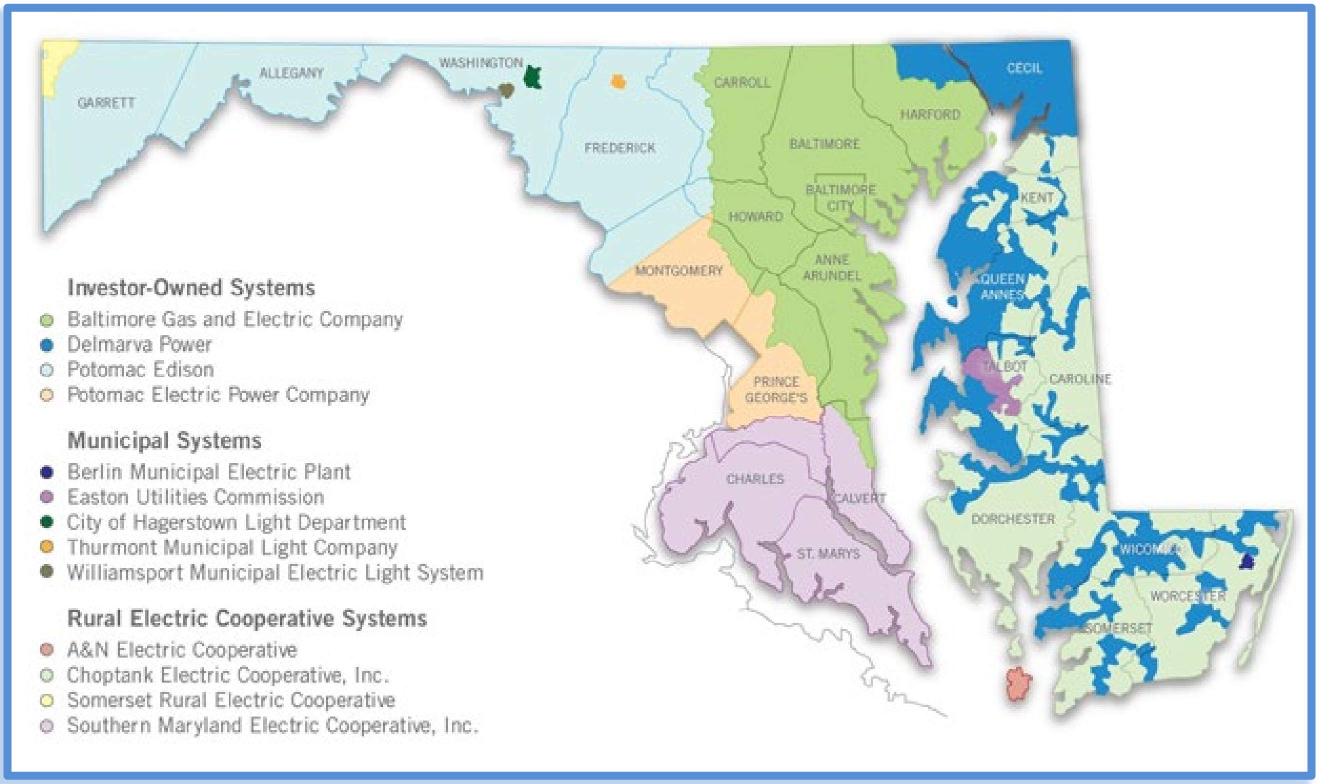
[67] National Transmission Needs Study | Department of Energy

Table 3-5 Maryland Electric Distribution Companies, 2023

Company	Approximate Number of Maryland Consumers
INVESTOR-OWNED*	
Potomac Edison Company (owned by FirstEnergy)	291,969
Baltimore Gas & Electric Company (owned by Exelon)	1,345,287
Delmarva Power & Light Company (owned by Exelon)	219,581
Potomac Electric Power Company (owned by Exelon)	602,071
Subtotal	2,458,908
MUNICIPAL SYSTEMS**	
Berlin Municipal Electric Plant	2,667
Easton Utilities Commission	11,022
City of Hagerstown, Light Department	17,539
Thurmont Municipal Light Company	2,879
Williamsport Municipal Electric Light System	1,023
Subtotal	35,130
COOPERATIVE SYSTEMS**	
A&N Electric Cooperative***	303
Choptank Electric Cooperative, Inc.**	56,142
Somerset Rural Electric Cooperative, Inc.****	798
Southern Maryland Electric Cooperative, Inc.*	174,357
Subtotal	231,564
Total Customers	2,725,602

* Source: Maryland Public Service Commission, Electric Choice Enrollment Report December 2023.
** Source: Maryland Public Service Commission, Ten-Year Plan for 2023-2032. Forecast number of customers. Actual 2023 data were not available for these utilities.
*** Source: U.S. Energy Information Administration, EIA-861 2022.
**** Source: Somerset Rural Electric Cooperative, Utility Annual Report for 2022. https://www.psc.state.md.us/annual-utility-reports/

Figure 3-15 Electricity Distribution Service Areas



3.4 Maryland Electricity Consumption

Maryland end-use customers consumed about 59.7 thousand gigawatt hours of electricity during 2022.[68] Between 2010 and 2022, the annual average growth rate in electricity consumption in Maryland was lower than in the U.S. as a whole (negative 8.7% in Maryland versus a positive 4.6% in the United States). Additional information on Maryland electricity consumption can be found on PPRP's website.

3.4.1 Maryland Electricity Consumption Forecast

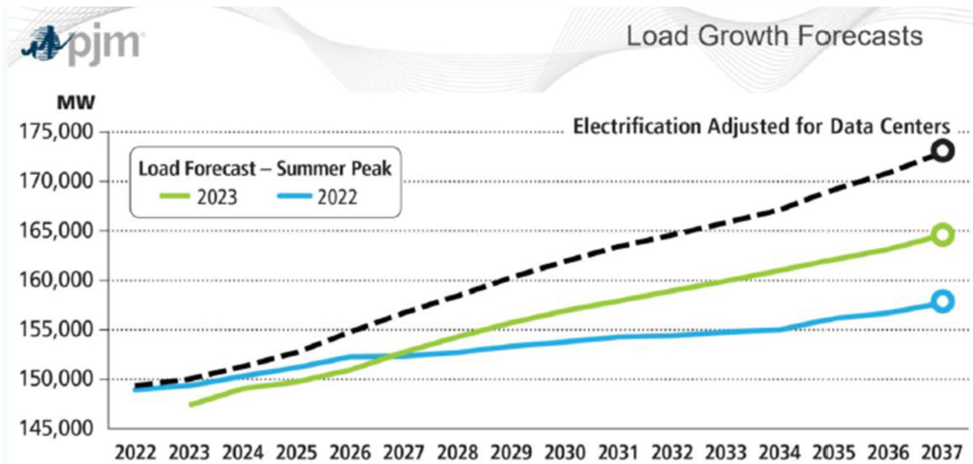
Additional information on Maryland electricity consumption forecast can be found on PPRP's website.

[68] U.S. Energy Information Administration, Annual Data by Sector, by State, by Provider: https://www.eia.gov/electricity/data.php .

Increased Load from Data Centers

Northern Virgina is home to the highest concentration of data centers in the world. For Loudon County, Virginia, and surrounding areas, PJM expects 40% load growth by 2039 because of data centers. Data center expansion is driven by increased use of cloud-based services by business, smartphone and 5G technology, digitization of data, and artificial intelligence.

PJM 2023 demand forecasts show that data centers and vehicle electrification will increase summer peak demand to nearly 173 GW by 2037, an increase of about 1% from 2022's forecast, and an increase of 5.6% for 2029 as compared to 2022.



Source: energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx

The Maryland General Assembly passed a bill in 2020 that allowed sales, use, and personal property tax exemptions for data centers to compete with Virginia and 24 other states with tax exemptions for data centers. The Governor has made data center development in Maryland a top priority.

Data center community developer, Quantum Loophole, has proposed a data center campus called Quantum Frederick, on a 2,100-acre abandoned industrial site in Frederick County. Campus power demand could be as much as 800 MW at full buildout.

In 2023, the PJM Board of Directors approved $5 billion of transmission projects in response to 7,500 MW of data centers in Virginia and Maryland.

Sources: https://www.datacenterdynamics.com/en/news/pjm-transmission-zone-to-see-grid-loads-increase-40-by-2039/

National-Load-Growth-Report-2023.pdf (gridstrategiesllc.com)

PJM Load Forecast Report January 2024, https://www.pjm.com/-/media/library/reports-notices/load-forecast/2024-load-report.ashx

https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/sb0397?ys=2020RS&search=True

https://www.streamdatacenters.com/glossary/tax-incentives-for-data-centers/

https://www.wusa9.com/amp/article/news/local/maryland/maryland-governor-wes-moore-hurdles-mega-data-center-development-in-frederick-county/65-d2a710e2-b148-4b8e-9445-ae9ef71d04b8

National-Load-Growth-Report-2023.pdf (gridstrategiesllc.com)

PJM 2023 Regional Transmission Expansion Plan, p. 1, https://www.pjm.com/-/media/library/reports-notices/2023-rtep/2023-rtep-report.ashx

3.5 Policy Initiatives and Energy Programs

By law, Maryland encourages the development and use of clean energy technologies such as solar, wind, energy storage, and electric vehicle charging stations. In addition, the state continues to evaluate and implement policies that encourage a customer-centered distribution grid that is affordable, reliable, and environmentally sustainable. A brief discussion of the Maryland Renewable Energy Portfolio Standard can be found in Section 3.1.5 and additional information can be found on PPRP's website in the Policy Initiatives and Energy Programs discussion.

3.5.1 Net Metering in Maryland

Ratepayers with distributed generation (e.g., rooftop solar) may receive compensation for generation beyond their consumption through a billing mechanism known as net metering. Net metering is the method of compensating consumers with distributed generation capacity in periods when a customer produces more energy than they consume. Essentially, when a consumer is producing more electricity than they are consuming, the meter "runs backwards" to track the net amount of energy the customer consumes in a billing period. Net metering allows the consumer to sell electricity back to the utility in the form of a per-kWh credit, and the excess energy is exported to the distribution grid for the utility to sell to other customers. Net metering is like a ratepayer using the local electric grid as battery storage. Additional information about net metering in Maryland can be found on PPRP's website in the Policy Initiatives and Energy Programs discussion.

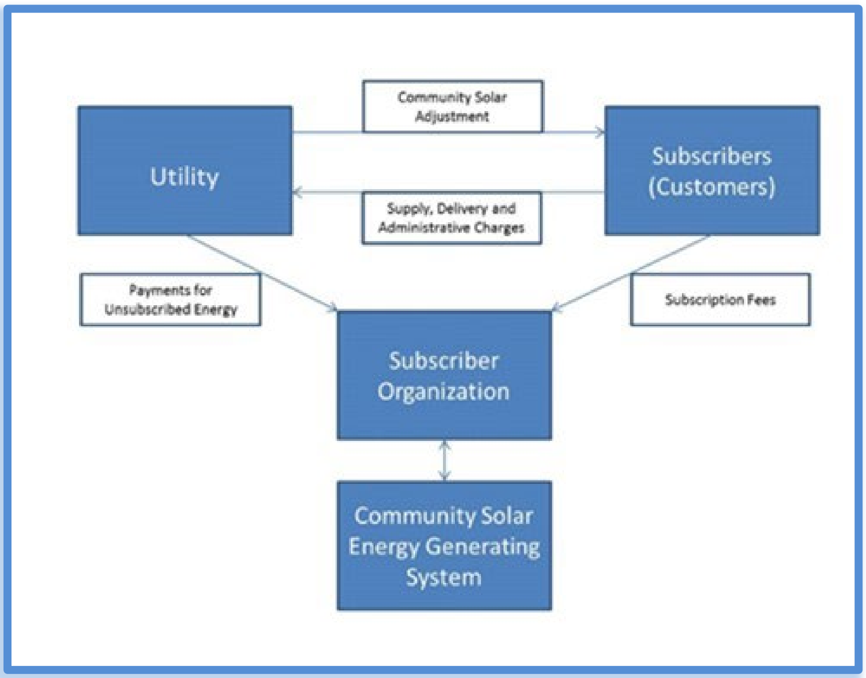
3.5.2 Community Solar in Maryland

Customers who may not have the means to own or install their own solar energy system may buy or "subscribe" to blocks of capacity from a nearby solar facility through community solar. A community solar facility is often located offsite; however, some facilities are referred to as "shared" and are located on the rooftop of an apartment complex or split among rooftops of a community, allowing that community to purchase the solar energy as a group. Community solar provides a credit to each subscriber of a community solar system based upon the amount of energy to which the customer has subscribed.

Community solar was implemented on a project-by-project basis in Maryland until the establishment of a Community Solar Pilot Program in July 2015. The pilot program commenced in April 2017 and is intended to attract new investment in solar systems and to provide a small carve-out in the total capacity for solar systems built on parking lots, industrial areas, or brownfields. The Community Solar Pilot Program contributes to and is included as part of the total state net metering limit of 3,000 MW.

Figure 3-16 provides a simple overview of how community solar projects work in Maryland. Community solar projects are built and operated by PSC-approved subscriber organizations, such as utilities, electricity suppliers, and solar developers. A subscriber must submit an interconnection application to the appropriate investor-owned utility (IOU) based upon the service territory in which the project is located. Upon receiving conditional interconnection approval from the IOU, a subscriber organization must apply to the Community Solar Energy Generating System (CSEGS) Pilot program administered by the PSC. Once approved, the subscriber organization may sell community solar subscriptions to customers, and the project is constructed once enough subscribers have enrolled. The subscriber organization will receive payment from the IOU for any generation produced by the CSEGS above what has been subscribed.

Figure 3-16 Basics of Maryland Community Solar Projects



Source: Adapted from bge.com/SmartEnergy/MyGreenPowerConnection/Pages/HomeBusiness/CommunitySolarSubscriberOrg.aspx.

Subscribers can purchase a share of the CSEGS, up to 200% of the subscriber's historical annual energy consumption. A subscriber pays either an upfront fee or a fixed monthly payment to the subscriber organization for the portion of power procured, and in return, the subscriber will receive a community solar adjustment credit on their electric bill from their IOU. A subscriber still receives its services from the IOU, including supply and delivery, and the credit offsets those charges. In this way, community solar is virtually net metered.

As of June 2023, 583.2 MW of community solar projects across the state have been proposed, 426.1 MW have been accepted, and 113.8 MW are in operation. Table 3-6 shows the Community Solar Pilot Program's reserved capacity (most of the offered capacity) and the amount accepted by IOUs compared to the amount of total capacity available over seven years.

Table 3-6 Maryland Community Solar Pilot Program Capacity as of June 30, 2023 (MW)

Utility	Offered Capacity	Accepted Capacity	Operating Capacity
Baltimore Gas and Electric Company	305.30	229.72	62.47
Delmarva Power & Light Company	49.84	46.04	10.80
Potomac Electric Power Company	150.85	82.78	22.53
Potomac Edison Company	77.18	67.57	17.97
State Total	**583.17**	**426.11**	**113.77**

Accepted capacity source: Maryland Public Service Commission, Report on the Status of Net Energy Metering in the State of Maryland, November 2023, https://www.psc.state.md.us/wp-content/uploads/2023-Net-Metering-Report.pdf.

The Maryland General Assembly revised the Community Solar Pilot Program to extend the termination date of the pilot program from July 2020 to no sooner than December 31, 2024. Additionally, it removed the limit on the maximum number of subscribers to a community solar system to allow for any number of subscribers to participate in a project and raised the maximum capacity for an individual community solar project to 2 MW. The PSC submitted a report to the General Assembly by July 1, 2022, regarding the PSC's findings and recommendations concerning community solar. The PSC recommended a full cost-benefit analysis at the end of the Solar Pilot Program, more low- and moderate-income (LMI) participation, coordination with electric companies, and pairing projects with energy storage.[69] In 2022, the General Assembly passed legislation to increase the maximum size of a community solar project from 2 MW to 5 MW effective October 1, 2022.[70]

In 2023, the Maryland General Assembly made the Community Solar Pilot Program permanent and required at least 40% of the power output community solar projects to serve LMI subscribers, unless such subscribers wholly own the solar system. The General Assembly also relaxed restrictions on the co-location of community solar systems exceeding 5 MW if they are located on rooftops, in areas previously or currently zoned for industrial use, on brownfield sites, on multilevel parking structures, or located over parking lots or roadways, on or over transportation ROWs, or at airports. Furthermore, the legislation (i.e., HB 908) allowed co-located community solar facilities of 10 MW or less as long as at least 75% of the aggregate capacity serves LMI customers.[71]

The General Assembly also directed the PSC to revise current regulations by January 1, 2025, and enact regulations by July 1, 2025, that would, among other things, accomplish the following:

- Eliminate all program categories, project generating capacity limits, annual programmatic and electric company specific capacity limits, and expiration dates so that the total number and capacity of community solar energy generating systems is subject only to the overall statutory limitation (3,000 MW) for all net metering projects; and

[69] Maryland Public Service Commission, Report on the Status of Net Energy Metering in the State of Maryland, November 2023, p. 11, https://www.psc.state.md.us/wp-content/uploads/2023-Net-Metering-Report.pdf

[70] Ibid., p.13.

[71] Maryland Department of General Services, *Fiscal and Policy Note for HB 908*, April 12, 2023, https://mgaleg.maryland.gov/2023RS/fnotes/bil_0008/hb0908.pdf.

- Implement consolidated billing by electric companies and establish other specified billing/crediting requirements.[72]

3.5.3 EmPOWER Maryland

The EmPOWER Maryland energy initiative was announced in July 2007, with a goal of reducing Maryland's per capita energy consumption and peak demand by 15% by 2015. This initiative was codified by the EmPOWER Maryland Energy Efficiency Act of 2008 (EPM Act). Additional information about EmPOWER Maryland can be found on PPRP's website in the Policy Initiatives and Energy Programs discussion.

3.5.4 Smart Grid and Cybersecurity

Smart grid proponents believe that electric infrastructure will evolve over the next few decades into a highly automated and interconnected network similar to the internet. The smart grid involves a network of two-way communications connecting electric meters and "smart" devices containing microprocessor or computer technology to transformers and centralized electric grid operations centers. This two-way communication enables grid operators to better respond to moment-to-moment variations in the electric system through real-time balancing of generation and electric delivery. The desire to make the grid smarter, safer, more reliable, and more cost-effective is driving the growth of smart grid technologies in the U.S. The smart grid of the future will be largely automated and self-correcting, efficiently balancing the needs of energy suppliers and users and largely self-balancing to ensure reliability in real-time.

Additional information about smart grid and cybersecurity can be found in CEIR-21, Section 3.5.5.

[72] Maryland General Assembly, House Bill 908, 2023 session, https://mgaleg.maryland.gov/2023RS/bills/hb/hb0908E.pdf.

Chapter 4 – Markets, Regulation, and Oversight

Traditionally in the U.S., the electricity system was dominated by regulated vertically integrated utilities, each operating its local generation, transmission, and distribution system. Following deregulation of other industries, such as telecommunications and air travel in the 1990s, some states began to examine ways to restructure the electricity industry. California was the first state to begin restructuring its electricity sector but suspended retail electric restructuring following the 2000–2001 electricity crisis in which electricity supplies were constrained and prices increased dramatically. Though the California experience caused some states to halt restructuring efforts, 13 other states, typically states characterized by high electricity prices, and the District of Columbia continued with their restructuring plans. This has led to a national electricity system landscape in which some states continue to operate under a traditional regulated regime and others have moved toward competitive generation at the retail level. In Maryland, the Electric Customer Choice and Competition Act of 1999 restructured the electric utility industry to functionally separate it into three distinct businesses: generation and supply, transmission, and distribution.

4.1 Wholesale Markets and PJM

The costs of generation and supply of electricity are not regulated by the State of Maryland, and prices are set by the competitive wholesale and retail electricity markets. The high-voltage transmission system is regulated at the federal level and operated by the regional transmission organization (RTO), PJM Interconnection LLC (PJM). Note that the State of Maryland retains regulatory control over siting for new generation (over 2 megawatts [MW]) and high-voltage transmission development (over 69,000 volts [V]) through the Certificate of Public Convenience and Necessity (CPCN) process (see Chapter 1).

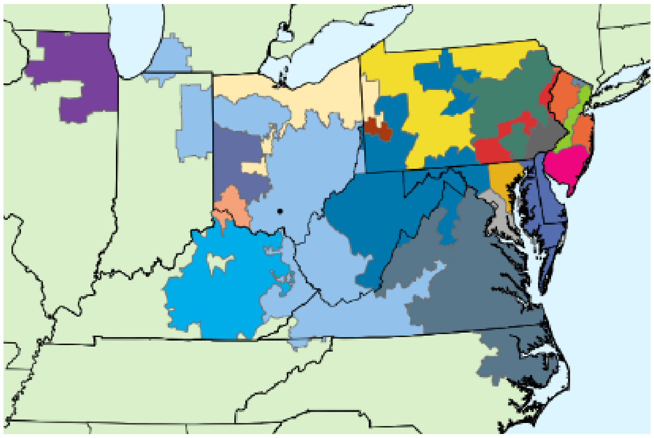
In states with restructured markets such as Maryland, electricity is generated by a power company that is separate from the entity responsible for transporting and delivering power to end-use customers. Entities selling energy on the wholesale market include competitive suppliers and power marketers that are affiliated with utility holding companies, independent power producers not affiliated with a utility, and traditional vertically integrated utilities located within the region. Entities that purchase energy in the wholesale market to supply to end-use consumers are referred to as load-serving entities (LSEs) and can be either distribution utilities or independent energy suppliers. Like many other commodities, electricity is frequently bought and resold several times before finally being consumed. These sales and resale transactions make up the wholesale market.

PJM operates and independently monitors the markets for the purchase and sale of both energy and capacity. Energy refers to the electric power that is used by customers over a given period and is measured in units of watt-hours. Energy costs typically include fuel and operating expenses. Capacity refers to the infrastructure and physical plant available to produce electrical power at some instant in time and is measured in watts. Costs for capacity typically include fixed and capital-related costs.

Evolution of PJM

PJM is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 13 states: Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM manages the high-voltage transmission grid to serve over 65 million people. PJM also operates a wholesale competitive power market that annually exceeds $33 billion in volume. PJM is the oldest, continuously operating power pool in the world.

PJM's Service Area



Source: PJM

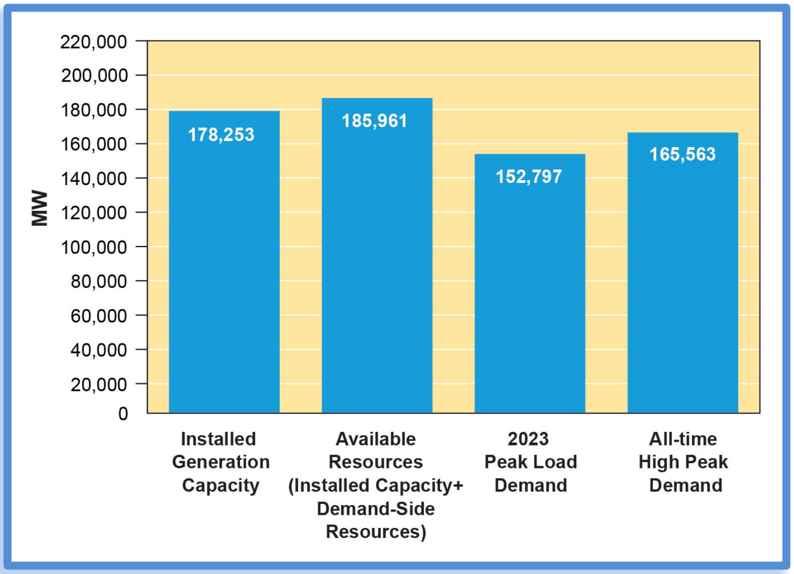
PJM began in 1927 when the Public Service Electric and Gas Company, Philadelphia Electric Company (now a subsidiary of the Exelon Corporation) and Pennsylvania Power & Light Company formed the PA–NJ Interconnection power pool. The intent of the power pool was to centrally dispatch electric generating plants in the pool by cost, decreasing the generation costs for all members. The PA–NJ agreement also called on member utilities to make transmission capacity available for power interchange, share load and reserves, and assist each other during system emergencies. Each member utility was responsible for planning its own generation and transmission, which were reviewed by a PJM planning and engineering committee to ensure that, in combination with other member utilities, they would meet PJM reliability targets. The name was changed to the Pennsylvania–New Jersey–Maryland Interconnection, or PJM, in 1956 when Baltimore Gas and Electric Company (BGE) (now a subsidiary of Exelon Corporation) and General Public Utilities (now a part of FirstEnergy) joined.

In 1997, the Federal Energy Regulatory Commission (FERC) approved PJM as the first fully functioning independent system operator (ISO). ISOs operate but do not own transmission systems and allow non-utility users access to the transmission grid. In an effort to develop competitive wholesale power markets and operate a multi-state transmission system, FERC encouraged PJM to form an RTO. PJM became the first fully functioning RTO in 2001 and integrated a number of utilities into its system between 2002 and 2013, including Rockland Electric (2002), Allegheny Power (2002), Commonwealth Edison (2004), American Electric Power (2004), Dayton Power and Light (2004), Duquesne Light (2005), Dominion (2005), ATSI (2011), Cleveland Public Power (2011), Duke Energy Ohio and Duke Energy Kentucky (2012), and East Kentucky Power Cooperative (2013). In addition, Ohio Valley Electric Corporation integrated into PJM in 2018. These additions allow for the diversification of electricity resources available within PJM's wholesale electricity market.

Source: PJM, PJM Annual Report for 2020, services.pjm.com/annualreport2020/ "PJM History," PJM Interconnection, pjm.com/about-pjm/who-we-are/pjm-history.aspx.

A reliable supply of energy depends upon sufficient electric generating capacity at times of high demand. States in the Northeast that have restructured their retail electricity markets rely on a combination of energy markets and capacity markets to create sufficient economic incentives for the development of new generation capacity necessary to meet electricity demand. Figure 4-1 shows supply and demand in PJM in 2023.

Figure 4-1 PJM Supply and Demand for 2023



Source: Installed Generating Capacity and 2023 Peak Demand: Monitoring Analytics, 2023 State of the Market Report for PJM.

4.1.1 Wholesale Energy Pricing

PJM uses a uniform price auction based upon locational marginal prices (LMPs), which vary across PJM zones and time of day, to establish energy prices. Electricity generators offer the amount of energy they would like to sell at a particular time and price.

PJM administers and operates two wholesale energy markets: the day-ahead market and the real-time market. As implied by their names, the day-ahead market clears a day in advance of actual usage; that is, sellers commit supplies to PJM and purchasers commit to purchase the supply based on expected loads. The real-time market is typically used as a balancing market for loads and generation in real-time but can also be relied on to meet full load requirements. Together, these markets are referred to as the “spot” energy market. In addition to this spot energy market administered and operated by PJM, there are bilateral transactions for energy between a particular buyer and seller, with prices largely determined by the “forward” markets, where sellers offer to provide and buyers offer to purchase specific quantities of energy (e.g., 50 megawatt hour [MWh]) over a defined period of time (e.g., each hour of the month). Forward markets can extend several years into the future.

For energy products on the day-ahead market, the PJM operator determines the sub-hourly dispatch of plants based on price bids submitted by suppliers. Energy prices in PJM are based upon the offers that designate a price and quantity at which a generator is willing to sell electricity. PJM stacks these offers from lowest price to highest price until it can satisfy the quantity required to meet energy requirements in its footprint. It is the price of the last resource called upon—the marginal price—that becomes the PJM-wide energy component of the hourly, day-ahead LMP. The average PJM region day-ahead and real-time LMPs for 2023 are shown in Table 4-1. The factors that affect LMPs are discussed at length in on PPRP's website in the Electricity Markets and Retail Competition discussion.

Table 4-1 PJM Off-peak and On-peak Hourly Locational Marginal Prices for 2023 ($/MWh)

	Day-Ahead		Real-Time	
	Off-peak	On-peak	Off-peak	On-peak
Average	$25.51	$36.01	$24.97	$35.13
Median	$23.68	$32.49	$21.85	$30.22

Source: Monitoring Analytics, 2023 State of the Market Report for PJM.

Because energy prices may vary considerably by location due primarily to transmission congestion, PJM must also account for congestion costs. Congestion occurs between two delivery points on the transmission system when the transmission grid cannot accommodate the power flows between these specific locations. When congestion occurs, higher-priced local resources are used instead of lower-cost electricity that would otherwise be used to meet load by being transported into the area via transmission lines. During periods of congestion, PJM must dispatch generation resources that are located at or near the load zone even if those resources are not the most economic resources that would otherwise be available to meet load. The cost of congestion refers to the incremental cost of dispatching these more expensive, location-specific resources.

Congestion most often occurs during times of high demand, when transmission lines are reaching full capacity and certain sections become constrained. LMP differentials between PJM regions (see Table 4-2) have been mainly due to congestion between the western region, where abundant low-cost generation is located, and the Mid-Atlantic region, where the large load centers are located.

Table 4-2 Real-time Average Annual Load-weighted Locational Marginal Prices ($/MWh)

PJM Zone	2019	2020	2021	2022	2023
Baltimore Gas and Electric Company (BGE)	$30.82	$25.78	$45.77	$95.44	$38.80
Potomac Electric Power Company (Pepco)	$29.68	$23.59	$44.62	$91.68	$36.59
Delmarva Power & Light Company (DPL)	$27.71	$22.90	$40.24	$83.32	$31.06
Allegheny Power Systems (APS)	$27.83	$22.40	$40.44	$79.01	$32.49

Source: Monitoring Analytics, 2023 State of the Market Report for PJM.

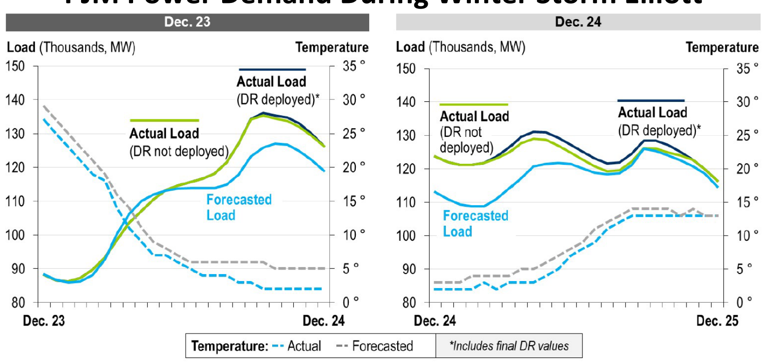
Based on real-time market outcomes, PJM estimates that in 2023, congestion added approximately $6.43/MWh to the average LMPs in the Baltimore Gas and Electric Company (BGE) zone, $4.46/MWh in the Potomac Electric Power Company (Pepco) zone. In 2023, congestion actually had a negative impact of $0.94/MWh in the Delmarva Power & Light Company (DPL) zone. In 2023, the congestion component accounted for 16.6%, 12.2%, and -3% of the real-time load-weighted average LMP in the

BGE, Pepco, and DPL zones, respectively. BGE, with a real-time, load-weighted average congestion component of $6.43/MWh, had the highest real-time congestion component of all PJM control zones in 2023.[73] Between 2022 and 2023, PJM total congestion costs decreased 57.3%, from $2,501.3 million to $1,432.7 million. There was a greater decrease in real-time congestion costs (from $3,879.7 million to $1,411.7 million, or -63.6%) compared to day-ahead congestion (from $3,025.2 million to $1,364.5 million, or -54.9%).[74] The previous high congestion costs can be attributed to Winter Storm Elliot, transmission outages, and increased demand as the Nation recovered from the Covid-19 pandemic.[75]

Winter Storm Elliott

Between December 23 and 26, 2022, Winter Storm Elliott swept over Central and Eastern U.S., with several locations reporting record low temperatures and rapid drops in temperature. When temperatures decline during the winter, power consumed by electric heating systems and fans in natural gas furnaces and boilers increases. The PJM load forecast did not account for such a rapid and sustained temperature decline and the concurrent increase in electricity demand, and as a result, PJM underestimated electricity demand by over 10%. PJM operators implemented multiple emergency procedures and appealed to the public to reduce energy use to maintain service throughout the region.

