MARYLAND DEPARTMENT OF NATURAL RESOURCES

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PPRP

Maryland Power Plants and the Environment

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

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MARYLAND POWER PLANT RESEARCH PROGRAM

LARRY HOGAN, GOVERNOR
BOYD RUTHERFORD, LT. GOVERNOR

The Maryland Department of Natural Resources 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 the department strives to reach that goal through its many diverse programs.

Jeannie Haddaway-Riccio, *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 http://dnr.maryland.gov/pprp.

This twentieth edition of CEIR (CEIR-20) is divided into the following chapters:

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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 an increased temperature of up to 12°F. This and other issues prompted the creation of PPRP to ensure a comprehensive, 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 ground water, air, land and socioeconomics for proposed power 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 prior to the start of construction. The applicant must provide notification of the CPCN application to each county or 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 reviews applications for a CPCN in a formal adjudicatory process that includes written and oral testimony, cross examination, and the opportunity for full 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 ratepayers), and PPRP (acting on behalf of

[1] Not all projects are subject to CPCN review. Projects under 2 MW in capacity are exempt from the CPCN requirement. And 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 only 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 percent of the energy generated on an annual basis; and (3) projects under 25 MW that use at least 10 percent of the energy generated annually onsite. In addition, 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 PUC Article 7-207.1).

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 may have a right to participate as intervenors in these hearings. The broad authority of the PSC allows for the comprehensive review of all pertinent issues related to power plant licensing.

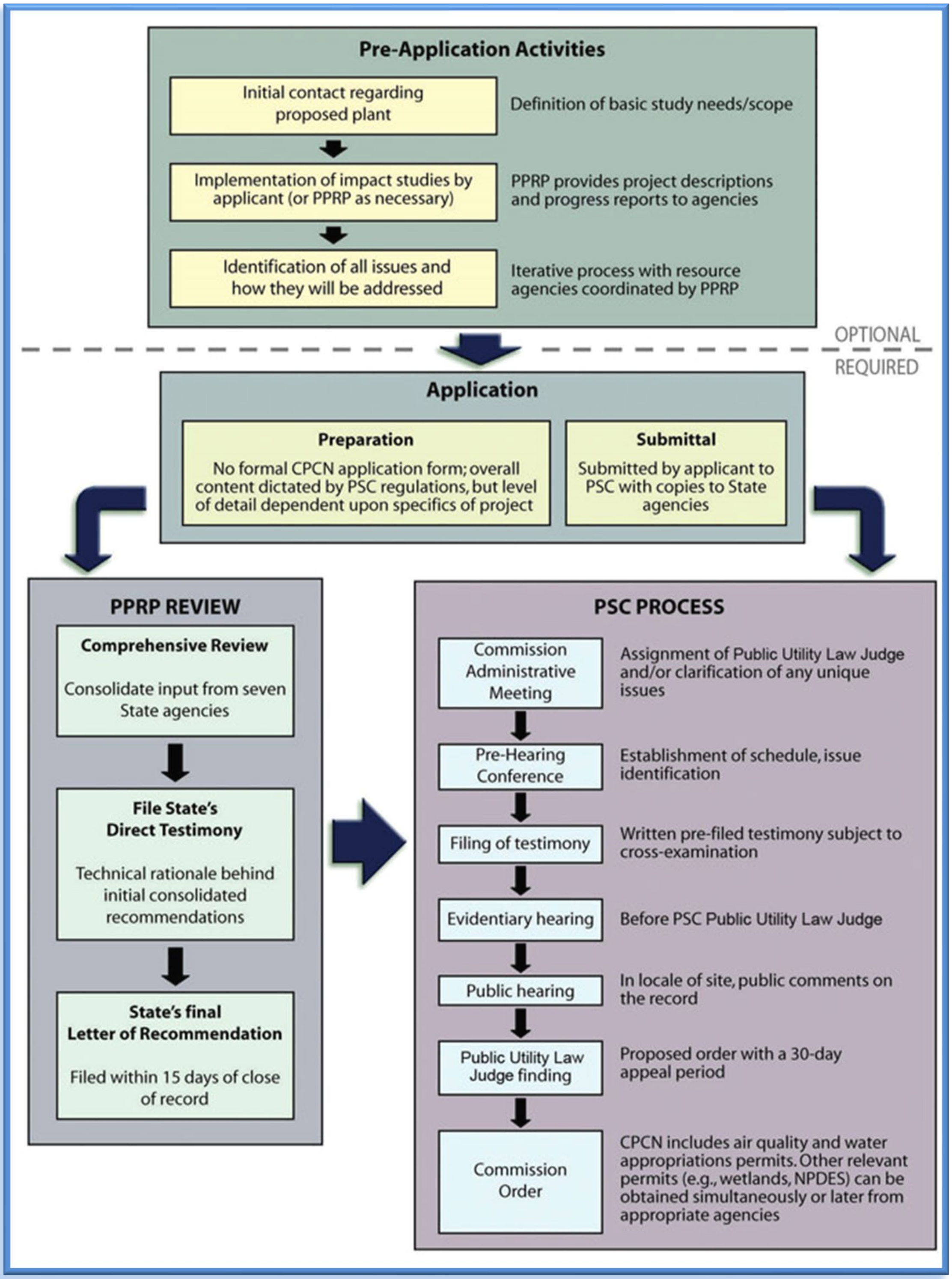
The CPCN licensing process provides an opportunity for the state to examine all of the significant aspects and impacts of a proposed power facility or transmission line, including the cumulative effects, interrelations between various impacts, and county and municipality input. This is a unique process 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 to 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.

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 creative 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 close proximity to each other or to existing plants, or when proposed transmission lines span multiple regions and resource areas, PPRP includes cumulative impacts within the consolidated review process. In such cases, impacts to air, water, terrestrial, socioeconomic and other resources are evaluated and compared to any identified thresholds of acceptability. Additionally, the cumulative analysis identifies any license conditions that are necessary to address cumulative impacts.

Figure 1-1 illustrates the elements of the CPCN licensing process. The primary steps in the CPCN licensing process are described below.

Figure 1-1 The CPCN Licensing Process



Pre-application. While there are no required pre-CPCN application procedures, PPRP encourages prospective applicants to meet with PPRP staff to identify potential issues with the proposed project and to determine whether and how all relevant concerns will be addressed. This process provides an opportunity for the applicant to become familiar with the PSC regulations and procedures. By the time the applicant files for a CPCN, there has usually been a significant amount of dialogue. Through a diligent and thorough pre-application process, a prospective developer can limit the risk of submitting an unsuccessful CPCN application by making changes during the preliminary design 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 ground water), air, land, ecology, and socioeconomics (such as 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. In the case of new electric generation, there is no regulatory requirement to demonstrate need. 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 Public Utility Law Judge (PULJ) to the licensing case at a preliminary administrative meeting after an application for a CPCN has been received. 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 own 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 also 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 comment; 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.

Chapter 2 –Evolving Energy Topics in Maryland

Systems for generating electricity and providing 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 Clean Energy Policies

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.

2.1.1 Maryland RPS

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. Every megawatt-hour (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 the PJM. The 2004 RPS law has been modified by legislation 11 times from 2007 through 2019, mainly to increase the requirement and to change the eligibility of renewable energy resources. Figure 2-1 illustrates the RPS requirements over time. The current version of the Maryland RPS, the Maryland Clean Energy Jobs Act, passed in 2019 and 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 (including black liquor from paper mills), solar, wind, waste-to-energy, refuse-derived fuel, and offshore wind. The Tier 1 requirement began at 1 percent and increases annually; in 2018 it was 15.8 percent and will reach its 50 percent maximum in 2030.

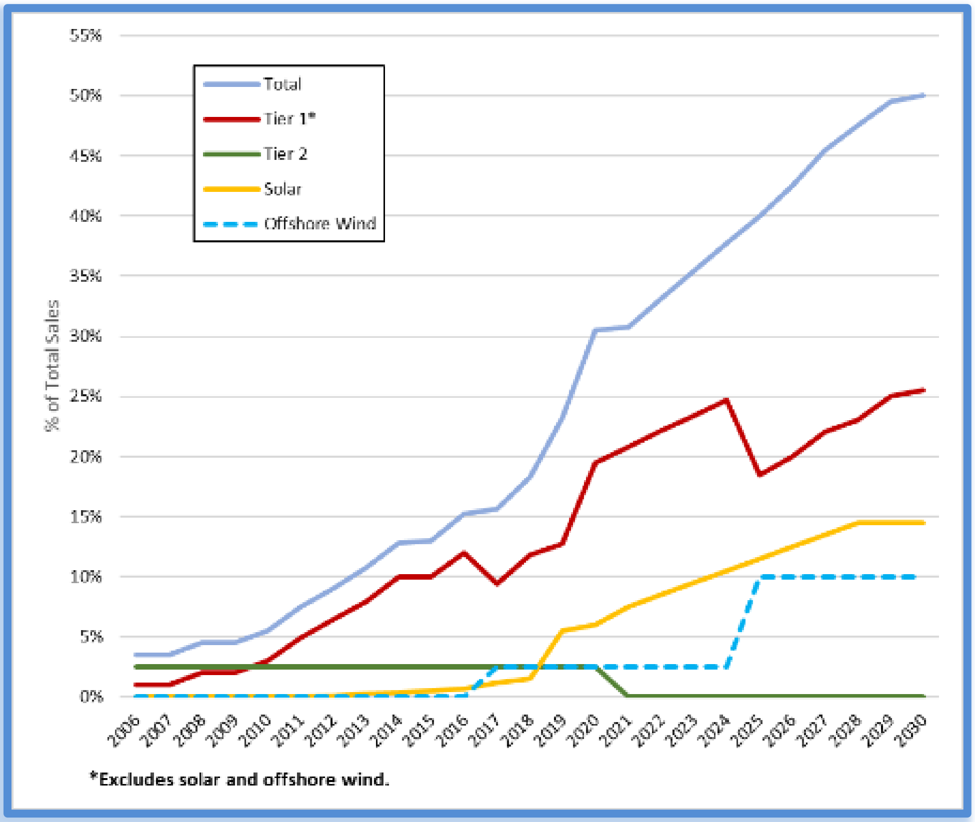
- The solar energy carve-out requires that a specified percentage of energy supply must come from instate solar facilities. The solar carve out began in 2008 at 0.005 percent and will reach its maximum of 14.5 percent in 2028. The 14.5 percent solar requirement is part of the Tier 1 overall 50 percent 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 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

1200 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.[2]

- 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 percent Tier 2 standard. Tier 2 was originally set to expire in 2018, but that sunset has now been extended to 2020.

Figure 2-1 Maryland RPS Summary, 2006-2030



Source: Maryland Senate Bill 516; 2019.

Electricity suppliers have the option to make an Alternative Compliance Payment (ACP) in lieu of RECs. As summarized below, 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) in 2019 and remains constant thereafter.

[2] Maryland General Assembly, Maryland Public Utility Articles §7-701 - §7-713.

- Tier 1 Solar Carve-Out ACP – Began at $0.45/kWh ($450/MWh) in 2006 but has since decreased to $0.175/kWh in 2018. The ACP will continue to decrease reaching $0.1/kWh by 2020; $0.035/kWh by 2025; and finally reaching a maximum of $0.02235/kWh ($22.35/MWh) by 2030.

- Tier 2 ACP – $0.015/kWh ($15/MWh) until it sunsets in 2020.

At the conclusion of 2018, there were 62,187 renewable energy facilities certified by the Maryland PSC, providing approximately 13,250 MW of renewable energy capacity in PJM (See Table 2-1).

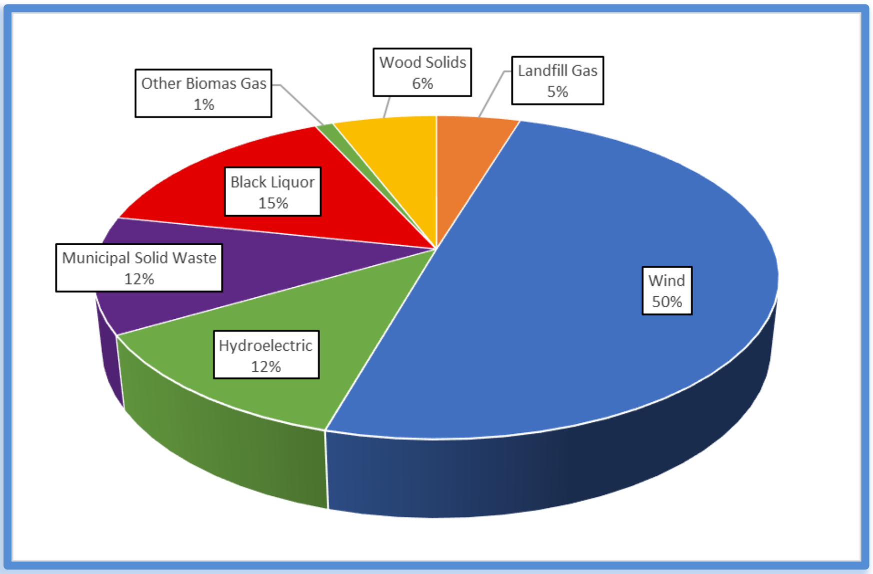
Table 2-1 Maryland RPS Certified Capacity as of December 2018 (MW)

		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	1,087	7	190	20	32	-	65	139	4	2	474	2,020
Delaware	-	-	-	-	9	-	-	-	-	-	-	9
Illinois	-	-	3,210	20	118	-	-	-	-	-	-	3,348
Indiana	-	-	1,872	8	-	-	-	-	-	-	-	1,880
Kentucky	-	-	-	2	16	-	-	-	5	-	-	23
Michigan	-	-	-	15	3	-	-	-	-	-	-	18
Missouri	-	-	146	-	-	-	-	-	-	-	-	146
New Jersey	-	-	8	11	76	-	-	-	-	-	-	95
North Carolina	-	-	208	-	-	-	152	-	-	-	680	1,040
North Dakota	-	-	180	-	-	-	-	-	-	-	-	180
Ohio	-	-	605	-	64	6	93	-	-	-	47	815
Pennsylvania	-	-	1,096	95	162	1	164	-	-	-	501	2,019
Tennessee	-	-	-	-	-	-	50	-	-	-	157	207
Virginia	-	-	-	42	127	2	288	63	50	-	30	602
West Virginia	-	-	620	55	-	-	-	-	-	-	159	834
Washington D.C.	-	-	-	-	-	14	-	-	-	-	-	14
TOTAL	**1,087**	**7**	**8,135**	**268**	**607**	**23**	**812**	**202**	**59**	**2**	**2,048**	**13,250**

Source: PJM Generator Attributes Tracking System (GATS), as of December 31, 2018.
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.

As depicted in Figure 2-2, 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. In 2018, the Tier 2 requirement was fulfilled solely by hydroelectric power.

Figure 2-2 Tier 1 Nonsolar Retired RECs by Fuel Source, 2018



Source: Maryland Public Service Commission, Renewable Energy Portfolio Standard Report With Data for Calendar Year 2018, December 2019, https://www.psc.state.md.us/wp-content/uploads/CY18-RPS-Annual-Report.pdf

The PSC is charged with ensuring compliance with the RPS and certifying eligible facilities. Retail electricity suppliers are required to submit annual compliance reports by April of the following year. Table 2-2 shows the aggregate supplier obligation, the RECs retired and the ACPs submitted from 2006-2018. [3] Each retired REC represents one MWh of renewable energy generated from a Tier 1 or Tier 2 facility.

In 2018, Maryland generated over 2.5 million MWh of renewable electricity from instate Tier 1 resources and nearly 2.8 million MWh of renewable electricity from instate Tier 2 resources, with a grand total of 2.7 million RECs produced. Of the total Maryland-generated RECs retired for compliance purposes in 2018, about 33 percent were retired in Maryland. Overall, the cost of compliance with the 2018 RPS requirement was about $85 million, with ACPs accounting for approximately $67,796 (0.08 percent of the total).

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[3] Retirement of a REC means that it has been used by the owner, it can no longer be sold.

Table 2-2 Maryland RPS Compliance, 2006-2018

RPS Compliance Year		Tier 1 Solar	Tier 1 (nonsolar)	Tier 2	Total
2006	RPS Obligation (MWh)	--	520,073	1,300,201	1,820,274
	Retired RECs (MWh)	--	552,874	1,322,069	1,874,943
	ACP Required	--	$13,293	$24,917	$38,209
2007	RPS Obligation (MWh)	--	553,612	1,384,029	1,937,641
	Retired RECs (MWh)	--	553,374	1,382,874	1,936,248
	ACP Required	--	$12,623	$23,751	$36,374
2008	RPS Obligation (MWh)	2,934	1,183,439	1,479,305	2,665,678
	Retired RECs (MWh)	227	1,184,174	1,500,414	2,684,815
	ACP Required	$1,218,739	$9,020	$8,175	$1,235,934
2009	RPS Obligation (MWh)	6,125	1,228,521	1,535,655	2,770,301
	Retired RECs (MWh)	3,260	1,280,946	1,509,270	2,793,475
	ACP Required	$1,147,600	$395	$270	$1,148,265
2010	RPS Obligation (MWh)	15,985	1,920,070	1,601,723	3,539,778
	Retired RECs (MWh)	15,451000	1,931,367	1,622,751	3,569,569
	ACP Required	$217,600	$20	$0	$217,620
2011	RPS Obligation (MWh)	28,037	3,079,851	1,553,942	4,661,830
	Retired RECs (MWh)	27,972	3,083,141	1,565,945	4,677,058
	ACP Required	$41,200	$48,200	$9,120	$98,520
2012	RPS Obligation (MWh)	56,130	3,901,558	1,522,179	5,479,867
	Retired RECs (MWh)	56,194	3,902,221	1,522,297	5,480,712
	ACP Required	$4,400	$0	$1,050	$5,450
2013	RPS Obligation (MWh)	133,713	4,858,404	1,521,981	6,514,098
	Retired RECs (MWh)	134,124	4,871,586	1,526,789	6,532,499
	ACP Required	$2,440	$40	$0	$2,440
2014	RPS Obligation (MWh)	203,827	6,062,635	1,520,966	7,787,428
	Retired RECs (MWh)	203,884	6,062,135	1,521,022	7,787,041
	ACP Required	$15,600	$46,600	$3,765	$65,965
2015	RPS Obligation (MWh)	299,456	6,131,624	1,531,193	7,962,273
	Retired RECs (MWh)	299,525	6,134,653	1,531,279	7,965,457

RPS Compliance Year		Tier 1 Solar	Tier 1 (nonsolar)	Tier 2	Total
	ACP Required	$7,000	$16,000	$1,515	$24,515
2016	RPS Obligation (MWh)	411,466	7,210,870	1,500,440	9,136,129
	Retired RECs (MWh)	411,787	7,216,439	1,501,587	9,129,813
	ACP Required	$0	$520	$30	$33,933
2017	RPS Obligation (MWh)	556,929	7,004,181	1,442,923	9,029,149
	Retired RECs (MWh)	557,224	7,006,113	1,448,567	9,011,904
	ACP Required	$1,170	$3,375	$255	$55,032
2018	RPS Obligation (MWh)	8,627,719	857,023	1,500,715	11,017,750
	Retired RECs (MWh)	8,627,737	857,232	1,599,819	11,084,788
	ACP Required	$2,280	$795	$135	$67,796

Source: Maryland Public Service Commission, Renewable Energy Portfolio Standard Report Annual Reports. Most recent report was the Renewable Energy Portfolio Standard Report With Data for Calendar Year 2018, December 2019, https://www.psc.state.md.us/wp-content/uploads/CY18-RPS-Annual-Report.pdf

Federal Production Tax Credit and Investment Tax Credit

Business Energy Investment Tax Credit

The federal Investment Tax Credit (ITC) provides a federal tax credit of 30% for investments in solar electric, solar heating and lighting technologies, fuel cells, and small wind and large wind plants. There is also a 10% federal tax credit available for investments in geothermal heat pumps and electric systems, microturbines, and combined heat and power systems. The ITC has been amended several times, with the most recent amendment occurring in February 2018. Electric and nonelectric solar systems are eligible for the full 30% tax credit until the end of 2019. After that, the tax credit drops to 26% at the end of 2020, 22% in 2021, 10% from 2022 onwards, and expires altogether for residential customers in 2022 but remains at 10% for nonresidential customers. The ITC for large wind systems also declines over time, beginning at 30% in 2016, 24% in 2017, 18% in 2018 and 12% in 2019 before expiring altogether in 2020. Projects that begin construction or incur 5% or more of the total cost of the facility in the year that construction begins can receive a four year extension for project completion.

The Renewable Electricity Production Tax Credit

The federal Renewable Electricity Production Tax Credit (PTC) is a per-kWh tax credit for electricity generated by qualified energy resources (wind, geothermal, closed-looped biomass and solar systems not claiming the ITC) and sold by the taxpayer to an unrelated person during the taxable year. Originally enacted in 1992, the PTC has been renewed and expanded numerous times. For nonwind resources the credit expired at the end of 2017. The full credit of 2.37¢/kWh remains available for wind projects that commence construction before December 31, 2019; however, the credit is phased down each year between 2017-2019. If under construction by the PTC deadline, projects will be eligible to receive the PTC for a total of 10 years. The PTC was reduced by 20% per year to 80% in 2017, 60% in 2018 and to 40% in 2019. In December 2019, Congress extended the PTC to the end of 2020 and somewhat reversed the phase-out by going back to allowing 60% of the value of the PTC for wind projects that begin construction in 2020. The bill also retroactively extends the full PTC through 2020 for closed and open loop biomass, geothermal, municipal solid waste, marine, and hydrokinetic and qualified hydropower facilities. Like the PTC, projects that begin construction or incur 5% or more of the total cost of the facility in the year that construction begins can receive a four year extension for project completion.

Sources: https://www.energy.gov/savings/business-energy-investment-tax-credit-itc; U.S. Congress, Bipartisan Budget Act of 2018, February 9, 2018, https://www.congress.gov/bill/115th-congress/house-bill/1892/text/eas2?q=%7B%22search%22%3A%5B%22bipartisan+budget+act+of+2018%22%5D%7D&r=1#toc-

In 2017, the General Assembly enacted legislation requiring PPRP to conduct a comprehensive review of the costs and benefits of the state's RPS and the likely impacts of increasing the RPS in the future. The legislation directed PPRP to consider a wide range of topics including: the standard's effectiveness in reducing the carbon content of imported electricity; the impact of long-term clean energy contracts; whether RPS benefits are equitably distributed among communities; whether adequate supply exists to meet a more ambitious RPS; specific opportunities for job creation; the types of system flexibility needed to meet future goals; how best to address flexible resources such as advanced energy storage systems; and the role of instate clean energy in reaching GHG reduction goals and promoting economic development. The final report was submitted to the General Assembly in December 2019 and is available at PPRP's web site.[4] The Maryland Clean Energy Jobs Act of 2019 statute requires PPRP conduct a supplemental study on the cost and benefits of increasing the RPS to 100 percent by 2040 and to study nuclear energy's role as a renewable or clean energy resource for addressing climate change in the state. The study on Maryland nuclear energy is due to the General Assembly by January 2020 and the supplemental RPS study is due to the General Assembly by January 2024.

2.1.2 Net Metering in Maryland

Ratepayers with distributed generation, i.e., 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, under net metering when a consumer is producing more electricity than they are consuming, the meter "runs backwards" in order 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. Essentially, net metering is like a ratepayer utilizing the local electric grid as battery storage.

Maryland's net metering regulations, originally enacted in 1997, have been amended multiple times. The current law, set forth in Public Utilities Article (PUA) §7-306 and Code of Maryland Regulations (COMAR) 20.50.10 sets a statewide aggregate cap of 1,500 MW[5] for net metered systems. All investor-owned utilities (IOUs), cooperatives, and municipal utilities comply with the regulations by installing a meter capable of accurately measuring bi-directional flow of electricity. Additionally, each electric provider in the state must offer a tariff rate or contract rate at nondiscriminatory prices to customers with qualified onsite generation who wish to receive net metered service.

Net metering is commonly associated with photovoltaic (PV) solar panels, but can also be used for numerous other onsite distributed generators like small-scale wind, biomass and fuel cells. Specifically, the State of Maryland designates solar, wind, biomass, fuel cell, closed-conduit hydroelectric, and micro-combined heat and power (CHP) as resources eligible for net metering. Ownership of the net metered system can be direct or through a third party contract such as through a lease or purchase power agreement (PPA). The maximum capacity for individual net metered systems is limited to 200 percent of the customers total annual baseline energy consumption, capped at 2 MW. Residents, schools, businesses and government entities may participate in net metering as long as the net metered system is installed with the principle intention of offsetting the customer's onsite energy consumption (i.e. a rooftop solar array on a residential building used to deliver a portion of the resident's electricity). The

[4] Maryland Department of Natural Resources, Power Plant Research Program, *Final Report Concerning the Maryland Renewable Portfolio Standard as Required by Chapter 393 of the Acts of the Maryland General Assembly of 2017*, December 2019, https://dnr.maryland.gov/pprp/Documents/FinalRPSReportDecember2019.pdf.

[5] This limit was set in 2014 based on 10 percent of Maryland's peak electricity demand for the year, which was around 15,000 MW.

net metered system must be interconnected with the local utility's transmission and distribution facilities.

The PSC must submit an annual report on the status of the net metering program to the General Assembly by September 1 each year. A summary of the net metering capacity through June 30, 2019 is provided in Table 2-3. As of June 30, 2019, there was a total of 754 MW of net metering capacity, or just over 50 percent of the capacity limit set by the PSC; solar PV represents 749 MW of this capacity. At current growth rates, the PSC projected that the net metering cap would be reached in 2025 or 2026. While installed net metering capacity has grown every year, the annual growth rate has slowed from a peak of 93 percent year over year in 2016 to 13 percent in 2019. Despite the decrease in growth, in that same time span installed capacity has nearly doubled from 387 MW in 2016 to 754 MW in 2019.

Table 2-3 Net Metering Capacity as of June 30, 2019

Utility	Solar (kW)	Wind (kW)	Biomass (kW)	Total	Year Over Year Percentage Change
Baltimore Gas and Electric Company	288,953	64	-	289,017	10%
Choptank Electric Cooperative	24,414	368	30	24,812	21
Delmarva Power and Light Company	90,107	889	-	90,996	18
Easton Utilities Commission	2,609	-	-	2,609	0
Hagerstown Utilities Commission	194	-	-	194	6
Thurmont Municipal Light Company	125	-	-	125	20
Mayor and Council of Berlin	397	-	-	397	11
Potomac Electric Power Company	209,903	71	2,535	212,509	18
Potomac Edison Company	77,470	7	256	77,733	5
Williamsport Municipal Light Plant	28	-	-	28	0
Southern Maryland Electric Cooperative	55,450	36	320	55,806	10
Maryland Total	**749,650**	**1,435**	**3,141**	**754,226**	**13%**

Source: Maryland Public Service Commission Report on the Status of Net Energy Metering in the State of Maryland, September 1, 2019, https://www.psc.state.md.us/wp-content/uploads/2019-MD-PSC-Report-on-the-Status-of-Net-Energy-Metering.pdf

In Maryland, if a customer's generation is greater than its demand (a concept known as net excess generation), then the billed kWh credit is carried over to the next month. Once per year (ending in April of each year), if the customer still has net excess generation remaining, the utility compensates the customer for the net excess generation balance at the prevailing electricity commodity rate. Customers have the added benefit of owning all renewable energy credits accumulated by their net metered system, allowing the customer to sell its credits in the REC market. Table 2-4 shows the net excess generation credits paid to customers over the 12-month period ending April 30, 2019. In total, Maryland utilities paid $2, 921,334 with the Potomac Electric Power Company (Pepco) and Baltimore Gas and Electric Company (BGE) paying 33 percent and 32 percent, respectively, of the total net excess generation.