PJM Power Demand During Winter Storm Elliott



Some equipment at power stations and natural gas pipeline compressor stations is installed outdoors and exposed to the weather. Precautions are taken to prevent this equipment from freezing. Nonetheless, low temperatures during this period caused several generator outages. A total of 47,000 MW of generation capacity, 24% of the total system capacity, was not available on December 24th. Over 90% of generator outages were reported to PJM with less than an hour's notice or no notice at all. Freeze-ups at natural gas wellheads and temperature-related pipeline compressor outages reduced the supply of natural gas available for power generation. Natural gas supply curtailments resulted in shutdowns totaling 11,000 MW, approximately 70% of total natural gas generation capacity.

In July 2023, PJM published recommendations for improving performance during winter extreme weather conditions that included forecasting and modeling improvements, improving generation weatherization to prevent freeze-ups, and improving gas-electric coordination in scheduling.

Source: item-0x---winter-storm-elliott-overview.ashx (pjm.com)

20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx (pjm.com), Figure 18

[73] Marketing Analytics, LLC, *PJM 2023 State of the Market Report*, Volume 2, Section 11, Table 11-4.

[74] Marketing Analytics, LLC, *PJM 2023 State of the Market Report*, Volume 2, Section 11, p. 617.

[75] U.S. grid congestion costs jumped 56% to $20.8B in 2022: report | Utility Dive

4.1.2 Power Plant Construction

See Section 4.1.2 of CEIR-21 for background information on Power Plant Construction.

As with many grid operators around the country, PJM is experiencing the retirement of coal plants and the growth of natural gas and renewable energy. This is due to lower wholesale electricity prices during the past decade, coupled with other factors, such as stricter environmental regulations for fossil-fuel plants and the aging of the coal fleet. Some companies have opted to either retire older, less efficient coal plants or convert them to natural gas. PJM's Market Monitor estimates between 24,000 MW and 58,000 MW of plant retirements through 2030, consisting of planned retirements (4,285 MW), retirements for state and federal environmental regulation reasons (19,635 MW), and retirements because the plants are uneconomic (33,744 MW).

With respect to new generation, 4,400.2 MW of capacity went into service in 2023, of which 60.1% is supplied by combined cycle units, 20.6% by solar units, and 11.0% by natural gas-fired combustion turbine units. As of December 31, 2023, there was 268,472.8 MW in the PJM generation queue, either active, under construction, or suspended. Based on historical completion rates, 37,057.9 MW (13.8%) of capacity is expected to go into service.[76] Renewable energy projects account for 75.2% (202,990.3 MW) of the total nameplate MW capacity in the PJM interconnection queue. PJM anticipates 11,162.9 MW, or 5.5% of the renewable energy capacity in the queue, to go into service when accounting for project completion rate and for the lower capacity value of renewable energy projects.[77]

Inclusive of plant retirements and additions, PJM noted that, for June 1, 2024, the Reliability Pricing Model (RPM) reserve margin is 21.9%, which is more than the 19.9% reserve margin as of June 1, 2023, but less than the reserve margin of 24.2% as of June 1, 2020.[78] For PJM's most recent base residual capacity auction for the 2024/2025 delivery year, enough capacity cleared to result in a 20.4% reserve margin, or 5.7% higher than the target reserve margin of 14.7%.[79]

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[76] Marketing Analytics, LLC, *PJM 2023 State of the Market Report*, Volume 1, p. 79.

[77] Marketing Analytics, LLC, *PJM 2023 State of the Market Report*, Volume 1, p. 79.

[78] Marketing Analytics, LLC, *PJM 2023 State of the Market Report*, Volume 1, Table 12.

[79] PJM, *2023/2024 RPM Base Residual Auction Results*, Undated, https://sdc.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-base-residual-auction-report.ashx

Brandon Shores Retirement Mitigation Project

In April 2023, Talen Energy, the owner of the Brandon Shores coal-fired plant, provided notice to PJM of the company's plans to retire the plant by June 1, 2025. As with the retirement of any generation project, PJM conducts analyses to ensure electric service reliability will not be negatively impacted. With Brandon Shores, PJM's analyses found substantial voltage drop and thermal violations that could result in the disruption of service to customers within the BGE and Pepco service areas if there was one major failure on the transmission grid, and a possible voltage collapse if another failure on the transmission grid occurred. As a result, PJM directed BGE and other utilities to implement several transmission system upgrades. PJM also entered into a reliability must run (RMR) agreement with Talen Energy to stay in operation through 2028. Costs for the RMR agreement are over $14.6 million per month, of which BGE ratepayers are responsible for 74%.

In July 2024, BGE filed for a CPCN at the Maryland Public Service Commission (PSC) for several transmission upgrades in relation to Brandon Shores. These include:

- Upgrading an existing 2.2-mile-long, 230 kV overhead transmission line to a 500 kV overhead transmission line that would run from the Maryland-Pennsylvania border southwest to BGE's Graceton Substation located in Harford County. This part of the project is known as the Graceton to MD-PA Segment.

- Connecting an existing 500 kV overhead transmission line and the terminal of an existing 230 kV line to the Graceton Substation. This part of the project is known as the Graceton Connections Segment.

- Building a new 29-mile-long, 230 kV double-circuit overhead transmission line from BGE's Graceton Substation to the new Batavia Substation in Baltimore County. This part of the project is known as the Graceton to Batavia Segment.

- Reconductoring an existing 230 kV overhead transmission line from the new Batavia Substation to BGE's Riverside Substation in Baltimore County, and the installation of overhead transmission lines to connect to the new Batavia Substation. This part of the project is known as the Batavia to Riverside Segment.

- Building overhead transmission line connections for the new Solley Road Substation in Anne Arundel County. This part of the project is known as the Solley Road Segment.

BGE estimates the capital cost will be $350 million and the annual operating cost to be $420,000. BGE expects to have the project in service by the end of 2028 should it receive a CPCN from the Maryland PSC by third quarter 2025.

Source: Baltimore Gas & Electric, *Application of Baltimore Gas & Electric Company for a Certificate of Public Convenience and Necessity for the Brandon Shores Retirement Mitigation Project*, Filing before the Maryland PSC, Case No. 9748, July 11, 2024.

4.2 Retail Electricity Markets and Billing

The distribution of electricity continues to be a regulated monopoly function of the local utility and hence continues to be subject to price regulation by the Maryland PSC. The fundamental objective of the 1999 Maryland Electric Customer Choice and Competition Act was to foster retail electric competition as a means of achieving favorable retail electricity prices for customers, stimulating an array of alternative supply products (for example, green power products and innovative rate design options) and giving customers a choice in their electric power supplier.

4.2.1 Maryland Retail Electric Supply

Maryland's competitive market did not develop as rapidly as envisioned when the legislation was adopted. At the beginning of 2009, 10 years after the 1999 Maryland Electric Customer Choice and Competition Act's enactment, only 2.8% of residential customers were being served by competitive suppliers. From December 2020 to December 2023, the number of residential and small commercial and industrial customers who bought electricity from competitive suppliers decreased. For mid-sized commercial and industrial customers, the decline continued until 2022, but the trend started reversing in 2023. On the other hand, the percentage of large commercial and industrial customers who opted for competitive electricity supply remained steady, at or above 80% (see Table 4-3). As of December 2023, competitive electric suppliers in the state served an aggregate of 395,672 customers, which represents a decrease of 23% compared to the number of such customers as of December 2020. The number of retail electric suppliers in Maryland rose slightly to 722 at the end of December 2023 as compared to 714 in 2022.

Table 4-3 Percentage of Customers Served by Competitive Suppliers (2020–2023)

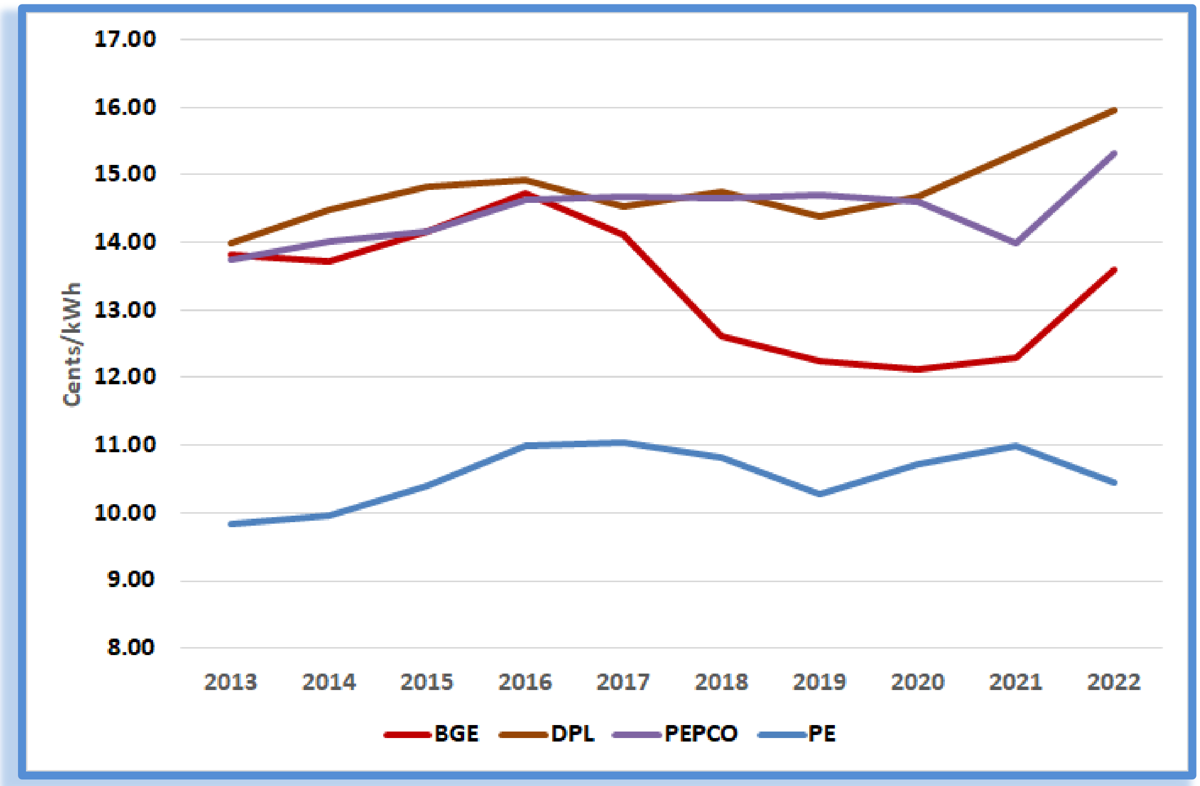
Year	Residential	Small Commercial & Industrial	Mid-size Commercial & Industrial	Large Commercial & Industrial	Total Customers
December 2020	18.1%	31.6%	51.9%	81.9%	515,691
December 2021	16.8%	29.6%	48.1%	80.0%	483,372
December 2022	14.6%	28.5%	46.8%	81.4%	432,994
December 2023	12.8%	28.0%	54.1%	87.9%	395,672

Source: Maryland Public Service Commission, Electric Choice Enrollment Monthly Reports, for Months Ending December 31, 2020, December 31, 2021, December 31, 2022, and December 31, 2023. Available at https://www.psc.state.md.us/electricity/electric-choice-monthly-enrollment-reports/.

Residential and small commercial customers who cannot or do not choose to transact with a competitive supplier are provided electricity service from their local utility at rates approved by the PSC. This utility-supplied service is referred to as standard offer service (SOS). Maryland investor-owned utility (IOUs) procure 25% of the total residential SOS load every six months under two-year, fixed-price contracts with competitive wholesale suppliers.

All customers purchase electricity at prices reflecting the wholesale market, either through SOS or competitive suppliers. Wholesale market prices remained relatively stable from 2012 through 2018 but have experienced some volatility in recent years, depending upon the utility. Figure 4-2 shows the average annual IOU residential rates in effect in Summer 2013 and for each subsequent summer.

Figure 4-2 Average Annual Retail Electricity Rates for Maryland Residential Customers, 2013–2022



Source: EIA Table 6, Utility Bundled Retail Sales—Residential

For more information on Retail Electric Billing see PPRP's website, Retail Electric Billing Section.

4.3 Transmission and Distribution System Planning and Reliability

See PPRP's website, Transmission and Distribution System Section for additional background information on reliability, transmission congestion, and transmission planning.

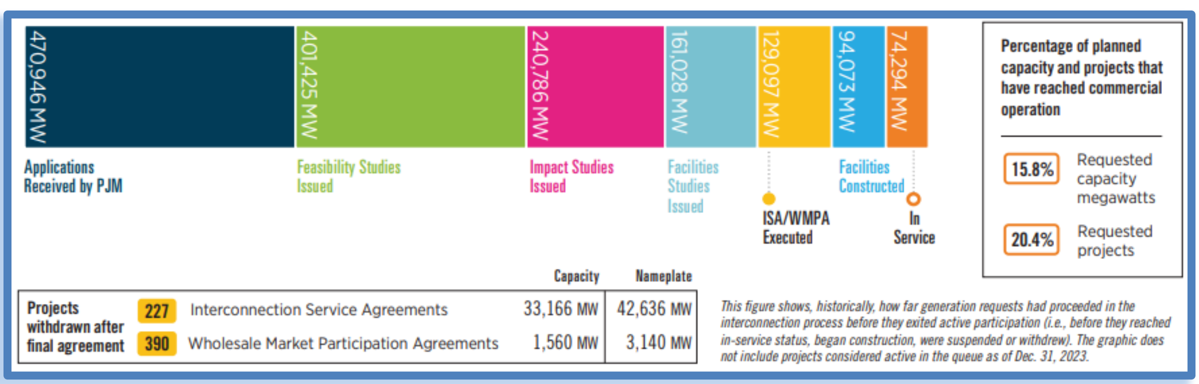
4.3.1 PJM Transmission Planning

In March 2024, PJM released the 2023 Regional Transmission Expansion Plan (RTEP) report, which outlines planned system upgrades approved by the PJM Board. The RTEP employs a 15-year planning horizon. Highlights of the report include:[80]

- 229,538 MW of energy projects were in PJM's queue seeking to interconnect into PJM's system;
- 157 interconnection requests, representing 19,700 MW, were issued agreements with PJM allowing construction activities to begin; and
- 486 interconnection requests were processed by PJM for new generation totaling over 32,000 MW in nameplate capacity.

The vast majority of projects in the queue will not come online. As shown in Figure 4-3, as generation requests move through the queue, the amount of generation decreases through each step of the process; the percentage of planned capacity and projects that reached commercial operation were 15.8% of requested capacity (MW) and 20.4% of requested projects.

Figure 4-3 PJM Generation Queue



Source: PJM 2023 Regional Transmission Expansion Plan, March 2024, p. 9, https://www.pjm.com/-/media/library/reports-notices/2023-rtep/2023-rtep-report.ashx

The fuel mix of the generation queue is increasingly renewable energy resources. The queued generation fuel mix, in requested capacity interconnection rights as of December 31, 2023, consisted of:[81]

- Solar 74,729 MW (106,070 MW in nameplate capacity)
- Storage 53,746 MW

[80] PJM, 2023 RTEP Report, March 2024, https://www.pjm.com/-/media/library/reports-notices/2023-rtep/2023-rtep-report.ashx.

[81] PJM, 2022 RTEP Report, Figure 1.6

- Wind 21,088 MW (37,262 MW in nameplate capacity)
- Hydro 299 MW
- Natural Gas 8,118 MW
- Methane 6 MW
- Hybrid 28,672 MW
- Other 70 MW

The number of interconnection requests, particularly from renewable energy and energy storage facilities, submitted to PJM has grown rapidly in recent years. In 2020, PJM began a stakeholder process to overhaul PJM's generation interconnection process. Stakeholders reached consensus on a plan in April 2022, and by order issued November 29, 2022, FERC accepted for filing PJM's tariff revisions implementing the interconnection process reforms.[82]

PJM Market Efficiency

As part of PJM's RTEP planning process, transmission projects submitted during the RTEP Process Window to resolve reliability criteria violations undergo a market efficiency analysis to determine whether the project can provide economic benefits by relieving congestion. The purpose of the market analysis is to (1) ascertain whether economic benefits are realized if the project is accelerated, (2) determine whether additional enhancements may result in economic benefits, and (3) identify economic benefits that may result from modifying a transmission project to relieve one or more economic constraints. Market efficiency enhancements are reviewed during a 12-month or 24-month process before they are presented to the PJM Board of Managers for approval. The 12-month process is designed to review all approved RTEP projects, while the 24-month process reviews economic transmission projects proposed to be implemented during years five through 15 of the 15-year RTEP study period. During both review processes, PJM develops assumptions such as fuel prices, emissions prices, annual PJM load forecast, quantity of demand and generation modeled, and generation additions and retirements. PJM then performs its market efficiency analysis to determine whether the projected economic benefits will exceed PJM's required minimum benefit/cost ratio of 1.25. PJM performs its benefit/cost calculations by comparing the present value of the total energy and capacity benefits for 15 years compared to the total annual cost over the first 15 years of the life of the enhancement. Once PJM has identified potential solutions, it solicits comments and recommendations from its Transmission Expansion Advisory Committee (TEAC), which is responsible for reviewing PJM's assumptions and analysis. After incorporating comments and recommendations, PJM presents its final RTEP market efficiency plan to the PJM Board of Managers for approval.

Maryland RTEP Upgrades

For Maryland, the 2022 PJM RTEP lists seven baseline upgrade projects, with a combined cost of $8.16 million (shown in Table 4-4), and 11 supplemental upgrades, with a combined cost of $31.31 million (shown in Table 4-5). Baseline projects ensure compliance with North American Electric Reliability Council (NERC), regional, and local transmission owner planning criteria and address market efficiency and congestion relief. Supplemental projects (previously known as Transmission Owner initiated projects) are not required for compliance with system reliability but could address equipment

[82] FERC, *Order Accepting Tariff Revisions Subject to Condition*, Docket Nos. ER22-2110-000, ER22-2110-001, 181 FERC 61,162, November 29, 2022.

material condition performance and risk, operational flexibility and efficiency, infrastructure resilience, and customer service.

Table 4-4 Baseline Projects in Maryland Included in 2022 PJM RTEP

Baseline Projects	Date	Cost ($M)	Zone
Upgrade Windy Edge 115 kV substation conductor to increase ratings of the Windy Edge-Chesco Park 110501 circuit.	6/1/2026	0.50	BGE
Replace the 4/0 SDCU stranded bus with 954 ACSR and a 600A disconnect switch with a 1200A disconnect switch on the 6716 line terminal inside Todd substation (on the Preston-Todd 69 kV circuit).	6/1/2026	0.75	DPL
Replace terminal equipment (stranded bus, disconnect switch, and circuit breaker) at Church substation (Townsend-Church 138 kV).	12/1/202	1.00	DPL
Upgrade terminal equipment on the Loretto-Fruitland 69 kV circuit: Replace the 477 ACSR stranded bus on the 6711 line terminal inside Loretto substation and the 500 SDCU stranded bus on the 6711 line terminal inside Fruitland substation with 954 ACSR conductor.	6/1/2026	0.80	DPL
Upgrade two breaker bushings on the 500 kV line 5012 (Conastone-Peach Bottom) at Conastone substation.	12/1/2027	2.00	BGE
Install cable shunts on each phase, on each side of four dead-end structures, and replace existing insulator bells to increase maximum operating temperature of DP&L circuit 22088 (Colora-Conowingo 230 kV).	6/1/2027	0.26	DPL
Install a new breaker at Graceton 230 kV substation to terminate a new 230 kV line from the new greenfield North Delta station.	6/1/2029	2.85	BGE
Replace one 63 kA circuit breaker “B4” at Conastone 230 kV with 80 kA.			

Source: PJM 2023 Regional Transmission Expansion Plan, Table 6.25.

Table 4-5 Supplemental Projects in Maryland Included in 2022 PJM RTEP

Supplemental Projects	Date	Cost ($M)	Zone
Upgrade a line relay on 230 kV circuit 23058 (Ritchie-Oak Grove) at Oak Grove substation.	12/1/2023	0.42	Pepco
Replace Pumphrey circuit breakers No. B22, B28, B	11/30/2021	5.2	BGE
Replace Windy Edge circuit breaker No. B27.	9/30/2021	1.00	BGE
Replace 230 kV circuit breaker No. 3A at Burtonsville, associated disconnect switches, and strain bus.	12/1/2022	1.07	Pepco
Replace 230 kV circuit breaker No. 4A at Burtonsville, associated disconnect switches, and strain bus.	6/1/2022	1.07	Pepco
Upgrade relays and metering on 230 kV circuit 23090 (Burches Hill-Palmers Corner).	12/1/2022	0.25	Pepco
Replace Windy Edge circuit breaker No. B6.	4/7/2022	1.30	BGE
Replace Windy Edge circuit breaker No. B32.	5/6/2022	1.30	BGE
Replace Windy Edge circuit breaker No. B26.	6/3/2022	13.00	BGE

Supplemental Projects	Date	Cost ($M)	Zone
Upgrade relays and metering on 230 kV circuit 23008 (Mt. Zion-Norbeck) at Norbeck substation.	7/31/2022	0.40	Pepco

Source: PJM 2023 Regional Transmission Expansion Plan, Table 6.26.

4.3.2 Federal Energy Regulatory Commission

See Section 4.4.1 of CEIR-21 for background information on the FERC.

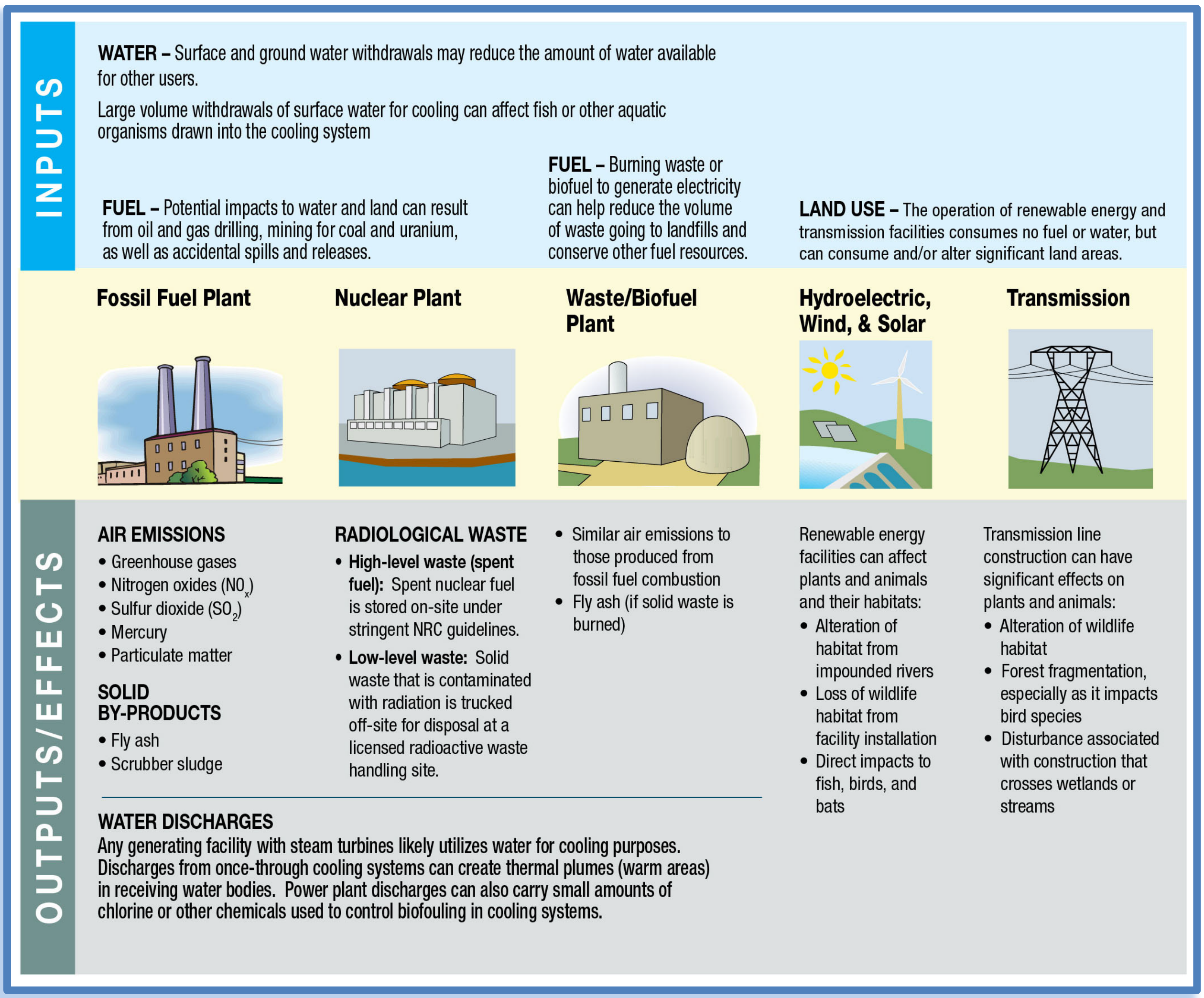
In July 2011, FERC issued Order No. 1000, which was intended to strengthen the transmission planning and cost allocation requirements established in earlier FERC orders such as Order 890. Although Order 1000 was viewed as a landmark order, it has not produced the expected results. Order 1000 was intended to expand transmission to meet the increase in renewable generation, and while new transmission has come online since the order went into effect, 70% of the system is 25 years or older. Therefore, in July 2021, FERC unanimously voted for an advanced notice of a proposed rulemaking, "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection."[83] The proposed rulemaking is exploring how long-term regional planning can be improved and how costs associated with network upgrades are allocated.

[83] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation & Generator Interconnection*, 86 FR 40266 (July 15, 2021), 176 FERC P 61,024 (2021).

Chapter 5 – Impacts of Power Generation and Transmission

Abundant and reliable electricity has facilitated tremendous improvements in human health and safety as well as economic development. However, the benefits of electric power generation and transmission are accompanied by a variety of environmental and socioeconomic impacts associated with the construction, operation, and maintenance of these facilities.

This chapter describes each of these impact areas in some detail and discusses the Power Plant Research Program's (PPRP's) efforts to better understand the magnitude of these impacts in Maryland and how they can be mitigated, minimized, and managed. Controlling the amount of electrical energy Marylanders use, and the amount of fuel consumed to generate that electricity is also critical to reducing adverse environmental impacts. Other chapters of this report provide more information on how Maryland is promoting energy efficiency and the development of more sustainable energy sources. The following figure illustrates some of the primary environmental impacts associated with electricity generation and transmission in Maryland.



5.1 Impacts on Air Quality

5.1.1 Overview

The Clean Air Act (CAA) was the first major federal environmental law in the U.S. that required the development and enforcement of regulations to protect the general public from air pollutants known to harm human health. Section 5.1.1 of CEIR-21 provides the history of the CAA as well as its amendments over the past 60 years and how those amendments laid the framework for the air quality standards as we know them today. The Amendments of 1990 addressed four significant threats to the health and welfare of Americans, all of which are related to power plants and other sources of air pollution: acid rain and regional haze, toxic or hazardous air pollution, urban air pollution, and stratospheric ozone depletion.

Since the early days of air quality management in the U.S., regulators have based many air quality rules and regulations on the National Ambient Air Quality Standards (NAAQS) that the CAA authorized the U.S. Environmental Protection Agency (EPA) to develop (see Table 5-1). EPA established NAAQS, which represent the maximum pollutant concentrations that are allowable in ambient air for six common air pollutants (referred to as the "criteria" pollutants). "Primary" NAAQS are based on health risk assessments and are designed to protect public health, including the health of sensitive populations such as asthmatics, children, and the elderly. "Secondary" NAAQS are designed to protect public welfare by preserving visibility and preventing damage to crops, animals, vegetation, and buildings. EPA routinely evaluates the NAAQS to determine whether more stringent or different standards are warranted. The most recent update to the NAAQS was the 8-hour ozone standard in October 2015.

Table 5-1 National Ambient Air Quality Standards

Pollutant	Primary/ Secondary	Averaging Time	Level	Form
Carbon Monoxide (CO)	Primary	8 hours	9 ppm	Not to be exceeded more than once per year.
		1 hour	35 ppm	
Lead (Pb)	Primary and Secondary	Rolling 3-month average	0.15 µg/m^3 (1)	Not to be exceeded.
Nitrogen Dioxide (NO_2)	Primary	1 hour	100 ppb	98th percentile of 1-hour daily maximum concentrations, averaged over 3 years.
	Primary and Secondary	1 year	53 ppb (2)	Annual mean.
Ozone (O_3)	Primary and Secondary	8 hours	0.070 ppm (3)	Annual fourth-highest daily maximum 8-hour concentration, averaged over 3 years.
Particle Pollution (PM), $PM_{2.5}$	Primary	1 year	9.0 µg/m^3	Annual mean, averaged over 3 years.
	Secondary	1 year	15.0 µg/m^3	Annual mean, averaged over 3 years.
	Primary and Secondary	24 hours	35 µg/m^3	98th percentile, averaged over 3 years.
Particle Pollution (PM), PM_{10}	Primary and Secondary	24 hours	150 µg/m^3	Not to be exceeded more than once per year on average over 3 years.
Sulfur Dioxide (SO_2)	Primary	1 hour	75 ppb (4)	99th percentile of 1-hour daily maximum concentrations, averaged over 3 years.
	Secondary	3 hours	0.5 ppm	Not to be exceeded more than once per year.

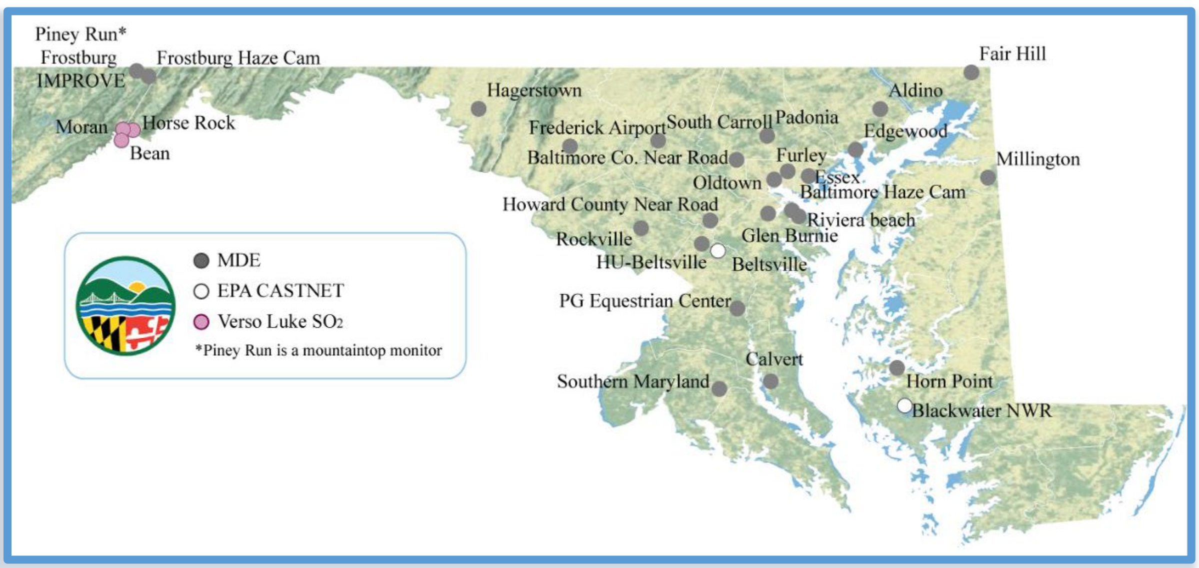
Source: United States Environmental Protection Agency, "National Ambient Air Quality Standards." Reviewing National Ambient Air Quality Standards – Scientific and Technical Information. epa.gov/criteria-air-pollutants/naaqs-table, last accessed July 24, 2024.

ppm - parts per million
ppb - parts per billion
mg/m^3 - milligram per cubic meter
µg/m^3 - microgram per cubic meter

1. In areas designated nonattainment for the Pb standards prior to the promulgation of the current (2008) standards, and for which implementation plans to attain or maintain the current (2008) standards have not been submitted and approved, the previous standards (1.5 µg/m^3 as a calendar quarter average) also remain in effect.
2. The level of the annual NO_2 standard is 0.053 ppm. It is shown here in terms of ppb for the purposes of clearer comparison to the 1-hour standard level.
3. Final rule signed October 1, 2015, and effective December 28, 2015. The previous (2008) O_3 standards additionally remain in effect in some areas. Additionally, some areas may have certain continuing implementation obligations under the prior revoked 1-hour (1979) and 8-hour (1997) O_3 standards.
4. The previous SO_2 standards (0.14 ppm 24-hour and 0.03 ppm annual) will additionally remain in effect in certain areas: (1) any area for which it is not yet one year since the effective date of designation under the current (2010) standards; and (2) any area for which implementation plans providing for attainment of the current (2010) standard have not been submitted and approved and which is designated nonattainment under the previous SO_2 standards or is not meeting the requirements of a State Implementation Plan (SIP) call under the previous SO_2 standards (40 Code of Federal Regulations (CFR) 50.4(3)). A SIP call is an EPA action requiring a state to resubmit all or part of its SIP to demonstrate attainment of the required NAAQS.

Across the country, EPA, state, and local regulatory agencies monitor concentrations of the criteria pollutants near ground level. The Maryland Department of the Environment's (MDE's) Ambient Air Monitoring Program conducts ambient monitoring in Maryland. Figure 5-1 presents the locations of ambient air monitoring stations in Maryland. In addition to the ambient air monitoring stations operated by MDE, two Clean Air Status and Trends Network (CASTNET) sites are located in Maryland: Blackwater National Wildlife Refuge and Beltsville. CASTNET is a long-term environmental monitoring network with 90 sites located throughout the U.S. and Canada. CASTNET was established under the 1990 CAA Amendments to assess trends in acidic deposition due to emission reduction programs such as the EPA's Acid Rain Program. Figure 5-1 shows three SO_2 monitoring sites (Moran, Horse Rock, and Bean) located near the Verso Luke paper mill in Allegany County. The paper mill shut down operations in May 2019, and Verso instructed its contractor to remove the monitoring equipment on June 8, 2020. Verso Luke Mill subsequently surrendered its Permit to Operate. No further monitoring at this location is planned.

Figure 5-1 Ambient Pollutant Monitoring Stations in Maryland



Source: Maryland Department of the Environment, Ambient Air Monitoring Network, mde.maryland.gov/programs/Air/AirQualityMonitoring/Pages/Network.aspx, Last accessed August 31, 2023.

EPA makes attainment/nonattainment designations for any area of the country on a pollutant-by-pollutant basis. The air quality in an area, therefore, may be designated as attainment for some pollutants and nonattainment for other pollutants simultaneously. The designation is important because regulators base many air regulatory requirements in part on whether a source is located in an attainment area, where emissions must be limited to ensure the air quality remains in attainment with the standards, or in a nonattainment area, where emissions must be reduced to bring the area into attainment. As such, air pollution control requirements are generally more stringent for sources located in nonattainment areas. Section 5.1.1 of CEIR-21 provides a summary of Maryland's NAAQS attainment status for criteria pollutants such as NO_2, $PM_{2.5}$, PM_{10}, CO, and Pb, as well as Maryland's attainment status for the 2010 1-hour SO_2 NAAQS, as of 2022. For current NAAQS attainment status information see EPA's Green Book at https://www.epa.gov/green-book.

5.1.2 Power Plant Emissions and Impacts

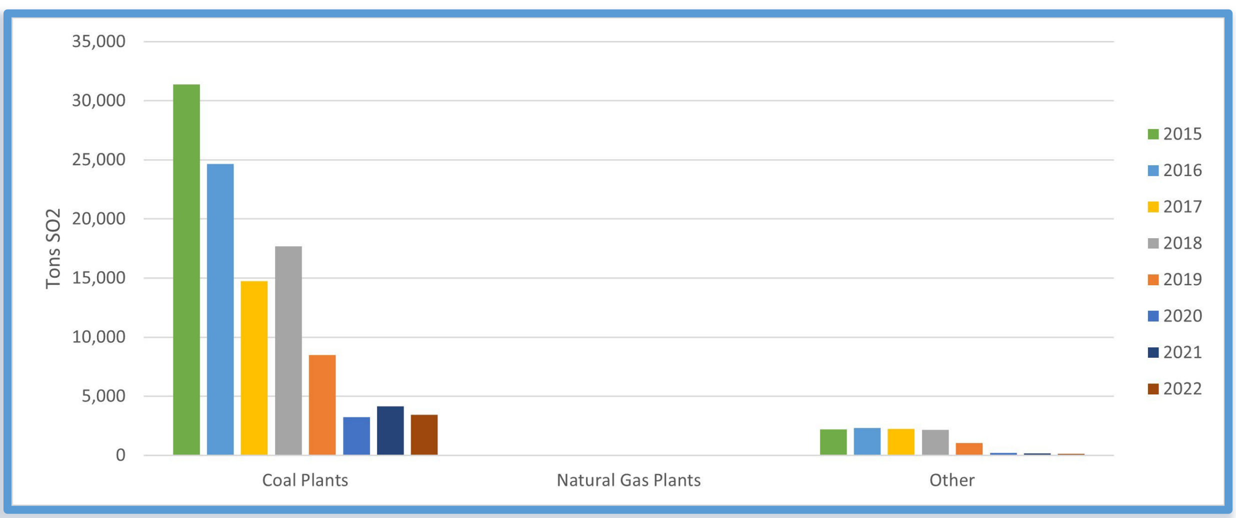
Power plants in the U.S. are a major source of air emissions. However, according to the report "Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States" (based on the November 2023 update),[84] emissions of SO_2, nitrogen oxide (NO_x), carbon dioxide (CO_2) and mercury (Hg) have all decreased significantly in recent years. Power plant emissions of SO_2 and NO_x were 94% and 87% lower, respectively, than in 1990 when the Clean Air Act amendments were passed, Hg emissions were 93% lower than they were in 2000, and CO_2 emissions decreased by 34% from their peak in 2007. Overall trends in electric generation show a displacement of coal by natural gas and renewable energy sources, influencing the observed decrease in emissions over time.

Section 5.1.2 of CEIR-21 provides an overview of air emissions from power plants in the United States. Air emissions are often discussed in terms of three classes of pollutants: criteria pollutants, hazardous air pollutants (HAPs), and greenhouse gases (GHGs). Section 5.1.2 of CEIR-21 discusses emissions of these classes of pollutants by Maryland's power plants and compares Maryland's power plant emissions to those in other states.

Sulfur Dioxide and Nitrogen Oxides

In Maryland, power plant emissions are associated with the combustion of fossil fuels and biomass. Trends in SO_2 and NO_x emissions from generating units in Maryland of different fuel types are shown in Figure 5-2 and Figure 5-3, respectively. SO_2 and NO_x emissions from coal-fired power plants have continued to steadily decrease as the power sector continues to move away from coal and toward natural gas and renewable energy sources.

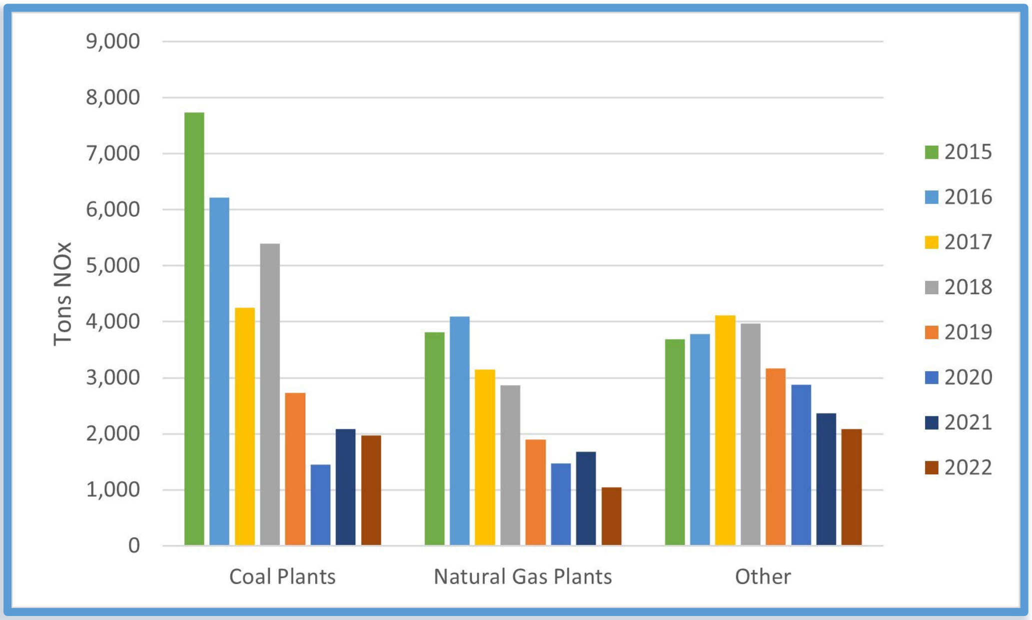
Figure 5-2 Annual SO_2 Emissions by Power Plant Type in Maryland



Source: Emissions reported in Maryland Electricity Profile 2022 https://www.eia.gov/electricity/state/maryland/xls/md.xlsx, last accessed November 21, 2023.

[84] Ceres. Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States. November 2023. https://www.ceres.org/news-center/press-releases/carbon-emissions-us-power-sector-decreased-slightly-2022-nineteenth, last accessed November 20, 2023.

Figure 5-3 Annual NO_x Emissions by Power Plant Type in Maryland



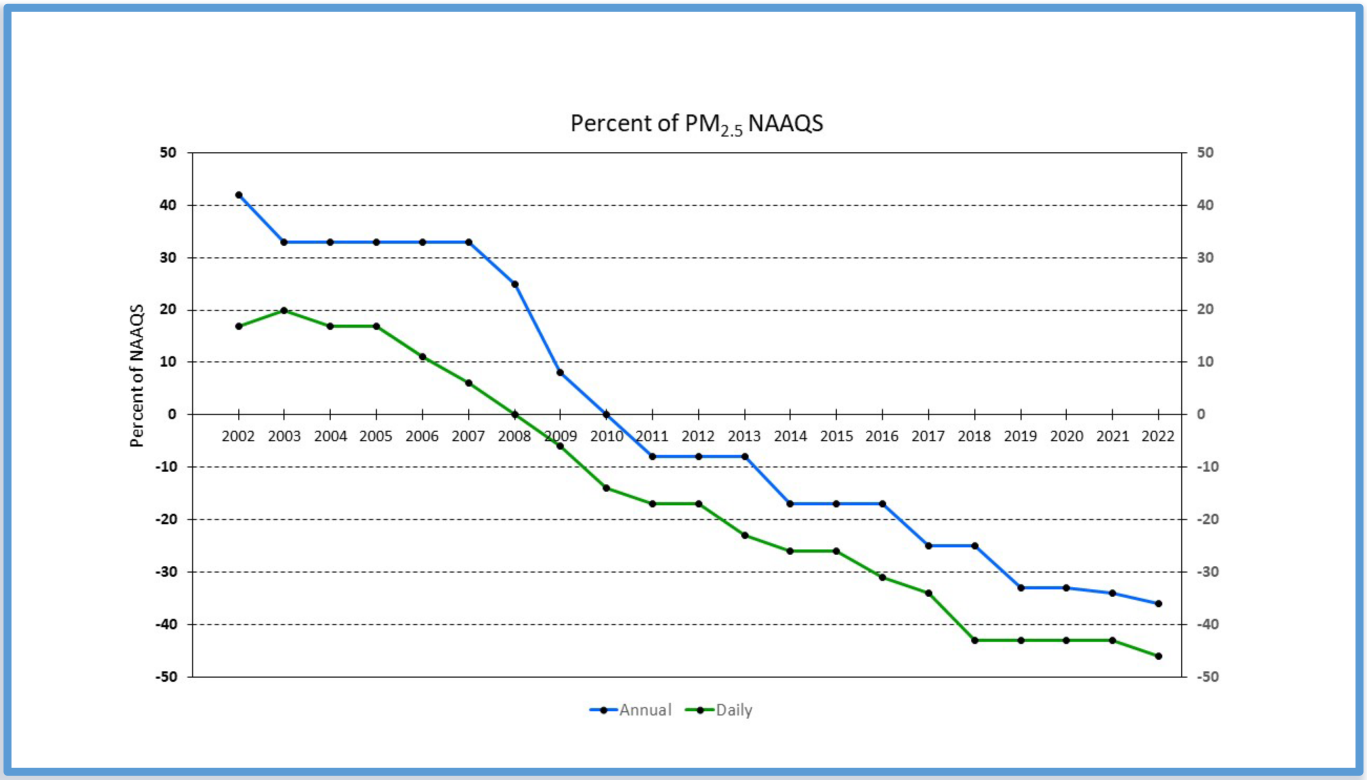
Source: Emissions reported in Maryland Electricity Profile 2022 https://www.eia.gov/electricity/state/maryland/xls/md.xlsx, last accessed November 21, 2023.

To put Maryland's power plant emissions in perspective, additional figures are available on PPRP's website in the CEIR Information, Air Quality Section, which presents a comparison of SO_2 and NO_x emission rates from all power plants in Maryland against emission rates from power plants in other states.

Particulates

Power plants are required by federal and state regulations to monitor NO_x and SO_2 emissions continuously and report those emissions publicly. Most plants are not required to monitor and report $PM_{2.5}$ emissions in the same manner, so $PM_{2.5}$ emissions data from power plants are not readily available. Figure 5-4 shows annual ambient $PM_{2.5}$ concentrations (rather than emissions) as a percentage of the NAAQS across Maryland over the last 21 years, as reported in the "Maryland Clean Air 2023 Progress Report." $PM_{2.5}$ concentrations in Maryland have decreased steadily in recent years because recent regulations have required significant reductions in $PM_{2.5}$ precursor emissions (SO_2 and NO_x), particularly from coal-fired power plants. See Section 5.1.3 in CEIR-21, subsection "Visibility and Regional Haze" for further information on particulate matter emissions in addition to how the CAA established regulations to federally manage improvement of visibility in certain areas, including Class I areas near Maryland (see Figure 5-13 in CEIR-21 for a map of the Class I areas).

Figure 5-4 Annual and Daily Ambient $PM_{2.5}$ Design Values in Maryland



Source: 2023 Clean Air Progress Report https://storymaps.arcgis.com/stories/621d6e8ee2d34323b8c0caeea6dc808d, last accessed November 24, 2023.

Mercury

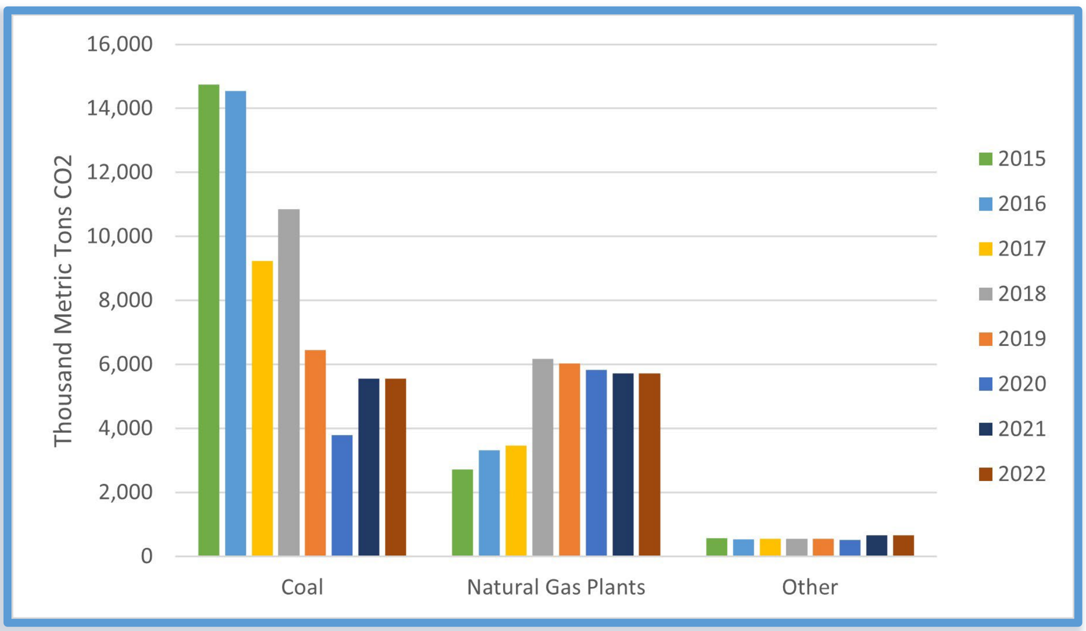
The "Hazardous Air Pollutant Emissions" subsection of CEIR-21 Section 5.1.2 details the CAA Amendments of 1990 that focused on this class of pollutants that cause or might cause an adverse impact to health or the environment. Among the HAPs emitted by power plants, Hg is a pollutant of particular concern because of its significant adverse health effects. The primary stationary sources of Hg in the U.S., in order of decreasing emissions, are coal-fired power plants, industrial boilers, gold mining, hazardous waste incineration, chlor-alkali chemical plants, municipal waste incinerators, and medical waste incinerators. Mercury emissions figures are available on PPRP's website, CEIR Information, Air Quality Section.

PPRP has been involved for many years in conducting complex modeling studies to estimate the quantity of Hg from Maryland and other regional sources that is deposited in water bodies throughout the state. The "Mercury Impacts" subsection of Section 5.1.3 of CEIR-21 describes further how PPRP plays an important role in supporting scientific research regarding power plant Hg emissions as well as the effects of Hg emissions. The subsection also contains details of the analysis PPRP has conducted to determine the reduction in Hg loads to the state's water bodies due to the implementation of Maryland Healthy Air Act (HAA) Hg controls.

Carbon Dioxide

A GHG is broadly defined as any gas that absorbs infrared radiation in the atmosphere. The pollutant "GHG," as defined in federal air regulations (40 CFR Part 51.21), is the aggregate of six greenhouse gas compounds: CO_2, methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulfur hexafluoride (SF_6). The "Greenhouse Gas Emissions" subsection of CEIR-21 Section 5.1.2 further describes the principal GHGs that enter the atmosphere due to human activities. Figure 5-5 presents CO_2 emissions from fossil-fuel-fired power plants in Maryland for 2015–2022. Power plants do not have add-on CO_2 pollution control systems, so GHG emissions are generally a direct result of the amount of fuel burned, thus fluctuations in annual GHG emissions are largely a result of changes in fuel consumption caused by power demand. These emission trends illustrate the decrease in coal combustion and the concurrent increase in generation from natural gas-fired units and renewables over the past decade.

Figure 5-5 Annual CO_2 Emissions by Power Plant Type in Maryland



Source: Emissions reported in Maryland Electricity Profile 2022 https://www.eia.gov/electricity/state/maryland/xls/md.xlsx, last accessed November 21, 2023.

Note: Emissions reported at https://www.epa.gov/egrid/data-explorer, last accessed September 5, 2023.

Additional information on out-of-state emissions of CO_2 can be found on PPRP's website, CEIR Information, Air Quality Section.

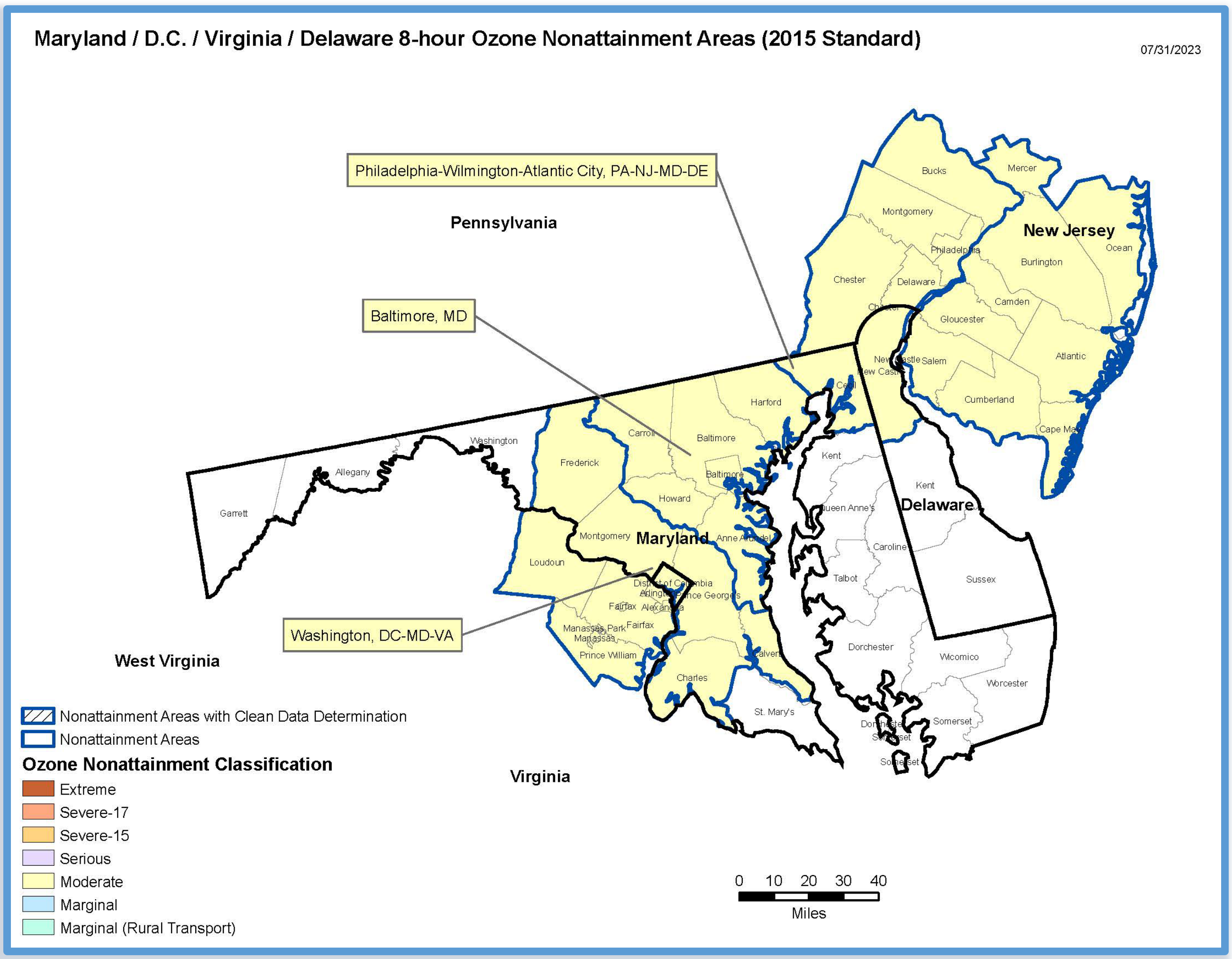
Ozone

Ozone is an invisible and reactive gas that is the major component of photochemical smog. Sources do not emit ozone directly into the atmosphere in significant amounts, but ozone instead forms through chemical reactions in the atmosphere.

Ozone is recognized as a regional rather than a local pollutant; thus, in the CAA, Congress recognized that ozone pollution and its precursors can be transported from state to state. The 1990 CAA Amendments created the Northeast Ozone Transport Region (OTR), composed of 12 states (including Maryland) and the District of Columbia to address the regional nature of ozone pollution. As part of the OTR, the entire State of Maryland must follow nonattainment area requirements as if all areas were ozone nonattainment areas, even though ozone monitoring indicates that only the central portion of the state is in nonattainment.

Much of the urbanized portions of Maryland, like most densely populated areas across the eastern U.S., are not meeting the NAAQS for ozone. On October 1, 2015, a new 8-hour ozone NAAQS of 0.070 parts per million (ppm) went into effect. Figure 5-6 depicts the current ozone nonattainment area designations in Maryland for the 2015 ozone NAAQS.

Figure 5-6 Ozone Nonattainment Areas in Maryland



Source: U.S. Environmental Protection Agency, "Maryland/ D.C./Virginia/Delaware 8-hour Ozone Nonattainment Areas (2015 Standard)," https://www.epa.gov/green-book. Last accessed August 22, 2023.

Figure 5-7 Maryland's Ozone Trend

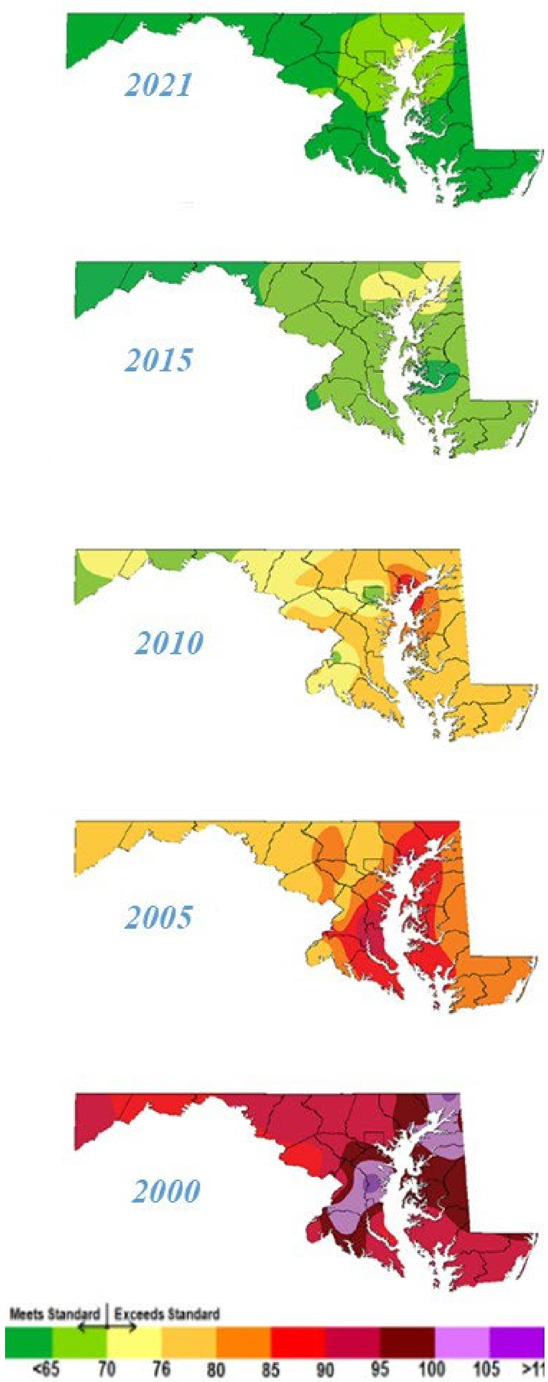


Figure 5-7 depicts the positive trend in ozone concentrations in Maryland since 2000. The subsection titled "Ozone" of Section 5.1.3 of CEIR-21 further details the sources and effects of ground-level ozone and describes the federal NO_x reduction regulations that Maryland has been subject to since the mid-1990s.

Source: MDE Report on the Environment, "Clean Air Progress Report 2022," https://storymaps.arcgis.com/stories/142652cce2db4327ae40f7e348877d61.

5.1.3 Recent and Developing National and State Air Regulatory Drivers Affecting Power Plants

Developing Maryland SO_2 Regulations

MDE has been working on several new control initiatives to reduce SO_2 emissions within a small area in Anne Arundel and Baltimore counties identified by EPA as not meeting the 2010 SO_2 NAAQS. This designation was not based on monitoring data, which is typical for attainment designation, and MDE's analysis projected that SO_2 levels would be below the standard. The main sources of SO_2 in this area are the Brandon Shores and Herbert A. Wagner power plants. The two coal units at C.P. Crane had historically been large emitters of SO_2; however, the plant was shut down in June 2018. All units at both plants have installed controls for SO_2 at the coal-fired generating units. Both units at Brandon Shores have been operating with state-of-the-art flue gas desulfurization (FGD) systems since 2010; coal units at Wagner began using lower-sulfur coal and operating dry sorbent injection (DSI) pollution control systems in 2015 and 2016. In December 2021, Raven Power Fort Smallwood LLC requested that the Maryland PSC approve a Certificate of Public Convenience and Necessity (CPCN) modification exemption for Raven Power to convert Wagner Unit 3 and Brandon Shores Unit 1 and Unit 2 from coal to oil.

In June 2017, a monitoring plan was submitted to the EPA that detailed the path that MDE planned to implement to attain compliance with the 1-hour SO_2 NAAQS. The plants subject to the plan were Brandon Shores, C.P. Crane (since decommissioned), Chalk Point, H.A. Wagner, Verso Luke Mill (shut down in 2019), and Morgantown. Upon further evaluation of the SO_2 modeling, MDE will develop regulations to bring the SO_2 nonattainment areas into attainment status.

In January 2020, MDE submitted its 1-hour SO_2 SIP to EPA for approval.[85] Due to the shutdown of the Verso Luke Mill Plant and as recommended by MDE,[86] on August 13, 2020, EPA notified MDE of its intention to classify Allegany County as attainment/unclassifiable.[87]

EPA determined, as of November 2, 2022, that based on 2019 to 2021 ambient air quality monitoring data and air dispersion modeling, the Anne Arundel-Baltimore County nonattainment area has attained the 2010 1-hour SO_2 NAAQS. EPA's clean data determination suspends the requirement for the area to SO_2 NAAQS attainment plan SIP elements for as long as the area continues to meet the 2010 1-hour SO_2 NAAQS.[88]

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[85] Maryland Department of the Environment, "State of Maryland 1-Hour Sulfur Dioxide (SO2) National Ambient Air Quality Standard (NAAQS) State Implementation Plan for the Anne Arundel County and Baltimore County, MD ("Wagner") Nonattainment Area," January 31, 2020, SIP # 20-01, mde.maryland.gov/programs/air/airqualityplanning/pages/index.aspx, last accessed August 20, 2021.