Table 2-4 Net Excess Generation Credit Payouts for Period Ending April 30, 2019

Utility	Residential Excess Generation Credits Paid	Commercial Excess Generation Credits Paid	Total Excess Generation Credits Paid	Percentage of Total Net Excess Generation Credits Paid
Baltimore Gas and Electric Company	$632,365	$303,855	$936,220	32%
Choptank Electric Cooperative	47,566	33,555	81,121	3%
Delmarva Power and Light Company	120,688	546,507	667,195	23%
Easton Utilities Commission	625	8,035	8,661	0%
Hagerstown Utilities Commission	6	2	8	0%
Thurmont Municipal Light Company	-	-	-	0%
Mayor and Council of Berlin	436	1,691	2,127	0%
Potomac Electric Power Company	514,231	460,656	974,887	33%
Potomac Edison Company	79,437	82,138	161,574	6%
Williamsport Municipal Light Plant	-	-	-	0%
Southern Maryland Electric Cooperative	87,017	2,525	89,542	3%
Total	**$1,482,370**	**$1,438,965**	**$2,921,335**	100%

Source: Maryland Public Service Commission Report on the Status of Net Energy Metering in the State of Maryland, September 1, 2019, https://www.psc.state.md.us/wp-content/uploads/2019-MD-PSC-Report-on-the-Status-of-Net-Energy-Metering.pdf

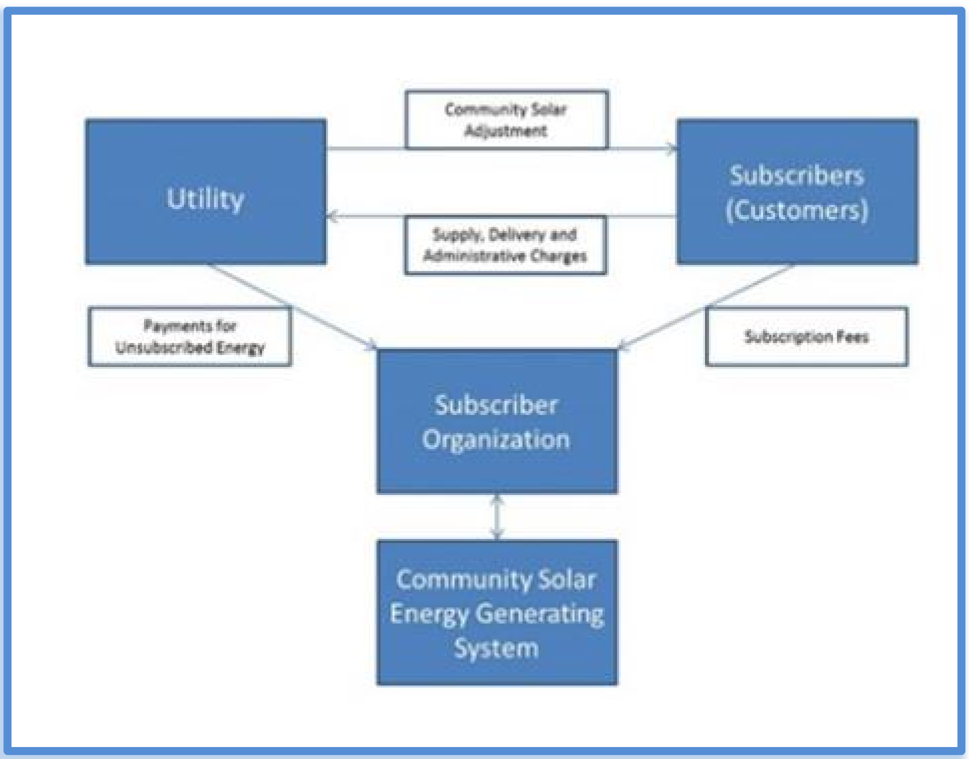
2.1.3 Community Solar in Maryland

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 the customer has subscribed to.

Community solar has been implemented on a project-by-project basis in Maryland until the establishment of a Community Solar Pilot Program in July of 2015. The pilot program, commenced in April 2017, 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. Maryland has a statewide limit for community solar of 193 MW, with a carve-out of 60 MW for projects focused on low- and moderate-income customers. The Community Solar Pilot Program contributes to and is included as part of the total state net metering limit of 1,500 MW.

Figure 2-3 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 utilities (IOU) based upon the service territory the project is located in. 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 2-3 Basics of Maryland Community Solar Projects



Source: Adapted from https://www.bge.com/SmartEnergy/InnovationTechnology/Pages/BGECommunitySolarPilotProgram.aspx."

Subscribers can purchase a share of the CSEGS, up to 200 percent 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 September 2019, 154 MW of community solar projects across the state have been proposed. The IOUs have to approve the CSEGS before the capacity can be accepted as part of the Community Solar Program Pilot, and of that 154 MW, 106 MW has been accepted. About 10 MW of community solar is in operation. Table 2-5 shows the Community Solar Program Pilot's reserved capacity, the amount accepted by IOU compared to the amount of total capacity available over three years. The amount of capacity offered each year varies by utilities, therefore, not all of the capacity will be available until 2020.

Table 2-5 Maryland Community Solar Program Pilot Capacity

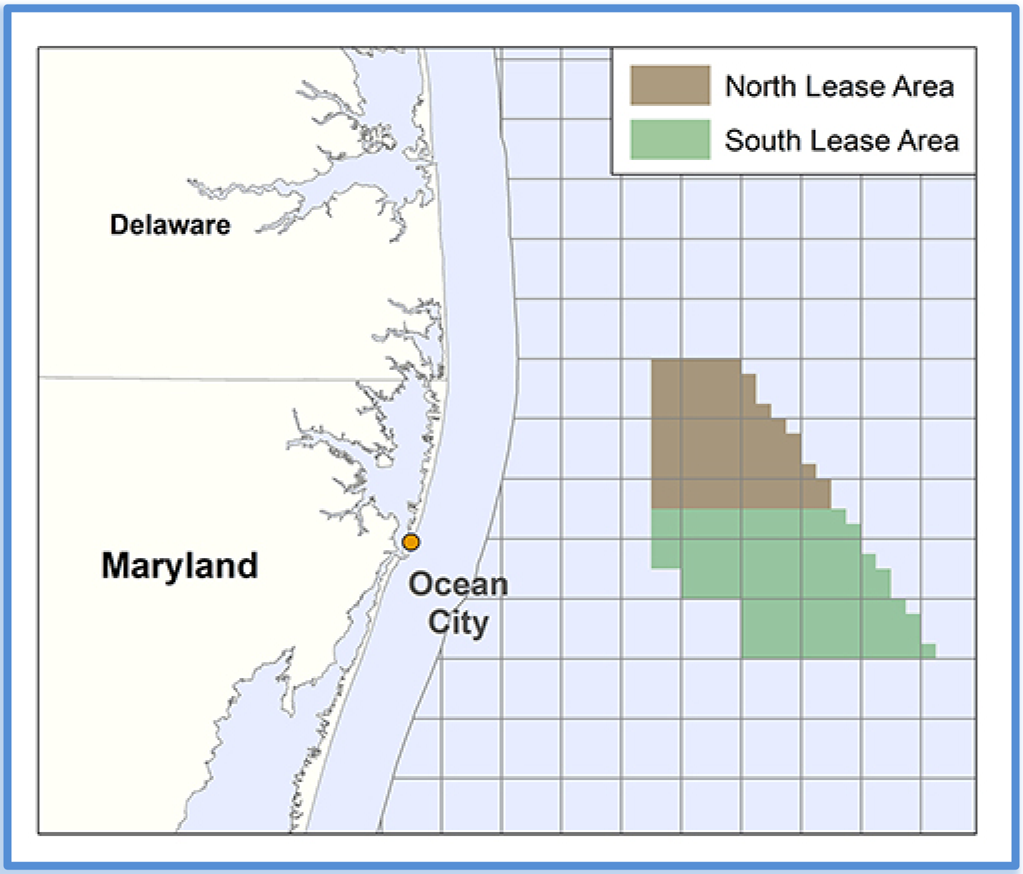
Utility	Three-Year Total Capacity	Offered Capacity (MW)	Accepted Capacity (MW)	Operating Capacity (MW)
Baltimore Gas and Electric	100.7	80.5	51.5	2.0
Delmarva Power and Light Company	16.5	13.2	13.2	2.0
Potomac Electric Power Company	50	40.0	23.0	5.5
Potomac Edison Company	25.8	20.3	19.1	0.1
State Total	**193**	**154.0**	**106.18**	**9.6**
	Accepted capacity source: Maryland Public Service Commission Report on the Status of Net Energy Metering in the State of Maryland, September 1, 2019, https://www.psc.state.md.us/wp-content/uploads/2019-MD-PSC-Report-on-the-Status-of-Net-Energy-Metering.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 is required to submit a report to the General Assembly by July 1, 2022, regarding the PSC's findings and recommendations concerning community solar.

2.1.4 Offshore Wind in Maryland

In February 2012, the United States Bureau of Ocean Energy Management (BOEM) solicited public comments on areas off of Maryland's coast for offshore wind development consideration. Throughout 2012, BOEM conducted environmental reviews and studies on the areas to evaluate the impacts of offshore renewable energy development. Finding no significant impacts, BOEM held a commercial lease sale for two commercial wind energy leases in the Maryland Wind Energy Area (WEA) in August 2014. Maryland's WEA is approximately 80,000 acres, with the closest area located 10 nautical miles off the Ocean City coastline. Figure 2-4 indicates the area of Maryland's WEA, identifying the North and South lease areas. U.S. Wind won both of the leases, for a total bid of $8.7 million and the two leases were subsequently merged into one.

Figure 2-4 Maryland WEA Lease Areas



Source: https://mdcoastdispatch.com/2014/08/21/offshore-wind-farm-lease-areas-auction-for-8-7m/

In 2013, Maryland passed the Maryland Offshore Wind (OSW) Act. The OSW Act set forth the regulations for approving OSW projects and amended the state's RPS to include a 2.5 percent maximum carve-out for offshore wind resources that must be located between 10-30 miles off the coast of Maryland on the Atlantic seaboard. The 2013 Act also set an application and review process for qualified projects to receive Offshore Wind Renewable Energy Credits (ORECs).

On May 11, 2017, the PSC conditionally approved two projects: The Skipjack Offshore Energy LLC project and the U.S. Wind Inc. project, for a total of 368 MW of offshore wind. An overview of each project is provided in Table 2-6.

Table 2-6 Currently Approved Offshore Wind Projects in Maryland

	US Wind Inc. Project	Skipjack Project
Capacity	248 MW	120 MW
Estimated ORECs	913,845	455,482
Distance from shore	17 miles*	19.5 miles*
Point of interconnection	Indian River Substation, DE	Ocean City Substation, MD
Estimated construction cost	$2.5 billion*	$720 million
Projected online date	Early 2023*	November 2022

* Values updated with recent estimates from corresponding project website
Sources: Maryland PSC, May 11, 2017, https://www.psc.state.md.us/wp-content/uploads/PSC-Awards-ORECs-to-US-Wind-Skipjack.pdf; http://dwwind.com/project/skipjack-wind-farm/; http://www.uswindinc.com/maryland-offshore-wind-project/.

Both projects may sell ORECS at a price of $131.93 per OREC, with a one percent escalator. One OREC is equivalent to one MW. Collectively, the approved projects will result in a $1.40 impact per month for residential customers ($0.97/month for U.S. Wind and $0.43/month for Skipjack) and an approximate 1.4 percent increase on nonresidential customer monthly bills.

The two projects are estimated to provide $957 million of instate expenditures during the development and construction phases ($610 million for U.S. Wind and $347 million for Skipjack) and the operations phase will result in $878 million in instate expenditures ($744 million for U.S. Wind and $134 for Skipjack). The conditions set forth in the PSC Order guarantee a total of $624 million in instate expenditures through requirements of expenditures for development and construction, investment in the Offshore Wind Development Fund, a steel fabrication plant in Maryland, and upgrades at Sparrows Point. In addition to the required investments, the projects must put forth best efforts to apply for all eligible state and federal grants, rebates, tax credits, loan guarantees.

In its evaluation, the PSC cited additional benefits, such as employment, environmental, and health benefits, as well as how the projects contribute toward the achievement of state goals, such as the Greenhouse Gas Reduction Act. Table 2-7 summarizes the projected benefits for each project.

Table 2-7 Projected Employment and Air Emission Benefits

	EMPLOYMENT	AIR EMISSION REDUCTIONS (tons/year)		
	Full Time Equivalent	CO_2	NOx	SOx
U.S. Wind	7,050	12,809	6.8	3.1
Skipjack	2,635	6,384	3.4	1.6
TOTAL:	**9,685**	**19,193**	**10.0**	**5.0**

In December 2019, the PSC granted a request from Ocean City to consider the impacts of much larger turbines being used for the two offshore wind projects than expected. Skipjack expects to use General Electric's 12-MW Haliade-X offshore wind turbine that is over 850 feet high when the turbine blade is straight up in the air. U.S. Wind has not made a final decision on what offshore wind turbine it will use, but it is considering 8-, 10-, and 12-MW units.

In 2019, the General Assembly amended the Maryland RPS to require two rounds of offshore wind projects. Round 1 projects are defined as offshore wind projects between 10-30 miles off the coast of Maryland, approved by the PSC before July 1, 2017, and Round 2 projects are defined as projects located at least 10 miles off the coast, approved after July 1, 2017. The OSW carve-out remains at 2.5 percent in 2019 and 2020 and increases to 10 percent by 2025 with the remaining levels to be determined by the PSC. By 2026, 2028, and 2030 the state is required to have at least 400, 800, and 1,200 additional MW of offshore wind, respectively, to meet the OSW carve-out.

Other states are also adopting initiatives to foster offshore wind, as depicted in Table 2-8. The Department of Energy (DOE) states that the U.S. has a total project pipeline of 25,794 MW of offshore wind energy as of December 2019, including 2,073 MW of announced project-specific capacity and 23,751 MW of undeveloped lease area potential capacity. The American Wind Energy Association estimates that about 9,112 MW of new offshore wind capacity is expected to go online by 2026. DOE estimated that as much as 22 GW of offshore wind could be operating by 2030, and 86 GW by 2050.

Table 2-8 Offshore Wind Goals or Requirements in Northeastern U.S.

State	Offshore Wind Target (MW)	Year
Connecticut	2,000	2030
Maryland	1,600	2030
Massachusetts	3,200	2035
New Jersey	7,500	2035
New York	9,000	2035

The State of Offshore Wind In PJM

Along with Maryland, several states in the PJM region have plans for development and deployment of offshore wind along the Atlantic coast.

Delaware

Delaware began its offshore wind program in 2008 with the passage of Senate Bill 238 which approved a 200 MW offshore wind farm expected to be the nation's first; however, the project was cancelled in 2011. In August of 2017, Governor Charles Carney Jr. signed Executive Order 13 which created the Offshore Wind Working Group. The group was tasked with studying how the state can participate in offshore wind development and leverage the economic opportunities from that development. In June 2018 the group submitted its report to the governor, recommending that Delaware should put off development of offshore wind projects until project costs further decline.

New Jersey

Plans in New Jersey began on January 31, 2018 when Governor Phil Murphy signed Executive Order No. 8. The order directed the New Jersey Board of Public Utilities (NJBPU) to take all necessary action to implement the Offshore Wind Economic Development Act (OWEDA) for obtaining 3,500 MW of offshore wind capacity by 2030. In November 2019, Governor Murphy issued another executive order to increase the offshore wind target to 7,500 MW by 2035. The offshore wind solicitation was held on September 17, 2018 for 1,100 MW of offshore wind capacity and was closed on December 28, 2018. In June 2019, New Jersey granted the state's first OREC award to Ørsted's 1,100 MW Ocean Wind project, the largest offshore project planned in the U.S. to date. The project has an estimated levelized net OREC price of $46 per MWh after revenues are refunded to ratepayers. NJBPU plans to consider future solicitations for 1,200 MW each in 2020 and 2022. Projects will receive financial support through an Offshore Wind Renewable Energy Credit (OREC), similar to Maryland, as well as an offshore wind tax credit program, capped at a total of $100 million for qualifying projects.

North Carolina

Compared with other PJM states, North Carolina has not shown much interest in offshore wind development, or even onshore wind development for that matter. An 18-month moratorium for onshore wind projects recently expired on January 1, 2019. Despite the efforts to dampen wind development in the state, the Bureau of Ocean Energy Management (BOEM) reports that one offshore wind project is slated for development off the coast of the Outer Banks. BOEM states Avangrid Renewables, LLC won the lease for the Kitty Hawk Wind Energy Area which was signed on October 10, 2017. The preliminary term for the lease was extended to November 1, 2019. The project is still in its initial phase, but the area leased is approximately 191 square miles, representing a potential of up to 2.5 GW of offshore wind resources.

Virginia

Established in 2010, the Virginia Offshore Wind Development Authority (VOWDA) was tasked with facilitating, coordinating and supporting the development of offshore wind energy projects and related supply chain opportunities along the coast of Virginia. In October 2018, Governor Ralph Northam released a strategic vision for implementation of an offshore wind demonstration project along with goals for developing the full potential of Virginia's offshore wind resource estimated at around 2,000 MW by 2028.The demonstration project was approved by State Corporate Commission (SCC) the following month. To be constructed by Dominion Energy, the project will consist of two 6 MW turbines, located approximately 27 miles off the coast of Virginia Beach. In September 2019, Governor Northam issued an Executive Order calling for 2,500 MW of offshore wind by 2026. Shortly after, Dominion Energy announced plans to build and own a 2,640 MW offshore project by 2026, the largest offshore wind project announced in the U.S. to date.

2.2 Solar Energy Topics

While Maryland's renewable energy resources comprise a mix of hydroelectric, wind and solar, over the past few years solar development has been growing most rapidly. PPRP and other state agencies have done a considerable amount of work to understand the technical issues surrounding solar power. This section describes some of the land use issues surrounding utility-scale solar development, the benefits and costs of distributed solar generation (smaller than utility-scale facilities), and how increasing the RPS to a 50 percent target level may affect emissions of GHGs and other pollutants.

2.2.1 Land Use Impacts of the RPS

Growing energy demands for domestic use and export are increasing the land use footprint of energy-related facilities in the U.S. Although much of this "energy sprawl" is associated with fuel extraction, renewable generation technologies and associated facilities also play a role.

In Maryland, utility-scale solar energy generating systems (SEGS) are becoming consumers of land in the state's generation mix. Solar photovoltaic (PV) systems require between 5 and 10 acres per megawatt to generate electricity. Slope is an important consideration in PV facility siting and development costs are lower on previously cleared land. Typically, utility-scale solar facilities do not require public infrastructure, such as water and sewer. As a result, the sites most attractive to solar developers are often on productive agricultural lands in Maryland, particularly on the Eastern Shore. Solar developers have found willing participants within the state's agricultural community to lease or sell their land to solar developers.

Projected land requirements for solar PV development are not insignificant. Under the DOE's SunShot scenario, direct utility-scale PV land requirements for the U.S., much of which would be sited on non-agricultural lands in the Southwest, are projected to range from 667 thousand to 2.1 million acres in 2030, and from 1.4 to 4.4 million acres in 2050. The Clean Energy and Jobs Act (HB 1158), which passed in the 2019 legislative season, requires 14.5 percent of the state's electricity to be generated from instate solar capacity by 2028. If one assumes a 25 percent capacity factor for solar PV, and uses load projections from the Maryland PSC's *Ten Year Plan (2018-2027)*, approximately 3,347 MW of solar capacity will be needed to meet the 14.5 percent solar carve-out in 2028.[6] If one further assumes that 50 percent of this capacity will be utility-scale PV sited on farmland, solar PV will occupy roughly 0.66 percent of Maryland's agricultural land by 2028. In order to gauge the upper bound of potential impacts to farmland, PPRP has also calculated the land use impact of siting all PV capacity needed to fulfill the solar carve-out on farmland. Additional calculations account for existing utility-scale and distributed solar PV systems in the state. The results of these calculations, shown in Table 2-9, suggest that utility-scale solar will occupy between 0.61 percent to 1.32 percent of Maryland's agricultural land by 2028.

[6] Load values for 2028 are extrapolated using the compound annual growth rate from the preceding period.

Table 2-9 Farmland in Maryland Required to Fulfill the 14.5% Solar Carve-out Requirement in 2028

Acres Required	Percentage of Farmland in Maryland	Assumptions
13,389	0.66%	50% of entire solar capacity requirement is fulfilled with new utility-scale PV (UPV) on farmland
26,779	1.32%	Entire solar capacity requirement is fulfilled with new, UPV on farmland
12,353	0.61%	All existing PV >1 MW is on farmland; 50% of the incremental capacity requirement is fulfilled with new UPV on farmland
21,107	1.04%	All existing PV >1MW is on farmland; entire incremental capacity requirement is fulfilled with new UPV on farmland[1]

[1] According to PJM-GATS, there are 1,159 MW of solar capacity in Maryland, of which 450 MW are due to facilities ≥1 MW, as of November 2019.
Source: PPRP, *Final Report Concerning the Maryland RPS as Required by Chapter 393 of the Acts of the Maryland General Assembly of 2017*, December 2019, https://dnr.maryland.gov/pprp/Documents/FinalRPSReportDecember2019.pdf.

Section 5.4.1 provides more detailed discussion of solar power development and land use issues.

2.2.2 Benefits and Costs of Distributed Solar on the Maryland Grid

In 2017, the MD PSC, under Public Conference 44 (PC44), commissioned a study of the benefit and cost impacts of distributed solar on the state's electric grid. The study, "Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland" conducted by Daymark Energy Advisors (Daymark), evaluated the benefits and costs of behind the meter (BTM) and utility scale solar installations on the bulk power system, local power distribution systems, society and the economy in each of the state's IOUs service territories.[7] (The study was conducted as part of the PSC's work under Public Conference 44, addressing a range of grid modernization issues; see Section 2.3.)

The study concluded that while the deployment of solar incurs costs, such as transformer/line upgrades, there are significant associated benefits to the state's electric grid and the local distribution systems, with smaller levels of societal and economic benefits. Table 2-10 outlines the main findings from the Daymark Value of Solar Study broken into benefits to specific sectors/areas of focus.

[7] https://cleantechnica.com/files/2018/11/MDVoSReportFinal11-2-2018.pdf.

Table 2-10 Benefits to Maryland from Utility-Scale and Distributed Solar Installations

Sector	Main Benefits	Secondary Benefits
Bulk Power System	Energy Value of Solar	Avoided Capacity, Avoided RECs
Local Distribution System	Reduced Distribution System Loss	Reduced Peak Load, Improved System Reliability[2]
Societal	Avoided CO_2 Emissions	Health Benefits
Economic[1]	Increased Jobs	Increased Labor Income, Increase Tax Revenue

[1] Economic benefits are gross benefits since opportunity costs of investment outside of solar were not considered.

[2] Reductions in peak load are contingent upon the installation of battery storage systems and improvements to system reliability are contingent upon the implementation of smart inverters by utilities.

Source: Based upon data provided in the Daymark Energy Advisors Report on the Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland, November 2, 2018.

Benefits to the bulk power electric grid are primarily from avoided energy, avoided capacity, and avoided renewable energy credits (RECs). The source of these benefits is dependent upon whether it is a behind-the-meter or utility-scale solar project.

Avoided energy benefits are derived for:

- Distributed solar from the reduction of energy that a utility must purchase from the wholesale market.
- Utility scale solar from the downward pressure on locational marginal prices (LMPs) from displacing higher cost marginal resources.

Avoided capacity benefits are derived for:

- Distributed solar through a project's ability to reduce load on the grid.
- Utility scale solar since the projects operate like supply resource, receiving compensation at the capacity market price.

Avoided REC benefits are derived for:

- Distributed solar through the avoided RPS compliance costs.
- Utility scale solar through the sale of RECs.

Table 2-11 presents the estimated range of values for the three primary components of the Bulk Power category of the value of solar.

Table 2-11 Main Source of Benefits to Maryland's Bulk Power System

Benefit	Value ($/MWh)[1]
Avoided Energy Costs	$43-63
Avoided Capacity Costs	4-23
Avoided RECs	1-2

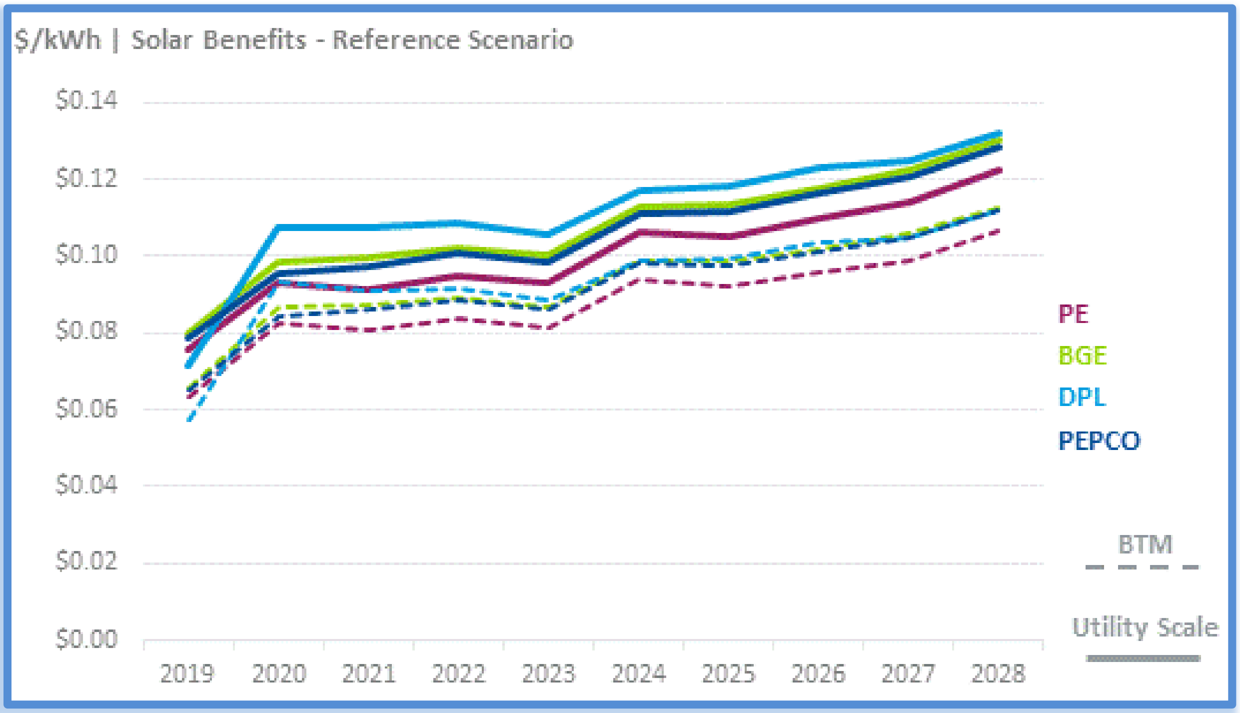
[1] The range of values represents the estimated value of solar from each utility across multiple scenarios.