[86] Letter from Ben Gumbles (MDE) to Cosmo Servidio (EPA Region 3) dated May 29, 2020, epa.gov/sulfur-dioxide-designations/sulfur-dioxide-so2-designations-round-4-maryland-state-recommendation, last accessed August 20, 2021.

[87] Letter from Cosmo Servidio (EPA Region 3) to Governor Lawrence Hogan signed August 13, 2020, epa.gov/sulfur-dioxide-designations/sulfur-dioxide-so2-designations-round-4-maryland-state-recommendation, last accessed August 20, 2021.

[88] Air Plan Approval; Maryland; Clean Data Determination and Approval of Select Attainment Plan Elements for the Anne Arundel County and Baltimore County, MD Sulfur Dioxide Nonattainment Area, November 2, 2022, Federal Register, 87

Recent Maryland GHG Regulation

During its 2015 session, the Maryland General Assembly codified the Maryland Commission on Climate Change (MCCC) into law, officially charging the Commission with advising the Governor and General Assembly "on ways to mitigate the causes of, prepare for, and adapt to the consequences of climate change." The MCCC is chaired by the MDE Secretary or designee and consists of members representing state agencies and the legislature, local government, business, environmental nonprofit organizations, organized labor, philanthropic interests, and the State University system.[89]

The Climate Solutions Now Act (CSNA)[90] that was passed into law in 2022 is one of the most ambitious climate change laws adopted in the United States. The CSNA calls for Maryland to reduce GHG emissions by 60% (compared to a 2006 baseline) by 2031 and for the Maryland economy to reach net-zero emissions by 2045.

Under CSNA, the MCCC must create several new reports and add four new working groups with an extensive list of required representatives to be appointed. The Commission currently has four working groups: Mitigation; Adaptation and Resiliency; Scientific and Technical; and Education, Communication, and Outreach. The four new working groups the CSNA added are: Just Transition Employment and Retraining; Energy Industry Revitalization; Energy Resilience and Efficiency; and Solar Photovoltaic Systems Recovery, Reuse, and Recycling. The MDE hosts the Commission meetings at least four times per year, with additional meetings called by the Chair as needed.

National Emission Standards for Hazardous Air Pollutants

Under 40 CFR Part 63, EPA established the National Emission Standards for Hazardous Air Pollutants (NESHAP) pursuant to Section 112 of the CAA as amended November 15, 1990. These NESHAPs regulate specific stationary source categories that emit (or have the potential to emit) one or more HAPs listed in 40 CFR Part 63 pursuant to Section 112(b) of the CAA. The standards 40 CFR Part 63 are independent of NESHAP contained in 40 CFR Part 61.

The NESHAPs are based on maximum achievable control technology (MACT). The NESHAPs are sometimes referred to as "MACT standards" because the underlying control technology for the Part 63 NESHAPs is MACT. MACT is not only limited to technology but also can include processes, methods, systems, and techniques that are used by a facility to reduce its HAP emissions.

The NESHAPs typically apply to a "major source," which is defined as any stationary source (or group of stationary sources) that emits at least 10 tons of any single HAP or 25 tons of multiple HAPs annually. If a source is not major, then it is considered an area source. Some Part 63 NESHAPs also apply to area sources.

FR 66086, https://www.federalregister.gov/documents/2022/11/02/2022-23709/air-plan-approval-maryland-clean-data-determination-and-approval-of-select-attainment-plan-elements, last accessed November 26, 2023.

[89] Maryland Commission on Climate Change, https://mde.maryland.gov/programs/Air/ClimateChange/MCCC/Pages/index.aspx, last accessed November 26, 2023.

[90] Senate Bill 528 (SB0528), https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/sb0528?ys=2022rs, last accessed November 26, 2023.

The two 40 CFR Part 63 NESHAP source categories that are especially relevant to large Maryland power plants are as follows, and each is summarized:

- Subpart UUUUU—NESHAP: Coal- and Oil-fired Electric Utility Steam Generating Units
- Subpart YYYY—National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

Utility Mercury and Air Toxics Standard (MATS) – Subpart UUUUU

On December 21, 2011, the EPA promulgated a MACT standard, referred to as the Mercury and Air Toxics Standard, or the "Utility MATS," that will reduce emissions of HAPs from power plants. The rule established emission standards for new and existing fossil-fueled electric utility steam generating units with generating capacities greater than 25 megawatts (MW). The rule is intended to reduce emissions of heavy metals (Hg, arsenic, chromium, nickel), acid gases (hydrogen chloride [HCl] and hydrogen fluoride [HF]), and organic HAPs (formaldehyde, benzene, and acetaldehyde) from coal- and oil-fired power plants.

After promulgation of the Utility MATS, in a 5–4 decision announced on June 29, 2015, the U.S. Supreme Court overturned MATS, ruling that the EPA did not properly consider the costs of emissions reductions in creating the regulations; the Court did not take issue with the standard itself. The EPA's response was the 2016 Supplemental Finding, published in the Federal Register on April 25, 2016, that included a consideration of the costs and benefits of the rule, concluding that taking "cost of control" into account does not change its previous determination that MATS is "appropriate and necessary" to regulate HAP emissions from coal- and oil-fired generating units. However, on December 27, 2018, the EPA proposed to revise the Supplemental Finding for the MATS rule, determining that it is *not* "appropriate and necessary" to regulate HAP emissions from power plants under Section 112 of the CAA. In the May 22, 2020, Federal Register, EPA promulgated its finding that it is not ''appropriate and necessary'' to regulate HAP emissions from coal- and oil-fired electric generating units (EGUs), after mainly comparing the cost of compliance relative to the benefits of HAP emission reduction from regulation. In that same Federal Register notice, EPA also finalized the residual risk and technology review (RTR) conducted for the coal- and oil-fired EGU source category regulated MATS. Based on the results of the RTR analyses, EPA did not promulgate any revisions to the MATS rule. The MATS rule will remain in place because the EPA is not proposing to remove coal- and oil-fired power plants from the grouping of sources, which are regulated under Section 112 of the CAA.

On April 24, 2023, EPA proposed to amend MATS to strengthen the filterable particulate matter (fPM) emission standards for existing coal-fired EGUs to 0.010 pound (lb)/ million British thermal unit (MMBtu). EPA's proposal would also strengthen emissions monitoring and compliance by requiring coal-fired EGUs to comply with the standard using continuous emission monitoring systems (CEMS). For all existing and new EGUs subject to MATS, EPA is proposing to narrow the current definition of "startup." This new definition would be implemented 180 days after the effective date of the revised regulation. Compliance with all other proposed requirements would be required within three years. April's proposal comes from EPA's review of the previous May 22, 2020, RTR and reflects recent developments in control technologies and the performance of these EGUs.

As the MATS rule currently stands, for new and existing coal-fired generating units, the Utility MATS establishes numerical emission limits for Hg, PM (as a surrogate for toxic non-Hg metals), and HCl or SO_2 (as surrogates for toxic acid gases). For new and existing oil-fired generating units, the rule establishes numerical emission limits for PM (surrogate for all toxic metals), HCl, and HF. Existing sources were required to meet emission limitations and implement work practice standards by April 16, 2015, but about 200 plants were granted extensions to install pollution control equipment; newly constructed sources are subject to the standards at startup.

For affected power plant sources in Maryland, add-on pollution control systems, such as wet FGD systems installed for HAA compliance and powdered activated carbon injection for Hg, may be sufficient for compliance with the Utility MATS Hg and organic and metal HAPs standards. H.A. Wagner installed dry sorbent injection (DSI) systems in 2015 to meet the HCl emission limit.

Stationary Combustion Turbine NESHAPs – Subpart YYYY

Subpart YYYY establishes national emission limitations and operating limitations for HAPs emissions from stationary combustion turbines located at major sources of HAP emissions, and it sets requirements to demonstrate initial and continuous compliance with the emission and operating limitations.

Currently, in Subpart YYYY, stationary combustion turbines have been divided into eight subcategories. Most importantly, when Subpart YYYY was originally promulgated in 2004, EPA set a 91 parts per billion by volume (ppbvd) at 15% oxygen (O_2) formaldehyde limit for new and reconstructed lean premix and diffusion flame gas-fired turbines (those constructed or reconstructed after January 14, 2003). EPA later stayed the effectiveness of the emissions standard for lean premix and diffusion flame gas-fired turbines. A court ruled in 2007 that EPA has no authority to delist subcategories of sources (such as those subject to the stay). Consequently, a petition to delist the entire Stationary Combustion Turbines source category was filed in August 2019.

In the March 9, 2020, Federal Register, EPA published the Stationary Combustion Turbine residual RTR Final Rule. EPA did not finalize its proposed removal of the administrative stay for new lean premix and diffusion flame gas-fired turbine subcategories. EPA is still reviewing the comments on lifting the stay and will respond to those comments in a separate action. Those comments included the petition to delist the entire Stationary Combustion Turbines source category.

New Source Review

Maryland requires any new or modified air pollution source to obtain an air quality permit to construct unless specifically exempted by the relevant regulation. New major sources or modifications to existing major sources must comply with the applicable provisions of Nonattainment New Source Review (NA-NSR) and/or Prevention of Significant Deterioration (PSD), depending on the attainment status of the area where the source is located and the quantity and type of air pollutants emitted.

Maryland follows the federal PSD regulations found at 40 CFR 52.21, which are incorporated by reference at Code of Maryland Regulation (COMAR) 26.11.06.14. The NA-NSR requirements are found at COMAR 26.11.17. If a power plant is subject to PSD and/or NA-NSR requirements, they are included in the facility's CPCN. The requirements are enforced by MDE.

Both programs are complex, and revisions to the underlying guidance, and sometimes the regulations themselves, can occur. For example, in 2019 and 2020, EPA proposed or finalized three rules and issued five guidance documents.

Cross-State Air Pollution Rule

On July 6, 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) to address air pollution from upwind states that crosses state lines and affects air quality in downwind states. SO_2 and NO_x react in the atmosphere and contribute to the formation of $PM_{2.5}$. NO_x also contributes to the formation of ground-level ozone. These emissions and the $PM_{2.5}$ and ozone they form can affect air quality and public health locally, regionally, and in states hundreds of miles downwind.

CSAPR requires certain states in the eastern half of the U.S., including Maryland, to improve air quality by reducing power plant emissions that cross state lines and contribute to ozone and $PM_{2.5}$ levels in downwind states. These improvements help downwind areas attain and maintain the $PM_{2.5}$ and ozone NAAQS. CSAPR replaced the EPA's 2005 Clean Air Interstate Rule (CAIR) due to a 2008 court decision that required the EPA to issue a replacement regulation. Implementation of CSAPR began on January 1, 2015. On September 7, 2016, EPA revised the CSAPR ozone season NO_x program by finalizing an update to CSAPR for the 2008 ozone NAAQS, known as the CSAPR Update. The CSAPR Update ozone season NO_x program largely replaced the original CSAPR ozone season NO_x program starting on May 1, 2017. In the April 30, 2021, Federal Register, EPA finalized a Revised CSAPR Update for the 2008 ozone NAAQS. Starting in the 2021 ozone season, the rule requires additional NO_x emissions reductions from power plants in 12 states, including Maryland.

On June 5, 2023, the EPA published its finalized federal "Good Neighbor Plan" for the 2015 Ozone NAAQS. The rule established new NO_x emissions budgets applicable to the ozone season for EGUs in 22 states and industrial sources in 20 states. The covered EGUs, including EGUs in Maryland, will be subject to a revised CSAPR NO_x Season Group 3 Trading Program.

NAAQS Revisions

As mentioned previously, the CAA requires the EPA to review the NAAQS every five years. If EPA makes a NAAQS more stringent, it could have a significant impact on power plants in Maryland because MDE may dictate additional controls for various portions of the state to attain the more stringent standard. After a NAAQS is revised, EPA must determine which areas meet the standard and must also develop an implementation plan for the NAAQS to be attained and maintained.

The CAA establishes a framework for EPA to set NAAQS based on the "latest scientific knowledge" through a notice and comment rulemaking process. Reviewing the NAAQS is a lengthy process and includes the following major phases:[91]

- Planning
- Integrated Science Assessment
- Risk/Exposure Assessment

[91] epa.gov/criteria-air-pollutants/process-reviewing-national-ambient-air-quality-standards.

- Policy Assessment
- Rulemaking

EPA provides timelines for the review of each of the NAAQS.[92]

5.1.4 Greenhouse Gas Policies

Evidence of a rising average global temperature has driven global efforts to reduce human impact on the earth's climate. Human activities, such as fossil fuel combustion for electricity generation and transportation, industrial processes, and changes in land use, including deforestation, contribute significant amounts of CO_2 and other GHGs to the atmosphere. At the turn of the twenty-first century, record-high levels of atmospheric concentrations of GHGs sparked national debate about the responsibility to reduce human contribution to global climate change.

See Section 5.1.5 of CEIR-21 for background information on climate change.

Maryland has been working to reduce the state's impact on the climate. The Maryland Commission on Climate Change (MCCC) was formed in 2007 to develop a statewide Climate Action Plan, which was published in 2008. This plan contained 61 policy options, programs, and measures to reduce GHG emissions in the state and to help the state respond and adapt to the impacts of climate change.

Maryland also implemented the Greenhouse Gas Emissions Reduction Act of 2009 (GGRA), which was reauthorized in April 2016 (GGRA of 2016). That legislation is described in more detail in the following sections along with key federal and international climate initiatives.

The state continues to participate in the Regional Greenhouse Gas Initiative (RGGI) with the objective of reducing CO_2 emissions specifically from the electricity generation sector. That program is described in detail next.

Regional Greenhouse Gas Initiative

In 2005, the governors of Delaware, Connecticut, Maine, New Hampshire, New Jersey, New York, and Vermont created the first cap-and-trade program for CO_2 in the United States, the Regional Greenhouse Gas Initiative (RGGI). Maryland, as required by the state's Healthy Air Act of 2006, joined RGGI in 2007, the same year as Massachusetts and Rhode Island. For 2021, 2022, and 2023, the regional cap refers to the 11 participating RGGI states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont, and Virginia).[93]

Two Commonwealth Court decisions in 2023 have prevented Pennsylvania from participating in RGGI. The state's governor appealed these decisions in November 2023.[94] Litigation is ongoing. Virginia

[92] epa.gov/naaqs/historical-information-naaqs-review-process.

[93] https://www.rggi.org/program-overview-and-design/elements.

[94] https://www.spotlightpa.org/news/2023/11/pennsylvania-josh-shapiro-climate-change-appeal-regional-greenhouse-gas-initiative-court-case/#:~:text=HARRISBURG%20%E2%80%94%20Gov.,emissions%20and%20fight%20climate%20change.

enacted legislation to join RGGI in 2020. In 2022, Governor Glenn Youngkin issued an executive order to begin a regulatory process for withdrawing from RGGI.[95] The Virginia State Air Pollution Control Board voted to withdraw from RGGI in June 2023.[96] Litigation of Virgina's withdrawal from RGGI is ongoing.[97]

Under RGGI, total CO_2 emissions from fossil fuel–fired electricity generating units with nameplate capacities of 25 MW or greater were capped initially from 2009 through 2014 at 188 million allowances (or short tons), based on projected 2006–2007 emissions levels. A phased approach was used to provide regulatory certainty for electricity generators to begin planning for, and investing in, lower-carbon alternatives without creating dramatic electricity price impacts. As shown in Table 5-2, the annual allowances were reduced to 165 million tons following New Jersey's exit from the RGGI program at the end of 2011 and reduced again in 2014 to 91 million tons. In 2020, the last year of the fourth control period (2018–2020), the allowance cap increased 16 million tons to 96.4 million tons because of New Jersey's return to RGGI. Emission allowances were reduced 2.5% per year from 2015 through 2020, for a total reduction of 10%.[98]

Table 5-2 RGGI Emissions Allowance Budgets

		Annual RGGI Allowance Budget (million tons of CO_2)		
Year	Control Period	Total All States	Maryland	Maryland % of all States
2009	1	188.1	37.5	20%
2010	1	188.1	37.5	20%
2011	1	188.1	37.5	20%
2012	2	165.2	37.5	23%
2013	2	165.2	37.5	23%
2014	2	91.0	20.4	22%
2015	3	88.7	19.9	22%
2016	3	86.5	19.4	22%
2017	3	84.3	19.1	23%
2018	4	82.2	18.7	23%
2019	4	80.4	17.9	22%
2020	4	96.4	17.5	18%

[95] Commonwealth of Virginia, Office of the Governor, Executive Order Number 9, "Protecting Ratepayers from the Rising Cost of Living Due to the Regional Greenhouse Gas Initiative," January 15, 2022, https://www.governor.virginia.gov/media/governorvirginiagov/governor-of-virginia/pdf/eo/EO-9-RGGI.pdf.

[96] Governor Glenn Youngkin, "Governor Glenn Youngkin Praises State Air Pollution Control Board's Repeal of RGGI," Press Release, June 7, 2023, https://www.governor.virginia.gov/newsroom/news-releases/2023/june/name-1005558-en.html.

[97] Katherine Hafner, "Lawsuit over Virginia's departure from RGGI can continue, court rules," VPM, February 7, 2024, https://www.vpm.org/news/2024-02-07/lawsuit-over-virginia-departure-rggi-carbon-market-can-continue.

[98] https://www.rggi.org/program-overview-and-design/elements.

		Annual RGGI Allowance Budget (million tons of CO_2)		
Year	Control Period	Total All States	Maryland	Maryland % of all States
2021	5	92.6	16.8	18%
2022	5	89.8	16.3	18%
2023	5	87.0	15.8	18%

Source: Compiled from annual budget allowance data for each state. See https://www.rggi.org/allowance-tracking/allowance-distribution.

There were 16 power plants in the 2018–2020 control period in Maryland that had compliance obligations under RGGI.[99] Maryland's 2020 RGGI budget allowance was 17.5 million tons of CO_2 or 18% of the 2020 regional CO_2 budget of 96.4 million short tons. In the 2021–2023 control period, there were 13 power plants in Maryland with compliance obligations under RGGI, with CO_2 total emissions of 33.8 million tons subject to RGGI compliance obligations.[100]

Emissions in the power sector have fallen over the last several years due to plant closures, mild weather patterns, shifts to natural gas-fired generation, increased generation from renewable energy sources, and increases in conservation and demand response. Maryland's annual CO_2 emissions subject to RGGI compliance obligations have declined 57%, or 44.8 million tons[101] of CO_2, from the first RGGI control period (2009–2011) to the fifth control period (2021–2023). From 2005 through 2022, CO_2 emissions from Maryland's power sector have declined 66%, or 24.7 million tons.[102]

The RGGI states issued the Third Adjustment for Banked Allowances on March 15, 2021, which accounts for banked CO_2 allowances accumulated during the fourth control period and is applied to the RGGI cap. Table 5-3 shows the adjusted cap for 2021 to 2025 under the Third Adjustment pursuant to the 2017 Model Rule.

[99] RGGI CO_2 Allowance Tracking System, Compliance Summary Report. RGGI CO2 Allowance Tracking System (rggi-coats.org).

[100] RGGI CO_2 Allowance Tracking System, Summary Emissions Level Report for MD, 2021-2023; https://rggi-coats.org/eats/rggi/index.cfm?fuseaction=search.rggi_summary_report_input&clearfuseattribs=true. One emissions source, the Cove Point LNG Terminal, was not subject to RGGI compliance obligations for the period 2018-2022.

[101] RGGI CO_2 Allowance Tracking System, Summary Emissions Level Reports for MD, 2009-2023; https://rggi-coats.org/eats/rggi/index.cfm?fuseaction=search.rggi_summary_report_input&clearfuseattribs=true.

[102] EIA-923 Emissions Survey data. See https://www.eia.gov/electricity/data.php#elecenv.

Table 5-3 Adjusted CO_2 Emissions Cap (million tons), 2021–2025

	2021	2022	2023	2024	2025
Base Cap	108.7	105.3	102.0	98.7	95.4
Bank Adjustments	(17.3)	(17.3)	(17.3)	(17.3)	(17.3)
Adjusted Cap	**91.3**	**88.0**	**84.7**	**81.4**	**78.1**

Source: International Carbon Action Partnership (ICAP), RGGI announces downward cap adjustment for 2021–2025 | International Carbon Action Partnership (icapcarbonaction.com). March 18, 2021.

A comprehensive program review was conducted in 2012 by RGGI member states via a regional stakeholder process. An updated RGGI Model Rule was published in February 2013, resulting in, among other program clarifications, a 45% reduction in the regional emissions cap to 91 million tons starting in 2014. Other revisions include the establishment of interim control period requirements, a cost containment reserve program to help alleviate spikes in allowance prices and changes in the handling of offsets as described in the following.

The 2016 Program Review by member states began in late 2015 and concluded in December 2017, resulting in the 2017 Model Rule. The most significant change under the 2017 Model Rule included a reduction in RGGI's carbon cap by 30% from 2020 to 2030, effectively eliminating 22,750,000 tons of CO_2 from 2021 through 2030. The cost containment reserve program will continue to operate, albeit with increasing trigger prices ($13 per ton in 2021, increasing 7% annually to reach $23.89 per ton in 2030).[103]

Beginning in 2021, a new mechanism, the emissions containment reserve (ECR), commenced operation. States can withhold up to 10% of their annual budget under the ECR if prices fall below certain thresholds ($6 per ton in 2021, increasing 7% annually to reach $11.02 per ton in 2030).[104] States may then choose to impose further reductions if prices are lower than expected. The auction price floor in 2023 was $22.20 per ton, which increased by 5% plus inflation as measured by the Consumer Price Index.[105] The ECR is implemented in seven states: Connecticut, Delaware, Maryland, Massachusetts, New York, Rhode Island, and Vermont.

Table 5-4 lists the annual CO_2 emissions, by compliance period, for each RGGI member state. (Emissions from Virginia sources are reported beginning January 1, 2021.) It should be noted that of the 13 states (plus the District of Columbia) that are included in whole or in part in the PJM footprint, only Maryland, Delaware, and New Jersey participate in RGGI, although as mentioned, Pennsylvania's and Virginia's participation are being litigated. To some degree, therefore, "emissions leakage" may occur (i.e., reductions in emissions from plants covered in RGGI are offset by emissions from power plants not covered in RGGI). The reason for the potential emissions leakage is that the energy generated from plants in Delaware, Maryland, New Jersey, and Virginia is subject to the RGGI emissions cap, while generation in PJM states not participating in RGGI is not subject to the emissions cap. The extent of emissions leakage depends upon numerous factors, including energy consumption levels, power plant

[103] RGGI, Inc. 2017 Model Rule, Revised December 14, 2018, Table 1.

[104] RGGI, Inc. 2017 Model Rule, Revised December 14, 2018, Table 2.

[105] ICAP, *Emissions Trading Worldwide, Status Report 2023*, p.119. ICAP reports that, as of the March 2023 released date, the ECR trigger price was suspended, and therefore the ECR provision was not operational. https://icapcarbonaction.com/en/publications/emissions-trading-worldwide-2023-icap-status-report.

running-cost differentials, the price of RGGI emission allowances, the level of the emissions caps, and transmission congestion.

Table 5-4 CO_2 Emissions by RGGI States (million tons of CO_2)

	Annual RGGI Emissions					
	Annual Historical Emissions	Compliance Period 1	Compliance Period 2	Compliance Period 3	Compliance Period 4	Compliance Period 5
State	**2005–2008**	**2009–2011**	**2012–2014**	**2015–2017**	**2018–2020**	**2021–2023**
Maryland	32.38–37.26	25.57–27.96	18.68–20.90	12.68–18.33	10.2–17.3	9.1–13.1
Connecticut	8.99–11.32	7.15–8.53	7.12–7.46	6.83–8.15	8.1–9.4	6.6–10.0
Delaware	7.56–8.30	3.71–4.30	3.93–4.84	3.52–4.04	2.0–2.7	1.4–2.2
Massachusetts	21.44–26.64	15.63–19.80	11.79–13.68	10.89–12.04	5.5–8.3	6.2–6.5
Maine	3.37–4.59	3.34–3.94	2.25–2.94	1.07–1.78	0.8–1.2	1.5–2.0
New Hampshire	7.10–8.97	5.53–5.90	3.57–4.64	1.98–3.82	1.7–2.8	2.0–2.6
New Jersey	20.60–22.07	16.36–19.68	N/A (see note a)	N/A (see note a)	14.9	14.6–33.9
New York	48.35–62.72	37.15–42.11	33.48–35.64	24.58–32.55	24.6–27.7	28.4–30.6
Rhode Island	2.69–3.29	3.42–3.95	2.77–3.74	2.83–3.21	2.1–3.5	3.1–3.8
Vermont	0.0026–0.0078	0.0020–0.0065	0.0023–0.00276	0.0012 –.0043	0.00055–0.00207	0.00207–0.0039
Pennsylvania (2022 and 2023 Only)	—	—	—	—	—	40.6–74.7
Original RGGI 10 State Total	153.5–184.6	118.56–135.74	N/A	N/A	N/A	N/A
RGGI Through 2017 (9 States)	132.9–162.5	N/A	86.53–92.73	64.49–82.99	N/A	N/A
RGGI Through 2023 (11 States)	N/A	N/A	N/A	N/A	59.65–73.66	106.61–176.56

Source: rggi.org/.
Notes:
(a) New Jersey withdrew from the RGGI program at the end of 2011 and rejoined on January 1, 2020.

RGGI Allowance Auctions

Each RGGI member state has its own independent CO_2 budget trading program. States sell their CO_2 allowances in regional quarterly auctions, with each CO_2 allowance representing a limited authorization to emit one ton of CO_2. CO_2 allowances issued by any state are usable across all state programs; therefore, the individual state CO_2 budget trading programs, in aggregate, form one regional compliance market for CO_2 emissions. A power plant within an RGGI state must hold CO_2 allowances equal to its emissions to demonstrate compliance at the end of each three-year control period. During the program's first compliance period from 2009 to 2011, 206 of the 211 power plants subject to RGGI (over 97%) met the program's compliance obligations. For the second compliance period from 2012 to 2014, 161 of the 167 power plants subject to RGGI requirements met their compliance obligations. During the third control period from 2015 to 2017, 161 of the 163 power plants subject to RGGI requirements met their compliance obligations. For the fourth control period (2018–2020), 198 of the 203 power plants subject to RGGI requirements, or 97.5%, met their compliance obligations and 99.1% of covered power sector emissions were compliant.[106] For the 2022 interim control period, all 171 power plants subject to RGGI requirements met their obligations and 94.1% of the covered power sector emissions were compliant.[107]

Allocation of the Maryland Strategic Energy Investment Fund

The RGGI member states have agreed that a minimum of 25% of the revenue from each state's emissions allowances is to be used for consumer benefit or strategic energy purposes. As of the December 2023, auction, Maryland has raised $1.15 billion in RGGI proceeds. The revenue is directed to the Maryland Strategic Energy Investment Fund (SEIF), which is administered by the Maryland Energy Administration (MEA). The Maryland Legislature has directed MEA to allocate the SEIF as follows:

- Up to 50% – Energy bill assistance for low-income residents;
- At least 20% – Energy efficiency, conservation, and demand response programs (of which half must be used on low- and moderate-income families);
- At least 20% – Clean energy and climate change programs, outreach and education; and
- Up to 10%, but no more than $5 million – administration of the Fund.

While any entity may apply to participate in the quarterly auctions, in the first 44 auctions, 74% of the allowances were purchased by electric generators or their affiliates. Initially, the reserve or minimum allowance price was set at $1.86 per ton for the September 2008 auction and increased by 2.5% per year. However, beginning with the March 2014 auction, the reserve price was adjusted to $2 per ton and increases by 1.025% each year. Allowance clearing prices have ranged from $1.86 per ton to $14.88 per ton,[108] as shown in Figure 5-8.

Table 5-5 shows the results for RGGI allowance auctions since 2015 and revenue to Maryland from allowances sold (see Table 5-3 in CEIR-21 for results from 2008 to 2014). Beginning in December 2015, the auction clearing price began to decline, falling from a high of $7.50 per ton to $2.53 per ton in June 2017, slightly above the

[106] RGGI, Inc. "RGGI States Release Fourth Control Period Compliance Report," April 2, 2021, rggi.org/sites/default/files/Uploads/Press-Releases/2021_04_02_FoCP_Compliance.pdf.

[107] RGGI, Inc., RGGI CO2 Allowance Tracking System, Interim Compliance Summary Report, 2022 Interim, March 2023; chrome-extension://efaidnbmnnnibpcajpcglclefindmkaj/https://rggi-coats.org/eats/rggi/Docs/2022InterimComplianceSummaryReport.pdf.

[108] https://www.rggi.org/sites/default/files/Uploads/Auction-Materials/62/Auction_62_State_Proceeds_and_Allowances.pdf.

reserve minimum. In September 2017, the price began to increase and reached $5.62 per ton at the June 2019 auction. The average auction clearing price increased 18% from $5.42 per ton in 2019 to $7.41 per ton by the end of 2020. During the fourth control period (2018–2020), the average auction allowance price was $5.84 per ton. During the fifth control period (2021–2023), the average auction price was $12.16 per ton. In total, RGGI has resulted in $3.4 billion to participating states.[109] Maryland raised $415 million during this period, the majority of which has been used for low-income energy assistance.

Table 5-5 RGGI Allowance Auctions, 2015–2023

Auction Date	Auction Offering	Total RGGI Allowances Sold	Clearing Price Per Ton	Maryland Allowances Sold	Maryland Revenues (million USD)	Average Annual Price Per Ton	Control Period Price Per Ton
Mar-15	Current	15,272,670	$5.41	3,051,680	$16.51	$6.09	$4.76
Jun-15	Current	15,507,571	$5.50	3,053,288	$16.79		
Sep-15	Current	23,374,294	$6.02	5,323,721	$32.05		
Dec-15	Current	15,374,274	$7.50	3,053,288	$22.90		
Mar-16	Current	14,838,732	$5.25	2,994,243	$15.72	$4.47	
Jun-16	Current	15,089,652	$4.53	3,007,883	$13.6		
Sep-16	Current	14,911,315	$4.54	3,066,826	$13.9		
Dec-16	Current	14,791,315	$3.55	2,946,826	$10.5		
Mar-17	Current	14,371,300	$3.00	2,973,258	$8.9	$3.42	
Jun-17	Current	14,597,470	$2.53	2,973,542	$7.5		
Sep-17	Current	14,371,585	$4.35	2,973,543	$12.93		
Dec-17	Current	14,687,989	$3.80	2,973,543	$11.30		
Mar-18	Current	13,553,767	$3.79	2,539,908	$9.63	$4.42	$5.84
Jun-18	Current	13,771,025	$4.02	2,576,249	$10.36		
Sep-18	Current	13,590,107	$4.50	2,576,249	$11.59		
Dec-18	Current	13,360,649	$5.35	2,576,249	$13.78		
Mar-19	Current	12,883,436	$5.27	2,387,512	$12.58	$5.42	
Jun-19	Current	13,221,453	$5.62	2,389,718	$13.43		
Sep-19	Current	13,116,447	5.20	2,620,524	$13.63		
Dec-19	Current	13,116,444	5.61	2,620,525	$14.70		
Mar-20	Current	16,208,347	5.65	2,330,353	$13.17	$8.53	
Jun-20	Current	16,336,298	5.75	2,314,790	$13.31		
Sep-20	Current	16,192,785	6.82	2.314,790	$15.79		

[109] Allowances sold in Table 5-2 include Virginia.

Auction Date	Auction Offering	Total RGGI Allowances Sold	Clearing Price Per Ton	Maryland Allowances Sold	Maryland Revenues (million USD)	Average Annual Price Per Ton	Control Period Price Per Ton
Dec-20	Current	16,237,495	7.41	2,359,501	$17.48		
Mar-21	Current	23,467,262	$7.60	2,870,129	$21.81	$9.63	$12.16
Jun-21	Current	22,987,719	$7.97	2,851,783	$22.73		
Sep-21	Current	22,911,423	$9.30	2,851,783	$26.52		
Dec-21	Current	27,041,000	$13.00	3,401,257	$44.22		
Mar-22	Current	21,761,269	$13.50	2,477,283	$33.44	$13.46	
Jun-22	Current	22,280,473	$13.90	2,821,238	$39.22		
Sep-22	Current	22,404,023	$13.45	2,821,238	$37.95		
Dec-22	Current	22,233,203	$12.99	2,821,238	$36.65		
Mar-23	Current	21,522,877	$12.50	2,596,685	$32.46	$13.59	
Jun-23	Current	22,026,639	$12.73	2,616,709	$33.31		
Sep-23	Current	21,948,358	$13.85	2,616,709	$36.24		
Dec-23	Current	27,656,000	$14.88	3,397,263	$50.55		
Total		**1,399,163,220**		**253,400,595**	**$1,159**		

Source: rggi.org/market/co2_auctions/results.

See CEIR-21, Chapter 5.1.5, RGGI Section for additional information on RGGI Offsets and Maryland Offset Projects.

Maryland Climate Pathways Report

In June 2023, MDE released the Maryland Climate Pathways Report as required by the Climate Solutions Now Act. As the title suggests, the report outlines measures that need to be implemented if Maryland is to meet the Climate Solutions Now Act's goal of reducing GHG emissions by 60% from 2006 levels by 2031. MDE indicated that as of 2020, the state had already realized half of the GHG reductions needed, or 36.7 million metric tons of carbon dioxide equivalent (CO_2e) of the 73.3 million metric tons of CO_2e. Continued implementation of current policies will realize another 26 million metric tons of CO_2e, leaving a gap of 10.6 million metric tons of CO_2e that must be achieved through new policy initiatives. MDE said most of the reductions will come from the electricity and transportation sectors, but all sectors of Maryland's economy, such as industry and agriculture, must participate.

Figure 5-8 presents the suggested policy approaches in the Climate Pathways Report for meeting the 60% reduction in CO_2e, by sector.

Figure 5-8 Climate Mitigation Strategies by Sector

Sectors	Mitigation Strategies	Current & Potential Policy Approaches
	Provide market incentive for cost-effective mitigation	• Implement a cap and invest program
	Shift the electricity grid to clean generation	• Expand Renewable Portfolio Standard (RPS) to reach 100% clean electricity • Implement and raise awareness of IRA incentives, including tax credits and direct pay for clean energy production in low-income communities
	Shift PJM electricity grid to clean generation	• Strengthen the Regional Greenhouse Gas Initiative (RGGI) target to zero emissions by 2040
	Reduce passenger vehicle use	• Adopt new smart growth strategies • Increase public transit opportunities and access to safe walking/biking paths • Incentivize remote work, when possible
	Shift passenger vehicle fleet to ZEVs	• Achieve Advanced Clean Cars II targets • Implement and educate on IRA incentives • Implement electric vehicle (EV) infrastructure investments from BIL
	Shift freight trucking fleet to ZEVS	• Achieve Advanced Clean Trucks & Advanced Clean Fleets targets • Implement and educate on IRA & BIL incentives
	Electrify nonroad fuel usage	• Set new standards for equipment in construction, lawn care, warehouses, etc.
	Improve building efficiency	• Implement Building Energy Performance Standards and EmPOWER program • Implement and raise awareness of IRA incentives, including consumer tax credits for energy efficiency and clean energy upgrades • Set enhanced standards for new buildings
	Electrify all appliances	• Set zero-emission appliance standards • Set clean heat standards • Set all-electric construction standards
	Electrify industrial processes	• Implement EmPOWER program • Adopt Buy Clean policies (i.e. cement)
	Explore alternative fuels & energy sources	• Implement and raise awareness of IRA's hydrogen and CCS tax credits • Facilitate cement fuel switching
	Reduce HFC emissions	• Achieve AIM Act targets for HFC reductions • Achieve Maryland's HFC regulations
	Enhance efficiency in cement material	• Set new construction standards to reduce excessive use of cement • Adopt Buy Clean policies that prioritize cement products with high clinker replacement factor
	Reduce natural gas consumption	• Achieve policies across all consuming sectors
	Prevent and repair emissions leaks	• Implement Maryland natural gas methane regulation • Implement IRA methane fee
	Reduce methane from landfills	• Implement Maryland landfill methane regulation
	Divert and redirect waste	• Realize Maryland Sustainable Materials Management • Incentivize and facilitate composting • Prioritize circular economy policies
	Reduce methane emissions from enteric fermentation and manure management	• Incentivize best practices • Facilitate knowledge sharing

Source: Kennedy, K., A. Zhao, S. Smith, K. O'Keefe, B. Phelps, S. Kennedy, R. Cui, C. Dahl, S. Dodds, S. Edelstein, S. Francis, E. Ghosh, G. Hurtt, D. Irani, L. Ma, Y. Ou, R. Praisa, A. Taylor, A. Trivedi, N. Wetzler, J. Williams, and N. Hultman. *Maryland's Climate Pathway*, June 2023, https://cgs.umd.edu/sites/default/files/2023-09/file_final_Maryland%27s%20Climate%20Pathway%20Report.pdf

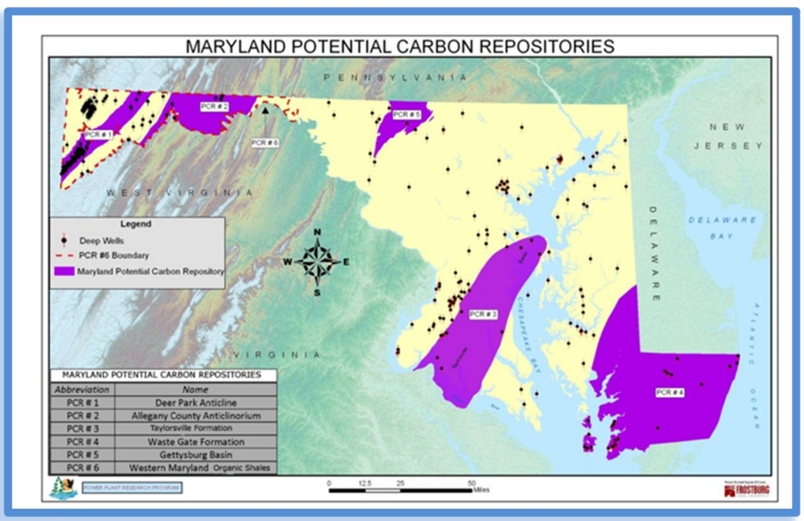
Maryland will reap substantial benefits should these CO_2e reductions be achieved—between $1.09 billion and $2.44 billion in health benefits and the creation of 16,000 jobs and increased personal income of about $1.5 billion by 2031.[110]

Geologic Carbon Storage

In addition to investments in renewable energy and switching from coal firing to natural gas, further mitigation of atmospheric CO_2 emissions could be achieved via carbon capture, use, and storage. While CO_2 is not a hazardous substance, it is an aggressive gas that poses certain environmental risks, and geological sequestration must be approached carefully to achieve the permanent, safe storage of this industrial gas. Geological sequestration involves injecting CO_2 into underground formations for permanent storage. Subsurface sequestration can be achieved through either structural mechanisms (i.e., physical trapping) or adsorption storage (i.e., chemical reaction). Structural storage carries the potential for CO_2 leakage, thus chemical storage is considered a more permanent solution. Chemical adsorption of CO_2 can occur on the surface of some rocks and with some brines.

The primary types of target geological reservoirs are depleted oil and gas fields, unmineable coal seams, and deep saline formations. Potential use of CO_2 occurs with geological sequestration in oil and gas fields, where pressurized CO_2 can be used to displace residual oil and gas, allowing greater extraction volume. Similarly, CO_2 can also be injected into unmineable coal seams to displace and recover coal bed methane. Igneous rocks containing high calcium and magnesium can also chemically adsorb CO_2, as can deep saline reservoirs. Maryland has several geologic formations that are potential reservoirs for CO_2 storage: deposits of "unconventional" natural gas; deep saline aquifers, and Triassic-age sedimentary basins bearing high calcium igneous intrusions. The figure below shows six potential formations that could serve as carbon repositories in Maryland. Further details on carbon capture, use, and storage opportunities in Maryland are presented in CEIR 21, Chapter 5.1.6, Fossil Fuel–Fired Generation and CO_2.

Maryland Potential Carbon Repositories



At present, these investigations show that the low carbon prices in the experimental trading markets will not stimulate forestry offset projects in Maryland. However, sustainable forestry that selectively harvests high-quality timber that can be converted into wood products with long lifetimes can be effective in increasing the amount of carbon removed from the atmosphere by biological processes and subsequently sequestered in stable forms for long periods.

[110] Kennedy, K., A. Zhao, S. Smith, K. O'Keefe, B. Phelps, S. Kennedy, R. Cui, C. Dahl, S. Dodds, S. Edelstein, S. Francis, E. Ghosh, G. Hurtt, D. Irani, L. Ma, Y. Ou, R. Praisa, A. Taylor, A. Trivedi, N. Wetzler, J. Williams, and N. Hultman. *Maryland's Climate Pathway*, June 2023, https://cgs.umd.edu/sites/default/files/2023-09/file_final_Maryland%27s%20Climate%20Pathway%20Report.pdf.

Maryland Climate Change Legislation

See CEIR-21, Chapter 5.1.5, Maryland Climate Change Legislation for background information on the Greenhouse Gas Emissions Reduction Act (GGRA).

Federal Power Plant GHG Initiatives

On May 23, 2023, EPA published a proposed rule for limiting emissions of GHGs from new and existing fossil-fired electric generating units (EGUs) under Section 111(b) and Section 111(d) of the CAA. On the same day, the EPA also proposed to repeal the Affordable Clean Energy (ACE) Rule finalized during the Trump Administration.

EPA proposed five separate actions addressing GHG emissions from fossil fuel–fired EGUs:

- Performance standards for GHG emissions from new fossil fuel–fired stationary combustion turbine EGUs;
- Performance standards for GHG emissions from existing fossil fuel–fired, steam-generating EGUs that undertake a large modification;
- Emission guidelines for GHG emissions from existing coal-fired and oil/gas-fired, steam-generating EGUs;
- Emission guidelines for GHG emissions from existing fossil fuel–fired stationary combustion turbine EGUs; and
- Repeal of the ACE Rule.

A standard of performance is based on EPA's determination of both (1) the best system of emissions reduction (BSER) that is "adequately demonstrated" for the regulated sources and (2) the degree of emissions limitation achievable through the application of the BSER.

For new sources, using the degree of emissions limitation consistent with BSER, EPA then promulgates New Source Performance Standards (NSPS). EPA's proposal includes an updated NSPS for new stationary combustion turbines. A "new" source is one that commences construction or reconstruction after May 23, 2023. New gas fell into three different subcategories: baseload, intermediate, and low load/peaking, based on the unit's capacity factor. The proposed NSPS will be implemented in three phases.

EPA did not identify any companies planning a new build or reconstruction of a fossil fuel–fired, steam-generating unit and is therefore not proposing updates to the NSPS for new construction of or reconstruction for fossil fuel–fired, steam-generating units or new coal at this time.

For existing sources, EPA must identify the BSER and the degree of emission limitation achievable through the application of the BSER. The agency then promulgates "emission guidelines" that each state uses to establish standards of performance for the affected sources within its geographic boundaries. State implementation plans must demonstrate to the EPA that the affected sources within a state will achieve emission reductions consistent with the BSER. States have flexibility in how they comply, and

EPA is seeking comments on how states might meet emission guidelines, including mass-based and rate-based trading programs and emission averaging.

EPA is proposing a compliance date of January 1, 2030, for affected steam-generating units. For existing coal-fired EGUs that have a baseload rating greater than 250 MMBtu/hour heat input of fossil fuel, EPA is proposing a BSER based on four different compliance paths depending on the operating horizon of the units. Existing coal-fired units fall into one of four subcategories: (1) imminent, (2) near, (3) medium, and (4) long-term. Imminent-term units must permanently cease operation before January 1, 2032.

The EPA is also proposing emission guidelines for existing natural gas and oil-fired steam-generating units greater than 250 MMBtu/hour heat input of fossil fuel. EPA is proposing presumptive standards of performance of 1,300 lb CO_2/MWh-gross for base load units (i.e., those with annual capacity factors greater than 45%) and 1,500 lb CO_2/MWh-gross for intermediate load units (i.e., those with annual capacity factors between 8% and 45%). Affected units must adhere to routine methods of operation and maintenance with no increase in emissions beginning January 1, 2030.

EPA is proposing emission guidelines for large (greater than 300 MW), frequently operated (capacity factor greater than 50%) existing fossil-fired stationary combustion turbines. The proposed BSER for existing units is similar to the BSER for new baseload combustion turbines. The proposed BSER is either the use of CCS by 2035 or co-firing of 30% low-GHG hydrogen by 2032 and co-firing 96% low-GHG hydrogen by 2038.

International Climate Change Initiatives

Section 5.1.5 of CEIR-21 presents a discussion of international climate change initiatives, beginning with the Paris Climate Agreement and ending with the results of the 26th Conference of the Parties to the United Nations Framework Convention on Climate Change (or "COP 26") that was held in Glasgow, Scotland, in 2021. These initiatives include the U.S. committing to cutting GHGs emissions 50% to 52% below 2005 levels by 2030, reaching a 100% carbon pollution–free power sector by 2035 and achieving a net-zero economy by no later than 2050.

COP 27 was held in Sharm El-Sheikh, Egypt, in November 2022. The conference resulted in a number of important outcomes, including:

- A decision to establish and operationalize a loss and damage fund to help developing countries cope with the impacts of climate change.
- A commitment to revisit and strengthen national climate plans by 2023 to align with the goals of the Paris Agreement.
- An agreement to increase climate finance from developed countries to developing countries.
- A recognition of the importance of adaptation to climate change and the need for increased support for adaptation efforts.

COP 28 will take place in November and December 2023, at Expo City, Dubai, in the United Arab Emirates. COP 28 is expected to provide a milestone opportunity for the world to come together, course correct, and drive progress to keep the Paris Agreement goal of 1.5°C within reach. The Paris

Agreement goal of 1.5°C is to limit global temperature rise to well below 2° Celsius, preferably to 1.5° Celsius, compared to pre-industrial levels.

5.2 Impacts on Water Resources

5.2.1 Physical and Chemical Impacts

All steam electric power plants in Maryland are located in the Chesapeake Bay watershed. Power plants are significant users of water in Maryland, and their operation can affect aquatic ecosystems as well as the availability of water for other users. This section describes the surface and groundwater withdrawals and consumption in Maryland from power plant operations. Section 5.2.2 discusses the effects of generation facilities and transmission lines on aquatic resources.

Other than a small segment of Western Maryland and small estuarine water bodies of the Atlantic shore, the bulk of Maryland's drainage system feeds into the Chesapeake Bay. All of Maryland's primary rivers drain into the Chesapeake Bay: Potomac, Patuxent, Patapsco, Susquehanna, Chester, Choptank, Nanticoke, Blackwater, and Pocomoke rivers.[111] Together, these rivers and the Chesapeake Bay extend over a large geographic area and encompass a broad range of aquatic habitat types, including marine, estuarine, and freshwater rivers and lakes.

Surface Water Withdrawals and Consumption

Electric power plants in Maryland use several types of generating technologies, including steam-driven turbines, combustion turbines, combined cycle facilities (a combination of steam and combustion turbine units), and renewable energy facilities (hydroelectric, solar, wind). Power plants using steam have significant water withdrawals because of the need to cool and condense the recirculating steam.[112] Power plant cooling accounted for about 75% of the total surface water appropriations in the state in 2022. Combined water withdrawal for all steam-generating power plants in Maryland during 2022 was reported at approximately 3.9 billion gallons per day as an annual average. By comparison, the Potomac River has an average discharge of roughly 7 billion gallons per day, and the Susquehanna River discharges an average of more than 20 billion gallons per day (actual daily flows in both the Susquehanna and the Potomac fluctuate greatly, both seasonally and from year to year).

Closed-cycle systems recycle cooling water and withdraw less than one-tenth of the water required for once-through cooling; however, depending on plant design and operating parameters, 50% to 80% of the water evaporates from the cooling tower and does not return to the source, thus representing a consumptive use. Consumptive use is water that is withdrawn but not returned directly to the surface or groundwater source and is unavailable to other users. In water-limited or highly regulated systems (rivers with multiple dams and reservoirs), consumptive use is a critical factor in determining the allocation and under what conditions competing uses have to be curtailed or prioritized.

[111] The Youghiogheny is the one river that drains into the Ohio water basin.

[112] Combustion turbines have minimal water needs in comparison; however, they do consume water to control emissions and improve efficiency. This water must be high quality because it comes in direct contact with turbine surfaces. Therefore, it is generally sourced from groundwater or purchased water supply.

Dewatering for Construction

Dewatering of saturated materials during the construction of power plants, including pipelines, foundations, and electrical connections, may be required when construction occurs in areas with a high water table, such as areas in the coastal plain of Maryland. A complete understanding of the influence that dewatering may have on the aquifer is necessary to avoid significant impacts to surrounding surface water resources and nearby groundwater users. PPRP has conducted analyses in recent licensing cases to ensure that proposed construction activities associated with power generation and transmission structures will not deplete groundwater resources or affect nearby water users.

The information needed to assess the potential impacts of construction dewatering includes the following:

1. Description of the site soils and geology, identifying the local aquifer system and annual precipitation for the area in which the water use will occur;
2. Identification of local users of the uppermost aquifer and nearby surface water bodies;
3. Depth to the groundwater table observed by piezometers installed at the project site (or demonstration that the water table does not exist within a reasonable depth below the proposed excavations);
4. Seasonal range in groundwater table elevations in the project area obtained from piezometers installed at the project site or using regional information obtained from existing nearby well or stream gauge records (e.g., from United States Geological Survey monitoring well or stream gauge records);
5. Site-specific hydraulic conductivity for the area in which the water use will occur. Estimates of specific yield, porosity, and aquifer thickness may be obtained from published literature, onsite testing, or a combination of both;
6. The location and dimensions (length, width, and depth) of excavations, including any trenches, pits, or basins that may either intercept the groundwater table, impound surface water, or otherwise require the appropriation of water;
7. Estimate of any additional flow into the excavation or from the dewatering points that is anticipated to be necessary to control water within the excavation as a result of storm events based on a two-year, 24-hour storm event for the project area;
8. Method of dewatering (e.g., via pumping from well points, direct pumping from the excavation, or other) including the number of well points or length of excavation that will be open at any given time;
9. Expected duration of dewatering and (for well points) the number of wells pumping at the same time; and
10. Details of how extracted water will be handled, treated, or discharged.

PPRP uses this information to conduct a hydrogeologic analysis of the site and to estimate water table drawdown associated with the construction dewatering. PPRP determines the extent of the impacts to nearby groundwater users, subject to groundwater appropriation applicability under State regulations, in close coordination with the MDE Water and Science Administration.

For power plants with once-through cooling systems, water losses within the cooling system itself are negligible, but the water discharged is at a higher temperature and this results in elevated evaporative losses in the receiving waters. These losses are not easily measured. PPRP's estimate of consumptive use from once-through cooling is based on work conducted in the 1980s by the Interstate Commission on the Potomac River Basin (ICPRB), which calculated instream evaporative losses caused by heated discharges from 14 Maryland power plants. The ICPRB found that, on average, instream losses were equivalent to about 0.6% of a plant's total discharge volume during the summer and 0.5% during the winter.

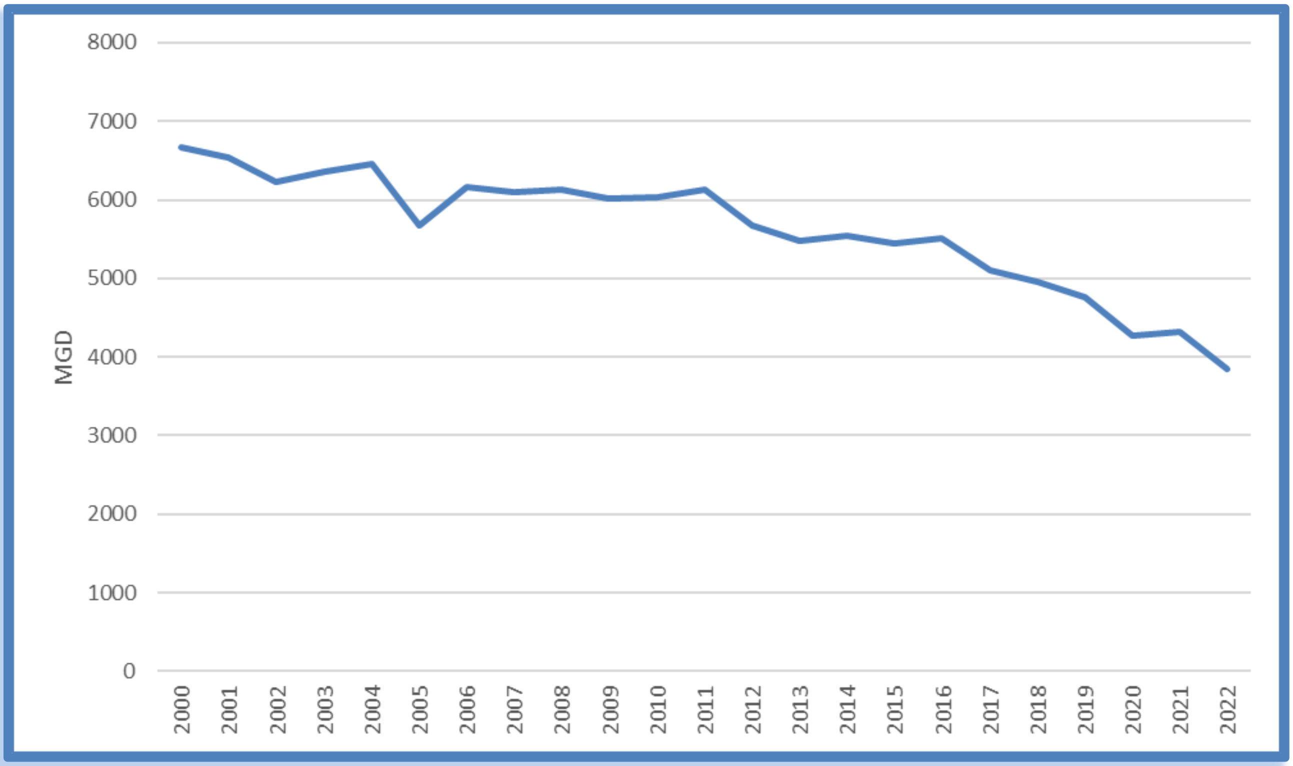
Calvert Cliffs Nuclear Power Plant (CCNPP) withdraws an average of 3.4 billion gallons per day directly from Chesapeake Bay. This is the largest single appropriation of water in Maryland. While most of the water withdrawn by Calvert Cliffs is returned to the Chesapeake Bay, an estimated 18.4 million gallons per day (mgd) is lost to evaporation as a result of the heated discharge. Please see PPRP's website, Surface Water and Groundwater Withdrawals and Consumption Section for the most recent data available on all power plant surface water withdrawals and consumption in Maryland.

When assessing the significance of water withdrawal impacts, the nature of the source water body is a key factor. In estuaries such as Chesapeake Bay and the tidal portions of Chesapeake Bay tributaries, the quantity of water "lost" is less important because tidal influx continually replaces the water withdrawn. In these estuarine environments, the ecological impacts of water withdrawals can be significant, but consumptive loss is not a concern. By contrast, consumptive loss in nontidal riverine systems can adversely affect aquatic habitat and other users of the water body. The Dickerson power plant was a major freshwater consumer until its surface water appropriation was deactivated in 2021 following the decommissioning of its coal-fired units.

Combined surface water withdrawals by steam electric plants in Maryland have steadily declined since 2000, reflecting the reduced amount of coal-fired generation (see Figure 5-9). The coal units at Chalk Point, Dickerson, and Morgantown all had significant water appropriations until their decommissioning. Large natural gas–fired generating stations built over the last 25 years—CPV St. Charles, Keys Energy Center, and Wildcat Point—do not have surface water appropriation permits from Maryland. CPV uses reclaimed water from the Mattawoman Wastewater Treatment Plant (WWTP), Keys uses dry cooling technology, and Wildcat Point obtains cooling water via pipeline from a direct withdrawal point on the Susquehanna River in Pennsylvania. All other new generators built in Maryland have been solar and wind facilities that do not require water for ongoing operations.

Section 5.2.1 of CEIR-21 includes more information about cooling system technology, consumptive use regulations, and MDE guidelines for reclaimed water use.

Figure 5-9 Surface Water Withdrawals at Steam Power Plants in Maryland (annual average, in mgd)



Groundwater Withdrawals

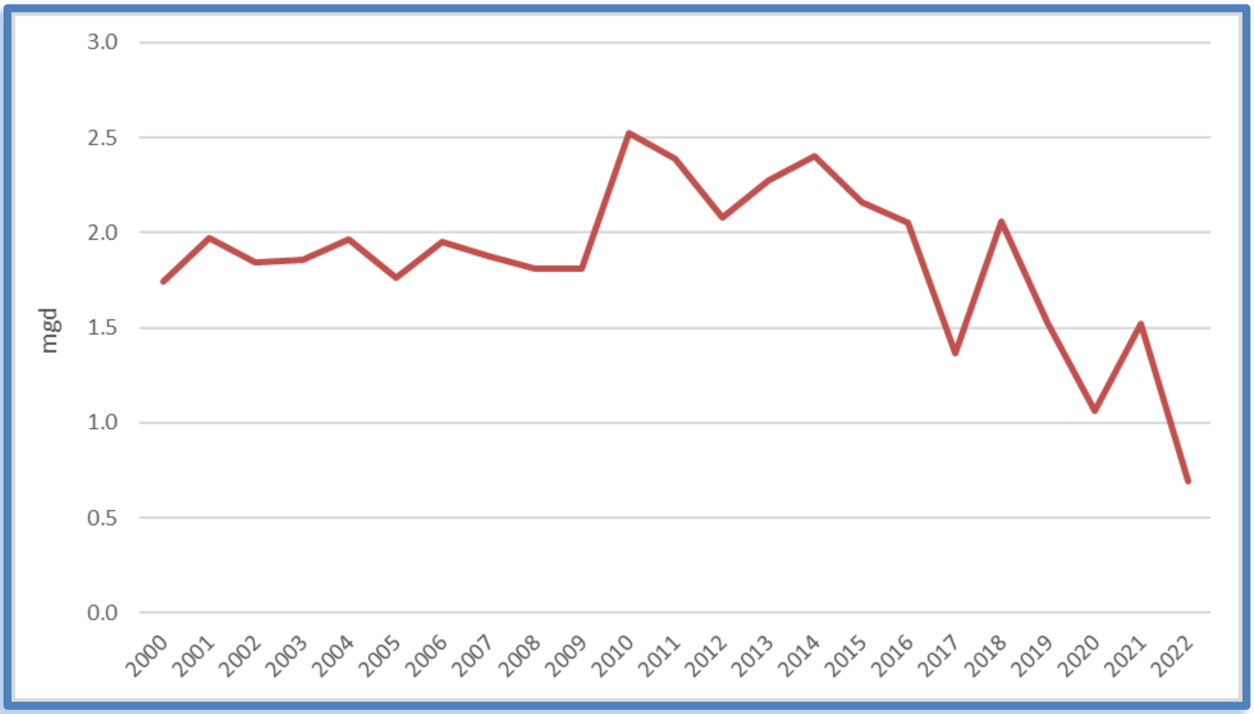
High-volume groundwater withdrawals have the potential to lower the water table of an area, thus reducing the amount of water available for other users. Excessive withdrawals from Coastal Plain aquifers can also cause intrusion of salt water into the aquifer. Although large volumes of groundwater are available in the Coastal Plain aquifers, withdrawals must be managed over the long term to ensure adequate groundwater supplies for the future. The impact of these withdrawals has been a key issue in Southern Maryland, where there is a significant reliance on groundwater for public water supply.

Currently, five power plants withdraw groundwater from Southern Maryland Coastal Plain aquifers for plant operations: CCNPP, GenOn Holdings' Chalk Point, and Morgantown power plants, GenOn Holdings' combustion turbine facility (located at the Chalk Point plant and formerly owned by Southern Maryland Electric Cooperative [SMECO]), and KMC Thermo's combined cycle power plant. These five plants have historically withdrawn groundwater from three aquifers in Southern Maryland: the Aquia, the Magothy, and the Patapsco. Chalk Point began withdrawing groundwater from the deeper Patuxent Aquifer in 2009. Groundwater is used for boiler feedwater in coal-fired power plants; as coal-fired units have ceased operating at Chalk Point and Morgantown, groundwater withdrawals at these sites have also declined. However, natural gas–fired units are still in operation, and groundwater is required for inlet air cooling and emissions control.

Three additional Maryland power plants currently have groundwater appropriation permits, but these facilities withdraw from sources other than the Coastal Plain aquifers: Dickerson, located in Montgomery County (New Oxford Formation); Perryman, located in Harford County northeast of Baltimore (Talbot Aquifer); and Vienna, located in Dorchester County on the Eastern Shore (Columbia Group Aquifer). These withdrawals are very small compared to the power plant withdrawals from Coastal Plain aquifers.

Figure 5-10 shows the total groundwater withdrawals from Maryland power plants from 2000 to 2022, expressed as daily averages. See PPRP's website, Surface Water and Groundwater Withdrawals and Consumption Section for more details on groundwater use at each facility, broken down by source aquifer.

Figure 5-10 Groundwater Withdrawals at Maryland Power Plants (annual average, in mgd)



Three government agencies—the Maryland Geological Survey, the United States Geological Survey, and PPRP—jointly operate a groundwater monitoring program to measure the water levels in the Coastal Plain aquifers of Southern Maryland to ensure the long-term availability of groundwater. MDE's Water and Science Administration, the permitting authority for all groundwater appropriations, uses the data from this joint monitoring program to assess the significance of impacts to aquifers when reviewing additional appropriation requests.

Long-term monitoring indicates a steady decline in water levels in the Aquia, Magothy, Patapsco, and Patuxent aquifers. While power plants have contributed to the decline in the water levels in these aquifers, increased withdrawals from municipal well fields in Southern Maryland have caused most of the recent declines. As noted earlier, power plant groundwater withdrawals have decreased significantly since 2010. Please refer to CEIR-21, Section 5.2.1 for a discussion of historical impacts and drawdown observed by the monitoring program in Coastal Plain aquifers.