Source: Based upon data provided in the Daymark Energy Advisors Report on the Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland, November 2, 2018.

Benefits of solar build-out to Maryland's distribution system can only be estimated on a locational basis, making it difficult to illustrate this category of the value of solar. However, the study found that if a large amount of solar is added to the distribution system on aggregate, then the potential benefit of reducing lines losses on the distribution-level could be valued up to $6/MWh.

In the study, the social benefits are primarily in the form of reduced carbon dioxide (CO_2) emissions, which indirectly impact health outcomes in the state. Continued build-out of utility scale and distributed solar resources is projected to provide instate health benefits ranging between $2/MWh to $6/MWh (2010$) in the year 2025 depending upon whether there is high or low price set for CO_2. Figure 2-5 illustrates the emissions reduction benefits (social benefits) on a dollar per kilowatt hour basis for both behind-the-meter and utility scale solar projects based upon the service territory over the ten-year study period.

Figure 2-5 Projected State Emission Benefits from Solar Projects

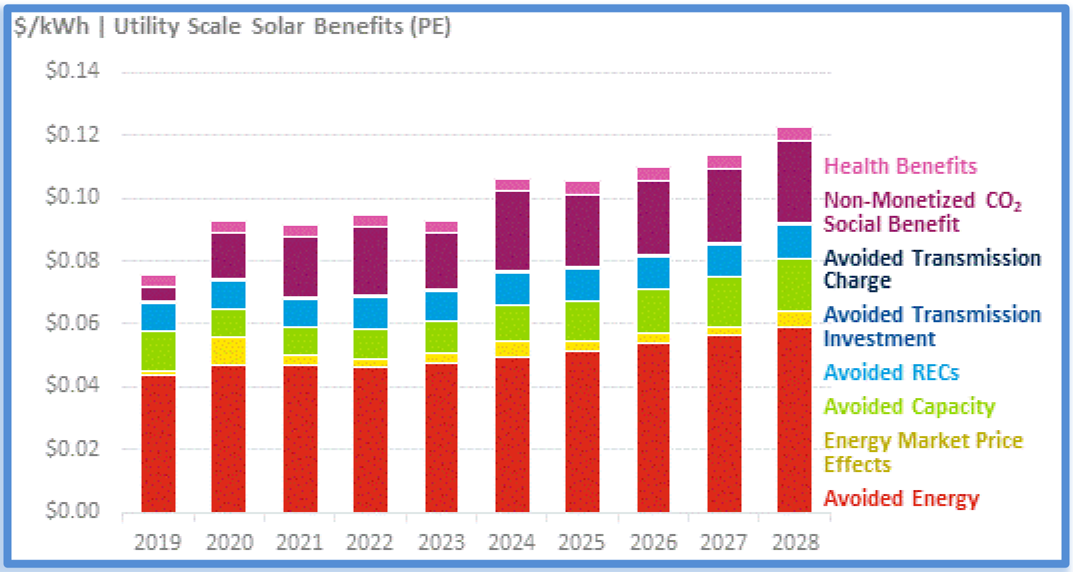


Source: Daymark Energy Advisors Report on the Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland, November 2, 2018.

The study also projected the macroeconomic benefits from solar deployment over the study period, with such savings only being recognized in the installation year only. Due to the fact that these benefits are not directly related to energy produced by solar projects, the study assumed that a total of 2.4 GW of solar is installed over the 10-year study period to project a benefit per capacity value to be estimated. Including direct, indirect, and induced macroeconomic impacts, Daymark concluded that 2.4 GW deployment of utility scale and distributed solar resources, combined, will provide Maryland with around $1.4 billion in labor income, $2.1 billion to Gross Domestic Product, and $4.1 billion in incremental local industrial output. Daymark also emphasizes that around 22,500 job-years will be generated over the ten-year period, with one job-year equal to one person being employed for one year.

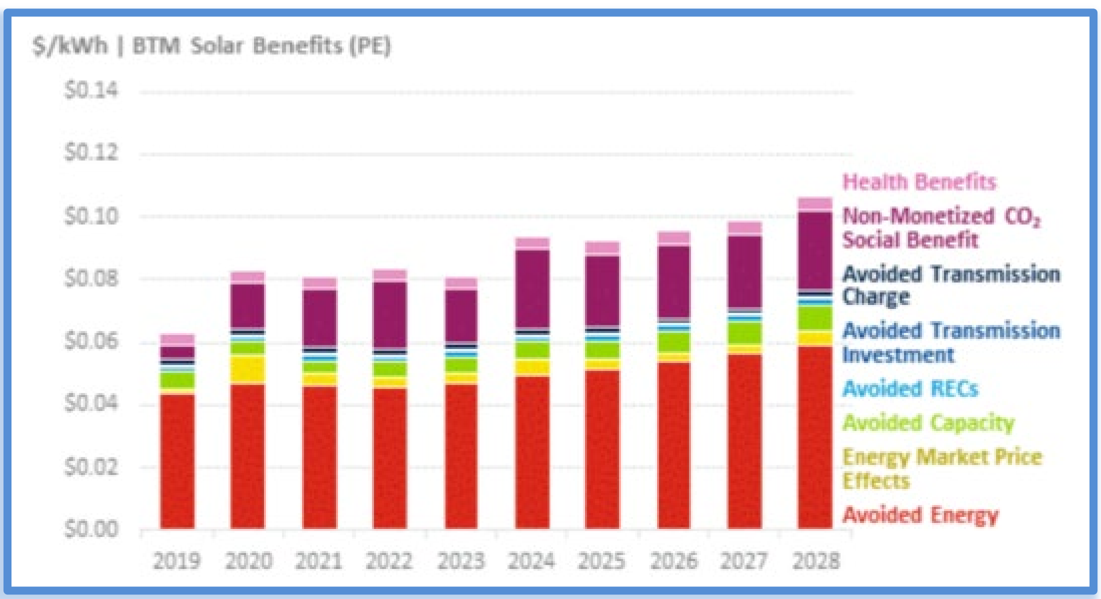
For each IOU, the study quantified the total value of solar on a dollar per kilowatt basis for 2019 through 2028 by each benefit. Figure 2-6 illustrates the annual value of utility scale solar and Figure 2-7 shows the annual value of behind-the-meter solar, both within Potomac Edison's service territory. The total level of benefits ranges from approximately $0.6-$0.7/kWh in 2019 and increases to approximately $0.11-$0.12/kWh by the end of the study period, depending upon the project type. For both types of solar projects, the avoided energy benefit is projected to provide the greatest level of benefit, followed by nonmonetized CO_2 societal benefit. BGE, Delmarva and Pepco are projected to recognize similar levels of benefits as Potomac Edison.

Figure 2-6 Projected Utility Scale Solar Benefits for Potomac Edison



Source: Daymark Energy Advisors Report on the Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland, November 2, 2018.

Figure 2-7 Projected Behind-The-Meter Solar Benefits for Potomac Edison



Source: Daymark Energy Advisors Report on the Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland, November 2, 2018.

2.2.3 Impacts of the Maryland 50 Percent Renewable Portfolio Standard on Emissions

This section summarizes the results of recent studies concerning the impact of the Maryland RPS on either air emissions, greenhouse gas emissions, or both. Since 2016, two reports have been issued that project the air and/or greenhouse gas emissions impact of a 50 percent Maryland RPS: PPRP's Long-Term Electricity Report ("LTER") and Energy + Environmental Economics' (E3's) policy scenario report for the Maryland Department of the Environment (MDE). In addition, in 2019, PPRP's Final Report Concerning the Maryland RPS (RPS Report) estimated the historical impact of the Maryland RPS on emissions.

Long-Term Electricity Report Emission Projections

In December 2016, PPRP released the LTER which addressed Maryland's long-term energy needs through a comprehensive assessment and estimation of several scenarios encompassing different economic and regulatory conditions over a 20-year period (2015-2035).[8] The LTER first projected a reference case (RC) which assumed likely electricity market conditions over the course of the 20-year period, including PJM's energy and peak demand forecast, projected coal and natural gas prices, current RPS policies in Maryland and elsewhere within PJM, and federal and state environmental regulations. The RC was then compared with the 13 alternative scenario projections in order to isolate key impacts from certain policy, regulatory, or economic conditions, including various percentage requirements for the Maryland RPS. One set of outputs that the LTER focused on was Maryland's CO_2, SO_2, NO_x and mercury emission levels.

Several of the LTER's alternative scenarios assessed the impacts of various Maryland RPS goals: 25 percent by 2020, including 2.5 percent solar (MD 25%); 35 percent by 2025, including 3.0 percent solar by 2025 (MD 35%); and 50 percent by 2030, including 5.0 percent solar (MD 50%). Under these scenarios, new wind capacity was assumed to be built in Maryland within a PJM zone in which a portion of Maryland lies to satisfy the goals of the RPS scenarios, excluding any solar carve-out requirements.[9] Figure 2-8 through 10 presents the impacts to SO_2, NO_x and mercury emissions and Figure 2-11 presents the impacts to the CO_2 for the RC scenario and for a Maryland RPS goals of 25, 35 and 50 percent.

Under the RC, for SO_2, NO_x, and mercury, the RC projected that emissions would stay relatively flat and well below the Maryland Healthy Air Act (HAA) limits through 2035. The RC projected that CO_2 emissions would increase above the Regional Greenhouse Gas Initiative (RGGI) in 2020 and remain above the RGGI limit through the end of the projection period, requiring Maryland's generators to purchase CO_2 emission allowances to ensure compliance with RGGI. However, under the 50 percent RPS scenario, SO_2, NO_x and mercury emission reductions are minimal as compared to the RC, only diverging slightly in the latter half of the projection period. The 50 percent RPS scenario has the greatest impact on the state's CO_2 emissions as compared to the RC to the point of nearly meeting the RGGI budget around 2027.

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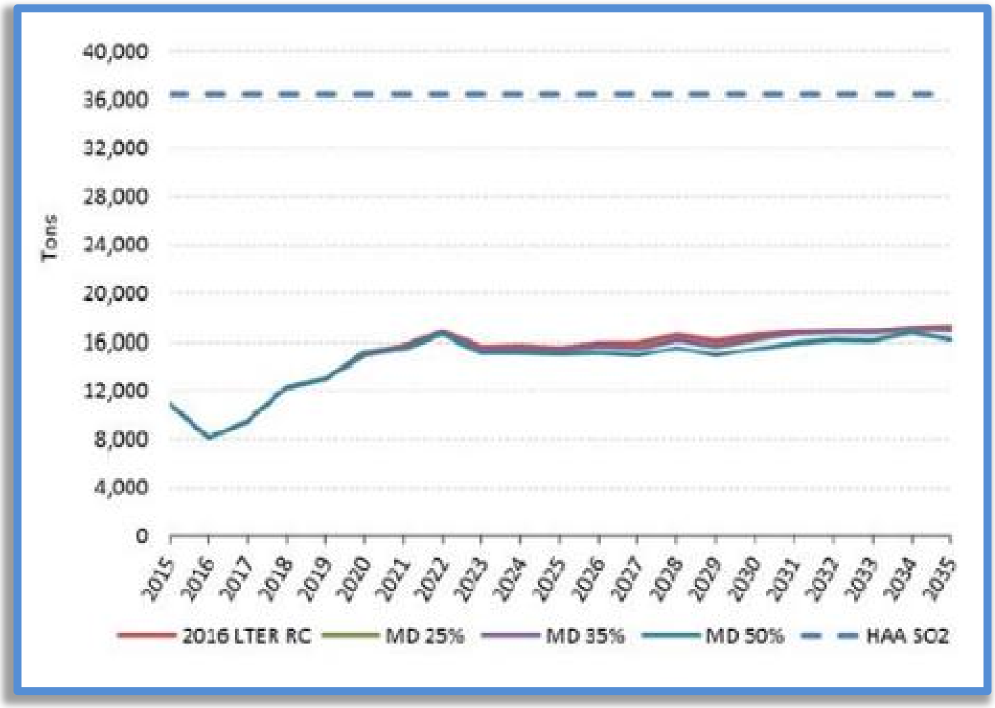
[8] https://dnr.maryland.gov/pprp/Documents/LTER-December-2016.pdf.

[9] The PJM zones include PJM-Southwest, PJM-Mid-Atlantic or PJM-Allegheny Power.


40,000
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2016 LTER RC
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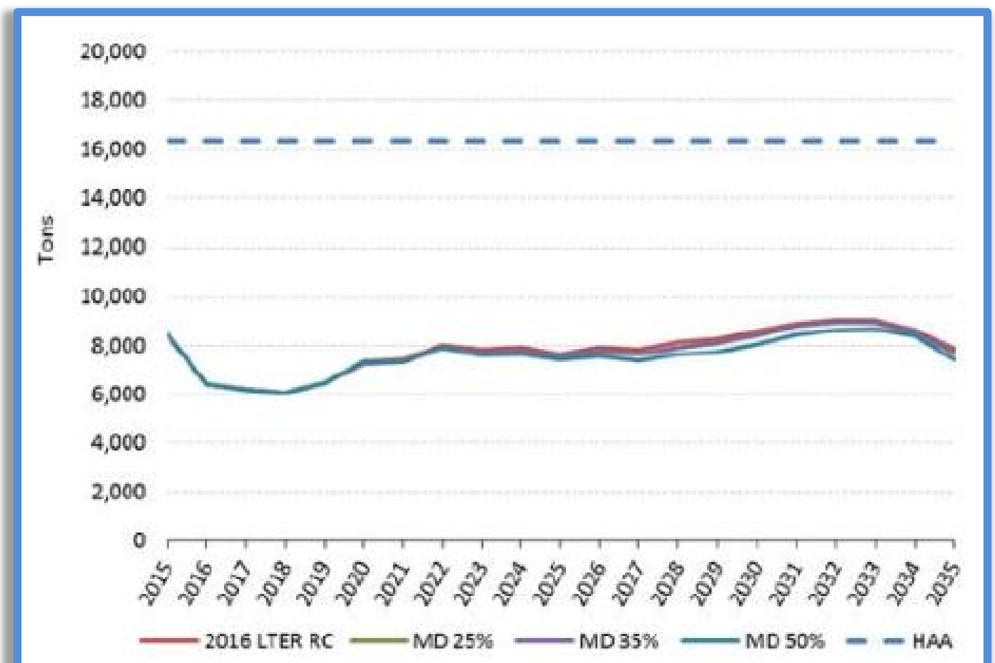
MD 35%
MD 50%
HAA SO2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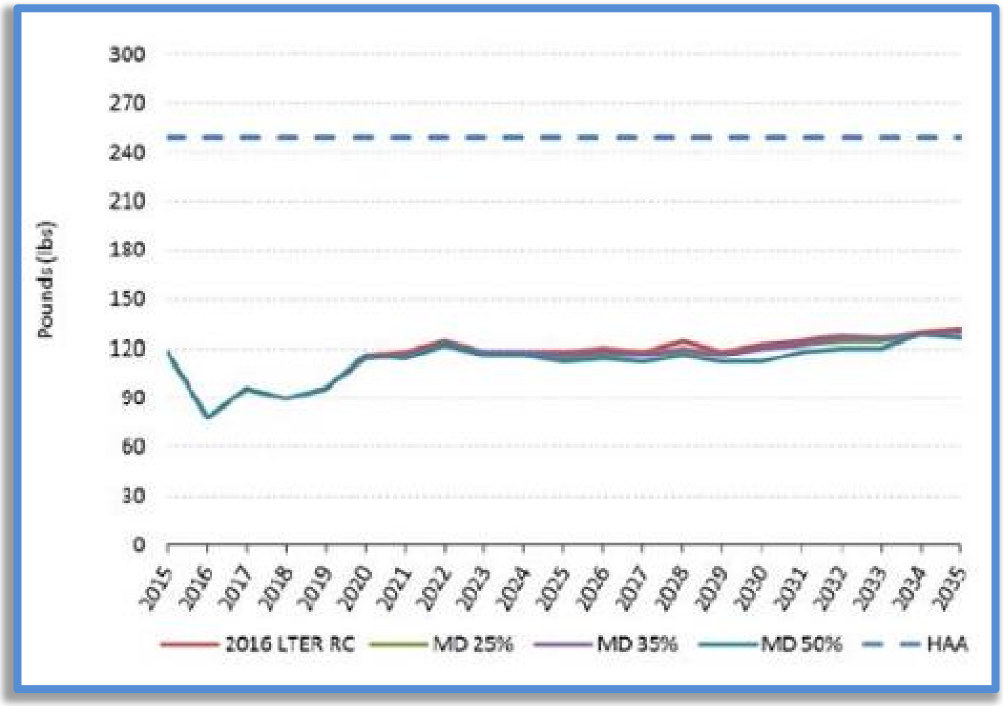
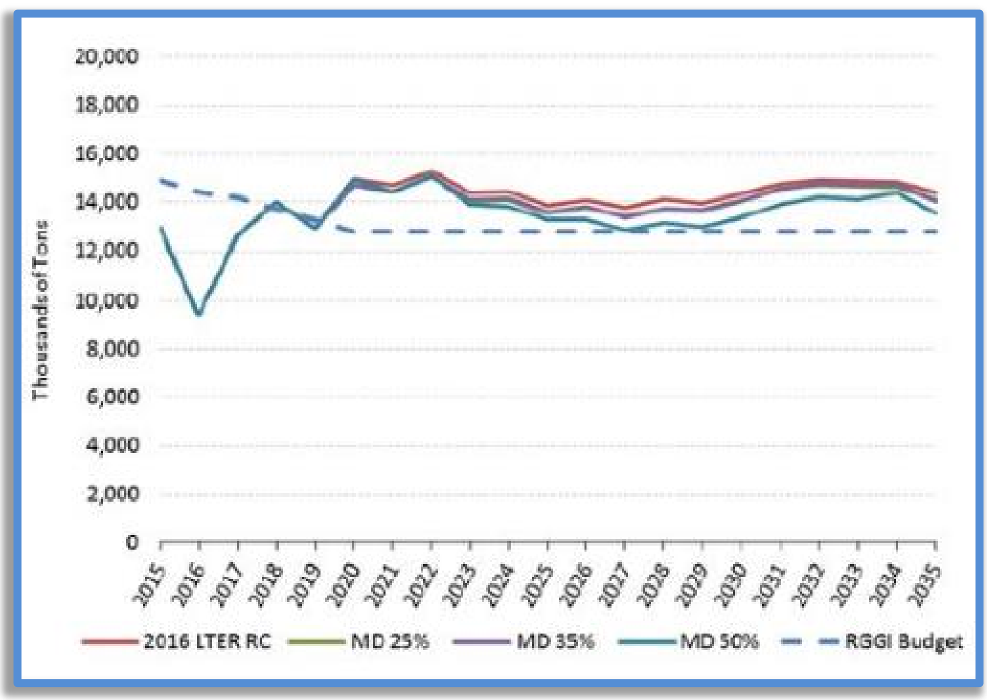
2033
2034
2035
2016 LTER RC
MD 25%
MD 35%
MD 50%
HAA

Figure 2-10 Maryland Mercury Emissions (HAA Plants)



Source: Maryland Power Plant Research Program, *Long-Term Electricity Report for Maryland*, December 2016.

Figure 2-11 Maryland CO_2 Emissions (All Plants)

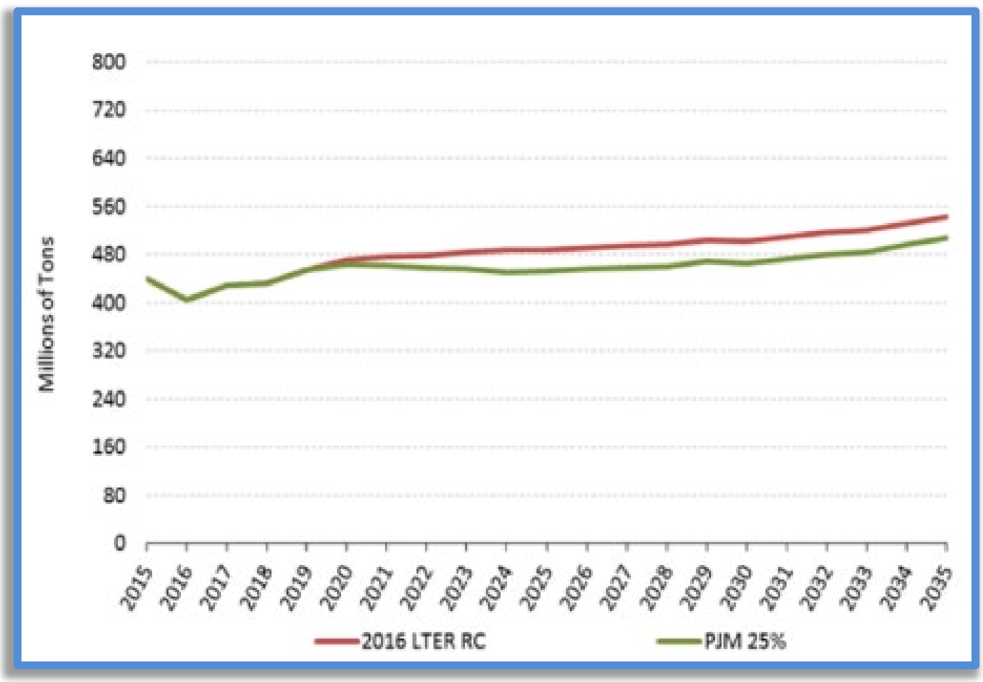


Source: Maryland Power Plant Research Program, *Long-Term Electricity Report for Maryland*, December 2016.

Overall, the LTER projected that a 50 percent RPS in Maryland will only have minimal impact on air and greenhouse gas emissions in Maryland. This is mostly because coal and natural gas plants in Maryland continue to operate at levels comparable to how they operate in the RC, and changes to the Maryland RPS do not significantly impact nonrenewable energy generation in PJM because Maryland accounts for approximately 8 percent of energy consumption in PJM.

In addition to increasing the RPS goal in Maryland, the LTER evaluated the impact of a PJM-wide 25 percent RPS standard on emissions within PJM. The results of this scenario are similar to those of the Maryland RPS scenarios indicating that the RPS has limited impacts on emissions of nonrenewable energy generation. Under the PJM-wide scenario, emissions are projected to only decline slightly throughout PJM due to a decline in the use of coal plants for generation (see Figure 2-12).

Figure 2-12 PJM CO_2 Emissions – PJM-Wide 25 Percent Scenario



Source: Maryland Power Plant Research Program, *Long-Term Electricity Report for Maryland*, December 2016.

E3 Report Emissions Impacts

In August 2019, the consulting firm Energy + Environmental Economics (E3) completed a separate study that projects state emissions associated with Maryland's RPS.[10] The report, which was commissioned by the Maryland Department of the Environment (MDE), includes a Reference Scenario

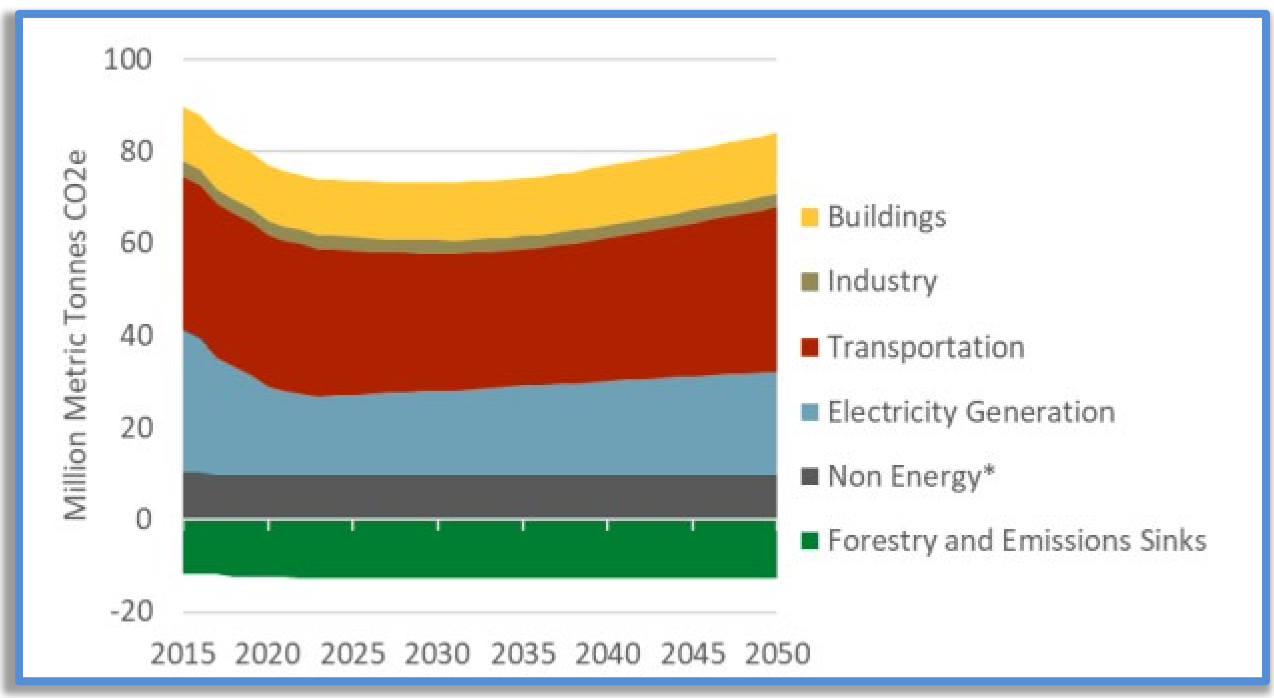
[10] Energy and Environmental Economics, Inc., *2019 GGRA Draft Plan, Appendix F: Documentation of Maryland PATHWAYS Scenario Modeling*, Maryland Department of the Environment, August 2019, https://mde.maryland.gov/programs/Air/ClimateChange/Documents/2019GGRAPlan/Appendices/Appendix%20F%20-%20Documentation%20of%20Maryland%20PATHWAYS%20Scenario%20Modeling.pdf

(RS) that is based on the continuation/extension of current efforts by the State of Maryland to curtail emissions including:

- Continue improving energy efficiency of state buildings;
- Increase the sales of light-duty zero-emission vehicles;
- Reduce the total amount of miles traveled by state residents;
- Achieve the 50 percent RPS requirement by 2030;
- Continue Maryland's Smart Growth initiative; and,
- Increase the amount of acreage in forest management and healthy soil conservation practices.

The RS evaluated the impact of these policies and efforts on emissions by sector. Figure 2-13 breaks down the GHG emissions into six emissions emitting sectors, one of which is electricity generation. Beginning in 2015, electricity generation emissions fall sharply before becoming relatively stable by 2030. This projected decline is attributed to the retirement of instate coal power plants and reduced demand due to efficiency, among other factors.

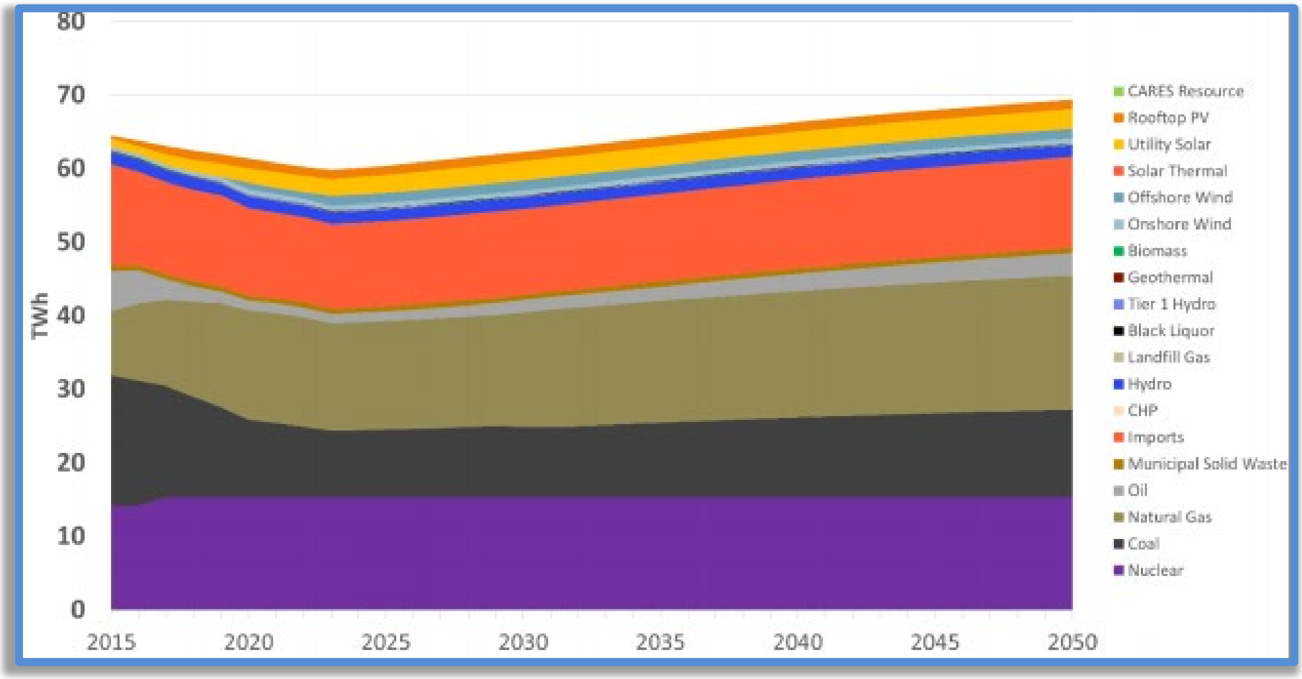
Figure 2-13 Total Emissions by Sector under PS1



Source: Energy + Environmental Economics, *2019 GGRA Draft Plan,* 2019.

The evolution of the fuel mix used for electricity generation through 2050 is illustrated in Figure 2-14. In addition to more renewable energy generation, there is a significant reduction in coal-fired generation due to plant retirements from 2015 through 2030, effectively lowering GHG emissions. However, natural gas-fired generation will increase to make up for the loss of coal-fired generation, thus offsetting a portion of the lowered emissions from coal plant retirements. By comparison, the LTER projected no plant retirements with a 50 percent RPS (as compared to the LTER's Reference Case), although there were reductions in the amount of new additions of natural gas-fired capacity.

Figure 2-14 Projected Electricity Generation by Resource – Reference Scenario

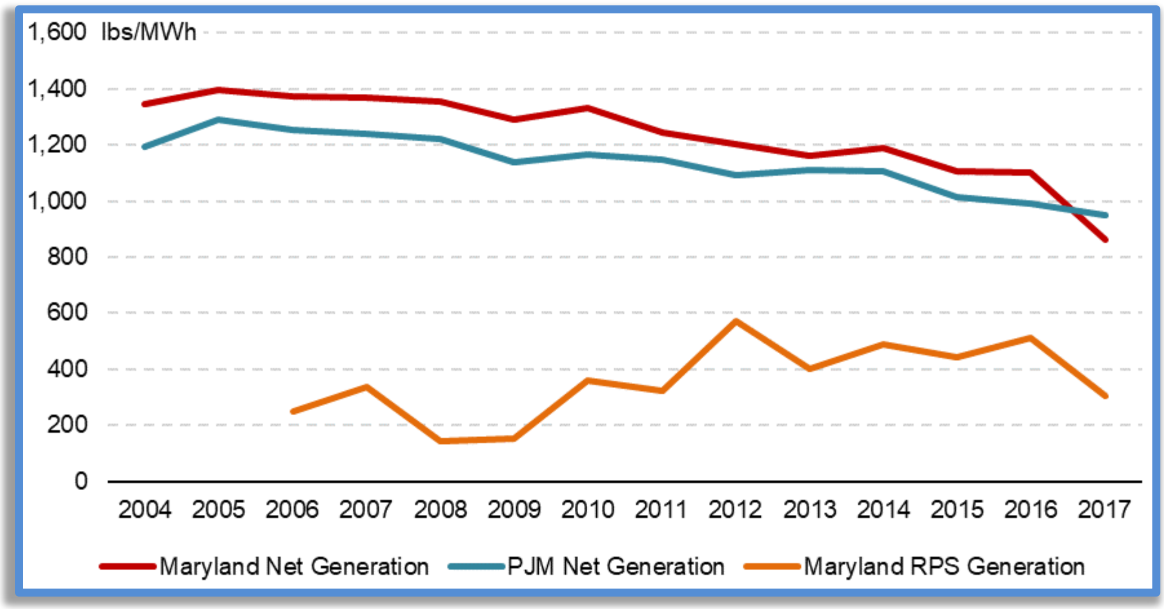


Source: Energy + Environmental Economics, *2019 GGRA Draft Plan,* 2019.

RPS Report Emission Calculations

In December 2019, PPRP completed a comprehensive review of the costs and benefits of Maryland's RPS. The report included an analysis of the role that that the RPS has played to date in lowering emissions throughout PJM. As noted in the report, CO_2 emissions per MWh of electricity generated in PJM have dropped significantly since 2005 (see Figure 2-15). This drop has been driven in large part by the retirement of coal plants and the rise of natural gas generation in its place. Based on PPRP's calculations, Maryland's RPS has played a role as well, as suggested by the lower emissions per MWh associated with Maryland RPS generation in Figure 2-15. Specifically, PJM-wide CO_2 emissions per MWh in 2017 were an estimated 0.8% lower than they would have been without the RPS, if one assumes that every REC retired for RPS compliance supported resources that would not have operated otherwise.

Figure 2-15 Weighted Average of Carbon Emissions in Maryland and PJM



Source: PPRP, Final Report Concerning the Maryland RPS as Required by Chapter 393 of the Acts of the Maryland General Assembly of 2017, December 2019.

In gauging the magnitude of Maryland's impact on PJM-wide emissions, it is useful to consider that Maryland represents roughly 8 percent of PJM-wide energy sales[11] and the Maryland RPS Tier 1 requirement in 2017 was 13.1 percent. The RPS therefore affected roughly 1.0 percent of PJM-wide sales in 2017 (i.e., 13.1 percent of Maryland's 8 percent of PJM-wide sales). PJM-wide CO_2 emissions were lowered by a slightly smaller percentage, 0.8 percent, in part because Maryland accepts RECs from several resources with emissions profiles, such as municipal solid waste, black liquor, and biomass.

2.3 Transforming Maryland's Electric Grid

In December 2016, the Maryland Public Service Commission (PSC) initiated Public Conference 44 (PC 44) with the intent of ensuring that Maryland's electric grid is customer-centered, affordable, reliable and environmentally sustainable. To achieve this goal, the PSC reviewed Maryland's electricity distribution system to explore areas to maximize benefits and choice to Maryland electric customers, and, in particular, assess how the evolving electric grid impacts low- and moderate-income 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:

i. Rate Design,
ii. Electric Vehicles,
iii. Competitive Markets and Customer Choice,
iv. Interconnection Process,

[11] "Monitoring Analytics, PJM Load by State - 2017," https://www.monitoringanalytics.com/data/pjm_load.shtml

v. Energy Storage, and
vi. Distribution System Planning.[12]

2.3.1 Rate Design

The Rate Design Workgroup is responsible for developing two time-of-use (TOU) pilot programs, one for customers that receive electric supply from standard offer service (SOS) and another for customers that receive electric supply service from a retail supplier. In August 2017, the workgroup provided the PSC its first workgroup report, which proposed two opt-in TOU pilot programs. The PSC found the proposals to be lacking specific details and provided guidance to the Workgroup to further develop the pilots. In February 2018, the Workgroup filed a second report requesting a PSC decision on six points regarding the pilots.

Ultimately, the PSC approved a voluntary, opt-in residential time-varying rate pilot program for BGE, Pepco and Delmarva Power.[13] The pilot will run for two years, with new time-varying rates effective as of April 1, 2019. Table 2-12 compares the PSC approved TOU rates ("On-Peak" and "Off-Peak") to the current SOS rate ("Current (Flat)") for each approved utility pilot. The peak-hour rates are significantly higher than off-peak rates.

Table 2-12 TOU Pilot Residential Pricing

BGE	Current (Flat)	On-Peak	Off-Peak	Ratio
Delivery Service Charges	$ 0.03147	$ 0.10571	$ 0.02051	5.2
Supply Charges	$ 0.08255	$ 0.23874	$ 0.05948	4.0
Total	**$ 0.11402**	**$ 0.34445**	**$ 0.07999**	**4.3**

Pepco	Current (Flat)	On-Peak	Off-Peak	Ratio
Delivery Service Charges	$ 0.04051	$ 0.16165	$ 0.01989	8.1
Supply Charges	$ 0.08258	$ 0.17706	$ 0.06650	2.7
Total	**$ 0.12309**	**$ 0.33871**	**$ 0.08639**	**3.9**

Delmarva	Current (Flat)	On-Peak	Off-Peak	Ratio
Delivery Service Charges	$ 0.05402	$ 0.20785	$ 0.02404	8.6
Supply Charges	$ 0.08143	$ 0.16669	$ 0.06481	2.6
Total	**$ 0.13545**	**$ 0.37454**	**$ 0.08885**	**4.2**

Source: Maryland Public Service Commission, Public Conference 44, Letter Order Dated May 7, 2018.

[12] 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.

[13] Maryland Public Service Commission Mail Log No. 220322.

In May 2018, the PSC directed BGE, Delmarva, and Pepco to issue requests for proposals (RFP) related to the retail supplier TOU pilot. The RFP was designed to solicit two proposals, one for a retail supplier TOU with a 3-5 hour summer on-peak period and optional peak during winter, and one for innovative retail supplier TOU rates. Upon reviewing the bids received through the RFP, the PSC ordered the utilities to reject all of the bids received, noting that they were not compliant with the requirements of the RFP. In March 2019, the PSC issued a Notice of Opportunity to comment on a statement of work for the Retail Supplier RFP. In June 2019, after reviewing the comments, the PSC issued an order with a finalized statement of work for the utilities' RFPs and ordered the utilities to issue their RFPs within 30 days.

2.3.2 Electric Vehicles

The Maryland PSC, recognizing the importance of electrification of the transportation industry, charged the Electric Vehicles (EV) Working Group with the following goals:

- Making currently available EV tariffs apply in other utility territories;
- Allowing retail choice for EV tariffs in all utility territories;
- Considering additional rate structures for customers with EV, including EV-only time-varying rates;
- Planning a limited utility infrastructure investment in EVSE [(electric vehicle supply equipment)], 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 our utilities to address grid-related costs associated with vehicle fleet electrification;
- Considering unique tariffs for corporate fleets and workplace & commercial EVSE; and
- Partnering with Maryland Department of Transportation and the auto industry to promote the cost savings and other benefits of EV rate structures.[14]

The EV Workgroup submitted its nonconsensus EV recommendations for the PSC's consideration in January 2018. In January 2019, following a hearing on the recommendations, the PSC concluded that the implementation of a coordinated and well-planned charging infrastructure will support the growth in EVs in Maryland. The PSC issued an order approving a five-year EV charging infrastructure pilot program, which is intended to test a limited EV charging deployment, and thus to limit exposure to Maryland ratepayers.[15] The PSC expects these pilots to provide the needed insight into Maryland's trajectory toward achieving its goal of 300,000 Zero-Emission Vehicles by 2025 and assisting in determining the appropriate next steps for implementing an efficient and reliable charging network in Maryland. The PSC approved these pilot programs:

- Residential
    - Rebates for a limited number of smart chargers
    - Lower off-peak rates for charging electric vehicles
    - Whole-house TOU rates for those who own electric vehicles

14 Maryland Public Service Commission, Mail Log No. 212176, p 8-9.

15 https://www.psc.state.md.us/wp-content/uploads/Order-No.-88997-Case-No.-9478-EV-Portfolio-Order.pdf.

- Nonresidential
    - Rebates for smart chargers in multi-unit and multi-tenant buildings
    - Demand charge credits for commercial customers who install chargers.
- Utilities to own and operate a limited number of public charging stations
- BGE's managed charging pilot study that could provide a potential mechanism for smoothing out electric vehicle TOU charging demand throughout the off-peak period.

The utilities will report to the PSC biannually, with a final report due in March 2024.

2.3.3 Competitive Markets and Customer Choice

The Competitive Markets and Customer Choice (CMCC) Workgroup is assigned to consider revisions to Maryland's retail choice electric and natural gas markets to promote competition, transparently. Additionally, the CMCC Workgroup is tasked with developing "a statewide standard data sharing format for implementation by utilities that have deployed Advanced Metering Infrastructure (AMI)."[16] In January 2018, the CMCC Workgroup requested the PSC initiate a rulemaking to consider draft regulations and the PSC established Rulemaking 62, *Revisions to COMAR 20.32, 20.50, 20.53, 20.55, and 20.59 – Competitive Markets and Retail Gas and Electric Customer Choice.* Below is a list of the Workgroup's proposed revisions:

- Implement instant connects for electric customers, i.e., customers can take service on the day they sign up with an electric supplier instead of requesting enrollment.
- Implement seamless moves for electric and gas customers, i.e., customers can retain their chosen electric supplier when relocating.

Neither of these proposed revisions was adopted by the PSC. However, the PSC did approve some additional protection for residential and nonresidential customers that elect to receive service from a retail supplier, including the following regulations:

- Regulations regarding criminal background checks for electric supplier employees who market door-to-door.
- Regulations that provide more transparency in regard to billing options with a supplier, i.e., budget billing.

2.3.4 Interconnection Process

The PSC tasked the Interconnection Workgroup with "implementing rules and policies that promote competitive, efficient, and predictable distributed energy resources (DER) markets that maximize customer choices."[17] In November 2017, after several meetings, the Workgroup requested the PSC to initiate a rulemaking proceeding to review draft regulations proposed by the group, including some nonconsensus regulations. In total, the Workgroup identified 45 items for potential revisions to Code of Maryland Regulations – COMAR 20.50.09. Subsequently, the PSC opened Rulemaking 61, *Revisions to*

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[16] Maryland Public Service Commission, Mail Log No. 212176, p 10.

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

COMAR 20.50.02 and 20.50.09 – Small Generator Facility Interconnection Standards. During the Rulemaking, the PSC did not accept the initial proposed COMAR revisions but provided the Workgroup with guidance on the pertinent issues. In March 2018, the Interconnection Workgroup submitted a modified COMAR revisions proposal for PSC consideration. In September 2018, the PSC adopted several, but not all, of the proposed revised regulations, including:

- Broadening the definition of 'small generator facility' to include: (i) energy storage devices, and (ii) facilities larger than 10 MW.
- Allowing a single interconnection point for a facility's multiple generating or storage devices.
- Streamlining the interconnection application process.

Two additional phases were added to address interconnection issues that arose during Phase I. Some of the issues addressed in Phase II included: FERC vs. Maryland interconnection jurisdiction, establishing fees for interconnection requests, assessing interconnection facility cost responsibility, and developing Smart Inverter requirements. Phase II has nearly concluded. The Workgroup has proposed revised regulations for the PSC's consideration, and a final decision by the Commission is anticipated in February 2020. Meanwhile, the Commission has requested that the Work Group address four issues in Phase III:

- Interconnection Facility Costs - Recommend an alternative to the "causer pays" principle for interconnection upgrade costs.
- Smart Inverters - Track the progress for setting statewide smart inverter settings.
- Utility Monitoring and Control Plans – Consider alternatives per stakeholder comments made in Phase II.
- Hosting Capacity - Consider additional hosting capacity topics per stakeholder comments made in Phase II.[18]

2.3.5 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 utilize energy storage as a distribution asset, and if so, how utility should be compensated for the investment. In January 2019, the Workgroup presented the PSC with a proposal, the short term Proof of Regulatory Concept Program, designed to evaluate various energy storage business and regulatory models focused on reducing ratepayer costs and providing benefits to competitive storage providers, the electric grid, ratepayers and utilities. Under the program, the utilities would solicit projects under the following four models to pilot over a three-year period:

- **Utility Only Model** – A utility would own and operate the energy storage system, as a rate-based asset, in an effort to defer distribution system upgrades. The energy storage asset could be offered as a resource into PJM in times when it is not being used for grid reliability to generate additional

[18] PC 44 Interconnection Workgroup, *Phase III Kick-off Presentation*, October 22, 2019.

revenue to offset the cost to ratepayers. An example is Southern California Edison's 8 MW / 32 MWh Tehachapi Wind Energy Storage Project.

- **Utility and Third Party Model** – A utility would own the energy storage system but would contract with a third party that would bid the asset into the PJM market when it is not in use for grid reliability. The revenues recognized from the PJM market would be used to offset the cost of the asset. This proposal would evaluate coordination with a third party and the PJM markets. An example is the 100 MW / 129 MWh government owned energy storage project at Neoen's Hornsdale Wind Farm in South Australia. The government uses 70 percent of the capacity of the battery system to balance the grid, allowing Neoen, the third party, to use the assets capacity in the wholesale market.
- **Third Party Ownership Model** – A third party would contract with a utility to provide grid reliability services through an energy storage system and the utility would recover the costs of the contract through an alternative mechanism. There is potential for this service to be less expensive than a utility investment. An example is the Lockheed Martin 500 kW / 3 MWh owned storage project in Boothbay, Maine built to defer a transmission line upgrade in an area with increased load. The project is fully dispatchable by the utility. The transmission line upgrade is estimated to have cost twice the amount of the project.
- **Virtual Power Plant Model** – A utility contracts with a third party developer which owns, operates, and synchronizes a portfolio of behind-the-meter storage, residential or commercial. The portfolio is used to meet distribution grid reliability needs as a flexible resource or a peaking resource to meet wholesale needs, thus, increasing system reliability through lower-cost behind-the-metered resources. An example is California's Demand Response Auction Mechanism (DRAM) where developers can bid its aggregated assets in the investor-owned utilities resource adequacy requirements and the California Independent System Operator's (CAISO's) real-time and day-ahead markets.

The PSC had yet to provide a decision on this proposal when Senate Bill (SB) 573 was passed during the 2019 legislative session. The bill requires the PSC to establish an energy storage pilot program with pilot projects ranging between 5 and 10 megawatts. Additionally, SB 573 requires each IOU to solicit offers for each of the ownership models: utility only, utility and third party, and third party ownership.

During Fall 2019, the Workgroup, with assistance from the Regulatory Assistance Project, developed methodologies to quantify different value streams that may be associated with the energy storage projects that will be proposed under the PC 44 Energy Storage proceeding. The values for which benefits are to be calculated include:

- Environmental and public health benefits associated with shifting load from high emissions periods to lower emissions periods;
- Avoidance or deferral of distribution system upgrades;
- Optionality benefits (i.e., additional flexibility in capital planning);
- Peak demand reduction, including reduced zonal capacity obligations;

- PJM market service revenue; and
- Distribution system improvements (e.g., increased reliability).[19]

2.4 PJM

PJM's Open Access Transmission Tariff (OATT) governs the operations of PJM and are regulated by the Federal Energy Regulatory Commission (FERC). When an issue arises, such as a FERC ruling, PJM utilizes its stakeholder process to determine if and what revisions need to be made to the OATT. First, PJM must determine which of its committees is best suited to work with the issue and within that body, a subcommittee will establish a work plan to develop proposed changes. The subcommittee will then report its consensus resolution (tariff changes) to the parent/standing committee for voting. If the resolution receives a favorable vote, PJM then files the tariff changes with FERC. FERC holds a proceeding to receive comments from interested parties and then releases an order as to whether the tariff changes may be adopted. PJM may also, on its own, petition FERC for tariff or market rule changes in the event that stakeholders cannot come to agreement. Over the last year, PJM has proposed two tariff changes related to the capacity, and energy and reserve markets.

2.4.1 Capacity Market Proposal

In recent years, PJM has expressed concern that out-of-market state subsidies, such as credits, which allow renewable energy and zero-emission generation resources (such as nuclear plants) to remain cost-competitive with fossil fuel generation, have reduced capacity auction clearing prices. In June 2016, PJM completed a white paper[20] which considered these effects, and whether it has limited the number of generators who can successfully bid into the capacity market. PJM concluded that generation resources which receive subsidies submit lower offer prices to the capacity market than they otherwise would absent the subsidy, thereby, suppressing the clearing price. PJM anticipates that as the use of subsidies expands, these suppressive effects will intensify and more generation resources will fail to clear capacity auctions, potentially rendering some of them uneconomic to operate.

PJM's OATT includes rules for the conduct of capacity market auctions. On March 21, 2016 Calpine, an electricity generator, and several other generation companies, filed a complaint with FERC claiming that PJM's OATT was unjust and unreasonable because it does not address the price-suppressive impact of out-of-market state subsidies in capacity auctions. The complaint requested PJM revise the Minimum Order Price Rule ("MOPR") in the OATT to prevent subsidized resources from submitting offers below a minimum price, thereby mitigating price suppression. The complaint also proposed interim revisions to the OATT to extend the MOPR to a limited set of existing generation resources while PJM developed and received approval for a long-term solution to the price suppression problem.[21]

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[19] Submission PC 44 Energy Storage Working Group, Case No. 9619, December 31, 2019.

[20] PJM White Paper, *Resource Investment in Competitive Markets,* May 5, 2016 https://www.pjm.com/~/media/library/reports-notices/special-reports/20160505-resource-investment-in-competitive-markets-paper.ashx

[21] Paul Ciampoli, "FERC Rejects PJM Capacity Market Proposals", *American Public Power Association,* July 2, 2018 https://www.publicpower.org/periodical/article/ferc-rejects-pjm-capacity-market-proposals.

In response, PJM offered two alternative changes to the OATT in an April 9, 2018 proposal to FERC, as follows:

- Option A - Capacity Repricing: PJM proposed a two-stage auction process in which the first auction is conducted as it is currently to select the generation resources needed to meet peak demand. A second auction is then conducted in which the state-subsidized generation resources are repriced with competitive offers to determine what the clearing price would have been without the subsidies.
- Option B - Extension of the Minimum Offer Price Rule ("MOPR-Ex"): PJM proposed revising the current MOPR provisions in the OATT so that a minimum price is set for all generation resources, irrespective of fuel type, that receive state subsidies. This effectively puts a floor on offers and mitigates the price-suppressive effects of subsidies on the clearing price. MOPR provisions currently in the OATT only apply to new-build natural gas fired generating plants. By contrast, the proposed MOPR-Ex would apply to any generation resource that receives out-of-market state subsidies with certain exemptions including those that meet renewable portfolio standards, self-supply resources and generation resources owned by public power entities or electric cooperatives.

On June 29, 2018, FERC issued an order that included responses to the 2016 complaint and to PJM's 2018 OATT revisions, reaching the following conclusions:

- FERC agreed with the complaint's assertion that the OATT was unjust and unreasonable but disagreed with their proposed interim revisions to the MOPR;
- FERC rejected both of PJM's proposed OATT revisions, finding Option A was unjust, unreasonable, and unduly discriminatory and preferential, stating that (1) the suppressive effect of the subsidies would remain in the first auction and the second auction clearing price would distort price signals, (2) subsidized resources may experience a windfall by receiving a higher price in the second auction, in addition to the subsidy, and (3) separating price and quantity for facilitating participation of subsidized resource would be unjust and unreasonable. PJM did not adequately demonstrate that Option B would not be unjust, unreasonable, and unduly discriminatory primarily because of the number of generation resources that receive subsidies that would not be subject to MOPR-Ex to the detriment of competitive resources; and,
- PJM did not provide sufficiently valid reasons for exempting so many types of generation resources from MOPR-Ex.22.

Additionally, FERC proposed two changes to the OATT to address the suppressive effect of out-of-market state subsidies:

1. Expand the MOPR to include all generation receiving out-of-market subsidies with few or no exceptions, and

[22] https://www.ferc.gov/CalendarFiles/20180629212349-EL16-49-000.pdf.

2. Allow state-subsidized generation resources to opt-out of the capacity markets along with the corresponding amount of electric load associated with each resource. Resources that opt out would be purchased by utilities separate from market-sourced capacity.

On December 19, 2019, FERC issued its order that expands the MOPR to include generation, demand response, energy efficiency, and energy storage resource that receive out-of-market state subsidies, while in turn declining to adopt its previous proposal of allowing state-subsidized generation to opt-out of the capacity markets. FERC's interpretation of subsidies is quite broad and extends to voluntary green power transactions, demand response, self-supply, energy efficiency and new resources from public power utilities and vertically integrated utilities that are regulated by state public utility commissions. FERC exempts existing generation (or planned generation with an interconnection agreement from PJM); demand response, energy efficiency, energy storage, self-supply and energy resources that do not receive state subsidies. New energy resources whose costs are below the MOPR without state subsidies can petition the PJM Market Monitor for an exemption.

Revising the capacity market to incorporate FERC's changes will result in higher retail electric prices as it will likely make state-subsidized resources uncompetitive, and fewer resources will be available to bid in PJM's capacity market. Estimates of the price impacts of FERC's order vary between $2.4 billion per year and $5.6 billion per year.[23] If the latter estimate is accurate, it would represent a 60 percent increase in capacity market costs and would result in roughly a $6 monthly increase for residential customers in PJM.[24]

2.4.2 Reserve Market Proposal

The reserve market is used to balance the grid and to maintain reliability during periods of unexpected loss of generation or transmission, or unanticipated increases in electricity demand, by utilizing quick response generation resources or from loads that can be removed from the grid, such as demand response. Reserve market resources are essential to maintain reliability, yet over the past few years, one of the reserve markets has experienced clearing prices that were at or near zero. PJM stated that these low clearing prices significantly undervalue the importance of reserve resources, averring that the market prices are unjust, unreasonable, and unduly discriminate against certain reserves.

After more than a year of PJM stakeholders at an impasse regarding the compensation of reserve market resources, PJM filed nonconsensus revisions to its Amended and Restated Operating Agreement of PJM Interconnection LLC (Operating Agreement) with FERC in March 2019 in Docket No. EL19-58-000. In

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[23] Commissioner Richard Glick, dissent, FERC, *Calpine Corporation, et al, versus PJM Interconnection LLC,* 169 FERC ¶ 61,239, December 19, 2020, https://www.ferc.gov/whats-new/comm-meet/2019/121919/E-1.pdf (for the $2.4 billion) and Michael Goggin and Rob Gramlich, *Consumer Impacts of FERC Interference with State Policies: An Analysis of the PJM Region*, Grid Strategies LLC, August 2019, https://gridprogress.files.wordpress.com/2019/08/consumer-impacts-of-ferc-interference-with-state-policies-an-analysis-of-the-pjm-region.pdf..