5.2.2 Impacts to Aquatic Biota

Conventional Facilities

Conventional electric power generation facilities affect the state's water resources during and as a result of water withdrawal, consumption, and discharge that are needed for plant operations. Negative impacts on rivers and estuaries from surface water withdrawal and consumption may include a reduction in river flow volumes due to evaporative water loss in the plant's cooling system. Many aquatic organisms are injured or die when they get pulled through the cooling system (entrainment) or collide with the cooling system's intake screens (impingement) as the facility uses high-suction pressure to withdraw water. The elevated temperatures of a plant's discharge may also influence aquatic resources in the receiving waters. Impacts to fish in rivers and canals include the potential loss of habitat due to lower water levels or altered water temperatures; these effects can be particularly damaging during low-flow periods if a plant's use of cooling water significantly affects downstream flow. Various agencies and organizations have monitored water usage and the resulting environmental impacts; PPRP has monitored these issues since 1972. In systems where multiple sources of potential impacts can affect water quality and aquatic habitats, the combined effects may compound or intensify the effects of the individual sources and accumulate in downstream areas. Further details of the impacts of conventional generating facilities can be found in CEIR-21, Chapter 5.2.2.

Hydroelectric Facilities

Maryland has two large-scale hydroelectric projects (with capacities greater than 10 MW): Conowingo Hydroelectric Project (see discussion in CEIR-21) on the Susquehanna River and Deep Creek Hydroelectric Station on the Youghiogheny River in Western Maryland. There are four small-scale facilities that generate electricity within the state, and an additional one (Jennings Randolph Hydroelectric Project) that has received a license from the Federal Energy Regulatory Commission (FERC) but has not yet been constructed (see map and table in Section 3.1.5 of CEIR-21). Hydroelectric facilities may present special environmental concerns that operators do not encounter at steam electric or other power plants. See CEIR-21, Chapter 5.2.2 for a detailed discussion of these impacts.

Susquehanna River Migratory Fish Restoration

Historically, the Susquehanna River supported large spawning runs of migratory fish species such as American shad (shad), river herring, striped bass, and American eel (eel). The massive diadromous fish migrations that extended as far upstream as Cooperstown, New York, were eliminated with the construction of four major hydroelectric facilities on the lower Susquehanna in the early 1900s (Maryland's Conowingo Dam and Pennsylvania's Holtwood, Safe Harbor, and York Haven dams).

By the year 2000, restoration programs for migratory fish had been operating for nearly 30 years, and fish passage devices had been installed at all four hydroelectric facilities, which partially reopened the Susquehanna River to migratory fish. These accommodations created the potential for shad and other migratory fishes to move as far upstream as New York State, and the potential expansion of ranges for fish populations represented renewed access to well over 400 miles of historic habitat. The results of monitoring studies indicate that the fish passage has only been partially successful to date. The hydroelectric licensees on the Susquehanna River continue to conduct studies at several of the lower river projects to address these issues as part of their federal license requirements.

Growth of the Susquehanna River shad stock in response to the restoration efforts and installation of fish passage devices has been problematic. The annual fish counts associated with the upstream passage program peaked in 2001, when nearly 200,000 American shad were passed (collected, counted, and physically transported) over the Conowingo Dam; however, the annual fish passage counts have declined since then for reasons that are the subject of ongoing studies and potential mitigation measures (see Figure 5-11). The 2019 fish passage data showed that fewer than 6,000 American shad passed Conowingo Dam, and less than 12% of that tally passed the next upstream dam (Holtwood). The Holtwood fish passage counts have historically been low, but improvements to the fish passage system at the facility that were made in conjunction with generation capacity added in 2013 were expected to result in an increased percentage of fish passing Holtwood. In the long term (2000–2019), Safe Harbor has passed 74% of the total numbers of fish that passed Holtwood, but York Haven only passed 13% of the total numbers of fish that passed Safe Harbor. PPRP, working with the hydroelectric dam owners and other state and federal agencies, is continuing efforts to enhance upstream migratory fish passage and the safe downstream passage of juveniles through operational and engineering modifications. Fish passage operations in 2020 were halted due to COVID-19 precautions and due to the threat of invasive fish species that include Northern snakehead (*Channa argus*) and blue catfish (*Ictalurus furcatus*). Fish passage has continued since 2020, and the program is closely monitored to provide active trap and transport of American shad and river herring from the west and east fish lifts and preclude passage of invasive species into Conowingo Pond from below the dam.

Similar to shad, American eels historically occupied the majority of the Susquehanna Basin but have been restricted from full access to the Susquehanna River since the mainstem dam construction in the early 1900s. Eel densities in the tributaries to the lower Susquehanna River below Conowingo Dam are higher than in other Chesapeake Bay tributaries. Young eels may be attracted to the discharge of the Susquehanna River, but they are unable to migrate up the mainstem due to these manmade impoundments. The dearth of American eels, one of the most abundant fish in the watershed historically, has had additional effects on the Susquehanna River ecosystem. The native freshwater mussel, Eastern elliptio (*Elliptio complanata*), is the most abundant mussel species in the Mid-Atlantic region, but its abundance in the Susquehanna River is lower than in other regional watersheds (e.g., Delaware River). Freshwater mussels require a host, usually a fish, to complete their reproductive cycle. Eels serve as an important host species for Eastern elliptio in the region, and the scarcity of eels in the Susquehanna River watershed has likely played a significant role in the limited abundance, size, age, and recruitment of the mussel populations.

During the period from 2009 to 2016, the U.S. Fish and Wildlife Service (USFWS) operated an eel ramp to capture juvenile eels below Conowingo Dam and move them upstream. [113] The goal of this program was to move 1 million eels to designated locations within the watershed to facilitate the growth of the

[113] Chris Reily, Steve Minkkinen, *American Eel: Collection and Relocation—Conowingo Dam, Susquehanna River, Maryland, 2016*, U.S. Fish and Wildlife Service, srbc.net/srafrc/docs/2016/Conowingo%20Eel%20Collection%202016.pdf.

mussel populations and restore the ecological balance. Eels contribute to the balance of the ecosystem by their predation on small fishes and crayfish.

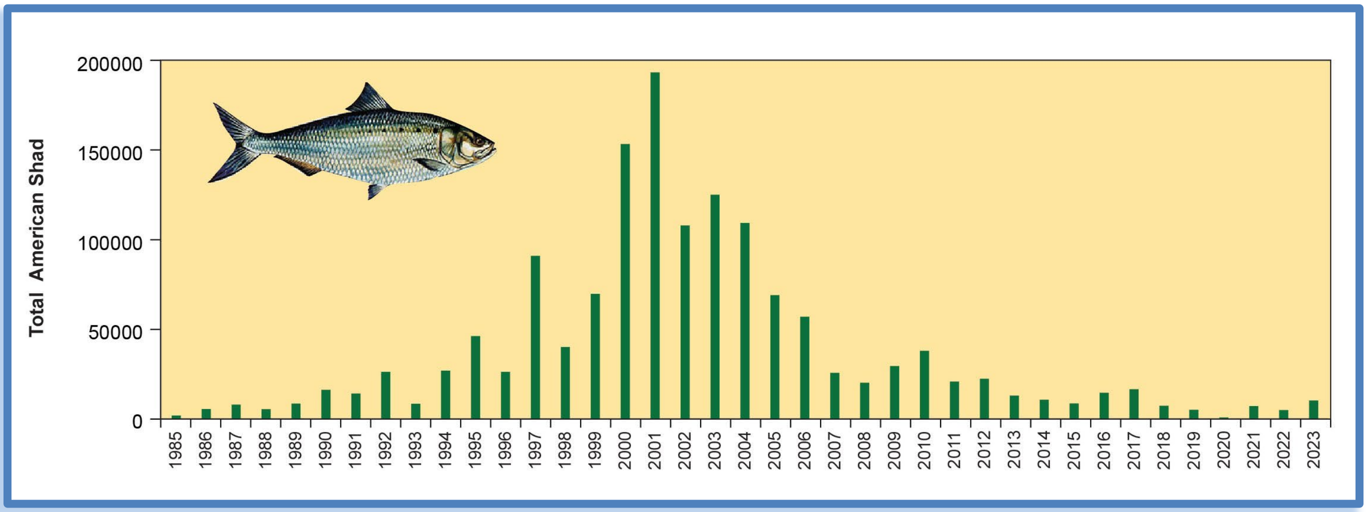
The number of elvers (young eels) collected and transported each year increased during the period from 2009 through 2013 (see Table 5-6) and then decreased during the period from 2014 to 2016. The relative decline in the numbers of elvers passing through the system could be related to the unusual weather conditions in 2015 and 2016, or the trend could be related to natural variability in eel populations. As part of its settlement agreement with USFWS, and as a condition of the Clean Water Act Section 401 Water Quality Certification for the Muddy Run facility in Pennsylvania, Exelon (the owner of the dam at the time) was required to construct a new eel ramp and transport system at Conowingo Dam in 2017. The numbers of eels collected and transported past the dam increased greatly in 2017 compared with 2016; the numbers declined in 2018, possibly due to high river flows that year. The numbers of eels transported upstream annually during the period from 2019 through 2023 showed large interannual differences and a peak of more than 600,000 elvers in 2021.

Table 5-6 Total Number of Elvers Collected, by Year, at Conowingo Dam, Maryland

Year	Total elvers collected
2005	42
2006	19
2007	3,837
2008	42,058
2009	17,437
2010	23,856
2011	84,961
2012	127,013
2013	293,141
2014	185,628
2015	58,444
2016	2,684
2017	122,300
2018	67,949
2019	126,181
2020	254,651
2021	607,743
2022	139,798
2023	204,018

Sources: USFWS, 2016. American Eel: Collection and Relocation Conowingo Dam, Susquehanna River, Maryland. 2016; Normandeau Associates, Inc. and Gomez and Sullivan Engineers, D.P.C. 2018. Muddy Run Pumped Storage Project Conowingo Eel Collection Facility; Normandeau Associates, Inc. 2019. Muddy Run Pumped Storage Project Conowingo Eel Collection Facility. Muddy Run Pumped Storage Project Conowingo Eel Collection Facility. Normandeau Associates, Inc. 2021, 2022, 2023, and 2024.

Figure 5-11 Number of American Shad Passed at Conowingo Dam (1985–2023)



Source: fishandboat.com/Fish/PennsylvaniaFishes/Pages/SusquehannaShad.aspx.

Other Generation Facilities

Offshore Wind

The first U.S. offshore wind generation facility, the Block Island Wind Farm, began commercial operations offshore of Rhode Island in December 2016. Several additional U.S. projects have been proposed, most in shallow waters (< 30 meter [m] depth) off the Atlantic coast, including two that would serve Maryland. Effects on avian and bat populations from the construction and operation of these offshore generation facilities are likely, based on the fatalities observed from collisions with turbines at land-based wind-energy projects. Turbine location relative to migration routes as well as breeding and feeding areas influence fatalities. While offshore turbine foundations may expand desirable habitat, environmental risks to marine resources include exposure of fish and other aquatic organisms to hazardous chemicals released into the ocean by accidental spills, increases in ocean noise pollution, changes in habitat conditions by altering hydrodynamics that ultimately alter species composition, abundance, and distribution.

The development of large offshore wind farms will also require underwater transmission infrastructure, which also has the potential to cause impacts to natural resources in this region. Burying cables will create disturbed swaths across the seabed, which will become warmer than the surroundings during transmission operations from heat dissipated by the cables. Warming temperatures could mimic seasonal changes and trigger life changes in fish that occupy sea floors. Underwater electric transmission cables within and from wind farms also generate electromagnetic fields (EMF) that are known to affect the communication and behavior of some fish, such as eels, rays, and sharks.

In 2013, the Maryland Legislature passed the Maryland Offshore Wind Energy Act, which provides economic incentives to develop offshore wind facilities that benefit Maryland. The PSC evaluates and approves or denies applications for these Offshore Renewable Energy Credits (ORECs). Under the Act, applicants must affirm plans to conduct an environmental review in compliance with applicable statutes, such as the 2022 updated National Environmental Policy Act (NEPA) guidelines, which include changes in the environmental review process specifically for offshore wind. Because of the potential for impacts on sensitive resources, these plans are also required to demonstrate compliance with the Endangered Species Act, Migratory Bird Treaty Act, and Marine Mammal Protection Act; applicable U.S. Bureau of Ocean Energy Management (BOEM) regulations and guidelines for surveying natural resources (including but not limited to avian species, benthic habitats [sediment and shallow sub-surface zones], fish, marine mammals, and sea turtles); local/state regulations; and the Coastal Zone Management Act.

The PSC received applications for ORECs under the Maryland Offshore Wind Energy Act from U.S. Wind, Inc. and Skipjack Offshore Wind Energy in November 2016. After review, the PSC approved both applications, with conditions, in May 2017 (PSC Order No. 88192). Before construction starts, PPRP may conduct studies to identify potential environmental impacts from any submarine transmission cables that cross Maryland's offshore waters. BOEM approved Site Assessment Plans in 2018 and the Draft Environmental Impact Statement (DEIS) for the proposed Maryland offshore wind project was released on September 29, 2023.[114]

Solar

Although solar generation facilities are generally not constructed near large bodies of water, there are instances when the facility is located on property containing a freshwater stream or in an area where drainage from the facility may impact a stream or the Chesapeake Bay. Construction of a solar facility may change the drainage pattern of the site, requiring the installation of appropriate best management practices (BMPs) based on the design of the facility. In some cases, this may reduce runoff to local streams and improve the water quality over time. In other cases, such as the Great Bay Solar Facility in Somerset County, construction occurred in non-jurisdictional drainage ditches, leading to flooding both onsite and offsite. In addition, consideration must be made to the interconnection process as well.

Transmission Facilities

Effects on Streams, Rivers, and Watersheds

Construction of transmission line rights-of-way (ROW) across or alongside streams and rivers may result in temporary ecological impacts during construction as well as permanent habitat degradation. Constructing and maintaining transmission lines can also affect streams near the ROW both directly and indirectly. Typical impacts include disturbance to aquatic plants and animals, erosion along shores, release of contaminants, and increased sediments in streams.

Large rivers may require placing transmission towers in or adjacent to the water. Potential impacts from these transmission support structures include disturbance to fish and river bottom organisms, water current changes, and potential hazards to navigation and commercial fishing. Towers may provide nesting and roosting opportunities for some birds, while other birds may collide with the towers or the wires between them.

[114] https://www.boem.gov/renewable-energy/state-activities/maryland-offshore-wind

General Impacts to Surface Waters

Construction and maintenance of transmission lines and their associated ROWs affect freshwater streams through loss of vegetation and shading, bank erosion and sedimentation during construction, and herbicide contamination during maintenance activities. Long-term effects of increased water temperature and habitat reduction due to clearing and runoff from maintenance treatments also elicit concern. However, good resource management practices can often minimize these effects on stream habitat. For example, the PSC requires that utilities use EPA-approved substances for vegetation management that degrade quickly and that have minimal side effects.

Even following best practices, the construction and maintenance of transmission lines and their ROWs can inadvertently introduce contaminants into a stream ecosystem. Any spills that occur during the construction phase of the project (e.g., gasoline or oil from construction equipment) must be contained immediately and removed to the maximum extent possible.

Impacts to Groundwater

Transmission line structures have a small potential to affect groundwater resources, particularly in areas where the water table is close to the surface. Potential impacts to groundwater would occur mainly during the construction or installation of the structures, whether aboveground or underground. The construction of new overhead transmission tower foundations or underground cable facilities may require drilling to depths that can penetrate shallow water tables or to deeper water underground. In many areas of the state, potable water supplies are much deeper than this and would not be at risk.

Alternatives to traditional overhead construction, such as underground and submarine cable installations, are becoming increasingly more common as the technology advances. Potential impacts associated with underground installations may include the redirection of groundwater flow associated with the construction or release of drilling fluids, which can lead to changes in water quality. Another potential effect could be an increase in groundwater temperature due to the heating of an underground cable during its operation.

Impacts to High-Quality Waters

The State of Maryland has determined that some sections of streams and rivers in the state have exceptional natural values that deserve additional regulatory protection. Maryland has official designations for these high-quality waters that include Scenic Rivers, Wild Rivers, and Tier II streams. The unique characteristics of high-quality waters are particularly vulnerable to the effects of development, such as transmission line ROWs. During the CPCN review, PPRP evaluates the potential impacts of proposed transmission line projects to ensure that the activities and structures associated with the projects would avoid or minimize impacts on these resources.

Scenic and Wild Rivers

Maryland's Scenic and Wild Rivers Act defines a Scenic River as a "free-flowing river whose shoreline and related land are predominantly forested, agricultural, grassland, marshland, or swampland with a minimum of development for at least 2 miles of the river length." This Act mandates the preparation of river resource management plans for any river designated as Scenic or Wild by the General Assembly. These plans identify river-related resources, issues, and existing conservation programs. The plans include recommendations on the recreational use of the river and protection of special riverine features. See CEIR-21, Chapter 5.2.4 for a map of Maryland's Scenic and Wild Rivers.

The CPCN reviews of proposed projects that would involve crossing any lands or waterways that influence Wild or Scenic Rivers or the rivers' natural buffers include focused attention to all river and stream crossings in the associated watersheds. The assessment includes a particular focus on the potential for any vegetation loss within 50 feet of the streams' shorelines and erosion that can lead to downstream sediment accumulations and changes in the downstream channels.

In addition, the towers and poles that support the transmission line cables in an unbroken line across the land may significantly degrade the visual environment along a river. Several Maryland-designated Scenic Rivers, including the Pocomoke River, the Patuxent River, the Monocacy River, and portions of the Potomac River, have incurred impacts to the visual environment from existing transmission line crossings. If the route of the line is transferred to an underground crossing for a short section near the river, such visual impacts may be eliminated or minimized. PPRP always considers the possibility of using this approach in sensitive areas (see Section 5.4.2 for additional details on Scenic Resource Assessment).

Tier II Streams

Maryland's antidegradation policy protects particularly high-quality stream segments from impacts that would degrade them. The Maryland Code specifies several correlated regulations that apply to designated Tier II (high-quality) streams to implement the policy. Tier II streams are in every county, but they are not evenly distributed throughout the state.

Maryland regulations for Tier II streams provide enhanced protection to maintain water quality and habitat, including limiting sediment loads. All development that could affect Tier II streams, including transmission line projects and solar facility project construction, is subject to review by MDE to eliminate any potential degradation resulting from the proposed activities.

Impacts to the Chesapeake Bay and Coastal Waters

The prospect of using offshore wind turbines to generate electricity combined with the need for more power on Maryland's Eastern Shore has justified proposals for transmission lines under large expanses of the Chesapeake Bay or the waters off Maryland's Atlantic coast. Simply put, submarine cables offer visual and engineering advantages compared to overhead lines across water bodies. To consider approving such infrastructure, though, PPRP must evaluate these advantages in parallel with the potential for impacts to the biological communities that inhabit the sea floor and the food chains that depend on access to those communities. The installation of a submarine transmission line will cause multiple short-term, acute impacts to the aquatic and benthic environments near the route. The construction disturbance, maintenance activities, and operation of the electric power line will cause numerous long-term impacts to these integrated environments.

Utility companies typically install underwater transmission cables several feet deep in the bottom sediments. Sometimes, horizontal drilling or trenching is used to create a path for the cables. There are several methods for installing cables, suitable for a variety of conditions, but each comes with its own set of potential impacts to the surrounding environment. Mitigation of potential effects is key to protecting ecosystems before, during, and after installation. For instance, activities associated with the installation of underwater cables might expose or distribute contaminated sediments, disturb or destroy habitats, and degrade water quality.

Impact of Transmission Structures in Waterways

Where overhead transmission lines cross lakes, estuaries, or wide rivers, it may be necessary to place supporting structures in the water, anchored to the bottom of the waterbody. These structures may have both positive and negative environmental impacts. Constructing the foundations for towers within the waterbody may stir up contaminated sediments, disrupt underwater habitats and species, temporarily smother habitat for fish and other aquatic species, and affect waterfowl that use the waterbody. Above the waterline, the towers and conductors may present collision dangers to birds or alternatively offer new nesting locations and hunting perches. If properly designed, the underwater support structures can provide hard surface habitat for species such as oysters and mussels and create niches that improve fish habitat.

Overhead transmission lines cross most of the major rivers in Maryland. Direct impacts include loss of bottom habitat and altered current flow. Although the actual bottom area occupied by each tower is relatively small, scouring by currents flowing around the tower foundations may increase the area of disturbed bottom and could alter the benthic community in a wider surrounding area. In some cases, the underwater structures are a concern for navigation and are surrounded by larger protective barriers that further modify the aquatic and aerial environment. Each river is unique and PPRP recommends that the potential effects be quantified through sediment and benthic community sampling and hydrodynamical modeling prior to construction.

PPRP carefully evaluates the potential loss of bottom habitat and the effects of proposed structures on natural resources, including aquatic vegetation, shellfish, fish, and birds. While the proposed CPCN is under review, the benefits of the project are always considered in parallel with the potential short-term and long-term effects of the construction, physical structures, and maintenance needs of the project.

To account for the potential risks associated with some of these activities, a CPCN can include licensing conditions recommended by PPRP that require utilities to develop a Contingency Plan using both pollution history and sampling data to help protect the living resources of streams in the event of an incident.

In Maryland, there are laws that protect the narrow strip of land designated as the Critical Area, which provides a buffer for the tidal areas of the Chesapeake Bay and the Atlantic Coastal Bays. The laws require thorough environmental evaluations for any proposed project that would involve construction in the buffer zone. The Critical Area includes all land within 1,000 feet of either the mean high-water line of tidal waters or the landward edge of tidal wetlands, the waters of the Chesapeake Bay, the waters of the Atlantic Coastal Bays, and the submerged land below the water. The Critical Area Act (1984) authorizes state and local governments to assess impacts caused by construction disturbances, runoff from the site, and activities within the 1,000-foot buffer zone. Any project that would directly or indirectly affect the Critical Area in the state, including transmission line ROWs, is required to seek and obtain approval from the Critical Area Commission (buffer zone) or MDE (tidal waters). Thus, several agencies would be engaged in the reviews for projects that propose an underwater transmission line in any of these areas.

During the project review for proposals that involve underwater cables, some of the impacts evaluated include effects on water quality, electromagnetic fields produced by the cables, and the creation of physical barriers. The heat released during the operation of the cable (electrical transmission along the cable) could create a permanently warm area that might affect benthic habitats, spawning times of non-mobile species, and water mixing patterns. Long-term heating of the sediment could also increase the rate of growth of bacteria such as *Vibrio vulnificus* and *E. coli*.[115,116] Oysters and other shellfish that ingest these bacteria pose a human health risk if they are consumed.

Aquatic habitats may be affected during construction or maintenance of the cables. The activities might resuspend (stir up) sediments and release contaminants or nutrients into the water column; these materials could then drift into nearby oyster and clam beds. An underwater cable could affect the benthic habitat and the species that depend upon it for food, spawning, or juvenile development. Some examples of benthic-dwelling organisms include oysters, softshell clams, worms, snails, and tiny crustaceans. Animals that might feed on benthic organisms include crabs, resident and migratory fish, and overwintering sea ducks. Thus, the integrated food network that relies on a supportive benthic habitat might be vulnerable to the effects of an underwater cable project.

Considering these potential impacts, PPRP has conducted research studies along Maryland's Atlantic coast to identify benthic and aquatic resources that would be at risk from transmission cables originating at offshore wind farms.[117] The report from the studies included a management tool that could be used to interpret the interconnection of offshore benthic communities and evaluate the relative ecological value of the community clusters to the local ecosystem as a whole.

[115] Jacobs, J.M., M. Rhodes, C.W. Brown, R.R. Hood, A. Leight, W. Long and R. Wood. "Predicting the Distribution of Vibrio vulnificus in Chesapeake Bay." NOAA Technical Memorandum NOS NCCOS 112. NOAA National Centers for Coastal Ocean Science, Center for Coastal Environmental Health and Biomolecular Research, Cooperative Oxford Laboratory. Oxford, MD. 2010.

[116] Blaustein, R. A., Y. Pachepsky, R. L. Hill, D.R. Shelton and G. Whelan. "Escherichia coli survival in waters: Temperature dependence." Water Research. Vol. 47, Issue 2, February 1, 2013, 569–578.

[117] Llansó, RJ. "Assessment of Ecological Value of Benthic Habitats in Offshore Wind Transmission Line Corridors" Prepared for the Maryland Department of Natural Resources, Power Plant Research Program, Annapolis, MD, by Versar, Inc., Columbia, MD. Draft, 2018.

5.2.3 Impacts to Rare, Threatened, and Endangered Species

Generation Facilities

The potential effects of the construction and operation of generation facilities on Maryland's rare, threatened, and endangered (RTE) species need to be considered for every project. Terrestrial and aquatic plant and animal habitat can be potentially negatively affected during the construction, operation, and maintenance of generation facilities. Many RTE species have specific aquatic habitat requirements or are particularly sensitive to changes in aquatic habitat conditions. For example, construction may increase sediment transfer or deposition and degrade water quality to the point where it can make a stream habitat unsuitable for local populations of aquatic and amphibious RTE species (for examples of how PPRP has accommodated the needs of some aquatic RTE species in Maryland see CEIR-21). The construction, operation, and maintenance of offshore generation facilities could potentially affect federally listed threatened and endangered species that live in the Chesapeake Bay and coastal waters of Maryland. Species that inhabit or migrate through these aquatic areas include fish, whales, and sea turtles.

For a current list of federally threatened or endangered species in Maryland, see ecos.fws.gov/ecp/report/species-listings-by-state?stateAbbrev=MD&statusCategory=Listed&s8fid=112761032792&s8fid=112762573902.

For information on RTE plant and animal species listed by the State of Maryland, see https://dnr.maryland.gov/wildlife/Pages/plants_wildlife/rte/espaa.aspx.

Transmission Facilities

Maryland's aquatic RTE species are potentially subject to the same impacts from the construction and maintenance of transmission line ROWs as other aquatic species, but RTE species and their habitats must be given specific protections that align with the particular needs of each of the relevant species in the area of the project. For instance, to the extent possible, the construction activities for the ROW must avoid the area that contains the habitat of each RTE species, and time-of-year restrictions may be applied to maintenance activities within the ROW to avoid times when the species is breeding or especially active.

5.3 Impacts on Terrestrial Resources

Impacts from new generation projects on Maryland's landscape depend on the mode of power production. Power plants that use traditional resources such as coal and natural gas are generally confined to relatively small, intensively developed installations and associated linear infrastructure, whereas renewable energy projects using wind turbines or solar panel arrays may occupy hundreds of acres. The construction and operation of new power generation facilities can have significant effects on terrestrial environments and habitats. Some of the primary mechanisms for the effects include altering the landscape, releasing effluent to the environment, creating physical barriers within natural habitats and flyways, and creating environments that encourage invasive species to establish territories.

PPRP has reviewed applications for more than 40 proposed solar generation facilities. The approved projects are located throughout the state, but the facilities raise several environmental issues, many related to a facility's distinctive features. For example, projects located near the Chesapeake Bay may include development in the Critical Area, and projects in agriculturally zoned areas may remove farmland from the production cycles. Many of the projects require mitigation under Maryland's Forest Conservation Act. The locations of utility-scale solar projects are frequently restricted by county zoning regulations, comprehensive development plans, and designated preservation areas. Several Maryland counties, including Frederick, Prince George's, and Caroline, have revised their solar facility approval processes and laws to limit development impacts, particularly in agricultural and environmentally sensitive areas.

New fossil fuel generation facilities have varied from being constructed entirely within an area that was already developed to one that required clearing a significant amount of natural habitat. Examples are found in CEIR-21.

Maryland has more than two thousand miles of electric power transmission line and natural gas pipeline ROWs. Constructing and maintaining these ROWs creates long, mostly linear, corridors that can affect nearby areas, including terrestrial habitats and wetlands, in a variety of ways, either temporarily during construction or over the long term. During the CPCN review process, PPRP reviews the potential impacts of the proposed project on wetlands, forests, rare species, and land cover conversions to assess the effects on the terrestrial environment and its inhabitants. See CEIR-21, Chapter 5.3 for more information on ways that PPRP's approaches seek to comply with Maryland's environmental regulations and meet the state's natural resource management objectives.

5.3.1 Impacts on Forests and Maryland's Green Infrastructure

Generation Facilities

The Maryland Department of Natural Resources (DNR) has established land conservation strategies to preserve and restore the state's ecological health. One of DNR's programs, the Green Infrastructure (GI) Assessment, is designed to identify and map large areas of contiguous forest habitat hubs and narrower natural corridors that connect the hubs and allow movement among faunal and floral populations. This GI Network is important to the state because the size and shape of forest patches correlates directly with the species of plants and animals that inhabit them and the diversity that the patch of forest can support. Larger forest patches that contain more forest interior habitat often support unique niches for RTE species.

Forest resources are important in numerous ways in addition to providing habitat for wildlife. Forests filter nutrients and other pollutants from stormwater and help prevent erosion. They also filter out air pollutants, sequester carbon dioxide, and produce oxygen. Carbon removed from the atmosphere is stored in above-ground plant tissue and below-ground in roots and soil. As a forest grows, nutrients are added to soils as dropped leaves and branches decay. Forests are also important commercial resources, providing construction materials and renewable fuel supplies. Given these important ecosystem services and compelled by the significant losses of Maryland's forest resources over time, the Maryland Legislature enacted the Forest Conservation Act (FCA) in 1991. Development that disturbs more than 40,000 square feet must comply with the FCA in accord with county implementation statutes (Forest Resource Ordinances). Heavily forested Allegany and Garrett counties are exempted from implementing County Forest Resource Ordinances under the FCA.

Under the FCA, evaluating existing forest conditions and character is an integral component of power plant and transmission line facilities siting and development. Significant changes were made to the FCA by the Legislature in 2023. While the FCA still requires the applicant to submit both a Forest Stand Delineation defining the nature and character of the existing forest and a Forest Conservation Plan for protecting the most ecologically valuable areas of forest, mitigation requirements and conservation goals were modified. Changes effective as of July 1, 2024, include replacing the statewide "no net loss" policy with the goal of a continuing net increase in forest acreage and granting an exemption to solar photovoltaic (PV) facilities from minimum forest cover (i.e., afforestation) requirements. Aside from solar facilities, the minimum tree cover requirement (15% or 20%, depending on the land use category) remains in effect for other generation and transmission facilities and must be achieved by planting trees (afforestation) if sufficient forest is not already present in the area to be developed. Reforestation, or planting new trees in proportion to the area of trees cleared on the net tract area of the development, remains generally in effect.

The FCA also assigns certain responsibilities with respect to forest conservation to the PSC during the CPCN review, as specified in the Natural Resources Article, 5-1603 (f): "After December 31, 1992, the PSC shall give due consideration to the need to minimize the loss of forest and the provisions for afforestation and reforestation set forth in this subtitle together with all applicable electrical safety codes, when reviewing applications for a certificate of public convenience and necessity issued pursuant to §7-204, §7-205, §7-207, or §7-208 of the Public Utilities Article." Thus, suitable compliance with FCA mitigation standards for tree removal or for developing unforested land is a requirement for obtaining a CPCN.

The State's FCA provides a set of minimum standards that developers must follow when designing a new project. County and municipal governments are responsible for making sure these standards are met but may choose to implement even more stringent criteria, although they cannot override the solar facility exemption. In issuing CPCNs, the PSC is obligated to give due consideration to the County's FCA requirements and recommendations but has the authority to pre-empt those requirements based on its own review. Once a CPCN is issued, certain FCA exemptions are available to utilities for subsequent maintenance activities.