[24] Michael Goggin and Rob Gramlich, *Consumer Impacts of FERC Interference with State Policies: An Analysis of the PJM Region*, Grid Strategies LLC, August 2019, https://gridprogress.files.wordpress.com/2019/08/consumer-impacts-of-ferc-interference-with-state-policies-an-analysis-of-the-pjm-region.pdf.

its filing, PJM proposes that to create a proper market that effectively values the resources, FERC should approve the following amendments:

- "Consolidate Tier 1 and Tier 2 resources into one product, called "Synchronized Reserve," with uniform commitment, compensation, and performance obligations to meet all Synchronized Reserve needs;
- Revise the current ORDC [operating reserve demand curve] by:
  - Raising the Reserve Penalty Factor to $2,000/MWh, to recognize that sellers could have legitimate opportunity costs up to that level during shortage conditions from foregoing energy market sales (or load reductions) in order to commit as reserves;
  - Changing the ORDC curve shape based on a systematic, probabilistic quantification of the same categories of load and supply uncertainties that PJM operators are currently trying to address when they bias dispatch schedules or take other out-of-market actions to guard against PJM falling short of its Minimum Reserve Requirements (MRRs); and,
- Align the day-ahead and real-time reserve markets to ensure that the reserves needed for real-time operation are recognized on a forward basis during the scheduling processes for the next operating day.[25]

There is significant opposition to PJM's proposal, which failed to achieve at least two-thirds vote before PJM filed it with FERC. Those opposing the amendments include large users, environmental groups, state commissions, state consumer advocates and PJM's market monitor. Those in opposition state that PJM's proposal:

- Fails to recognize that the market is securing sufficient reserves;
- Does not demonstrate how the clearing prices of the reserve market are unjust, unreasonable, or fail to compensate generators;
- Alters how energy prices are calculated without declaring that locational marginal prices are unjust and unreasonable;
- The sloped ORDC is not transparent, complex and increases the costs by $1.7 billion annually; and
- Excludes demand response resources.

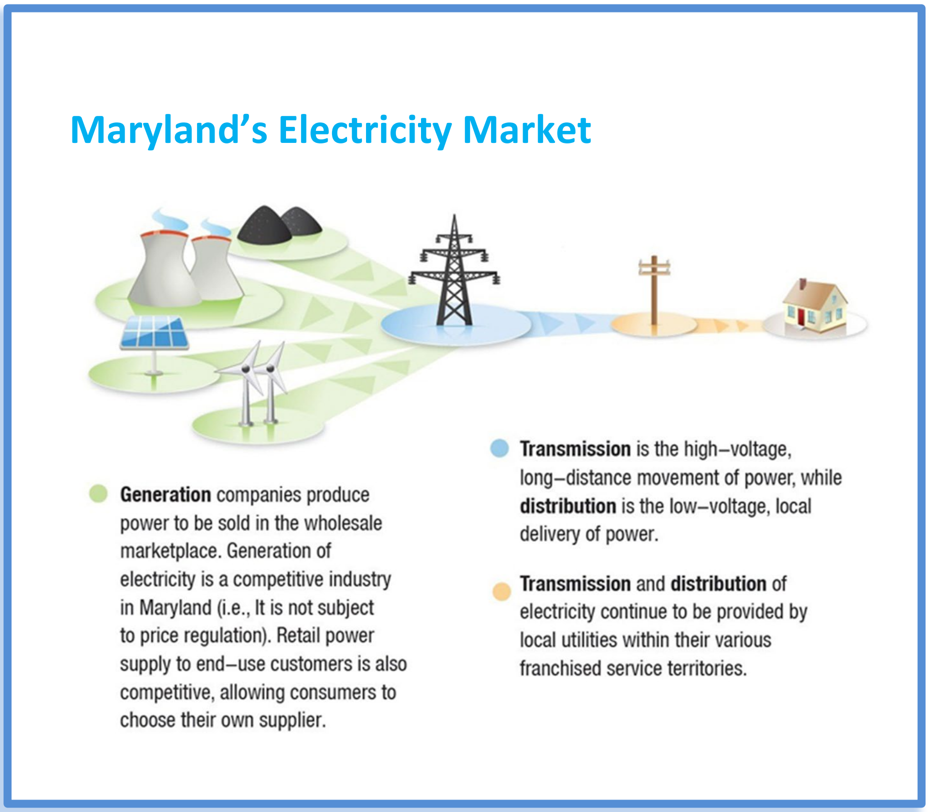
As of January 2020, FERC has not issued a ruling on this proposal. PJM had requested regulatory approval by mid-December 2019 in order to implement the amendments by June 1, 2020.

[25] https://pjm.com/directory/etariff/FercDockets/4036/20190329-el19-58-000.pdf.

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 is 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.

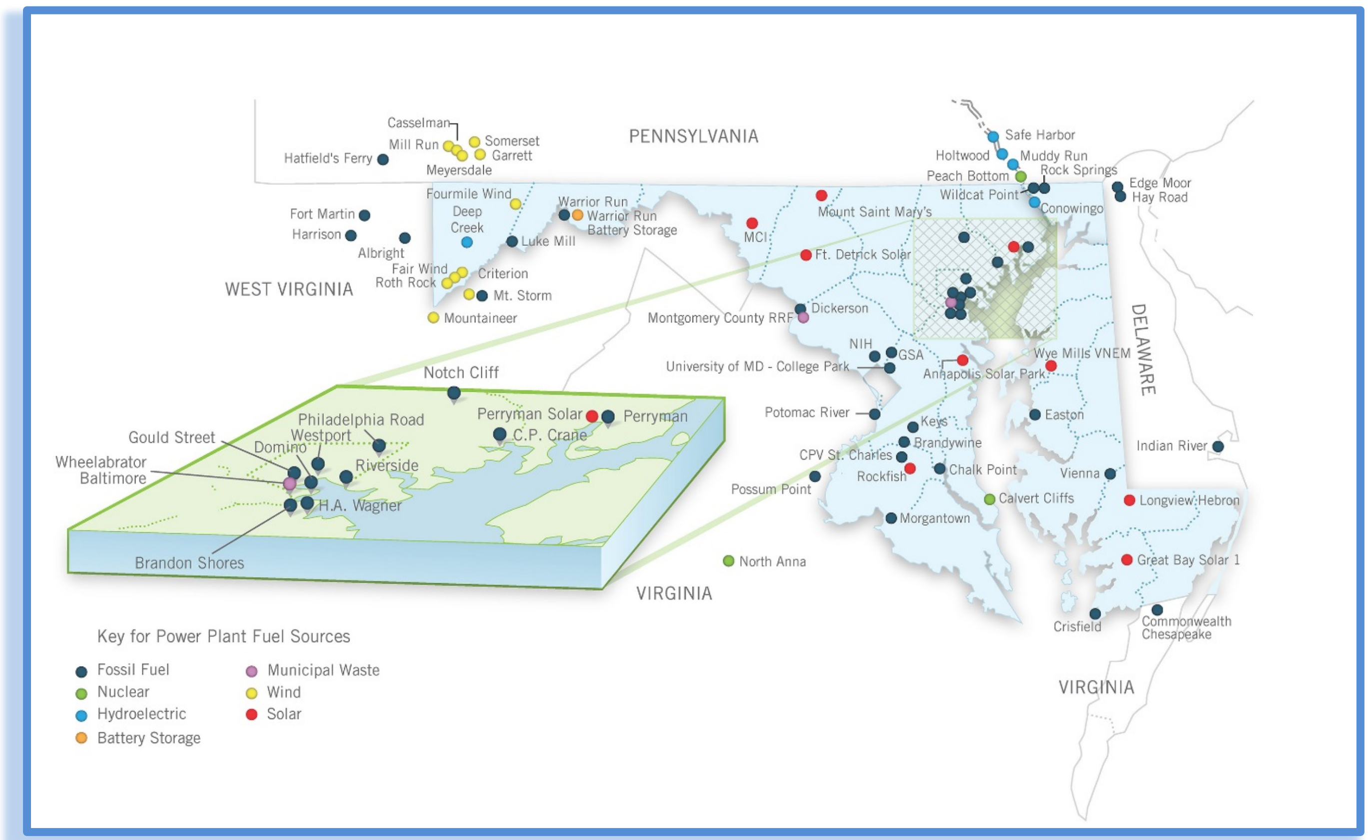


The high voltage bulk electric transmission system is a monopoly function, regulated by the Federal Energy Regulatory Commission (FERC), and the distribution of electricity is a monopoly function provided by local utilities (for more information on FERC see Section 4.4.1). It is therefore subject to price and quality-of-service regulation by the PSC.

3-1 Electricity Generation in Maryland

Currently in Maryland, 44 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 44 Maryland power plants represent more than 15,900 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's been a significant shift between coal and natural gas generation within the state, as noted in Figured 3-2. Since 2016, natural gas capacity increased approximately 12 percent and natural gas generation increased 17 percent while the capacity of coal has decreased almost 10 percent and generation has declined by14 percent.

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 CPCN to construct and operate a new 160 MW natural gas-fired facility at the existing site.

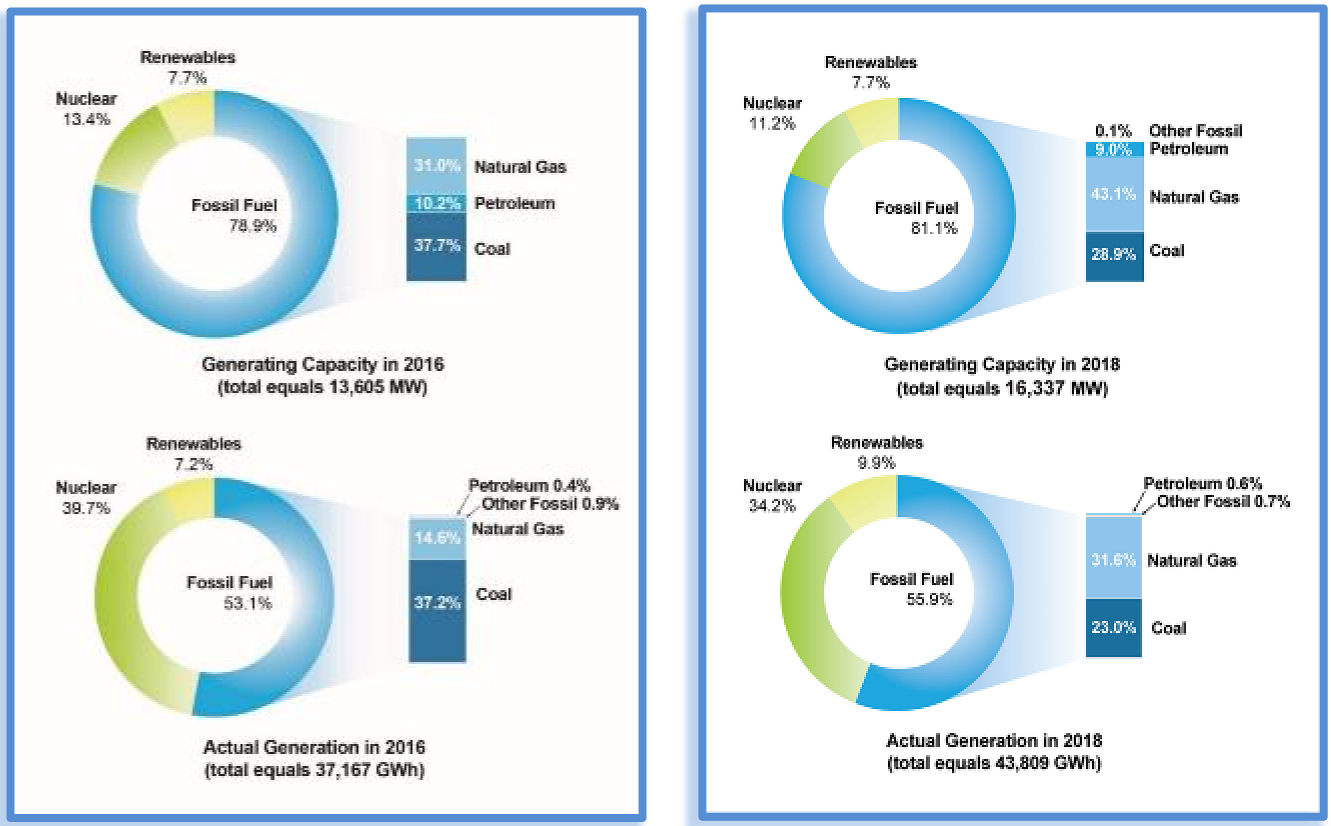
Table 3-1 Operational Generating Capacity in Maryland, December 2018 (10 MW or greater)

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
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
College Park	University of Maryland – College Park	Natural Gas	22
Covanta	Montgomery County Resource Recovery Facility (RRF)	Waste	68
CPV Maryland LLC	CPV St. Charles Energy Center	Natural Gas	746
Exelon Nuclear	Calvert Cliffs Nuclear Power Plant	Nuclear	1,829
Exelon Corporation	Conowingo	Hydroelectric	572
	Criterion Wind Park	Wind	70
	Fair Wind Power Partners	Wind	30
	Fourmile Ridge	Wind	40
	Gould Street	Natural Gas	104
	Mount Saint Mary's	Solar	14
	Notch Cliff	Natural Gas	144
	Perryman	Oil/Natural Gas	492
	Perryman Solar	Solar	17
	Philadelphia Road	Oil	83
	Riverside	Oil/Natural Gas	50
	Westport	Natural Gas	122
GenOn Chalk Point, LLC	Chalk Point LLC	Coal/Oil/Natural Gas	2,552
GenOn Mid-Atlantic LLC	Dickerson	Coal/Oil/Natural Gas	933
	Morgantown Generating Plant	Coal/Oil	1,548
Gestamp Wind	Roth Rock Wind Facility	Wind	50

Owner	Plant Name	Fuel Type	Nameplate Capacity (MW)
Great Bay Solar 1 LLC	Great Bay Solar 1	Solar	150
H.A. Wagner LLC	Herbert A Wagner	Coal/Oil/Natural Gas	1,059
KMC Thermo LLC	Brandywine	Natural Gas	289
Marina Energy LLC	Longview Solar - Hebron	Solar	14
Montevue Lane Solar, LLC	Fort Detrick Solar PV	Solar	16
NRG Energy	Vienna	Oil	181
PSEG Keys Energy Center, LLC	Keys Energy Center	Natural Gas	831
Pepco Energy Services	National Institutes of Health (NIH)	Natural Gas	28
Rockfish Solar LLC	Rockfish Solar LLC	Solar	10
Tesla, Inc.	Wye Mills VNEM	Solar	10
Verso Corporation	Luke Mill**	Coal	65
Wheelabrator Technologies	Wheelabrator Incinerator	Waste	60
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
	Rock Springs	Natural Gas	773
SELF-GENERATORS			
American Sugar Refining Co.	Domino Sugar	Natural Gas	10
GSA Metropolitan Service Center	Central Utility Plant	Oil/Natural Gas	54
Total			**15,903**

* Capacity figures for Exelon-owned facilities were provided by Exelon Generation.
** Luke Mill closed in May 2019.
Source: U.S. Energy Information Administration, Form EIA-860, 2018.

Figure 3-2 Power Plant Capacity and Generation in Maryland by Fuel Category, 2016 compared to 2018



Source: 2016 data "Existing Nameplate and Net Summer Capacity by Energy Source, Producer Type and State (EIA-860)," U.S. Energy Information Administration, 2016 Early Release; "Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923)," U.S. Energy Information Administration, 2016 Early Release.

2018 data "2018 Form EIA-860 Data – Schedule 3 'Generator Data' (Operable Units Only)," 2018 Final Release; "EIA-923 Monthly Generation and Fuel Consumption Time Series File, 2018 Final Revision, Sources: EIA-923 and EIA-860 Reports," 2018 Final Release.

Note: EIA data for generation contains 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 utilized to produce electricity. The primary fuel used for electricity in Maryland is coal. However, due to declining prices in recent years, the use of natural gas used to generate electricity has increased considerably.

Coal

In 2018, Maryland consumed 4.6 million tons of coal for electricity generation, which was a decrease of 17 percent compared to 2016. 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 2018 data, 99 percent of the coal received by Maryland plants was mined in the Appalachia region of the U.S. Table 3-2 lists the amount of coal received at each power plant in 2018 and its origin. According to the U.S. Energy Information Administration (EIA), U.S. bituminous coals sold for an average of $59.13/short ton in 2017 compared to $13.64/ short ton for subbituminous coals.

Table 3-2 Tons of Coal Purchased at Maryland Power Plants in 2018

Origin of Coal	Brandon Shores	H.A. Wagner	C.P. Crane	Dickerson	Chalk Point	Morgantown	Warrior Run	Luke Mill	Total by Source	Percentage of Total
Appalachia	2,311,778	190,449	-	81,865	181,169	1,030,235	586,372	187,638	4,569,506	98.5%
Colorado	-	25,484	-	-	-	-	-	-	25,484	0.6%
Powder River Basin	-	-	42,376	-	-	-	-	-	42,376	0.9%
Total Coal by Plant	**2,311,778**	**215,933**	**42,376**	**81,865**	**181,169**	**1,030,235**	**586,372**	**187,638**	**4,637,366**	**100.00%**

Source: U.S. Energy Information Administration, EIA-923 Schedule 5 Fuel Receipts and Cost Time Series File, 2018 Final Release.

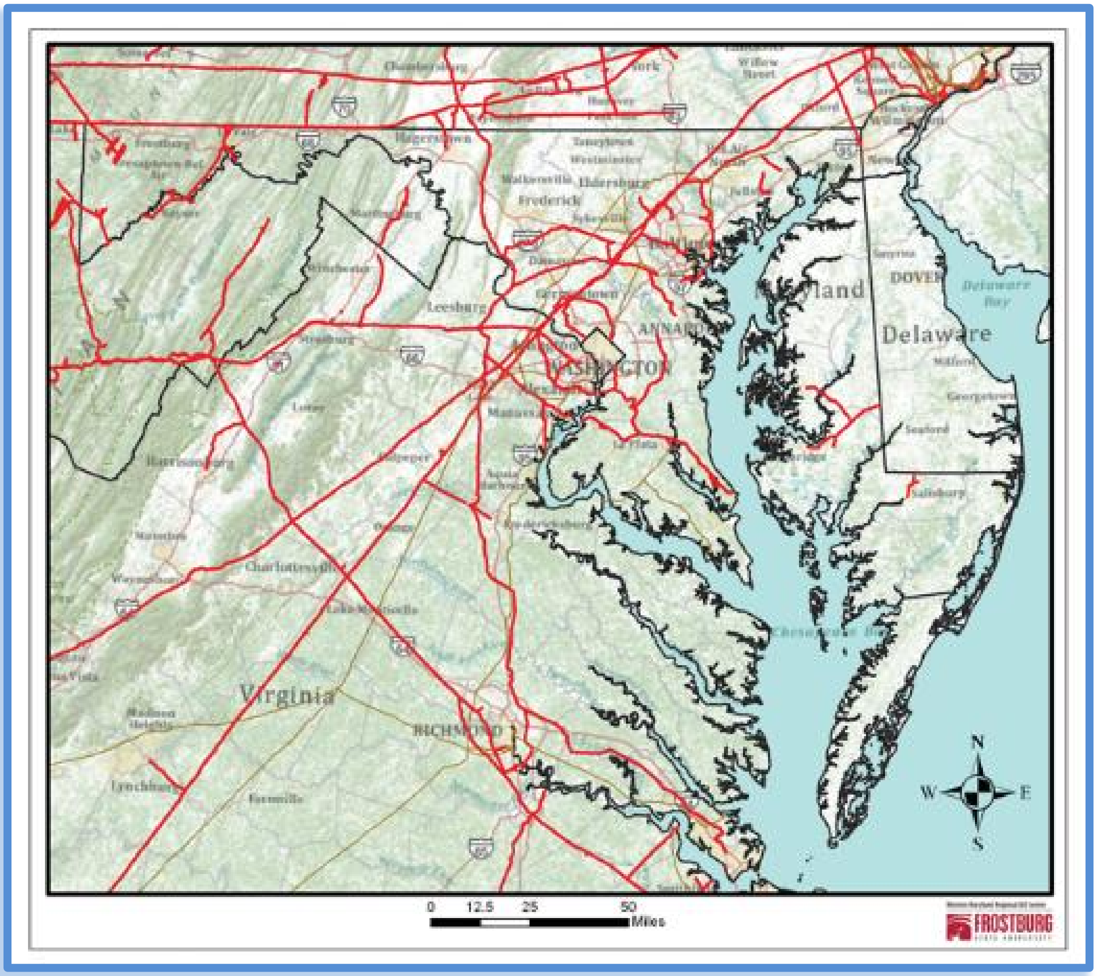
Natural Gas

In 2018, approximately 97.7 billion cubic feet of natural gas was used for electricity generation in Maryland, representing 32 percent of total statewide consumption of natural gas for all uses.[26] Both of these are sharp increases over 2018 when about 50.7 billion cubic feet of natural gas was used for electricity generation in Maryland, accounting for 23 percent of total statewide consumption of natural gas. 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 percent of the underground gas storage capacity in the region (which includes Maryland,

[26] U.S. Energy Information Administration, Natural Gas Consumption by End Use for Maryland, https://www.eia.gov/dnav/ng/NG_CONS_SUM_DCU_SMD_A.htm, December 31, 2019.

New Jersey, Pennsylvania, Virginia and West Virginia). Other potentially suitable storage sites may also exist in Western Maryland.

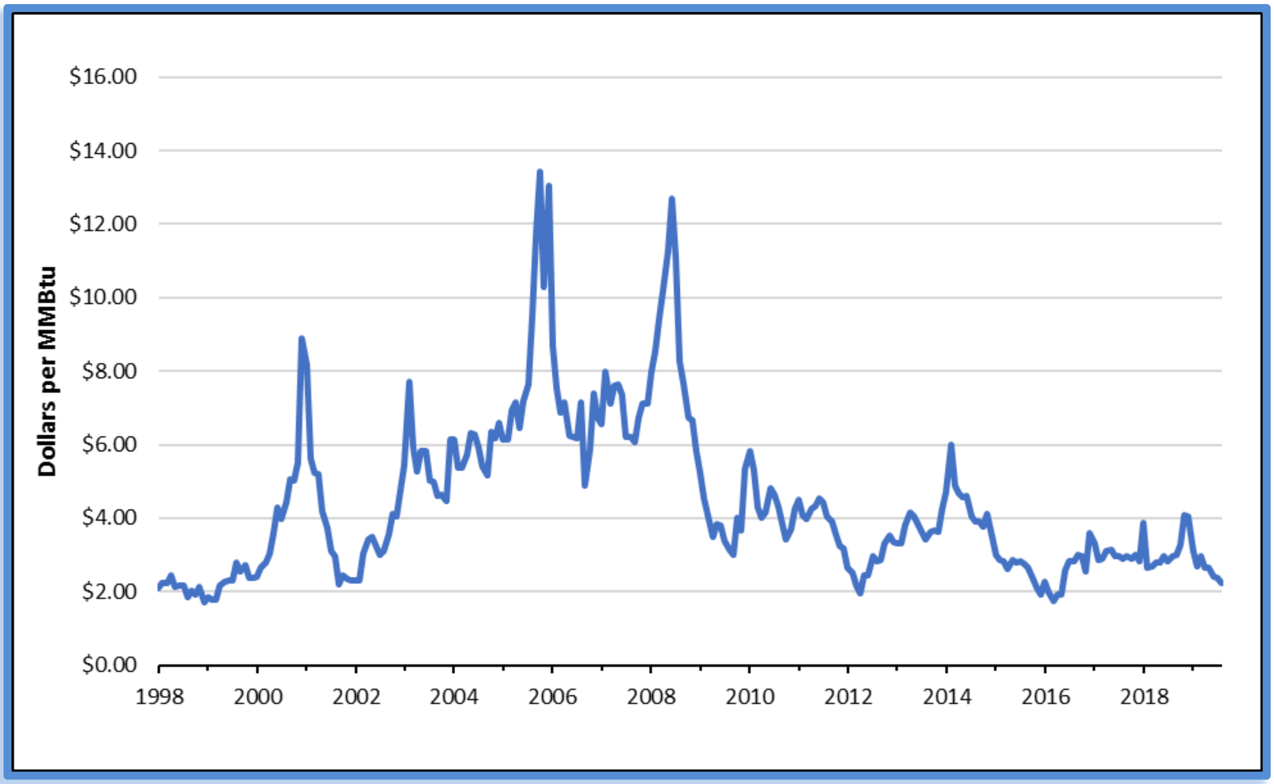
Figure 3-3 Interstate Natural Gas Pipelines in Maryland



There has been a significant increase in natural gas production in the U.S. resulting from the use of new drilling techniques. Shale gas trapped in deep, fine-grained rock formations in the southwest and northeast regions of the U.S. was not economical to recover until the development of horizontal drilling and hydraulic fracturing techniques in the 1990s. Between 2009 and 2018, as natural gas producers continued utilizing these techniques, U.S. natural gas production increased 51 percent. Domestic natural gas consumption over the same period increased only 30 percent, resulting in decreased imports of natural gas via pipeline from Canada and a reduction in liquefied natural gas (LNG) imports.

U.S. natural gas spot prices at Henry Hub[27] were between $2.00 and $2.50 per million British thermal units (MMBtu) in the late 1990s, and then began a steady increase, more than doubling to over $5.00/MMBtu by 2003 and reaching a high of $13.42/MMBtu in late 2005. Since then, natural gas prices have decreased, averaging between $2 and $4/MMBtu since 2015, primarily attributable to increased shale gas production (see Figure 3-4). In 2018, the average natural gas price was $3.15/MMBtu.

Figure 3-4 U.S. Natural Gas Henry Hub Spot Prices, 1998-2019



Source: U.S. Energy Information Administration, Henry Hub Natural Gas Spot Price.

The LNG price is linked to that of crude oil, which has increased as domestic natural gas prices have declined. The annual average export LNG price decreased from $0.83/MMcf in 2009 to $0.51/MMcf in 2018.[28] Import volumes at the Cove Point LNG facility in Lusby, Maryland increased 69 percent between 2013 and 2018.[29] Cove Point, which is owned by Dominion Cove Point LNG, LP, an affiliate

[27] Wholesale natural gas futures contracts priced on the New York Mercantile Exchange are based on the delivery price at the Henry Hub in Erath, Louisiana. Henry Hub is a major intersection of pipelines and the crossroads for a significant amount of natural gas moving to locations across the country.

[28] U.S. Energy Information Administration, "Price of Liquefied U.S. Natural Gas Exports," monthly release, accessed October 1, 2019.