As the license conditions are developed in the CPCN process, the quality of the natural resources that will be affected by the project is also considered. Effectiveness of reforestation efforts can be enhanced by following best management practices for tree planting.[118]

Transmission Facilities

The Working Committee on Utilities of the President's Council on Recreation and Natural Beauty[119] prepared an extensive report on actions required ensuring "utility transmission and distribution lines and utility plant sites are compatible with environmental values." Among the suggested practices that have

[118] Noel D. Preece, Penny van Oosterzee, Michael J. Lawes, Reforestation success can be enhanced by improving tree planting methods, Journal of Environmental Management, Volume 336, 2023, 117645, ISSN 0301-4797, https://doi.org/10.1016/j.jenvman.2023.117645.

[119] Report to The Vice President and to The President's Council on Recreation and Natural Beauty. 1968. United States. President's Council on Recreation and Natural Beauty. Working Committee on Utilities. Pp. 126.

been recommended to transmission line owners, but have been slow in implementation, are the following:

- ROW clearing should be kept to the minimum width necessary to prevent interference from trees and other vegetation. Selective tree cutting and removal should target trees that could cause damage to the line.
- The ROW edges through forests or timber areas should have undulated boundaries, not straight "walls" that create a "tunnel" effect.
- Small trees and plants should be allowed in the ROW to "feather" the height of the ROW vegetation from grass and shrubbery near the center to larger trees at the edges.

GI hubs and corridors are particularly vulnerable to disruption when ROWs are constructed through them, because the deforested ROW gap splits the forest habitat into fragments that may no longer be able to function as an integrated habitat unit for forest interior species. While the area of the removed forest may not be significant, there may be severe consequences for the species that depend on the hub or corridor habitat. Invasive plants can grow prolifically in the cleared-edge habitats of transmission line ROWs and can spread into the forest interior, limiting the growth of native species. Careful vegetation management in the ROW can minimize potential impacts. Siting new or expanding existing transmission line ROWs within GI network components is strongly discouraged unless it is not feasible to bypass the GI system and place the new ROW disturbance into areas supporting more compatible land uses.

5.3.2 Impacts to Wetlands

Generation Facilities

Wetlands form the interface between terrestrial and aquatic ecosystems and support diverse ecological communities that require the unique wetland habitat to survive. Wetlands also provide numerous benefits to human society, including fish and wildlife habitat, flood protection, erosion control, and water quality maintenance. To address wetland losses over time, the State developed regulations under Maryland's 1991 Nontidal Wetlands Protection Act, with the goal of no net loss of nontidal wetlands. Under nontidal wetlands regulations, permanent impacts to nontidal wetlands must be mitigated at various ratios depending on the type of wetlands affected (see CEIR-21for examples). Maryland developed similar regulations for tidal wetlands in 1994. Temporary impacts to wetlands and impacts to wetlands buffers do not usually have replacement mitigation requirements, but the State may require compensatory or enhancement measures for projects with these types of effects.

PPRP's CPCN analysis includes assessing potential wetland impacts and developing appropriate mitigation equal to or greater than that required by the state's wetland regulations. Wetlands are present at nearly all of Maryland's power facilities, and impacts to these wetlands can usually be avoided. Where especially valuable wetlands are present, PPRP's process, in consultation with MDE, clarifies the unique nature of the wetlands and identifies specific CPCN conditions to ensure the protection of the wetlands and the integrated hydrologic networks, as applicable.

Power generation facilities often require associated linear facilities that might include gas and water pipelines, transmission lead lines, and roads. Construction of linear facilities may affect streams and wetlands through vegetation removal or ground disturbance. Options to minimize permanent impacts to wetlands include advanced construction techniques such as horizontal directional drilling.

Transmission Facilities

The Critical Area Act protects land within 1,000 feet of tidal waters and tidal wetlands, and nontidal wetlands—including wetlands in utility ROWs—are protected by regulations enforced by the Nontidal Wetlands Protection Act. Maryland's overall goal is no net loss of nontidal wetland acreage or function. To achieve this goal, the State requires that any unavoidable wetland losses be replaced at least acre per acre. Greater replacement ratios (up to 3:1) are specified for forested wetlands and Wetlands of Special State Concern. New routes for linear facilities are usually planned to avoid wetlands, but ROWs constructed prior to the implementation of the Nontidal Wetlands Protection Act were often less favorably sited, and many undesirable wetland impacts occurred.

Wetland impacts result when vegetation, soil, or water flow is altered by a transmission line ROW, either directly or indirectly. Transmission line access roads within wetlands were often particularly damaging in the past because fill was used to raise the roadbed above the water table, which changed both the natural drainage and the soil characteristics. When flow to the wetland is diverted by the road or associated ditching, the wetland can dry up. Conversely, parts of the wetland upstream (or up-flow) of the blockage often are permanently flooded. Without proper management practices, invasive plants tend to colonize areas directly adjacent to a dry elevated roadbed and compete with the adjacent wetland plants for sunlight and water. Vigilant permitting oversight by MDE, U.S. Army Corps of Engineers, and DNR and appropriate planning by the utilities has effectively transformed the siting process such that transmission line access roads are now rarely constructed in wetlands. The preferred access for pole placement and line maintenance near wetland areas is via access points on either side of the wetland, which avoids direct impacts. Sturdy, temporary mats are often placed over wetland areas before and during construction to minimize damage from equipment and activities when upland access is not possible, without building permanent roads.

Indirect impacts from the construction and maintenance of transmission facilities and associated ROWs can affect wetlands primarily by disturbing upland soils, which allows runoff to convey loosened soil into streams and associated wetland areas. Construction activities can also disrupt nearby wetland habitat; such disturbances are especially damaging during critical reproductive periods for the plants and animals that inhabit the wetland ecosystem. Impacts can often be minimized during construction by the use of appropriate BMPs. Overall, transmission line construction has the least impact on wetlands when poles are placed in uplands areas, well away from the wetland area, or lines are placed in horizontally bored duct banks below the wetland.

5.3.3 Impacts to Wildlife

Generation Facilities

New facilities for power generation primarily affect wildlife by removing habitat during the construction of the project. Sometimes, facilities require large tracts of land to be cleared, and construction permanently changes the habitats and connecting corridors that wildlife use. The loss of habitat from clearing large, contiguous forested areas can affect forest interior dwelling species (FIDS) that require habitat in the interior of forests for reproduction or survival. A project that clears land from the edge of the forest into and including the deep interior of the forest can reduce FIDs habitat. It can also affect areas adjacent to the cleared area by increasing the amount of land that would then be vulnerable to edge effects (e.g., increased sunlight, more wind exposure, favorable environments for invasive and opportunistic species, and increased exposure to predators). The amount and pattern of forest loss can also reduce the interior patch size; the qualities of the patch, including size, determine whether the unique area can maintain ecological function. During the construction period, wildlife is affected by noise, human activity, changes in forest structure, and changes in light penetration and humidity.

Land-based wind energy projects can also have a substantial impact on wildlife during construction and operations. Wind turbines are usually installed in linear arrays, and wind power facilities can occupy large areas on the landscape when the turbines, service roads, and operations buildings are considered as a whole. A much greater area is often needed during the project construction phase as the large towers and turbine blades require broad laydown areas before and during assembly.

All of the land-based wind power facilities developed in Maryland thus far have been in the predominantly forested habitats of Garrett and Allegany counties. The forests of Western Maryland are a southern extension of the northern hardwood forests that spread more broadly in the northern areas. Logging, coal mining, and residential construction have fragmented these forests. Where contiguous forest areas exist, new construction, including projects for wind power development, within these forests would increase fragmentation. Forest fragmentation affects the habitats of birds, bats, and other terrestrial species. Some of the potential changes include direct loss of forested habitat, the encroachment of species that can have direct (e.g., predation) or indirect (e.g., disease) detrimental effects, the disruption of corridors used for daily movement, or seasonal migration. The changes imposed by the construction and operation of a wind power facility can lead to the eradication or displacement of species in the affected areas.

Birds and bats can be injured or killed after colliding with wind power structures and spinning blades. PPRP and DNR's Wildlife & Heritage Service (WHS) have reviewed and commented on Bird and Bat Conservation Strategies (BBCS) for wind power projects (see CEIR-21 for more details on this topic). An Avian Protection Plan or BBCS for a project outlines a program to reduce the potential risks of avian and bat mortality that may result from the project's construction and operation. The ultimate goal of these plans is to avoid impacts to avian, bat, and all protected species to the greatest extent possible.

Solar facilities are the most space-consuming type of power generation plants. Approximately five to seven acres of installed solar panels are required to produce each megawatt of power. Generally, larger solar projects in Maryland have been in the 100-acre to 300-acre range on previously cleared agricultural land. Other than acting as wildlife transportation corridors, such farmed lands usually offer little existing wildlife habitat, because they have been intensively managed, which limits nesting by birds or occupancy by other wildlife. Common species of wildlife that are compatible with agricultural environments may be present (e.g., mourning dove, groundhog), but overall biodiversity is limited. Some aspects of solar projects can be developed and maintained in ways that provide some benefits to wildlife. For instance, following the installation of the solar panel arrays, PPRP recommends that the areas below and between the solar panels be planted with native, warm season grasses and low-growing pollinator-friendly species to encourage ground-nesting birds and pollinators to visit or inhabit the area. PPRP promotes, on behalf of DNR, practices that support native Maryland pollinators and expand habitats for pollinator species (see sidebar).

Transmission Facilities

A large portion of the transmission line ROWs in Maryland cut through undeveloped areas that provide abundant wildlife habitat. Although many construction impacts are temporary, the long-term habitat alterations often continue to affect birds and other terrestrial animals.

A transmission line ROW maintains long, cleared zones with abrupt edges, which have the most impact to wildlife habitats where the adjacent land is forested. The ROW often provides a corridor for invasive species that compete with or prey upon native forest species. The effects of these edge areas are particularly severe near forested streams and wetlands. The edge impacts are less significant in shrub/scrub and agricultural habitat areas but maintaining the ROW in a mowed state can still result in gaps between natural habitat patches. Such gaps can present an insurmountable barrier to some species, thereby isolating the populations that are on each side of the ROW from each other. Even highly mobile species may not be able to maintain a viable population under these conditions, because individuals that attempt to cross the cleared area may be exposed to a high risk of predation.

The forest interior habitat is dense with tall trees and lush understory vegetation, nurtured by rich loamy soils and segregated from any edge effects; this type of habitat uniquely suits many birds and other terrestrial animals that are sensitive to unnatural disturbances in their environment. The forest interior is also important because it may form a core refuge for rare and common forest species that live in or near forest perimeters and for occasional use by non-interior species. FIDS are particularly sensitive to the size of the habitat patch. Interior habitat sufficient to support resident breeding populations of avian FIDS generally require several hundred acres of contiguous forest. According to the Natural Heritage Program, the populations of many avian FIDS are declining in Maryland, often because of the loss of suitable amounts of habitat. Thus, the effect on FIDS of a transmission line corridor that splits or reshapes the edges of a large forest parcel may be significant, and the impact can be particularly damaging in forest patches smaller than 100 acres or in densely forested areas along streams.

Birds occasionally collide with transmission lines; this can result in injury or electrocution. Bald eagles, ospreys, and cormorants occasionally nest on transmission line towers in Maryland. The U.S. Fish and Wildlife Service (USFWS) and the Avian Power Line Interaction Committee cooperatively developed guidelines to help prevent injuries to birds that contact power lines and reduce the likelihood of power outages caused by bird collisions. As older power lines are rebuilt, utilities typically use newer structure designs that minimize nest construction opportunities.

Promotion of Native Pollinators

Plants rely on pollen vectors, from wind to insects to birds and bats, to transport their pollen to another individual and attract the same species repeatedly to bring about successful pollination. These vectors must cause pollen transfer for plants to ultimately set seed and be successful. Pollinators contribute substantially to the success of fruit, nut, and vegetables crops; however, there has been a significant loss of pollinators, including honeybees, native bees, birds, bats, and butterflies, during the last few decades.

http://www.xerces.org/wp-content/uploads/2014/09/NortheastPlantList_web.pdf

In 2014, President Obama issued a memorandum establishing a Pollinator Health Task Force, cochaired by the U.S. Department of Agriculture (USDA) and EPA, to create a National Pollinator Health Strategy to promote the health of honeybees and other pollinators. Overall, eastern monarch butterfly populations have declined by more than 80% over the past two decades. The USFWS found that "listing the monarch butterfly as an endangered or threatened species is warranted but precluded by higher priority actions." Therefore, in 2020 it received a Candidate status and is currently awaiting further consideration.

The loss of native bees, which also play a key role in pollination, is much less studied, but many native bee species are believed to be in decline. Scientists believe that bee losses are likely caused by a combination of stressors, including poor bee nutrition, loss of forage, parasites, pathogens, lack of genetic diversity, and exposure to pesticides.

During Maryland's 2017 legislative session, a bill passed creating a pollinator habitat certification for solar facilities meeting specific criteria. This legislation was enacted in March 2020.

Information concerning the pollinator-friendly solar certification program can be found on PPRP's website. (dnr.maryland.gov/pprp/Pages/pollinator.aspx).

Pollinator habitat replaces frequently mowed herbaceous or crop areas (but never replaces forested habitats) on a project site. The pollinator habitats consist of native herbaceous plants that are known to attract a variety of pollinator species (a list of suggested seed mix suppliers can be found on PPRP's website.). These habitats are relatively maintenance-free, and once established, often only require an annual or semiannual mowing. They generally do not require herbicides or fertilizers and are friendly to native birds and other wildlife. Pollinator habitats can also be managed in electric transmission ROWs with integrated vegetation management as two distinct plant communities—grass and herbaceous plants within the wire zone (under and 20 feet outside conductors) and a shrub/scrub border zone from the wire zone to the ROW edge to develop meadow habitat and shrub habitat along the ROW border and in ravines.

5.3.4 Impacts to Rare, Threatened, and Endangered Species

Generation Facilities

Rare, threatened, or endangered (RTE) species inhabit areas throughout Maryland. Power generation projects proposed in Maryland must undergo an RTE species review by the DNR's WHS to identify RTE species known to occur in or near the affected area. Recommendations made by the WHS during the project review usually form the basis for license conditions in the CPCN to protect RTE species. Regardless of the kinds of habitat involved, threatened or endangered plants and wildlife are protected by law. (See CEIR-21, Chapter 5.3.4 for more information on this topic).

Western Maryland provides year-round habitat to some migrating bat species, which include species listed on federal and state RTE programs. (See CEIR-21 for more information on this topic). The seasonal and daily activity patterns of these rare species must be investigated further before concerns about the risks posed by proposed wind turbines can be adequately addressed and mitigation activities defined.

Transmission Facilities

Most RTE species occupy specific environmental niches that only support small populations. The critical step in protecting the species is to avoid anthropogenic influence on the unique habitats; even small disturbances may place the population at risk. New transmission line corridors are usually an undesirable disturbance, although existing transmission line ROWs sometimes create an ideal niche for a threatened or endangered species. As part of a CPCN review, WHS notes potential occurrences of RTE species and will require a Phase 1 study following USFWS protocols. If the survey identifies potential habitat, DNR's experts make specific recommendations regarding time-of-year restrictions and potential distances needed between the habitat and any construction disturbances to minimize impacts.

The CPCN review also considers the special needs of rare plant species that may inhabit areas in or near the vicinity of a proposed project. Coordination with WHS to protect species could include CPCN license conditions to flag or fence known RTE areas and could require the presence of a third-party environmental monitor during construction activities to help avoid or minimize impacts to sensitive species. PPRP could also recommend a license condition that requires the utility to assist in an invasive species control program for a period of time after construction to ensure that construction activities did not introduce invasive species that would outcompete native RTE species or degrade habitat needed for the species.

The WHS Natural Heritage Program maintains a database of all known observations of Maryland's designated RTE plant and animal species, with particular attention to those that require special habitat protection to support viable populations. The route of every proposed new or modified transmission line is compared to this database to identify all possible impacts to known populations and to identify habitat that may be suitable for any other RTE species. If the appropriate habitat is available, certain species could be present without documentation because site-specific surveys have not yet been conducted. PPRP and WHS work together to make specific recommendations for each species when habitats and potential habitats are identified near a proposed project. Recommendations include field surveys and protecting or mitigating impacts to any populations present, such as avoiding disturbances during breeding seasons or migrations, controlling hydrologic impacts during and after construction, controlling and monitoring sediment disturbance, and restricting actions or operations that will disturb or injure individuals of a vulnerable population.

5.3.5 Vegetation Management

In existing transmission line ROWs, vegetation management and past maintenance activities will have shifted the vegetation toward low-profile species, such as grasses, ferns, herbaceous plants or forbs, shrubs, and tree saplings. Many of the species present in the ROW may be non-native species that were planted after the initial clearing to prevent soil erosion or may be weedy and invasive species that have taken advantage of disturbed habitat in the corridor. In a few places, where clearing to maintain the ROW has not been frequent, taller vegetation may be present, but generally, the ROW will be open, with sparse vegetation cover and a different assemblage of plant and animal species than is present in the adjacent areas. The bordering ecosystems (within 100 feet to 300 feet of the ROW boundaries) can also be degraded to some degree when the vegetative community within the ROW has been significantly disturbed or altered by construction and maintenance, such as in forested areas. However, vegetation management is a constant and always present issue and must be addressed at regular intervals.

Trees in or near power line ROWs have historically presented special maintenance problems. While it is environmentally desirable to remove as few trees as possible, fallen trees and branches can have a major impact on reliability. In 2014, vegetation contact caused 22% of the total electrical outages throughout Maryland.[120] New PSC vegetation management standards for lower-voltage distribution power lines, known as Rule Making No. 43 (RM43), went into effect as of 2013. These standards dictate how close tree branches can grow to power lines and are implemented on a 4- to 5-year vegetation management cycle. RM43 also allows utility companies to identify and remove hazardous trees near power lines. Although there are fewer tree-fall events that cause outages of higher-voltage transmission lines regulated by the FERC, DNR has joined with the Maryland Electric Reliability Tree Trimming (MERTT) Council, which typically focuses on the lower-voltage lines, to develop a clear picture of trees that cause power outages in Maryland. Utility foresters are identifying each instance of a tree-caused power outage and recording the electric line characteristics, tree characteristics (e.g., species, size, health, and location relative to the utility ROW), and environmental conditions at the time of the outage. PPRP has assembled the data from utilities throughout the state into a common database and are analyzing the data to provide the PSC with accurate information on the causes of such outages. The results were used by MERTT Council members and PPRP to evaluate whether there are changes following the implementation of RM43. In recent years, there have been so few vegetation-related outages to high-voltage transmission lines that MERTT Council has not felt the need to continue monitoring these specific outages. However, MERTT Council continues to meet regularly and collect data for low-voltage outages and will continue to monitor high-voltage vegetation-related outages as the need arises.

NERC Regulations

Improperly maintained vegetation in a transmission line ROW can disrupt the integrity of the system and cause cascading power outages. The North American Electric Reliability Corporation (NERC), operating under the oversight of FERC, develops and enforces reliability standards for vegetation

[120] Maryland Public Service Commission Staff, Engineering Division Review of 2014 Annual Performance Reports on Electric Service Reliability, Case No. 9353, August 17, 2015.

management along transmission lines. The NERC Reliability Standard FAC-003-5 (Transmission Vegetation Management), approved by FERC in 2020, codifies current best practices and requirements for reliability and has been phased in over time. The standard requires transmission owners to have a documented Transmission Vegetation Management Program (TVMP) for all transmission lines operated at 200 kV and above, as well as for designated sub-200 kV lines and generator interconnection facilities. The purpose of the TVMP is to improve the reliability of the electric transmission systems by preventing outages from vegetation within a ROW. The TVMP must identify and document clearances between vegetation and overhead conductors, considering voltage, sag under maximum load, and wind velocity on conductor sway. Alternating-current voltages require minimum vegetation clearance distances (MVCD). The calculated minimum distances to prevent spark-over between conductors and vegetation at various altitudes and operating voltages are specified in the standard. In addition to maintaining the MVCD, the transmission owner is also required to specify the methods that will be used to control vegetation and has the option of adopting the procedures and practices in the American National Standard for Tree Care Operations, Part 7 (American National Standards Institute [ANSI] A300). The TVMP must also include a schedule for annual ROW inspections.

Current Practices

Transmission companies are required to maintain ROWs in a condition that ensures the reliable delivery of power in accordance with NERC standards. Although it has been common practice to achieve this goal by clearing and mowing the ROW, such vegetation management practices are not required and may cause unnecessary environmental damage, especially in sensitive areas and through forested habitat.

The alternatives suggested in the Guidelines of the Working Committee on Utilities of the President's Council on Recreation and Natural Beauty[121], and other advanced techniques such as the Integrated Vegetation Management approach recommended by the International Society of Arboriculture, can be implemented providing that required clearances are maintained. In general, most Maryland utilities use uniform, systemwide practices that may be more aggressive than NERC requirements. After forested land is cleared to create a transmission line ROW, several methods to maintain a low-stature vegetative community within the ROW are generally used, including mechanical clearing (e.g. mowing), selective removal and pruning of problem trees with chainsaws, and application of herbicides. Mowing is the most common method of maintaining an open grassland habitat. ROW corridors converted to and maintained as open grassland habitat within forested areas may not have much value for grassland breeding birds. Invasive and exotic species can be easily established in converted grassland as well. Clearing the entire ROW creates hard edges with no transition between habitats. Maintaining a scrub habitat, dominated by low-growing, bushy vegetation and young trees is preferable to mowing, particularly in forest habitats. It provides excellent habitat for wildlife including neotropical migratory birds, reptiles, amphibians, and pollinators (see sidebar on Promotion of Native Pollinators in Section 5.3.3)

Leaving the ROW in a natural state to the maximum extent possible is the best alternative for protecting wildlife in sensitive areas. Creating curved or wavy ROW boundaries and piling brush from the cleared

[121] Report to The Vice President and to The President's Council on Recreation and Natural Beauty. 1968. United States. President's Council on Recreation and Natural Beauty. Working Committee on Utilities. Pp. 126.

ROW so that it provides wildlife habitat would help mitigate impacts from ROW clearings in forested areas and aid in reducing the establishment of exotic species. These practices are detailed in CEIR-21.

Conditions and Compliance

Most Maryland utilities indicate that they now use a combination of selective herbicide application and mechanical cutting rather than exclusively one or the other. To encourage the implementation of environmentally friendly maintenance in ROWs, PPRP has, through its membership in the MERTT Council, compiled information on innovative practices that reduce adverse effects on local wildlife and plant communities, such as reduced mowing frequencies. Several of Maryland's utilities have adopted maintenance programs to improve wildlife habitats in ROWs in limited areas. The introduction of desirable species into the ROW through "right tree/right place" plantings or wildlife habitat enhancement projects is often possible. Where implemented, such programs have created more functional, stable habitats for wildlife and have saved thousands of dollars in annual maintenance costs.

Some research indicates that planting "connecting corridors" in the ROW between otherwise separated forest patches could be beneficial for many forest species. Such corridors could consist of native low-growing trees and shrubs that do not grow tall enough to present a danger to the overhead transmission lines. The state agencies encourage utilities to identify opportunities to create such cross-ROW connections, particularly in areas where the ROW fragments habitat used by forest interior dwelling species or crosses riparian areas and wetlands. PPRP continues to research the benefits of innovative BMPs for power line ROW vegetation management.

PPRP reviews the TVMPs of all applicants for CPCNs for new or modified transmission lines for compliance with the required standards and BMPs. As necessary, PPRP recommends license conditions for implementing such practices and for developing detailed vegetation management plans for sensitive locations along the ROW.

5.4 Socioeconomics and Land Use Issues

5.4.1 Generation Technologies and Socioeconomic Focus

Solar Photovoltaic – Generation Technologies and Agricultural Land Use

Siting utility-scale solar energy generating systems (SEGS) on agricultural land does not come without costs, and PPRP's role has been to weigh these costs against the benefits of renewable energy generation in its environmental reviews. Some of the issues PPRP has addressed are listed in the following sections along with a reference as to where expanded discussions on these topics can be located.

Loss of Prime Farmland – See PPRP's website, Socioeconomics and Land Use Section

A recurring issue in the siting of SEGS on productive agricultural land is the loss of prime farmland. Prime farmland is land that has the best combination of physical and chemical characteristics for producing food, feed, forage, fiber, and oilseed crops, and is also available for these uses (the land could be cropland, pastureland, rangeland, forest land, or other land, but not urban built-up land or water).

Farmland Critical Mass – See CEIR-21, Chapter 5.4.1

The direct loss of prime farmland acreage is just one aspect of the concerns regarding SEGS. There are also fears that solar PV development could reduce acreage below a critical mass of farmland needed for the agricultural economy in an area to remain viable.

Post-Solar Restoration of Farmland – See CEIR-21, Chapter 5.4.1

In Maryland and elsewhere, once the operating life of a solar facility ends (typically 30 years), the facility must be decommissioned and the land returned to its original condition. PPRP recommended licensing conditions include a requirement for a detailed decommissioning plan and surety agreement to be filed with the PSC. While decommissioning plans generally aim to remove all project components, plans include contingencies for structures, such as below-ground piles and buried underground cables, to be cut and abandoned in place.

Energy Sprawl and Suburban Sprawl – See CEIR-21, Chapter 5.4.1

Another issue for solar development on agricultural land is the conflict with neighboring homeowners of single-family homes on large lots or subdivisions in rural areas. View degradation is probably the most cited reason for opposition to solar facilities because open views of agricultural landscapes will be replaced by solar panels or, at best, a vegetated buffer.

Agricultural Operations Near Solar Facilities – See CEIR-21, Chapter 5.4.1

Solar arrays have a low vertical profile that, even in the absence of buffering, creates a small visual footprint. SEGS do not emit significant traffic, noise, air, or water pollutants or generate any hazardous waste that could potentially affect public health. As such, operational solar facilities would not appear to have the potential to affect nearby agricultural operations.

Cultural and Heritage Resources – See CEIR-21, Chapter 5.4.1

Cultural and heritage resources define Maryland in many respects. They comprise historic properties and archeological sites listed on the Maryland Inventory of Historic Properties (MIHP) and National Register of Historic Places (NRHP), heritage areas, scenic byways, and many other programs and properties in the public and private domain. Many of these resources are defined by their setting, or cultural landscape, which is sensitive to incompatible development. Historic preservation laws require state and federal government agencies to consider the direct or indirect effects of their projects on historic and archeological resources.

Mitigating Solar Impacts on Agricultural Land

With the state's 50% RPS Tier 1 solar carve-out increasing to 14.5% of instate solar generation in 2030, development pressure on agricultural land in Maryland for siting utility-scale energy facilities is expected to continue. Because of solar PV land requirements, there are few alternatives to agricultural tracts, particularly in Maryland and the rest of the eastern U.S. where less land is barren or unproductive. Concern about energy sprawl in agricultural landscapes is not confined to Maryland, however, and the potential of strategic renewable energy siting to mitigate environmental trade-offs is beginning to receive serious attention across the United States. These mitigation strategies do not necessarily remove utility-scale solar in its entirety from agricultural land but attempt to reduce the impact through land-sparing, dual use, and buffering. See CEIR-21, Chapter 5.4.1 for additional information on these mitigation strategies.

Solar Facility Decommissioning

Decommissioning refers to the process of permanently removing a facility from operation. In the power industry, plant decommissioning can include removing some or all of the physical components; however, some power plant structures may remain in place, especially if they may have value for future reuse or redevelopment. As solar power generating capacity in Maryland grows, increasing from 0.1 MW in 2007 to 1,636 MW in December 2022, there has been an increased focus on plans for decommissioning these facilities in the event a facility becomes non-operational.

Many components of renewable energy systems, such as the copper and aluminum in cables and solar modules, glass in the solar modules, or the steel in array supports can be reused, recycled, or disposed of locally. However, some components of solar energy systems present a disposal challenge. Some solar panels may contain trace amounts of potentially hazardous materials, and those panels not refurbished or repurposed may end up in a landfill. As yet, there is no solar PV-specific waste law in the United States that requires the recycling of end-of-life panels, and the revenues available from the retrieval of components such as tin, lead, and silver do not offset the additional cost of processing. Though there are a few recycling locations in the U.S. for these panels, the transport of retired solar PV components needs to be a cost and logistical consideration in solar decommissioning plans. Assuming that Maryland's utility-scale solar facilities currently in operation are dismantled after 25 years, about 25,000 tons of solar panels will need to be recycled or disposed of by 2045. Adding in smaller solar facilities that do not require CPCNs could approximately double the number of panels that will reach the end of their design life within that timeframe. By comparison, total solid waste generated in Maryland every year is more than 9 million tons.

States and counties across the U.S. are experimenting with a variety of approaches to ensure that there is sufficient funding to decommission a solar project when the time comes. Letters of credit and bonds appear to be the most popular options. The estimated costs of decommissioning solar projects vary widely, in large part because of the volatility of salvage values that can at least partly offset decommissioning costs. Because of the wide variation in decommissioning costs and salvage value, it is not possible for Maryland to ensure that decommissioning plans filed today or in the near future will include accurate cost and benefit forecasts. However, the state can assess whether these forecasts have been prepared by a responsible party, are based on valid economic assumptions, and are periodically updated.

CPCN conditions now require periodic updates from solar project developers to include decommissioning and salvage cost estimates. Solar facility operators must update the decommissioning plan, cost estimate, and funding mechanism every five years. As long as a project's approval is conditioned upon these forecasts (and any associated financial assurances) being updated regularly, today's decommissioning plans can be updated over time with better data before the decommissioning plan is executed.

Section 2.3 of CEIR-21provides additional discussion of decommissioning issues, including applicability to wind power, fossil fuel–fired facilities, nuclear, and hydroelectric plants.

Property Value Impacts

As the economy transitions to clean, renewable energy, utility-scale solar projects are becoming a common feature of the landscape and, although ground-mounted solar facilities can occupy significant acreage, solar panels, racking, and associated components have a vertical profile that rarely exceeds 12 feet. Still, concerns about alterations to views and other externalities lead to questions about changes to property values and reduced demand for residential properties near solar energy facilities. See PPRP's discussion on this topic on PPRP's website, Socioeconomics and Land Use Section.

Proximity to high-voltage transmission lines has been associated with changes in property values due to visual intrusion and perceived risk. See PPRP's discussion on this topic on PPRP's website, Socioeconomics and Land Use Section.

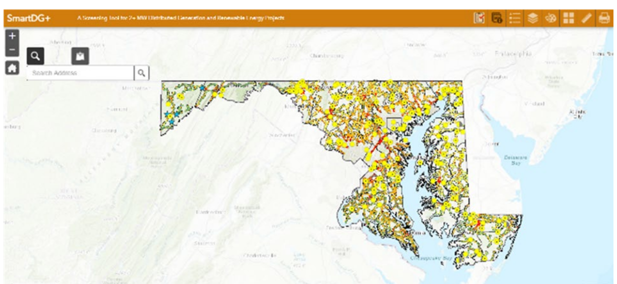
County Ordinances

While CPCNs are required for generating stations over 2 MW, generating stations under 2 MW are subject to county ordinance and permitting. With the increase in renewable energy projects in Maryland, particularly solar and wind, many counties have established ordinances pertaining to the approval and siting of generation. Although the PSC has the regulatory authority to approve electric generating stations above 2 MW, it takes into consideration a county's ordinances, if applicable, and concerns when reviewing an application for a CPCN. See PPRP's discussion on this topic on PPRP's website, Socioeconomics and Land Use Section.

SmartDG+

MEA and PPRP developed a free, online, map-based screening tool, SmartDG+, to assist developers and officials in identifying areas to locate new wind and solar projects. The tool maps 1- to 4-mile-wide corridors surrounding electric distribution and transmission lines that are likely able to handle renewable energy projects that are 2 MW or higher. Users can choose from the following screen factors/data layers to find potential project siting areas:

- Infrastructure Proximity
  - Electricity lines
  - Gas lines
- Renewable Resource Availability
  - Viable wind speeds
- Land Suitability
  - Protected areas
  - Flood zones
  - Land cover/land use
  - Airports
  - Department of Defense no-go zones
  - County zoning
- Installed wind and solar projects



Source: dnr.maryland.gov/pprp/Pages/SmartDG.aspx

5.4.2 Historic and Scenic Resources in Transmission Assessments

Scenic Resource Assessment

Transmission lines are an enduring feature of the rural landscape in Maryland. Virtually all transmission line corridors in the state have been in existence for more than 50 years. Most transmission line projects that have been proposed to the PSC in recent years have therefore involved reconductoring existing transmission lines to service projected increases in electricity demand and improve reliability throughout the state.[122] See CEIR-21, Chapter 5.4.2, for additional information on this topic.

Impacts on Heritage and Recreational Tourism

Many federal, state, and local land preservation and heritage overlays of Maryland contain scenic elements. See CEIR-21, Chapter 5.4.2, for additional information on land preservation and heritage area programs.

5.4.3 Renewable Technology Supply Chains

See PPRP's discussion on this topic on PPRP's website, Socioeconomics and Land Use Section.

[122] Reconductoring is the process of replacing the current-carrying conductors in a transmission line.

5.5 Radiological Issues

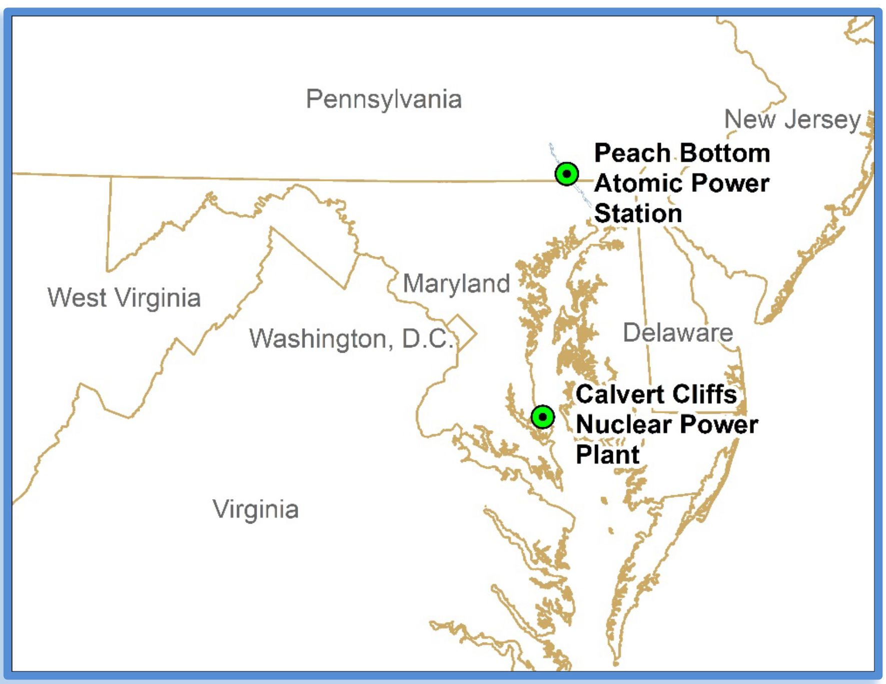
5.5.1 Pathways to Exposure

Production of nuclear power in the United States is licensed, monitored, and regulated by the U.S. Nuclear Regulatory Commission (NRC). Provisions in the operating licenses of each nuclear power plant allow utilities to discharge very low levels of radioactive material to the environment. The kind and quantity of releases are strictly regulated and must fall within limits defined in federal law as protective of human health and the environment. See PPRP's website, Radiological Issues Section for additional information.

5.5.2 Nuclear Power Plants of Interest to Maryland

Relevant to the CEIR, the study of radioactivity levels within Maryland focuses on the one nuclear power plant located in Maryland and the one closest to Maryland, near the northern state border (Figure 5-12). Calvert Cliffs Nuclear Power Plant (CCNPP) is located on the western shore of the Chesapeake Bay in Calvert County, and it is the only nuclear power plant in Maryland. Peach Bottom Atomic Power Station (PBAPS) is located on the western shore of Conowingo Pond in York County, Pennsylvania. The two power plants are owned and operated by Constellation Energy Generation LLC.

Figure 5-12 Nuclear Power Plants Nearest to Maryland



There are two operating power reactor units at CCNPP with the net generating capacity for the power plant of approximately 1,708 MW in 2022.[123] The units began service in May 1975 and April 1977, and

[123] United States Energy Information Administration: https://www.eia.gov/nuclear/reactors/reactorcapacity.php

the current NRC operating licenses will expire in 2034 and 2036. The two operating power reactor units at PBAPS have a net generating capacity of approximately 2,549 MW in 2022. The power plant began operations in 1974. The units are separately licensed through 2053 and 2054.

5.5.3 Monitoring Programs and Results

The releases to the environment (directly to air and water) from normal operations at CCNPP and PBAPS contain very small amounts of radioactive material. Aqueous discharges may contain varying concentrations of radionuclides that can be accumulated in the tissues of plants and animals, and the animals that consume them, or become trapped in bottom sediments. The components of the discharges are thus environmentally significant and may include iodine or metals such as cobalt, cesium, zinc, nickel, and manganese. Over time, these radionuclides may potentially contribute to a radiation dose to humans by transport through the food chain.[124] Releases of environmentally significant radionuclides have declined over the past two decades due to improvements in coolant water filtration technology at the nuclear power plants. See PPRP's website, Radiological Issues Section for additional information.

Monitoring conducted by PPRP meets Maryland's requirements to research the environmental effects of electric power generation, maintain oversight of environmental monitoring, and satisfy NRC requirements to verify the extent to which any releases from normal plant operations might result in potential doses to humans. Biennial reports published by PPRP document results of monitoring of radionuclide levels in the environment. See CEIR-21, Chapter 5.5 for more details about this topic.

Results of analyses of environmental samples collected in the vicinities of CCNPP and PBAPS can be found in the biennial environmental reports described previously. Some overall trends are evident in the long-term data, as summarized in the following list:

- Plant-related radionuclides are rarely detected in seafood (i.e., oysters and finfish).
- Plant-related radionuclides are rarely detected in sediments collected near the facilities.
- Although radionuclide concentrations fluctuate seasonally and annually, no long-term accumulation of plant-related radioactivity in local aquatic life and sediments is evident.
- The radioactivity introduced into the environment by CCNPP and PBAPS, when detected, is very small compared with background radioactivity in the environment from natural sources and weapons test fallout.
- Estimated radiation doses to humans associated with atmospheric and aqueous releases of environmentally significant radionuclides are well within regulatory limits.

5.5.4 Emergency Response

Federal, state, and county agencies conduct and evaluate the results of planned periodic exercises at CCNPP and PBAPS to test nuclear emergency preparedness and response plans. The multi-agency exercises demonstrate and provide practice for Maryland's and Pennsylvania's onsite and offsite response measures using simulated accidents at CCNPP or PBAPS, independently. The exercises

[124] McLean, R.I., T.E. Magette, and S. G. Zobel. 1982. *Environmental Radionuclide Concentrations in the Vicinity of the Calvert Cliffs Nuclear Power Plant: 1978–1980*. PPSP-R-4. Maryland Power Plant Siting Program, Annapolis, MD.

encompass the implementation of protective actions for all phases of the simulated accident. The exercises include collecting environmental samples in the area of the plant and delivering them to state-operated laboratories. The offsite portion of the exercises is evaluated by representatives from the Federal Emergency Management Agency.

5.5.5 Radioactive Waste

Nuclear power facilities produce waste products as a byproduct of normal power generation operations. In addition to releasing radioactive waste through atmospheric and liquid effluents, as described previously, power plants accumulate solid radioactive waste that has either low or high levels of radiation. The operating procedures at CCNPP and PBAPS specify how low- and high-level radiation waste is to be collected, treated, stored, and discarded. See CEIR-21, Chapter 5.5.5 for more details about this topic.

5.6 Power Plant Combustion Byproducts

5.6.1 Changes in CCB Regulations

At the federal level, coal combustion byproduct (CCB) disposal is regulated by the 2015 Federal Coal Combustion Residual (CCR) Rule (40 CFR Part 257). This rule specifies construction and monitoring requirements for CCB disposal sites (both impoundments [i.e., ponds] and dry landfills) that were active on or after October 2015. Since its enactment, the rule has been amended several times. In May 2023, the EPA published a proposed rule that would make the requirements of the 2015 Federal CCR Rule applicable to legacy CCB surface impoundments (those which stopped receiving CCBs before the 2015 Federal CCR Rule took effect). The 2023 proposed rule would also extend requirements to other CCB management units (i.e., landfills) that involved direct placement of CCBs on land, including units that stopped receiving CCBs before enactment of the 2015 Federal CCR Rule. As of September 2023, the EPA has received numerous comments on the proposed rule, but the proposed rule has not yet been finalized.

Although there are no CCB impoundments currently active in Maryland, there are several CCB landfills, fill sites, and one legacy impoundment that could be affected by the proposed rule, should it be finalized.

5.6.2 CCB Generation in Maryland

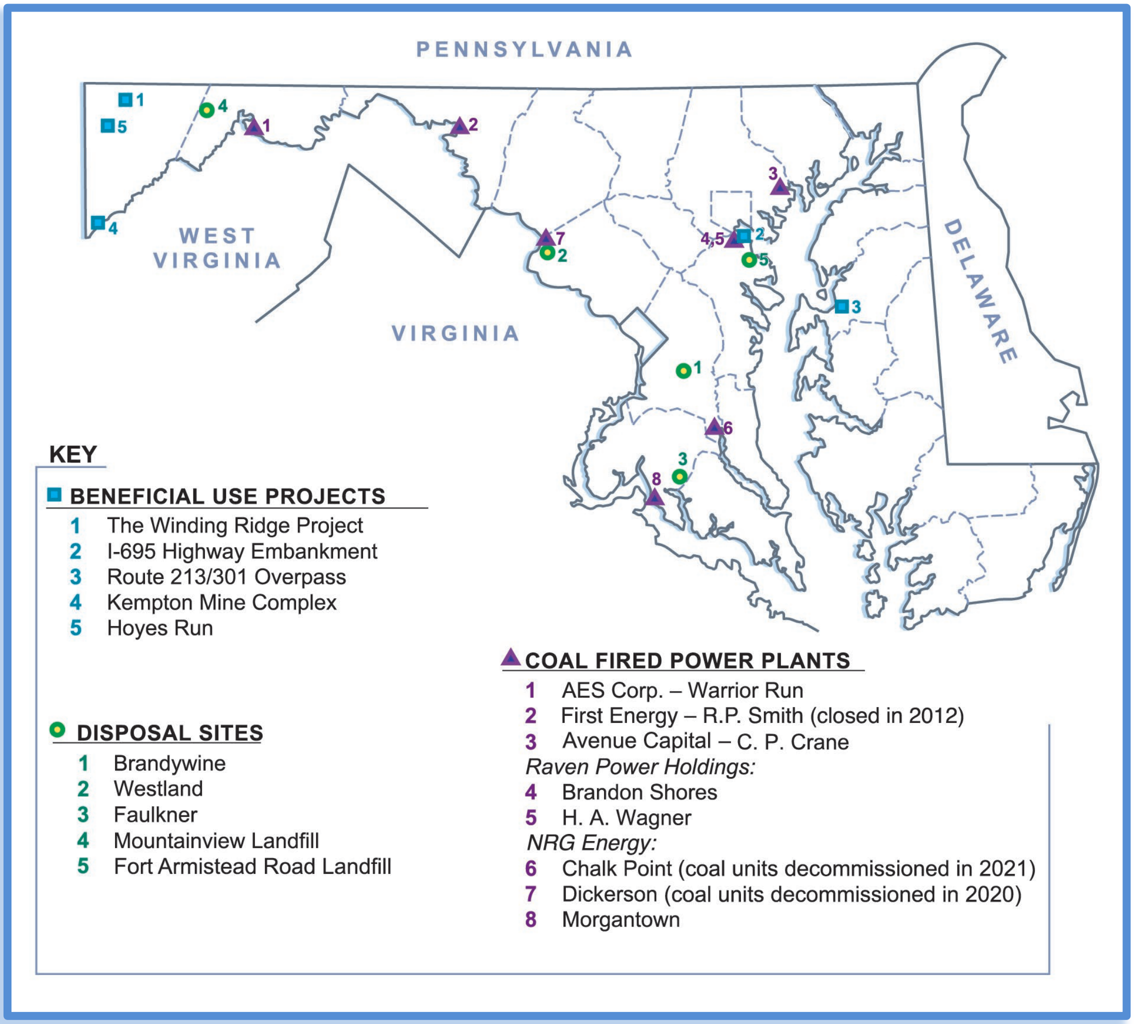
Figure 5-13 shows the locations of Maryland's four active coal-fired power plants; also shown are the following former coal-fired power plants:

- R. Paul Smith Power Plant (closed in 2012)
- C.P. Crane Power Plant (stopped burning coal in 2018 and was demolished in 2022)
- Dickerson Power Plant (coal-fired units decommissioned in 2020)
- Chalk Point Power Plant (coal-fired units decommissioned in 2021)
- Morgantown Power Plant (coal-fired units decommissioned in 2022)

Although these facilities no longer generate CCBs, their locations are significant because many coal-fired power plants had historic practices of onsite CCB disposal or using the material as fill for site development projects. The figure also highlights some of the significant CCB beneficial use sites and disposal sites across Maryland that have been active over the last 20 years.

See PPRP's website, Power Plant Combustion Byproducts Section for more information.

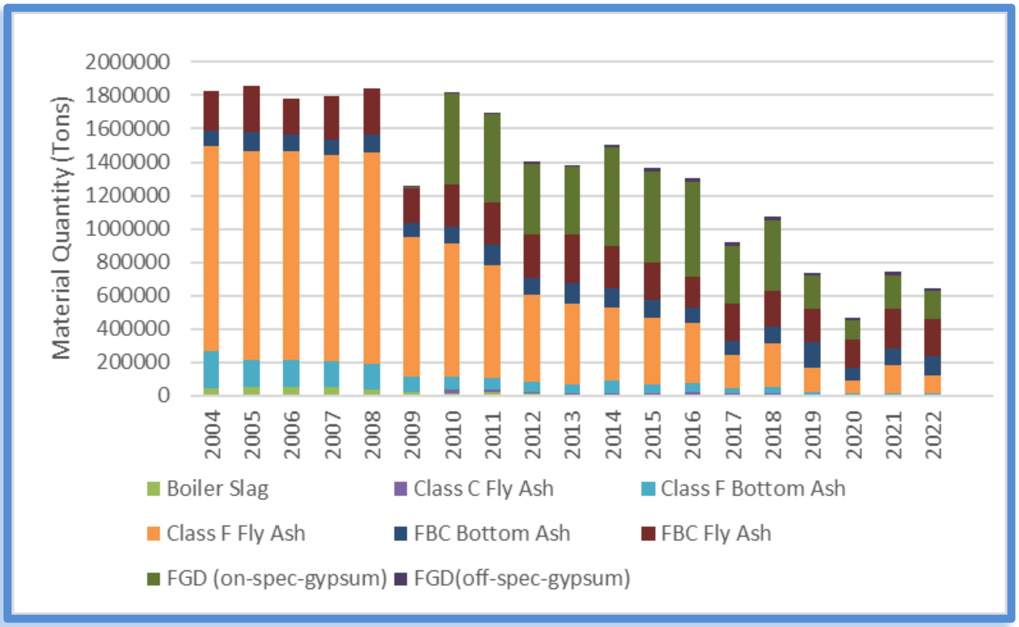
Figure 5-13 Locations of CCB Generation, Use, and Disposal in Maryland



According to annual tonnage reports submitted to MDE,[125] coal-fired power plants in Maryland generated 646,747 tons of CCBs in 2022. This is a significant decrease from the average of 2.5 million tons produced in 2004 (see Figure 5-14). The closure or conversion of older coal-fired power plants, including R. Paul Smith, C.P. Crane, Chalk Point, Dickerson, and Morgantown, has contributed to this change, in addition to active coal-fired power plants that are burning less coal in recent years. The figure also demonstrates the changes in the types of CCBs produced. Before 2010, Class F fly ash made up the largest proportion of Maryland CCBs with bottom ash, boiler slag, and fluidized bed combustion (FBC) ash making up smaller proportions of the total. With the addition of FGD scrubbers in 2010 and the gradual decommissioning of several coal-fired units, the types and proportions of CCBs generated in Maryland have shifted. As of 2022, FGD material and FBC ash make up the largest proportions of CCB material produced annually in the State.

[125] https://mde.maryland.gov/programs/land/solidwaste/pages/ccbs.aspx. Responses for 2022 were requested directly from power generators.

Figure 5-14 Quantity and Type of CCBs Produced in Maryland (2004–2022)

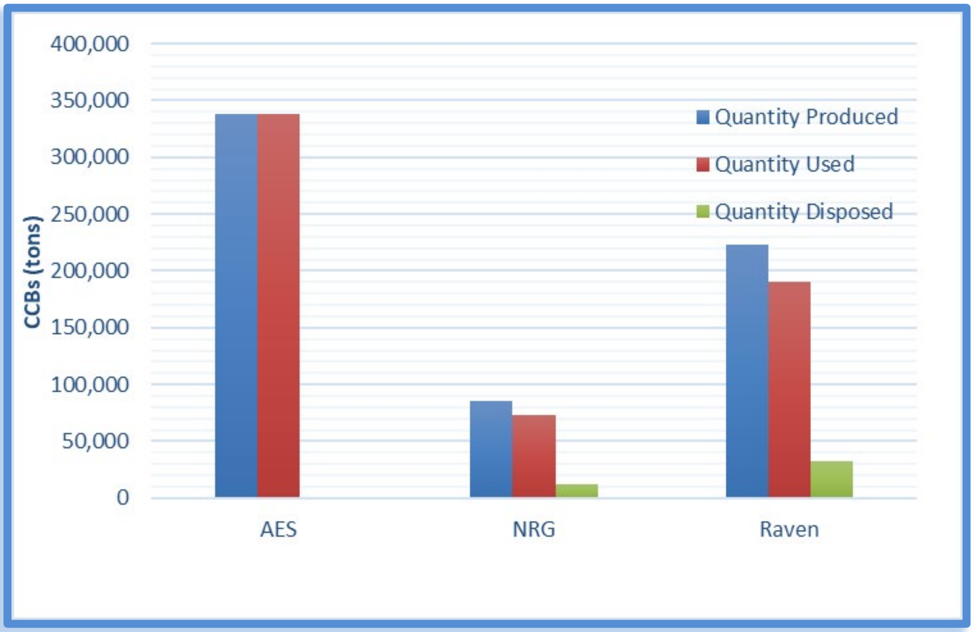


5.6.3 CCB Disposal and Beneficial Use

The CCBs generated at coal-fired power plants must be either disposed of or used. Figure 5-15 highlights the quantity of CCBs generated versus CCBs disposed of by Maryland's coal-fired power plants in 2022. About 93% of the CCBs produced in Maryland during that year were used, with only 7% being disposed of in landfills. This CCB use rate is higher than for the United States as a whole, which was reported as being around 60% for 2021.[126]

[126] American Coal Ash Association (ACAA), 2022. *Publications: Coal Combustion Products Production & Use Reports*. https://acaa-usa.org/publications/production-use-reports/ accessed 9/22/23.

Figure 5-15 CCB Generation and Disposal (2022)



Beneficial Use

For CCBs that are used, rather than disposed of, the uses and us-e rates vary by the type of CCB. Table 5-7 breaks down the CCBs produced in Maryland during 2022 by the type of CCB. The table also notes how each type of CCB was beneficially used in 2022.

Table 5-7 CCBs Produced in Maryland and Use Types in 2022

CCB Type	Source in Maryland	Quantity Produced in 2020 (tons)	% Used	Use Types
Class F Fly Ash	Brandon Shores H.A. Wagner Morgantown	110,045	86%	Cement, concrete
Bottom Ash	Brandon Shores H.A. Wagner Morgantown	11,341	0%	--
FBC Fly Ash/Bottom Ash	Warrior Run	338,446	100%	Coal mine reclamation (as backfill and to offset acid production in mine pavement)
FGD Material	Brandon Shores, Morgantown,	178,414	93%	Wallboard

The sale of fly ash to the cement and ready-mix concrete industries accounted for all the beneficial use of Maryland's Class F fly ash in 2022. The manufacture of cement and concrete are also potential beneficial uses for bottom ash, although these uses did not occur in Maryland in 2022. Nationwide, bottom ash is also used as road base/subbase, structural fill, and snow/ice control. Since the first FGD scrubbers were installed in Maryland in 2010, the majority of Maryland's FGD material has been sold to wallboard manufacturers as a replacement for natural gypsum. In 2022, all of Maryland's FGD material that was used beneficially went to wallboard manufacturers. Cement, concrete, and wallboard are encapsulated uses for CCBs, meaning that the CCBs are bound into a solidified product.

The other use that was active in 2022 was coal mine reclamation. About 230,000 tons of alkaline FBC ash were used to reclaim surface coal mines in western Maryland. The FBC is used both as a backfill material and as a source of alkalinity to offset acid produced by the oxidation of pyrite in the mined rock formation. As the CCBs release acid-neutralizing constituents, however, the potential exists for trace metals to be released as well. This is the only large-scale unencapsulated use of CCBs currently active in Maryland.

Disposal

The first state-permitted and lined CCB landfill in Maryland (the Fort Armistead Road Landfill) began operations in 2011. This landfill is fully compliant with current state and federal CCB disposal regulations. However, prior to December 1, 2008, there were no regulations in Maryland governing the disposal of CCBs. CCBs were disposed of in unlined landfills and were sometimes stored or used as backfill in applications that, under current state and federal regulations, constitute disposal. While high percentages of CCBs generated in Maryland are currently going into beneficial uses and current disposal practices are more protective of groundwater, these legacy ash disposal sites continue to have the potential to leach constituents into groundwater. One possible way to mitigate this impact is to "mine" the previously disposed CCBs for sale to commercial industries; this approach is further discussed in Section 5.6.4.

5.6.4 Legacy CCBs

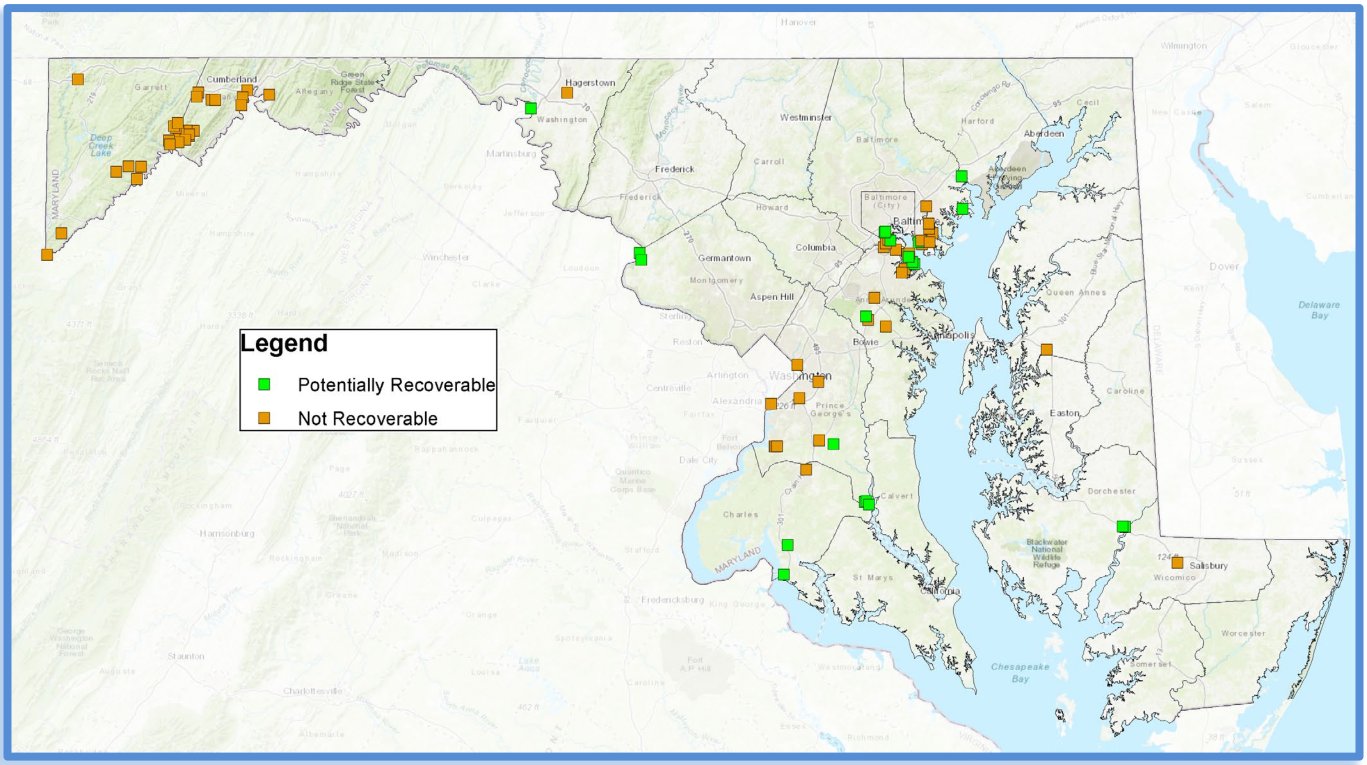
Legacy Ash Sites

The cement, concrete, and wallboard industries have a high demand for CCB materials, as evidenced by the high usage rates for Class F fly ash and FGD material from Maryland coal-fired power plants. As older coal-fired power plants are retired or replaced by gas-fired generating units, industries that use CCBs as raw materials are willing to consider, and pay for, CCBs that have been recovered from disposal sites.

Currently, there have been two large-scale CCB recovery projects associated with Maryland power plants. The first was the recovery of CCBs generated by the R. Paul Smith Power Plant, contained in the landfill located just across the Potomac River in West Virginia. Between 2009 and 2021, more than 3 million tons of CCBs were removed from this site and sold to cement manufacturers. This project resulted in the complete removal of CCBs from the landfill. Starting in 2019, a second large-scale CCB recovery project began at the Westland Fly Ash Storage Site, which received CCBs from the Dickerson Power Plant while it was still in operation. At the end of 2022, more than 450,000 tons of CCBs had been removed from this landfill and sold to cement manufacturers.

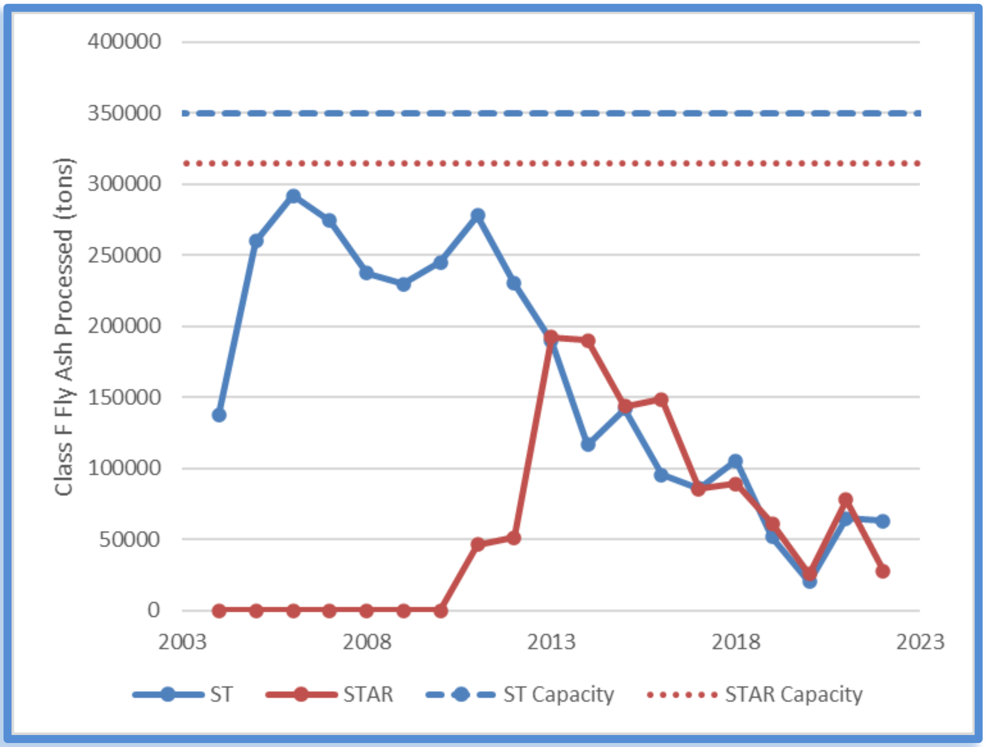
In recent years, PPRP has cataloged legacy CCB site locations (see Figure 5-16) as well as researched known information about them (i.e., time used, types of materials disposed, and disposal practices, where available). It is estimated that 20 million–25 million tons of CCBs are stored within these sites. Recovery of legacy CCBs from disposal sites for use in encapsulated form (such as cement, concrete, and wallboard) removes them from situations where they can potentially impact surface water and groundwater and supplies a raw material that these industries are willing to purchase. Identifying legacy CCB sites that can be recovered helps to ensure that these materials can be managed as a valuable resource.

Figure 5-16 Legacy CCB Sites in Maryland



Depending upon the requirements of industries, CCBs recovered from disposal sites may need to be processed before they can be used. Common types of processing include drying, disaggregation of clumps, and sieving to achieve consistent grain size. CCB beneficiation, involving the removal of unburned carbon from fly ash, is another type of processing that has been performed on fresh CCBs for several years in Maryland. This ensures that the fly ash meets the standards for use in ready-mix concrete. Before 2022, there were two CCB beneficiation facilities in Maryland: the ST facility, operating in connection with the Brandon Shores Power Plant, and the STAR facility, operating in conjunction with the Morgantown Power Plant. As power plants reduce their coal usage, the amount of fly ash they generate also decreases. This means that the beneficiation plants have extra space to receive more CCBs, if they become available. However, as of 2022, neither facility has processed recovered CCBs, and there are currently no plans to do so. With the end of coal combustion at the Morgantown Power Plant, the STAR beneficiation plant is no longer operating (See Figure 5-17).

Figure 5-17 CCB Beneficiation Processing Versus Capacity (2004–2022)



Appendix A – Permits and Approvals for Power Plants and Transmission Lines in Maryland

See CEIR-21, Appendix A for a list of the permits and approvals that may be required for a new power plant or transmission line or modifications to existing facilities in Maryland.

Appendix B – Electricity Markets and Retail Competition

See PPRP's website for additional information on this subject in the Electricity Markets and Retail Competition discussion.

Appendix C – Determinants of Electricity Demand Growth in Maryland

See PPRP's website for additional information on this subject in the Electricity Demand Growth in Maryland discussion.

Appendix D – Glossary

See PPRP's website for a glossary of commonly used terms in this document.

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