[29] U.S. Energy Information Administration, "U.S. Natural Gas Imports by Point of Entry," release date September 30, 2019, https://www.eia.gov/dnav/ng/ng_move_poe1_dcu_YCPT-Z00_a.htm.

of Dominion Resources, Inc., is one of 12 LNG import facilities operating in the U.S. Plans for new or expanded LNG facilities in the U.S. have either been canceled or modified for operation as LNG export facilities, in response to high LNG export prices. On October 7, 2011, the U.S. Department of Energy (DOE) authorized Dominion Cove Point LNG, LP to enter into contracts to export LNG to countries that have free trade agreements with the U.S. On April 1, 2013, Dominion announced that it had entered into 20-year contracts for all of the export capacity at Cove Point. Pacific Summit Energy, LLC, a U.S. affiliate of Japanese trading company Sumitomo Corporation, and GAIL Global (USA) LNG LLC, a U.S. affiliate of GAIL (India) Ltd., have each contracted for half of the marketed capacity. On September 29, 2014, the FERC issued an order authorizing Dominion Cove Point LNG, LP to export LNG.[30] The next month, construction began, and Cove Point LNG export facility was operational by April 2018. In 2018, Cove Point exported 143,134 MMcf of LNG.[31]

Petroleum

A small amount of electricity — less than 1 percent of the state's total — is generated by combusting distillate or residual fuel oil. According to the EIA, fuel oil consumption for electric power in Maryland totaled 23 million gallons in 2018, which is significantly lower than the 75.2 million gallons used for electric power consumption in 2007. Since 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. The Colonial Pipeline, a major petroleum products pipeline, traverses the state on its way to New York.

3.1.2 Nuclear

Maryland is home to one nuclear power facility, Exelon's Calvert Cliffs plant. In March 2000, the U.S. Nuclear Regulatory Commission (NRC) approved a 20-year extension to the original operating licenses for Units 1 and 2. The units' licenses will expire in 2034 and 2036, respectively. This 1,829 MW facility represents 11 percent of the state's total electricity generation capacity and accounted for 34 percent of the state's total generation in 2018.

More information on Calvert Cliffs is included in Section 5.5.2.

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. It 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. The majority of DG units are diesel-fired emergency backup generators. However, an increasing share of this capacity comes from solar energy, which is

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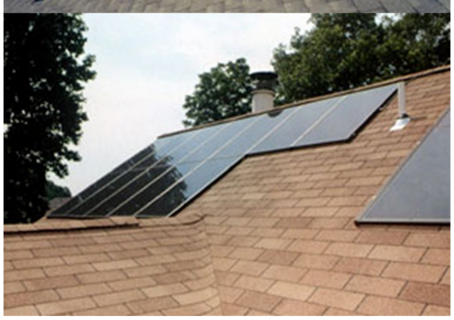
[30] Federal Energy Regulatory Commission, "Order Granting Section 3 and Section 7 Authorizations," September 29, 2014, https://www.ferc.gov/CalendarFiles/20140929192603-CP13-113-000.pdf.

[31] U.S. Energy Information Administration, "U.S. Natural Gas Exports and Re-Exports by Point of Exit," release date September 30, 2019, https://www.eia.gov/dnav/ng/ng_move_poe2_dcu_YCPT-Z00_a.htm.

Distributed Solar Generation

Distributed solar generation has played an increasing role in Maryland as a source of total generation. The increasing use of solar rooftop photovoltaic (PV) in Maryland is largely attributable to Maryland's Renewable Portfolio Standard (RPS) and a 30 percent federal tax credit. The tax credit is declining to 26 percent in 2020, 22 percent in 2021 and will be nonexistent in 2022.



FERC issued Order No. 792 in November 2013 that amends its existing rule on small generator interconnection agreements and procedures. The regulatory reforms are intended to streamline the grid interconnection process for solar projects that meet certain technical standards.

predominantly grid-tied for the purposes of net metering and generating solar renewable energy credits (RECs) for sale or trade (see Section 2.1.1 for discussion on RECs).

Onsite generators with a capacity of 2 MW or less are not required to obtain a Certificate of Public Convenience and Necessity (CPCN) or apply for a CPCN waiver (or exemption). In addition, certain generators of up to 70 MW in capacity are eligible to seek a CPCN waiver:

- Facilities with a capacity of less than 70 MW, consuming at least 80 percent of the electrical output onsite;
- Facilities less than 25 MW in capacity, consuming at least 10 percent of the electrical output onsite; and
- Land-based, wind-powered generating stations with a capacity of less than 70 MW, subject to additional qualifications (see Section 3.1.5).

The Maryland PSC requires an applicant seeking a CPCN exemption to identify its facility as one of four specific types:

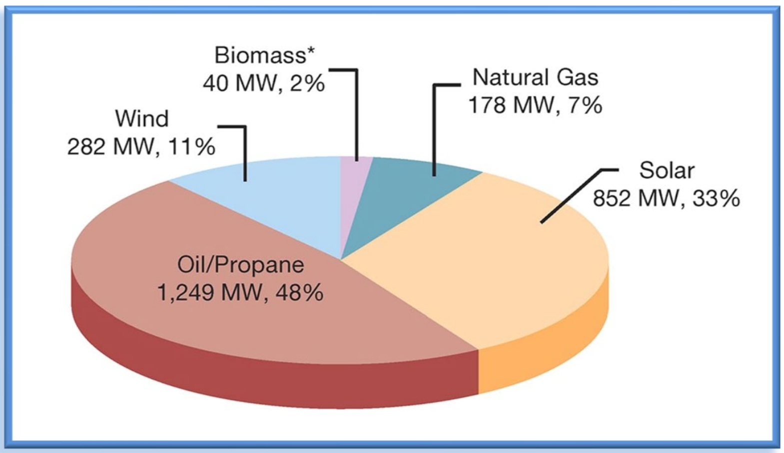
- Type I – a generator that is not synchronized with the local electric company's transmission and distribution system, and will not export electricity to the grid;
- Type II – a generator that is synchronized with the electric system, but will not export electricity to the grid;
- Type III – a generator that is synchronized with the electric system and will be exporting electricity to the grid for sale in the wholesale energy market; or
- Type IV – a generator that is synchronized with the electric system but is inverter-based and will automatically disconnect from the grid in the event of a grid power failure.

It is difficult to accurately estimate the total amount of DG in Maryland as systems smaller than 2 MW are not required to obtain a CPCN exemption. The vast majority of solar DG systems fall into this category.

From 2001 through September 2019, 1,847 MW of generation capacity had been granted CPCN exemptions in Maryland, including 178 MW of natural gas fired capacity, 102 MW of solar capacity, and 280 MW of land-based wind power. According to the 2019 PSC report on net metering, an additional 750 MW of solar DG and 1.4 MW of small wind facilities were installed in Maryland by April 2019 under net metering arrangements.

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 3-5) are mostly fossil-fueled, consistent with their use for backup power. An increasing, but still small, share of DG capacity is solar, which is predominantly grid-tied for purposes of net metering and generating solar RECs for sale or trade. Between 2017 and 2018, for example, statewide net metered solar system capacity increased 48 percent. 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 3-5 Distributed Generation by Fuel Type, as of 2018



Source: PSC CPCN Database and Maryland Public Service Commission, "Report on the Status of Net Energy Metering in the State of Maryland," September 2019 https://www.psc.state.md.us/wp-content/uploads/2019-MD-PSC-Report-on-the-Status-of-Net-Energy-Metering.pdf .

Note: This figure only includes solar from net metered systems and CPCN-exempted systems.

*Biomass includes digester and landfill gas units.

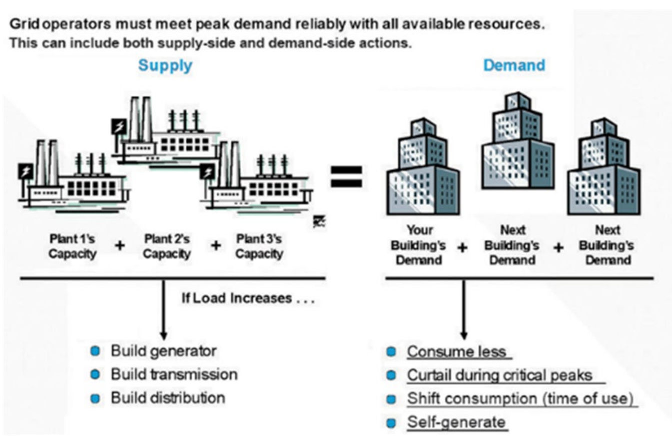
3.1.4 Demand Response

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). Demand response occurs when a customer reduces electricity use in response to either a change in the price of electricity or an incentive payment. Customers that 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. Small residential consumers can cycle 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.

Demand response within the PJM Interconnection, LLC (PJM) is utilized as a supply resource in the same way as generators. PJM runs several DR programs that compensate customers for reducing their load. DR resources are eligible to participate in PJM's energy markets, PJM's ancillary services markets, and PJM's capacity market (see Appendix B for a description of these markets).

PJM members that act as DR providers are called curtailment service providers (CSPs). Customers can act as their own CSP or sign with another CSP that can bid load reductions into PJM markets. CSPs can participate as a capacity resource in the capacity market and can bid load reductions into the energy markets, both for reductions needed during emergency events or reductions in response to high prices (economic events).

The Importance of Demand Response



Demand Response (DR) is a competitive resource that can be used to maintain the balance of supply and demand for grid operations and the associated wholesale markets. Retail electricity consumers tend to be unresponsive to wholesale prices. Therefore, as demand goes up, less efficient generators may be called on to serve higher demand. By reducing demand during these periods, the use of potentially less efficient and more expensive generation resources to meet higher demand can be avoided.

Demand response resources with adequate response times (i.e., within ten minutes) may bid into PJM's synchronized (spinning) reserve market, allowing PJM to utilize demand-side resources to respond to unexpected generator outages, unexpected changes in electric demand, or other system contingencies. DR resources are eligible to provide regulation reserves, synchronized reserves, and day-ahead reserves, limited to 33 percent for each category and for two of the three services. DR resources can also provide nonsynchronized (nonspinning) and supplemental reserves in PJM.

PJM's competitive capacity auction, known as the Reliability Pricing Model Base Residual Auction (RPM BRA) is conducted every three years prior to the delivery year to allow power supply resources to bid into the market to either increase energy supply or reduce demand. For example, an auction held in 2018 would be for the 2021/2022 delivery year.

Prior to the RPM BRA for delivery year 2018-2019 (held in 2015), PJM allowed for three different types of demand resources to be bid in:

- **"Annual"** wherein a customer could be curtailed an unlimited number of times per year (the specific hours of the day vary by season), but each curtailment can only last for a maximum of ten hours;
- **"Extended Summer"** wherein customer loads can be curtailed between May and October between 10:00 a.m. and 10:00 p.m., subject to the same 10-hour limitation; and
- **"Limited"** wherein customers may only be curtailed ten weekdays between June and September between the hours of 12:00 p.m. and 8:00 p.m. for a maximum of six hours at a time.

In response to poor generator performance during the Polar Vortex[32] in 2014, PJM revised and restructured its capacity market. Approved by the FERC in 2015, the PJM proposal eliminated the three types of DR products and created a single DR resource—Capacity Performance. The purpose of the product is to provide larger capacity payments for performance, including bonuses for overperforming, as well as to increase penalties for nonperformers. The revised capacity market went into effect with the 2018/2019 RPM BRA. In the most recent auction, 2020/2021 RPM BRA, 9,847 MW was offered, of which 7,820 MW cleared the auction, which is 2,528 MW lower than the prior auction.[33]

In March 2011, the FERC issued Order 745 which established that, where it is cost effective to do so, demand response resources are to be paid the same wholesale price of energy for energy reductions as a generator would be paid for the sale of energy at that same time. Allowing DR to bid into electricity markets and be treated as a dispatchable resource has encouraged the expansion of DR programs and services offered by both investor-owned utilities and competitive CSPs. In the spring of 2012, PJM became the first grid operator to comply with FERC Order 745. On May 22, 2014, in response to a petition filed by the Electric Power Supply Association, the American Public Power Association and the Edison Electric Institute, the D.C. Circuit Court of Appeals vacated FERC Order 745, finding that FERC overstepped its jurisdiction because states have the jurisdiction to regulate the electric retail market. In January 2016, the Supreme Court of the United States upheld FERC Order 745. The Supreme Court found that although FERC did intentionally impact the retail market; DR is a wholesale function and therefore FERC has the power to regulate the wholesale market even if it has indirect impacts on the retail market. The Supreme Court ruling did not have a significant impact on the PJM market, as PJM continued to conduct auctions.

Approved by the FERC in May 2012, PJM offers Price Responsive Demand (PRD) as another class of demand response. PRD applies only to those customers on Advanced Metering Infrastructure (AMI) dynamic rate structures where consumption can vary in response to PJM wholesale market price signals (see Section 3.4.4 for a description of AMI). PRD is an aspect of the smart grid and requires the widespread deployment of advanced meters to retail customers and the introduction of dynamic retail rates. The voluntary participation of PRD providers in PJM's markets was designed to enhance grid operations and reliability and provide a closer link between the wholesale and retail electricity markets. PJM's capacity and energy markets would be cleared with the predicted reductions from PRD already included in the supply forecast. This process allows PJM's operators to better forecast system demand under real-time conditions, as a separate forecast of DR supply becomes less necessary. In 2018, BGE offered its demand response as a PRD resource.

In February 2019, PJM proposed to align the PRD program with its Capacity Performance Resources general rules, with the main change being that the nominal PRD value would be the lesser of summer

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[32] The Polar Vortex was a period of intense cold weather across the PJM region in January 2014, resulting in record-setting winter peak demand and significant electricity price spikes.

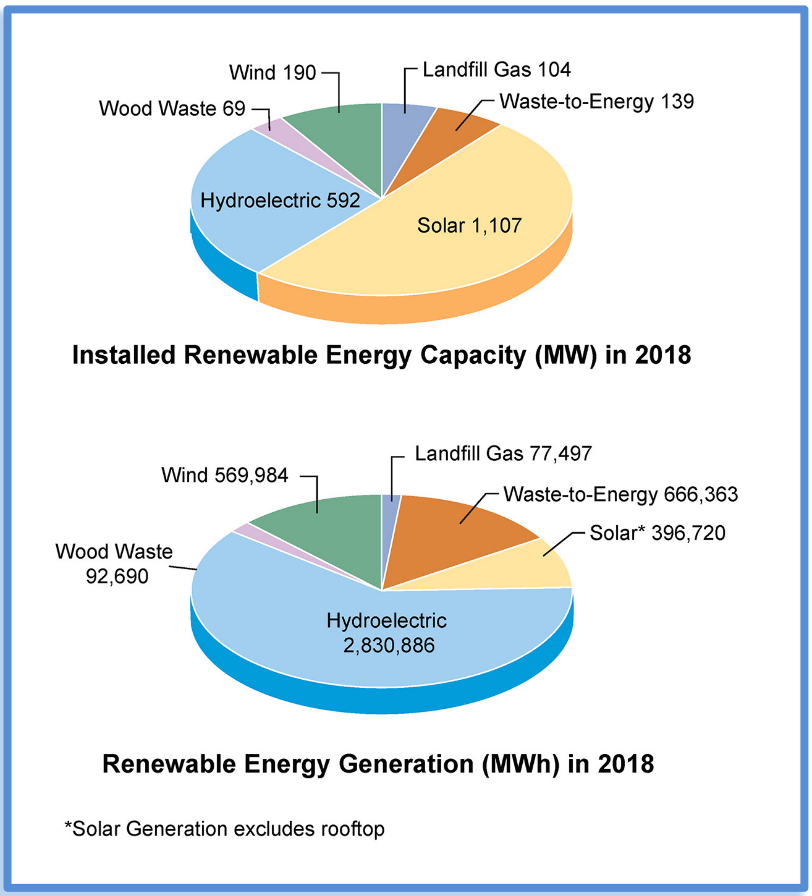
[33] PJM moved the 2019/2020 BRA for delivery year 2022/2023 delivery year to August 2019; however, PJM suspended all auction activities and deadlines related to 2022/2023 and 2023/2024 delivery year auctions until FERC issues an order regarding PJM's requested changes to its capacity market.

and winter load reductions. However, the Independent Market Monitor (IMM) stated that the proposal does not calculate the nominal PRD value (compensation) based on how PJM customers pay for capacity, i.e., the customer's load during PJM system peak. In June 2019, FERC agreed with the IMM and rejected PJM's proposal and stated that the PRD should be more consistent with annual peak-based billing framework for LSEs. See Section 3.4.4 for more information on smart grid technologies.

3.1.5 Renewable Resources

Presently, there are four main types of renewable energy resources in use in Maryland: wind, biomass (including wood waste, landfill gas, and municipal waste-to-energy), solar, and hydropower. Approximately 1,960 MW of generation capacity in Maryland comes from these resources (see Figure 3-6).

Figure 3-6 Renewable Energy in Maryland, as of 2018



Source: PJM Generator Attributes Tracking System (GATS) for capacity, and EIA-923 for generation. Solar capacity includes both utility-scale and rooftop solar. Solar generation excludes rooftop solar. Hydroelectric capacity includes 572 MW installed capacity for Conowingo, which differs from the capacity listed in PJM GATS.

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 and 3 MW, although some are as large as 5 MW.

At the conclusion of 2018, there was 97 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.[34] Texas is the leading state in land-based wind, with 25.6 GW of capacity. In addition to land-based wind, in December 2016, the United States had its first operating offshore wind energy plant, a 30 MW project at Block Island, Rhode Island. Five 6 MW wind turbines were built at the site. As of 2019, there were 15 active offshore wind commercial leases in the United States, totaling 25 GW.[35] Of those active leases, there are eleven specific projects totaling 7,492 MW, which is expected to be online by 2026.[36] Whether these projects will ever come online will depend on the status of the federal Production Tax Credit (PTC), the ability of developers to secure financing and power purchase agreements (PPAs), and navigating federal and state permitting requirements.

In Maryland, the greatest wind resources are located in the westernmost counties and off of the Atlantic Coast on the Outer Continental Shelf. The DOE's National Renewable Energy Laboratory (NREL) estimates that the United States may have a potential land-based wind resource capacity in excess of 10,000 GW. Maryland is estimated to have a potential land-based wind resource capacity of approximately 1.5 GW when the hub height is at 80 meters. Maryland's potential land-based wind resource capacity increases considerably at higher hub heights: 10.3 GW at 110 meters and 18 GW at 140 meters. The four NREL graphics included in Figure 3-7 illustrate the prospective land-based wind resource areas in Maryland.

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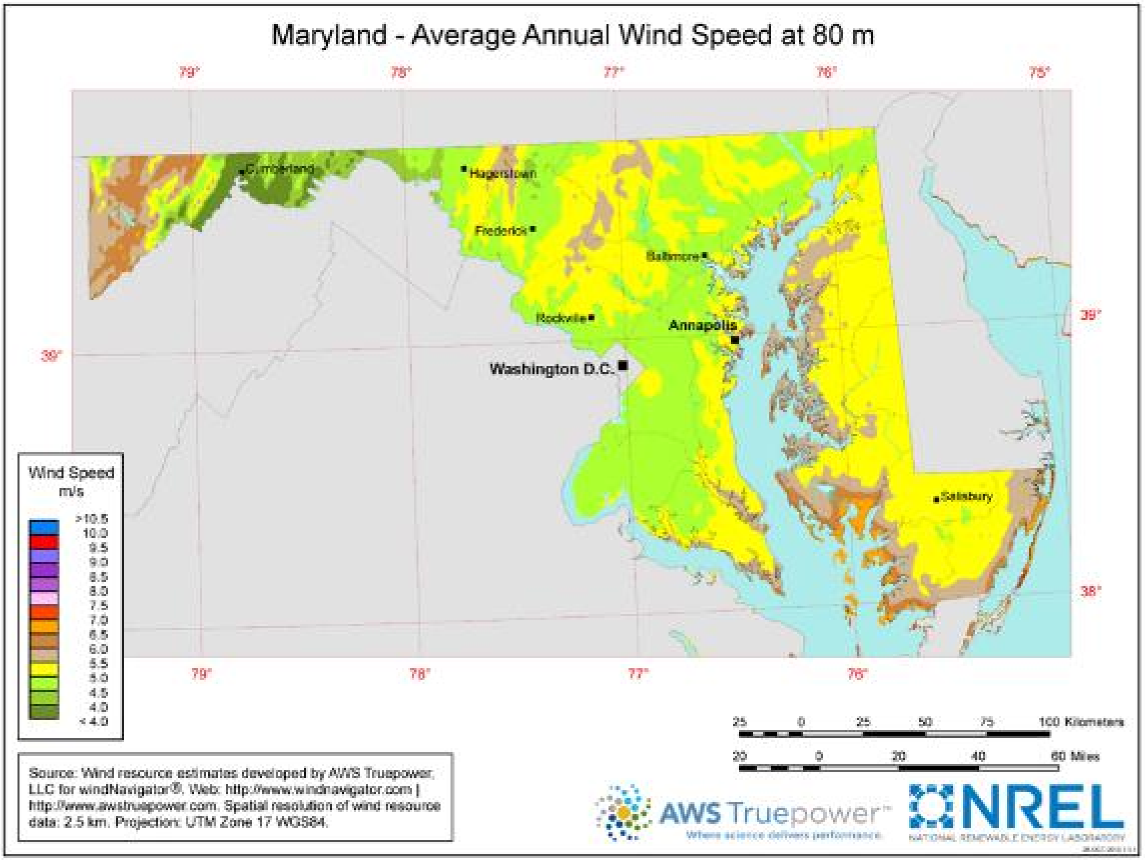
[34] World Wind Energy Association, "Global Wind Installations," https://library.wwindea.org/global-statistics-2018-preliminary/.

[35] American Wind Energy Association, "America's New Ocean Energy Resource," https://www.awea.org/policy-and-issues/u-s-offshore-wind.

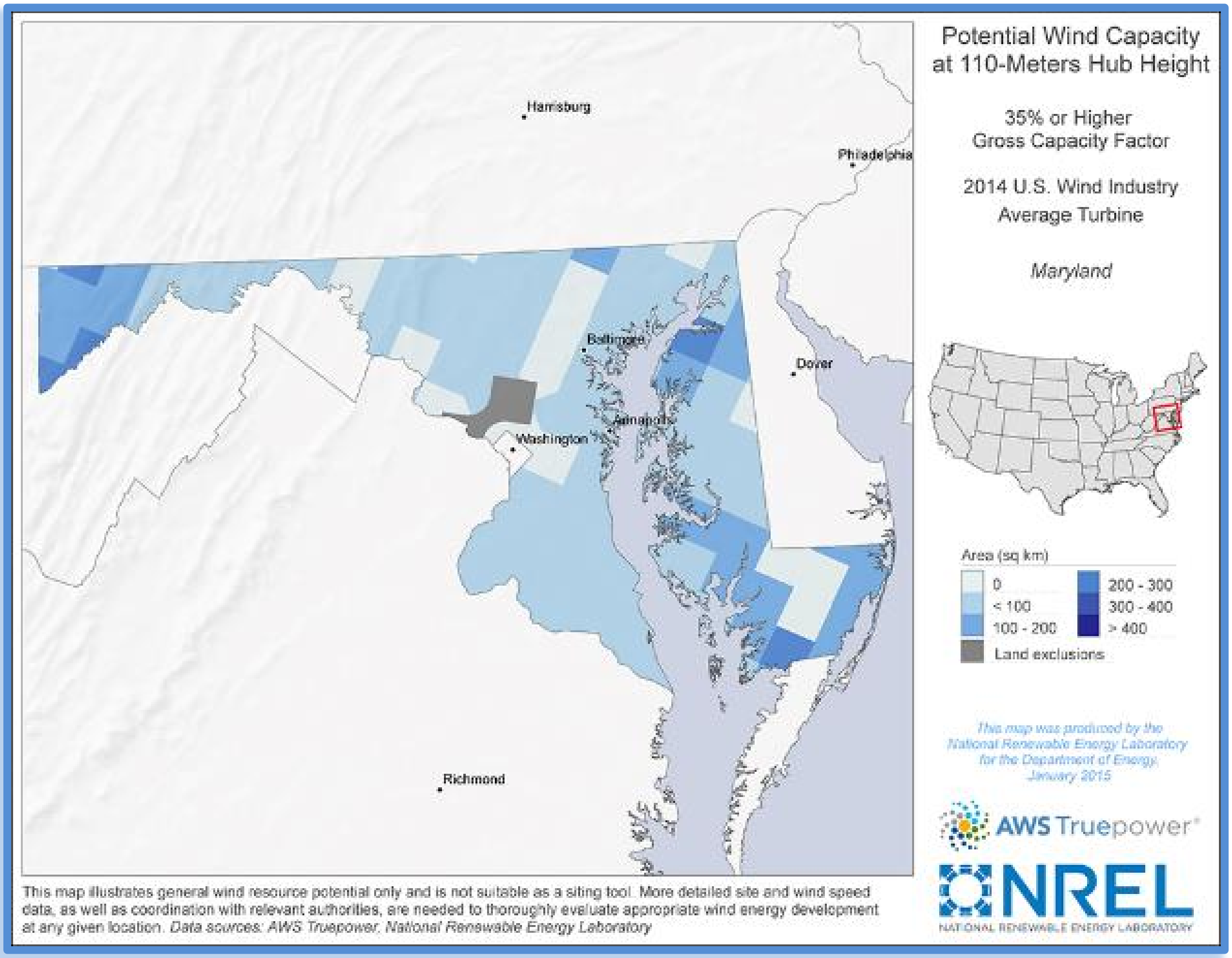
[36] American Wind Energy Association, "U.S. Offshore Wind Industry: Status Update – October 2019," https://www.awea.org/Awea/media/Resources/Fact%20Sheets/Offshore-Fact-Sheet-Oct-2019.pdf.

Figure 3-7 Maryland Potential Wind Resources



Source: "Maryland 80- Meter Wind Resource Map," NREL WindExchange, Department of Energy Energy Efficiency and Renewable Energy Office, https://windexchange.energy.gov/maps-data/54 .

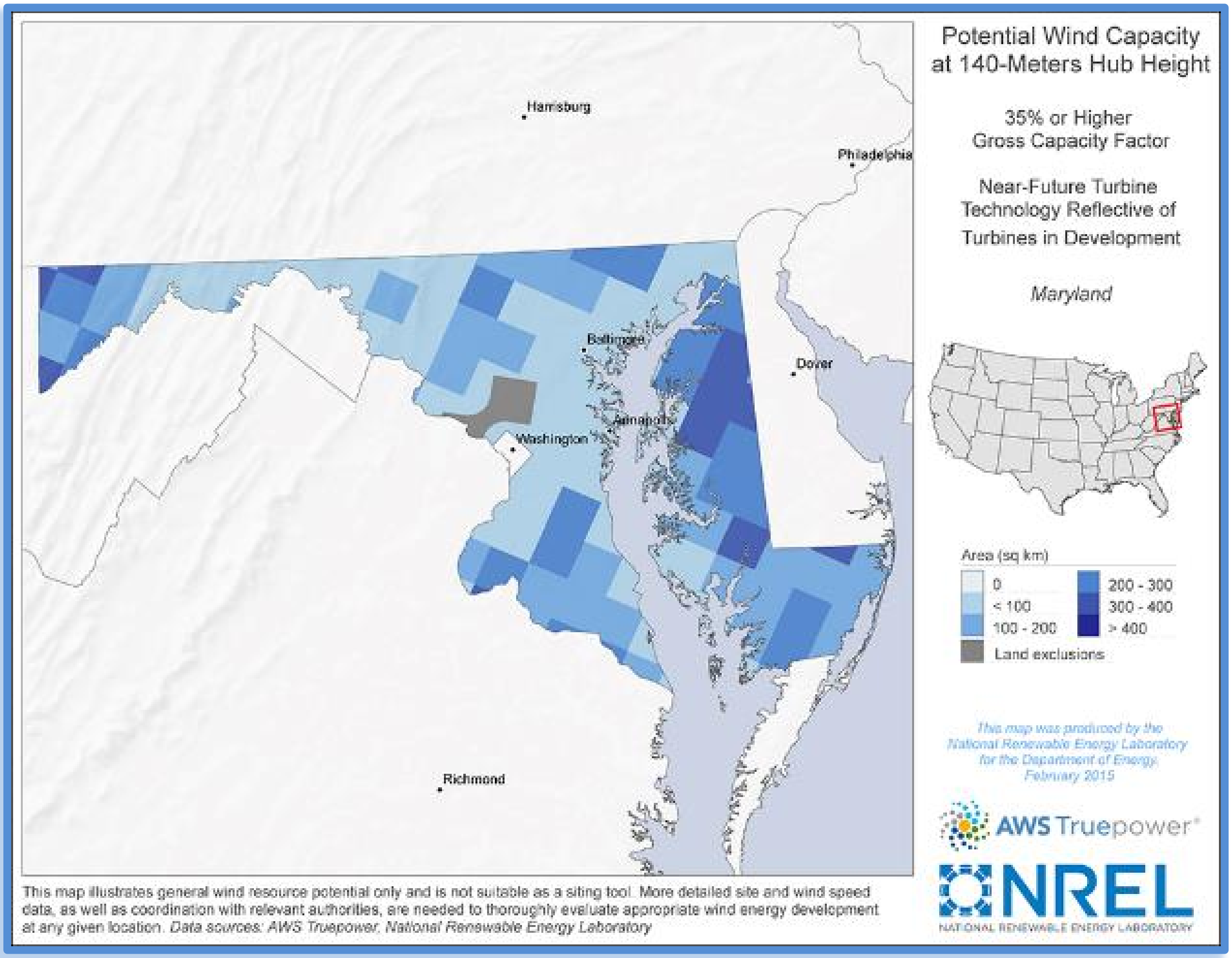
Figure 3-7 Maryland Potential Wind Resources (continued)



Source: "Wind Energy in Maryland," NREL WindExchange, Department of Energy Energy Efficiency and Renewable Energy Office, https://windexchange.energy.gov/states/md.

Note: The map shading indicates the amount of land area with a gross capacity factor of 35% or higher. The darker the shading, the larger the amount of developable area.

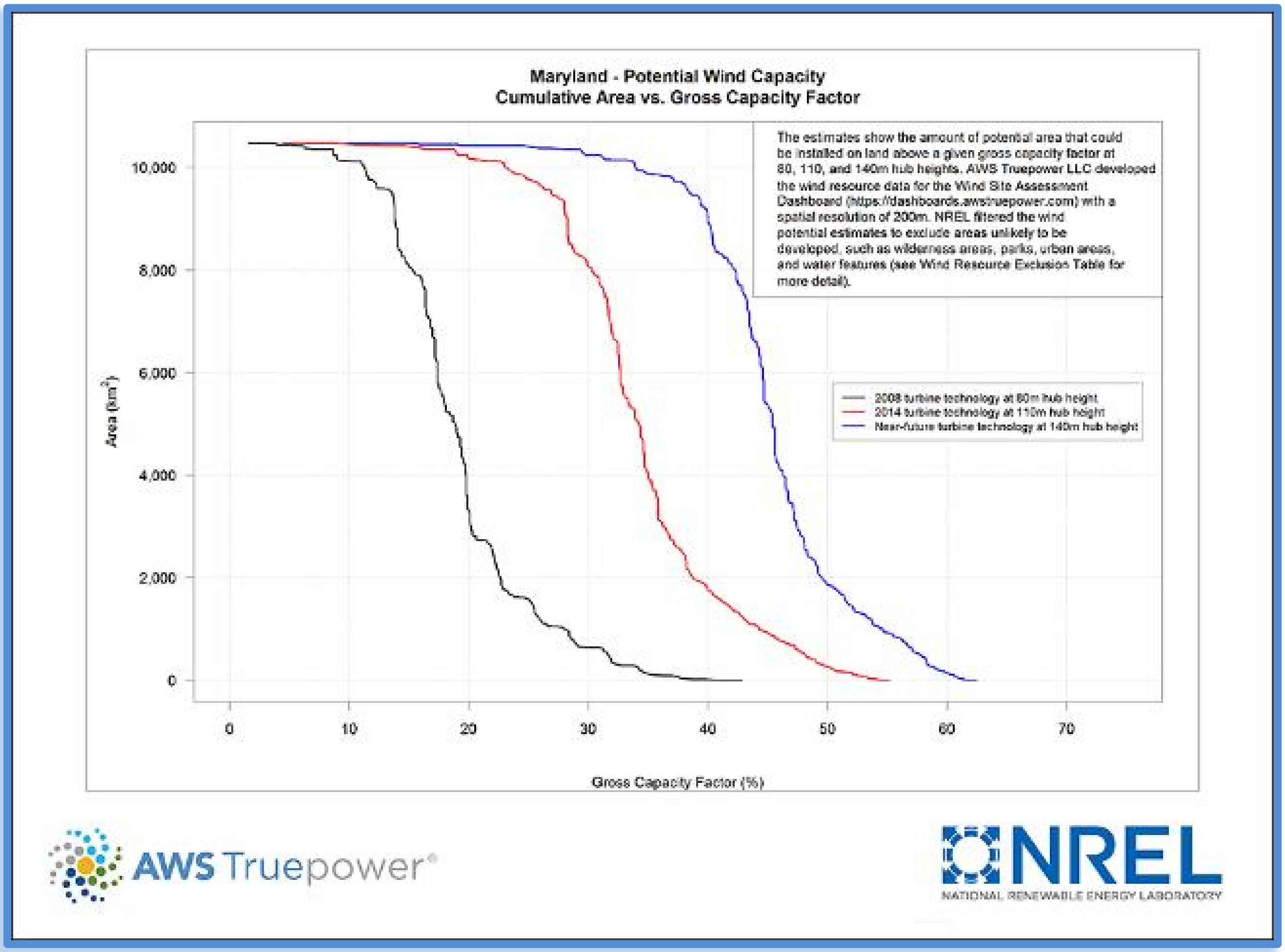
Figure 3-7 Maryland Potential Wind Resources (continued)



Source: "Wind Energy in Maryland," NREL WindExchange, Department of Energy Energy Efficiency and Renewable Energy Office, https://windexchange.energy.gov/states/md.

Note: The map shading indicates the amount of land area with a gross capacity factor of 35% or higher. The darker the shading, the larger the amount of developable area.

Figure 3-7 Maryland Potential Wind Resources (continued)



Source: "Wind Energy in Maryland," NREL WindExchange, Department of Energy Energy Efficiency and Renewable Energy Office, https://windexchange.energy.gov/states/md.

The Maryland General Assembly passed legislation in 2007 allowing new wind power facilities equal to or less than 70 MW in capacity to request an exemption from the CPCN requirement if:

- The wind facility is located on land;
- The electricity output is sold only on the wholesale market under an interconnection, operating, and maintenance agreement with the local utility; and
- The PSC allows for public input at a public hearing.

Wind facilities are still subject to any federal, state, and local approvals needed to address site specific issues such as erosion and sediment control, Federal Aviation Administration (FAA) lighting requirements, and threatened and endangered species impacts. In addition, the Maryland General Assembly passed an amendment in 2012 further requiring that any wind facility maintain a given distance from the Patuxent River Naval Air Station. The radius of this exclusion zone may not exceed 46 miles and would be determined in a PSC proceeding.

The majority of counties in Maryland have adopted some form of zoning ordinance for wind turbine development (see sidebar). Until very recently, Garrett County did not have any zoning regulations regarding the development of commercial-scale wind turbines. However, in 2013, the Maryland General Assembly enacted legislation establishing minimum setback requirements for utility-scale wind turbines in Garrett County — the only instance to date of the state legislature imposing county-specific requirements on wind power development. The statute requires a minimum distance from schools and residences of no less than 2.5 times the height of the wind turbine. Wind projects that have filed interconnection agreements with PJM before March 1, 2013 are exempt from this requirement. Wind developers can request a variance from the Garrett County Department of Planning and Development of up to 50 percent of the minimum setback requirement as long as all adjacent property owners give written authorization. The legislation also requires wind developers to post a bond equal to 100 percent of the estimated cost of decommissioning and site restoration.

Counties in Maryland with Wind Energy Ordinances

Land-based Wind Projects in Maryland

Table 3-3 and Figure 3-8 show the operating and proposed wind facilities 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 percent of Maryland's land-based wind resource potential at a hub height of 80 meters. Two other projects, representing about 140 MW, are currently in the planning and development stages.

Table 3-3 Status of Land-based Wind Projects in Maryland

Project – Developer/Owner	Size (MW)	Location	Nearest Town	Status
Criterion – Exelon	70	Backbone Mountain, Garrett County	Oakland	Operational
Roth Rock – Gestamp Wind	50	Backbone Mountain, Garrett County	Oakland	Operational
Fourmile Ridge – Exelon	40	Fourmile Ridge, Garrett County	Frostburg	Operational

Project – Developer/Owner	Size (MW)	Location	Nearest Town	Status
Dans Mountain – Laurel Renewable Partners	70	Dans Mountain, Allegany County	LaVale	CPCN Denied, County Approved, Appeal Pending
Fairwind – Exelon	30	Backbone Mountain, Garrett County	Oakland	Operational
Terrapin Ridge – EDF Renewables	69	Garrett County	Friendsville	Proposed but did not move forward

Figure 3-8 Approximate Locations of Wind Energy Projects in Maryland

Originally developed by Clipper Windpower, the 70 MW Criterion Wind Project was acquired by Constellation Energy (Constellation) in April 2010. More recently, the Criterion Wind Project was acquired by Exelon in 2012 through Exelon's merger with Constellation. Located on Backbone Mountain in Garrett County, the wind facility is comprised of 28 turbines that are approximately 415 feet tall with a maximum output of 2.5 MW each. Construction was completed in December 2010. Constellation signed a 20-year PPA with the Old Dominion Electric Cooperative for both the energy and the RECs produced by the wind facility. The Criterion Wind Project generated about 194,000 MWh in 2018.

The Roth Rock Wind Facility, developed by Synergics and now owned by Gestamp Wind, has a total installed power capacity of 50 MW. This facility, also located on Backbone Mountain near the Criterion Wind Project, consists of twenty 2.5 MW turbines, and stretches approximately three-and-a-half miles along a ridge near the West Virginia border. Gestamp Wind has a 20-year PPA with DPL for both the energy and the RECs produced at the facility. The Roth Rock Wind Facility generated about 109,000 MWh in 2018.

In January 2013, Fourmile Wind Energy, LLC, a subsidiary of Synergics, submitted an application to the PSC for a CPCN exemption for a 60 MW wind project in Garrett County. The PSC conducted a hearing in Garrett County to receive public comments in March 2013, and subsequently approved the CPCN exemption in April 2013. The project was revised to be developed under Exelon as a 40 MW project consisting of sixteen 2.5 MW turbines. The project commenced operations in 2015 and generated about 130,000 MWh in 2018.

Clipper Windpower proposed the 30 MW Fairwind Project to be located adjacent to the Criterion Wind Project. The PSC granted a CPCN exemption for this project in December 2013. Exelon took over the development rights to the Fairwind Project and brought the project online in 2015. The project consists of twelve 2.5 MW wind turbines and generated about 108,000 MWh in 2018.

Maryland's two other proposed land-based wind power proposals are described below. The ultimate generating capacity of these projects will depend on the specific turbine models selected for each project:

- Dan's Mountain is a 70 MW wind project in Allegany County originally proposed by US Wind Force. The PSC granted US Wind Force a CPCN exemption in March 2009, but the developers delayed the project after Allegany County enacted revised zoning regulations in May 2009. Laurel Renewable Partners purchased the project in May 2013. In December 2015, the PSC granted a request to delay construction to the end of 2016 and for the project to be online by the end of 2018. Earlier, in November 2015, the Allegany County Board of Zoning Appeals denied the developer's application for a special exception and variances from the county zoning requirements for wind projects. In January 2016, Laurel Renewable Partners petitioned the PSC for a CPCN, asking the Commission to preempt Allegany County's ordinances on wind turbines; the CPCN was denied, based on the County's opposition and the potential visual, noise, and shadow flicker impacts on nearby residents. Dan's Mountain appealed, and the Commission upheld its decision in June 2017. Dan's Mountain sought judicial review of the Commission's decision and in 2018, the Maryland Court of Special Appeals voted to send it back to the Allegany County zoning board for another review. In October 2019, the Allegany County Board of Zoning voted 2-1 to permit the construction of 17 wind turbines.

- Maryland's other land-based wind project, Terrapin Ridge, is to be located east of Friendsville. The project was granted a CPCN in 2012. The project developer switched its interconnection point and planned to be online by the end of 2018; however as of December 2019, the project has been suspended but is still in the PJM interconnection queue.

Two proposed wind projects in Maryland were converted to solar. Apex abandoned its proposed Mills Branch wind project in Kent County and proposed a 60 MW solar facility near Chestertown; however, the PSC denied this CPCN request in February 2017. Pioneer Green Energy proposed the 150 MW

Great Bay wind project in Somerset County, but public opposition and concerns by the U.S. Department of Defense (DoD) about the wind turbines' potential effect on radar at the Patuxent River Naval Air Station delayed the project. In 2014, U.S. Senator Barbara Mikulski (D-MD) successfully added an amendment to the DoD's appropriations bill that prevents the U.S. Navy from finalizing any agreement with Pioneer Green Energy until a $2 million study regarding the potential impact on test range and turbine motion was completed by the Massachusetts Institute of Technology (MIT). Pioneer Green Energy subsequently converted the project to solar and received approval by the PSC for the 150 MW Great Bay solar project in 2015. Phase I, the first 75 MW, was operational in early 2018 and Phase II, the remaining 75 MW, is currently under construction. The U.S. General Services Administration (GSA) committed to purchase half of the total output of the Great Bay solar project – i.e., Phase I.

Offshore Wind

According to an NREL study, the United States may have a usable offshore wind resource capacity of over 4,000 GW, with approximately 480 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 25 GW. A report prepared by the University of Delaware suggests that Maryland's unrestricted offshore wind potential is even higher, at 60 GW. Using existing offshore wind turbine technology and limiting development to shallow waters reduces the offshore wind potential to 14.6 GW. Still, if fully developed, offshore wind could supply 70 percent of the state's electric demand. For more information regarding Maryland's offshore wind, see Section 2.1.4.

Permitting Issues

Offshore wind energy facilities will require regulatory approval from both federal and state agencies, and in many cases local agencies as well.

Prior to construction, the developer's project must undergo an environmental and permitting review process. This process typically includes the following federal government reviews and approvals:

- A National Environmental Policy Act (NEPA) review, which calls for an Environmental Assessment (EA) and potentially a full Environmental Impact Statement (EIS).
- Demonstration of compliance with state coastal management programs as administered under the Coastal Zone Management Act.
- An Outer Continental Shelf (OCS) air permit, required to ensure that sources within 25 nautical miles of a state seaward boundary comply with air quality requirements of the nearest onshore area. Typically, the EPA issues this permit; however, the MDE requested delegation from the EPA for the implementation, administration and enforcement of Title 40 of the Code of Federal Regulations, Part 55 (OCS Regulations) and was granted approval in 2015.
- U.S. Army Corps of Engineers (USACE) permit for construction of any structures that might obstruct navigable waterways of the United States, as required by Section 10 of the Rivers and Harbors Act.
- USACE permit for dredging and backfilling that would be required for project construction, as required under Sections 401 and 404 of the Clean Water Act.
- FERC approval for connection at the transmission interface.

- Notice to the Federal Aviation Administration (FAA) of any construction exceeding 200 feet in height.
- U.S. Coast Guard permission to establish aids to maritime navigation.
- BOEM approval of the Site Assessment Plan, the Construction and Operations Plan, and the Decommissioning Plan.

In addition to federal approval, it will be necessary for developers to obtain state and local regulatory approval. For example, a CPCN from the Maryland PSC would be necessary to transmit electricity to the existing electrical grid.[37]

Exposure to Severe Weather

Nor'easters and hurricanes pose a significant risk to wind turbines off of the Northeast Atlantic Coast. Further, anticipated global temperature increases and elevated sea levels associated with climate change may impact the intensity of these storms.

A group of Carnegie Mellon University researchers found that turbines built along the Atlantic Coast may be vulnerable to hurricane-force extreme winds. The team found that the maximum wind speeds in severe storms can exceed the design limits of currently available wind turbines. In 2003, for example, seven wind turbines in Okinawa, Japan, were destroyed by typhoon Maemi and several turbines in China were damaged by typhoon Dujuan. The research team emphasized that developing reasonable safety measures, including improved design requirements and backup power for the motors that allow turbines to track the wind direction could mitigate serious hurricane damage.

Despite such findings, industry experts maintain that wind turbines off the coast of New Jersey or New York would have survived Superstorm Sandy in October 2012. Most offshore wind turbines are designed to withstand Category 3 hurricane conditions, which exceed the conditions imposed by Sandy. Additionally, the offshore wind industry is anticipating and preparing for the type of extreme weather challenges these facilities will be subject to during their 20+ year lifespans. Whether a particular turbine design can handle the load from extreme weather events in the Northeast remains unknown, and will be subject to further research.

Offshore Wind Turbines Research and Development

Over 60 percent of potential offshore wind locations in the U.S. are in deep waters,[38] i.e., the water is so deep that the usual techniques of fixing large steel piles or lattice structures to the ocean floor are not possible. Utilizing floating foundations for offshore wind turbines could access these offshore wind resource areas, and could also lead to improved offshore wind industry standardization as the floating platforms are not as sensitive to differences in seabed conditions or water depth. That, in turn, translates into greater efficiencies in manufacturing and assembling offshore wind turbines and could lead to an offshore wind project being constructed on land and towed out to sea. Additionally, floating foundations result in reduced environmental impacts as pilings do not have to be installed and the ocean seabed is not disturbed.

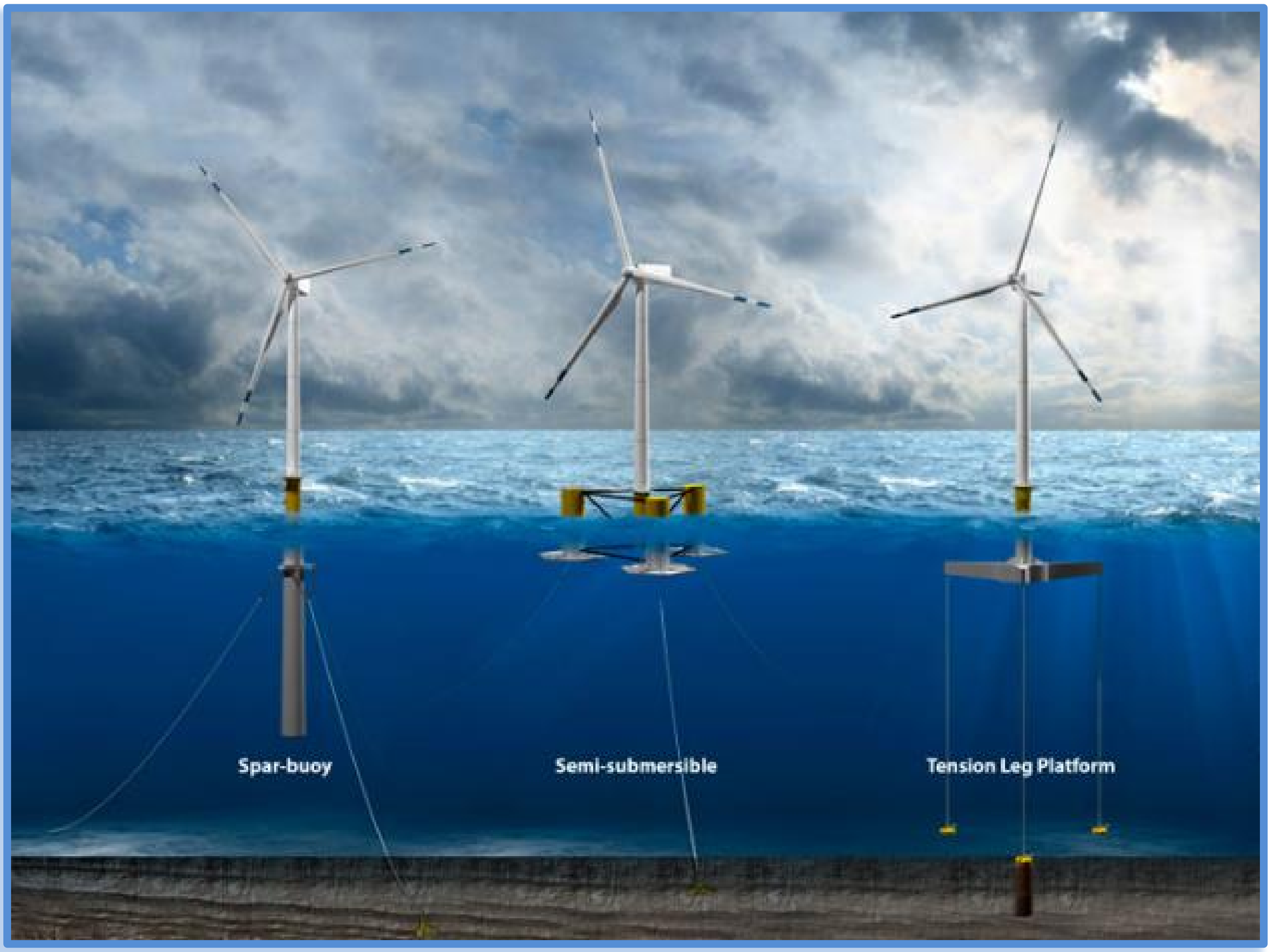
Floating foundations will need to meet new design criteria encompassing weight and buoyance requirements and the heaving and pitching from ocean waves. The technology is

[37] Navigant, "*Offshore Wind Market and Economic Analysis*," September 2014, http://energy.gov/sites/prod/files/2015/09/f26/2014-Navigant-Offshore-Wind-Market-Economic-Analysis.pdf., and BOEM*, "Guidelines for Information Requirements for a Renewable Energy Construction and Operations Plan (COP),"* April 2016, ver. 3.0, http://www.boem.gov/COP-Guidelines/.

[38] U.S. Department of Energy, "*Offshore Wind Research and Development*," http://energy.gov/eere/wind/offshore-wind-research-and-development

at an early stage and much more design and testing needs to be completed before floating foundations are commercially feasible. Three types of floating wind concepts are under investigation: Ballast Stabilized, Mooring Line Stabilized and Buoyance Stabilized. Ballast Stabilized foundations (also known as spar buoy) rely on mooring lines with anchors that drag in the water. Mooring Line Stabilized (also known as tension leg platform) foundations uses suction pile anchors— essentially, upturned buckets that are embedded in marine sediment through negative pressure. Buoyance Stabilized (also known as semisubmersible) foundations are similar to Ballast Stabilized foundations except that they are semisubmersible and are on a floating platform. Figure 3-9 depicts these concepts.

Figure 3-9 Floating Wind Turbine Concepts



Several floating wind turbine prototypes are being tested around the world. Prior to 2017, the turbine sizes were small, for example,

- Statoil's Hywind 2.3-MW test turbine, installed in 2009 off the coast of Norway in about 700 feet of water;

- Principle Power's 2-MW semisubmersible wind turbine, known as WindFloat, off the coast of Portugal that has been in the testing phase since 2011; and
- University of Maine's DOE funded two 6 MW wind turbines installed on a semisubmersible platform in 2013 off the coast of Monhegan Island, Maine.

Block Island Offshore Wind

In December 2016, Block Island Wind Farm became America's first operational offshore wind farm. Deepwater Wind developed the 5-turbine 30 MW project approximately 3 miles from Block Island, which is off the coast of Rhode Island. Prior to the project, Block Island was fueled by a small diesel power plant and not connected to Rhode Island's mainland power. The offshore wind project resulted in Block Island being connected to the New England power grid and the closure of the island's diesel power plant.

In 2017, Hywind implemented the largest floating wind technology testbed by installing five 6 MW floating turbines approximately 15 miles off the coast of Scotland in 345 feet of water. The turbines are 830 feet tall, with 256 feet submerged under water. During one winter period, the turbines were able to produce 65 percent capacity, even with hurricane season and 27-foot waves from a severe winter storm, compared to the average winter capacity of 40-60%. The size of project and amount of capacity produced is promising for the future implementation of floating wind technology. In addition to the success, there is still investment in larger models. For example, in 2019, DOE provided $10 million in funding to the University of Maine for the development of a 10-12 MW floating substructure design.

Environmental and Socioeconomic Risks

Wind turbines can provide environmental benefits through the reduction of GHG emissions and conservation of water resources. However, as with all energy sources, there are environmental and socioeconomic risks associated with offshore wind energy. Studies suggest that the potential risks associated with offshore wind projects are typically site-specific. Research at European-installed projects and U.S. baseline studies are building the knowledge base and helping to inform decision makers and the public. Outlined below are some of the primary stakeholder concerns regarding offshore wind power facilities:

- **Marine species populations:** Site-specific research is necessary to gain a better understanding of the potential impacts to populations of marine species including fishes, marine mammals and benthic organisms. European studies conducted to date suggest that the impacts of offshore wind facilities on marine populations are minimal, but U.S. studies may be required to replicate these results and address mitigation of any harmful effects. Submerged foundations for these offshore wind turbines can also act as artificial reefs, resulting in an increase in shellfish and the fish and marine animals that consume them.
- **Avian and bat populations:** Concerns exist regarding bird and bat mortality due to collisions with turbines; however, European studies suggest that birds are able to adapt to the turbines and avoid collisions. Some studies found a sharp decline in some bird species (Common Eiders and Black Scoters) but an increase in seagulls and cormorants. Another concern regarding avian populations is the possible fragmentation of their ecological habitat network (e.g., migration

pathways, breeding and feeding areas). Bats are known to traverse the offshore environment during migration, but the level of risk from offshore wind turbines is unknown.

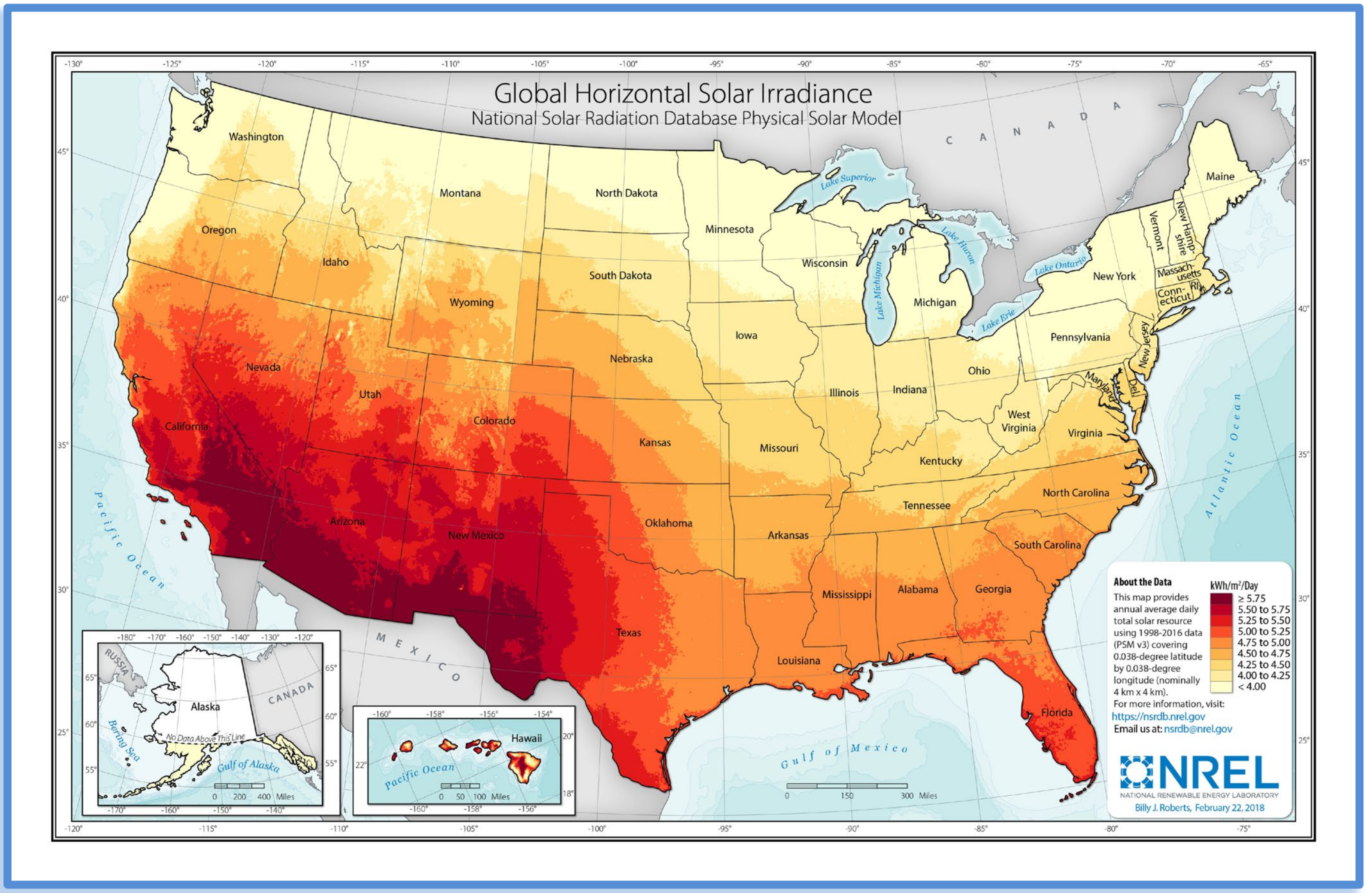
- **Visual effects/property values:** Extensive studies to estimate the change in property values as a result of the presence of offshore wind turbines have not been conducted for coastal communities in the United States. U.S. studies conducted for land-based wind projects, however, show minimal to no impact on real estate prices and property values as a result of the presence of wind turbines.
- **Tourism:** Coastal communities that are dependent on beach vacationers and the resulting local revenues and tax base have expressed concerns about the presence of offshore turbines, however, the evidence is ambiguous. Denmark currently attracts tourists with "Energytours" of offshore wind facilities.
- **Marine safety:** The possibility of a ship colliding with a turbine poses a potentially significant risk to the marine environment from fuel leaks from a disabled ship or to human safety should the turbine collapse. Measures will need to be taken to prevent collisions (e.g., navigation exclusion zones, distance requirements for routes, mapping on navigation charts, warning lights, etc.). The U.S. Coast Guard created the Atlantic Coast Port Access Route Study (ACPARS) to study the impact of alternative energy facilities, including offshore wind, on shipping lanes and vessel traffic. The ACPARS issued an interim report in 2012 which stated that offshore projects would disrupt vessel traffic, increase the density of vessel traffic and raise the risk of collisions that could lead to the loss of property, loss of life, and environmental damage. The final report, released in February 2016, included (1) recommended marine planning guidelines; (2) determination of the appropriate width of navigation routes for alongshore towing operations near offshore wind turbines; (3) recommendations to modify designated wind energy development areas to increase boating safety. In response to the Final Report, BOEM expressed concerns that the final report is a one size fits all approach that eliminates designated wind areas and that BOEM believes that a site-specific development for distance setbacks would be a more appropriate method. Additionally, the report was criticized for ignoring European risk assessments, such as one conducted for the Horns Rev II wind facility located off the coast of Denmark, which concluded that the likelihood of a ship-to-ship collision is "significantly higher" than the probability of a vessel colliding with a wind turbine. Despite several concerns filed against the report, the U.S. Coast Guard filed the Final Report with the Federal Register in 2017 without any modifications.
- **Noise:** Construction of offshore wind turbines can result in high amounts of noise that, absent mitigation, could contribute to marine species avoiding the area and can result in tissue damage and even higher mortality rates for fish. Noise from operational wind turbines is not thought to be of particular concern other than for Baleen whales, whose hearing is assumed to include low frequency sounds, and Right whales, who may respond to noise from wind turbines at close range.

Solar

By virtue of its location, Maryland has only an average solar resource with moderate solar energy intensities, as illustrated in Figure 3-10. However, Maryland has several policies in place that encourage the deployment of solar energy systems. One such policy is the state's RPS, which calls for 50 percent renewable energy by 2030, with 14.5 percent coming from solar energy sources by 2028 and 10 percent coming from offshore wind by 2025. Solar systems must be connected with the distribution grid in

Maryland to be eligible. Load serving entities (LSEs) can self-generate solar power, purchase solar renewable energy credits (SRECs), or pay the solar alternative compliance payment (ACP), providing a financial incentive to homeowners, businesses, and independent developers to install solar renewable energy systems. Solar generators must offer SRECs for sale to Maryland electric suppliers before offering them to anyone else.

Figure 3-10 Quality of Photovoltaic (PV) Resource



Source: https://www.nrel.gov/gis/images/solar/solar_ghi_2018_usa_scale_01.jpg

At the conclusion of 2018, there were 61,460 instate solar projects representing 1,100 MW of generating capacity in Maryland, 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), 125 systems larger than 1 MW have come online representing 453 MW of solar generating capacity. Table 3-4 lists the GATS-registered solar facilities by system size. In 2018, Great Bay Solar Phase I in Somerset County became the largest operational solar facility in Maryland. In total, since 2016, the PSC has issued CPCNs to 26 solar facilities with a combined capacity of 841.6 MW and there are 7 cases pending before the Commission with a combined capacity of 113.5 MW. The largest CPCN approved to date is for Cherrywood Solar, a 202 MW solar facility to be located in Caroline County.

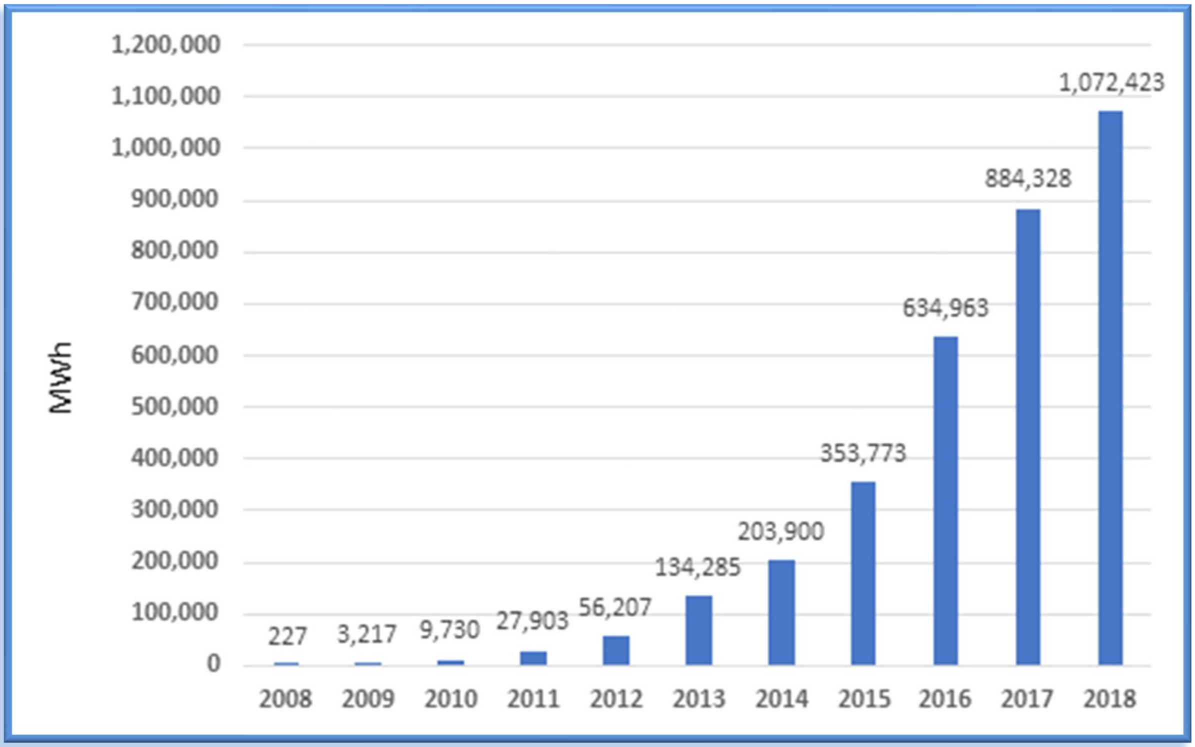
Table 3-4 Maryland's Solar Facilities Listed in PJM GATS, 2018

System Size (kW)	Number of Projects	Total Capacity (MW)
0 to ≤ 3	2,363	6
> 3 to 6	15,516	73
> 6 to 10	22,839	181
> 10 to 50	20,155	284
> 50 to 100	163	12
> 100	424	544
Total	61,460	1,100

Source: PJM Generation Attribute Tracking System.

Solar energy generation capacity in Maryland has gone from 0.1 MW in 2007 to 1,100 MW in 2018 due, in large part, to Maryland's implementation of a solar carve-out under the Maryland Renewable Portfolio Standard (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 percent by 2020 to 14.5 percent by 2028. Prior to that, in 2017, the solar carve-out had increased from 2 to 2.5 percent. Likely attributed to the continued increasing of the goal, solar generation in Maryland increased 799 percent, or approximately 938,138 MWh between 2013 and 2019 (see Figure 3-11). For more information on the Maryland RPS solar carve-out, see Section 2.1.1 Maryland RPS.

Figure 3-11 Solar Generation in Maryland, 2008-2018



Source: Maryland PSC, Renewable Energy Portfolio Standard Report, Various Years. Appendix A in this publication lists aggregate SRECs retired in Maryland.

Similar to Maryland, New Jersey also provides strong policy support for solar technologies. In 2018, New Jersey increased its RPS to 50 percent by 2030, with a solar carve-out of 5.1 percent. The amended New Jersey RPS eliminates the state's SREC system once either the 5.1 percent solar carve-out is reached, or by June 2021, whichever comes first, and requires a new program to be established to support distributed solar. Until the new program is established, the solar set-aside is 5.1 percent of all retail electric sales by 2024 and ramp down after that in recognition that solar facilities will reach the end of their 15-year SREC eligibility terms. As of November 2019, New Jersey had about 3.1 GW of installed solar capacity.[39]

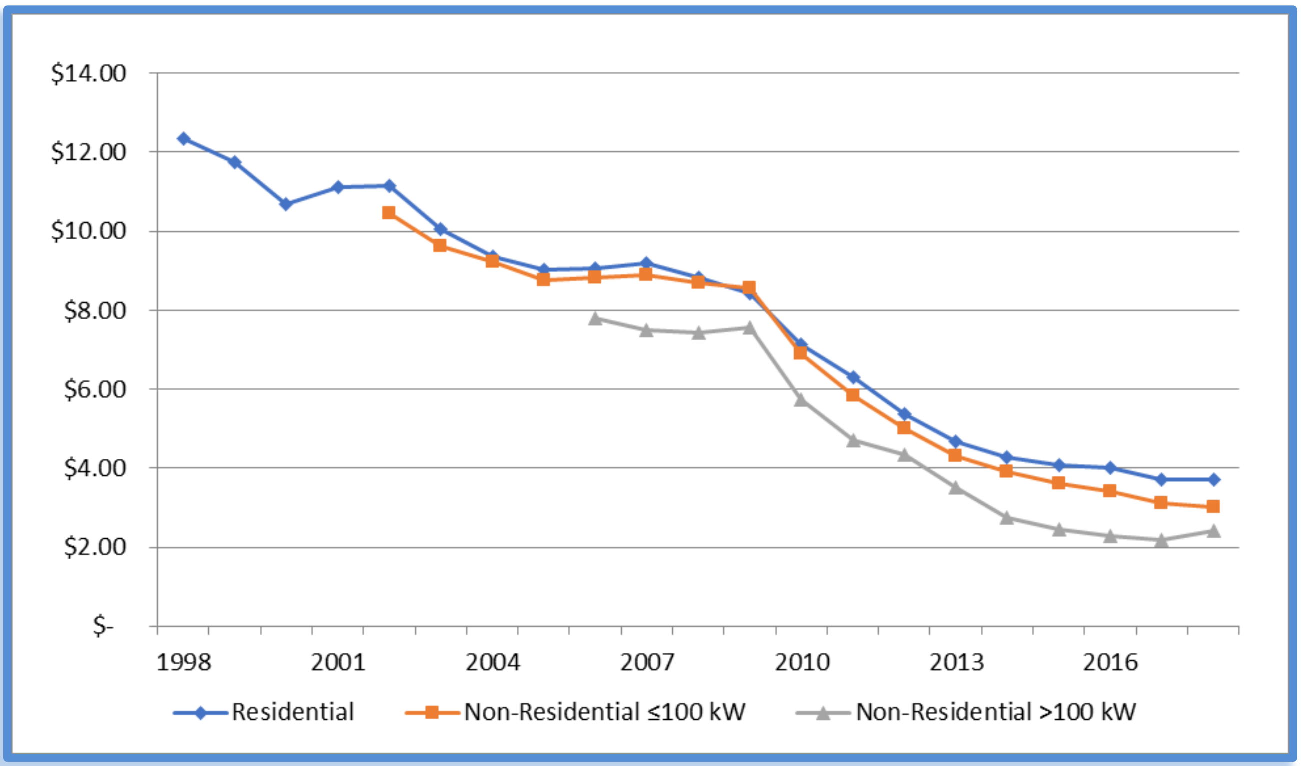
Nationally, installed solar costs have declined, on average, by 6 to 12 percent per year since 1998, depending on customer class (residential or nonresidential). Cost declines, however, have not occurred at a steady pace. In fact, installed costs have declined markedly since 2009. National median costs of solar systems dropped by 130 percent for residential systems, 186 percent for nonresidential systems

[39] New Jersey's Clean Energy Program, "Installation and Project Status Reports," December 2018, http://njcleanenergy.com/files/file/SRP/Installation%20Reports/FY19/Solar%20Installation%20Report%20December%202018.xlsx.

below 100 kW, and 68 percent for nonresidential systems over 100 kW (see Figure 3-12) in 2018, as compared to 2009.

Certain incentive policies, like the Maryland and New Jersey RPSs, have assumptions of declining PV installation costs built into the enforcement mechanisms. In the case of the RPS policies, the alternative compliance payment (ACP), which effectively places a ceiling on solar REC costs since it provides an alternative method by which to comply with the requirement, generally moves lower year to year. If the solar industry cannot match these downward cost profiles, utilities may begin opting to pay the ACP in lieu of installing solar facilities.

Figure 3-12 Cost of Solar PV in the United States ($/Watt), 1998-2018



Source: Barbose, Galen and Naim R. Darghouth, Tracking the Sun X: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States, Lawrence Berkeley National Laboratory, 2019, https://emp.lbl.gov/tracking-the-sun.

Hydroelectric

Hydropower is one of the oldest sources of power, used thousands of years ago to grind grain. The first U.S. hydroelectric power plant began operations in the 1880s. A hydroelectric dam is the most well-known form of hydropower production, often built on a very large scale by closing off an entire river and forming a large lake-like reservoir.

In 2013, President Obama signed two bills aimed at boosting development of the nation's hydropower resources. H.R. 267, the Hydropower Regulatory Efficiency Act, promotes the development of small hydropower and conduit projects and aims to shorten regulatory timeframes of certain other low-impact hydropower projects, such as adding power generation to the nation's existing non-powered dams and closed-loop pumped storage. Since 2013, the FERC reported it has extended 16 exemption permits for small conduit hydropower projects.

Hydroelectric Potential at Existing Dams

A report by the Department of Energy's Oak Ridge National Laboratory (ORNL) found that adding powerhouses to 54,000 existing U.S. dams that do not currently have generation facilities could garner up to 12.6 GW — enough renewable energy to power about 12.6 million homes. Moreover, most of these dams can be converted to generation facilities with minimal impact to critical habitats or wilderness areas. Several small (& 30 MW) sites are available in Maryland. One project is already in development. In December 2010, Fairlawn Hydroelectric Company filed an application with the Federal Energy Regulatory Commission for an original license to construct, operate and maintain its proposed Jennings Randolph Hydroelectric Project. The 13.4 MW project will be located at the U.S. Army Corps of Engineers' Jennings Randolph Dam and Lake in Garrett County, Maryland and Mineral County, West Virginia. The Jennings Randolph Dam (also known as Bloomington Lake Dam) is on the North Branch of the Potomac River near the towns of Barnum, West Virginia, and Swanton, Maryland, and was completed in 1985 by the Corps (Baltimore Division) for the purposes of flood control, recreation and natural resource management. The proposed project would occupy approximately 5.0 acres of federal land under the jurisdiction of the Corps. FERC issued a 50-year operating license on April 30, 2012. Construction was delayed as the project waited for approval by the U.S. Army Corp of Engineers. Typically, construction must begin within two years of issuance of the FERC operating license; however, due to the licensing delay, FERC granted an extension to initiate construction by 2021.

Jennings Randolph Dam

Conduit Hydroelectric Power in Maryland

The City of Frostburg received an exemption from FERC licensing to construct the 75 kW Frostburg Low Head Project, a small conduit hydropower project located on Frostburg's municipal raw water line in Allegany County. The plant uses the water main already in place on the eastern slope of Big Savage Mountain. As the water comes down the mountain, it turns the turbine, generating electricity. The project is expected to generate approximately 240 MWh annually. The construction of the plant was completed in 2012 and is fully operational.

President Obama also signed into law H.R. 678, the Bureau of Reclamation Small Conduit Hydropower Development and Rural Jobs Act, which authorizes small hydropower development at existing Bureau of Reclamation-owned canals, pipelines, aqueducts and other manmade waterways. Such development could provide enough power for 30,000 American homes with no environmental impact.

In 2018, Congress enacted the America's Water Infrastructure Act. The law required FERC to (1) create a two year decision timetable for qualifying facilities at existing non-powered dams; (2) establish a list of non-powered federal dams with the greatest potential for hydropower development; (3) develop a two year process for licensing of closed-loop pump storage projects; and (4) consider development opportunities for closed-loop pump storage projects at abandoned mine sites.[40] FERC issued implementation rules in April 2019.[41]

Conduit hydropower projects are able to extract power from water without the need for a large dam or reservoir. Existing or newly constructed tunnels, canals, pipelines, aqueducts, and other manmade structures that carry water can be fitted with electric generating equipment to produce hydropower. Conduit hydro projects are efficient and often cost effective, as they are able to generate electricity from existing water flows using infrastructure that is either already in place or is proposed regardless of a need for power.

Maryland has two large-scale (greater than 10 MW capacity) hydroelectric dam projects and two additional small-scale facilities that are currently in operation. Maryland's hydroelectric plants are listed in Table 3-5 with locations shown in Figure 3-13. Conowingo Dam, the state's largest hydro facility, is currently operating under an annual license from FERC until settlement agreement with MDE is approved by FERC. In October 2019, Exelon, the owner and operator of Conowingo Dam, proposed a settlement with MDE to FERC, where Exelon will spend over $200 million over 50 years to 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,

[40] America's Water Infrastructure Act of 2018, Pub. L. No. 115-270 (2018), https://www.govtrack.us/congress/bills/115/s3021/text. See also Anne E. Sibree, "Hydro Review: The Revitalization of Hydropower," *Hydro Review*, October 16, 2019, https://www.hydroreview.com/2019/10/16/hydro-review-the-revitalization-of-hydropower/.

[41] FERC Final Rule 18 CFR Pt. 7, Hydroelectric Licensing Regulations Under the America's Water Infrastructure Act of 2018, Order No. 858, 167 FERC ¶ 61,050 (2018), https://www.ferc.gov/industries/hydropower/gen-info/water-infr-act.asp. See also Anne E. Sibree, "Hydro Review: The Revitalization of Hydropower," *Hydro Review*, October 16, 2019, https://www.hydroreview.com/2019/10/16/hydro-review-the-revitalization-of-hydropower/.

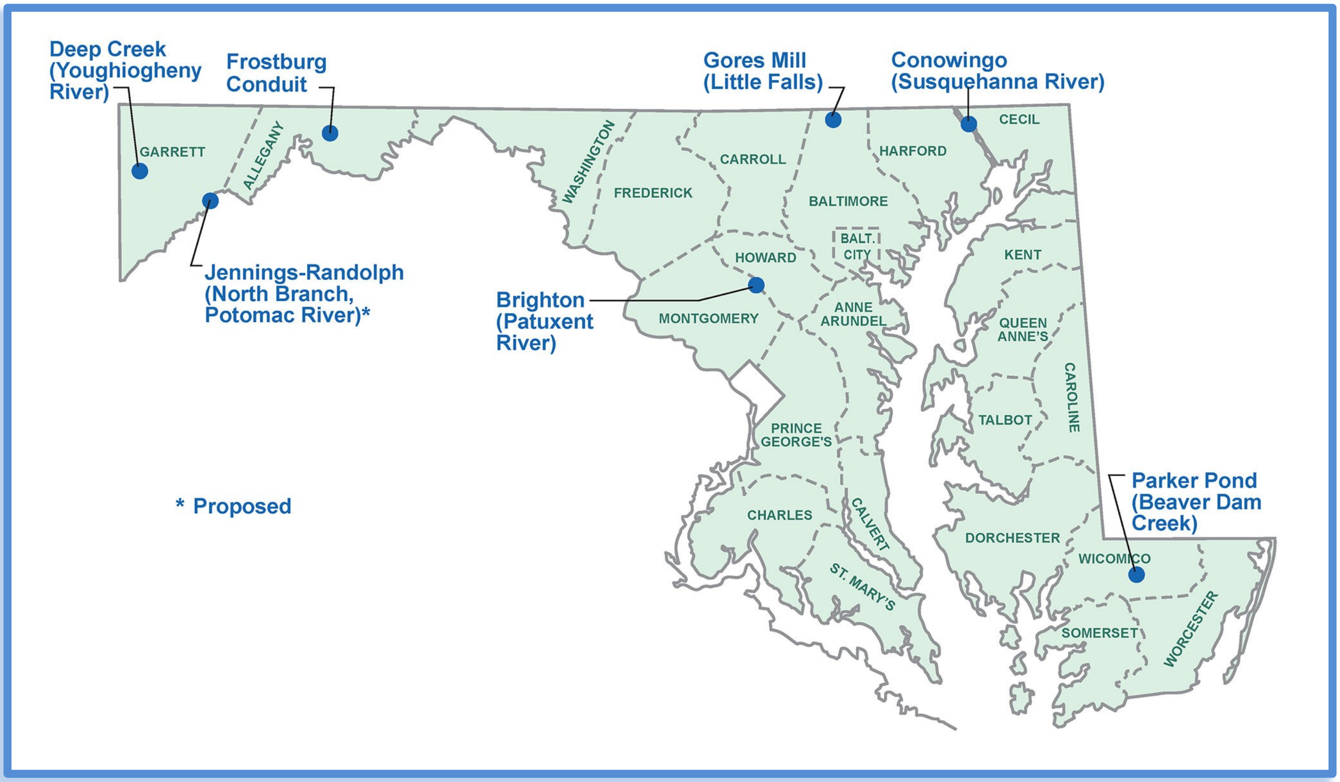
dissolved oxygen monitoring, shoreline management, turtle management, a waterfowl nest plan, sturgeon monitoring, mussel restoration, water quality project funding, and other measures.[42] Section 5.2.2 includes further discussion about hydroelectricity and its potential impacts.

Table 3-5 Hydroelectric Projects in Maryland

Project Name	Name-plate Capacity	River / Location	FERC Project No.	Owner	FERC License Type	FERC License Issued	FERC License Expires	Year Operational
LARGE-SCALE PROJECTS								
Conowingo	572 MW	Susquehanna/ Conowingo, Harford County	405	Exelon Corporation	Major License	1980	2014	1928
Deep Creek	20 MW	Deep Creek/ Oakland, Garrett County	-	Brookfield Power	None	-	-	1928
Jennings Randolph (proposed)	13.4 MW	North Branch Potomac River/ Bloomington, Garrett County	12715	Fairlawn Hydroelectric at USACE dam	Major License	2012	2062	FERC construction permit extended through 2021
SMALL-SCALE PROJECTS								
Brighton	400 kW	Patuxent River/Clarksville, Montgomery County	3633	KC Brighton LLC	Minor License	1984	2024	1986
Frostburg	75 KW	Big Savage Mountain Pipeline/Allegany County	14059	City of Frostburg	Conduit Exemption	2011	-	2012

[42] Exelon Corporation, "Exelon Generation and State of Maryland Reach Agreement to Restore and Sustain Chesapeake Bay," October 30, 2019, https://www.exeloncorp.com/newsroom/conowingo-announcement.

Figure 3-13 Location of Hydroelectric Facilities in Maryland



Wave and tidal power also harness the energy of moving water, specifically in ocean settings. Wave energy facilities typically float in the water and employ the vertical motion of the waves to create energy. Tidal power is produced by tidal stream generators, which capture the kinetic energy of moving water caused by tidal currents or the fluctuation of the sea level due to the tide. They work much the same way as wind power generators, but because water is much denser than air and tides are steady and almost continuous, the generators can produce significantly more power. Maryland has limited tidal resources at its Chesapeake Bay and Atlantic coast sites. Some potential exists for small-scale projects. Various technical obstacles and the relative immaturity of wave and tidal power technologies also limit potential development.

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 wastes 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 in order 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 percent and the weight of incoming waste by about 75 percent.

Until 2011, WTE was classified as a Tier 2 resource under the Maryland RPS, 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 2.1.1 for information on the Maryland RPS Tier 1 and Tier 2 requirements.

As of 2018, there are 68 WTE facilities currently operating nationwide according to the U.S. Energy Information Administration, including two major facilities in Maryland that are certified under Maryland's RPS. WTE facilities are heavily regulated due to various environmental impacts. As displayed in Table 3-6, one plant was shut down in 2016 and another had its permit revoked. 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 mercury, dioxin, furan, and other toxic metals and organic compounds unless adequate pollution controls are installed.

Baltimore City Clean Air Act

In early 2019, the Baltimore City Council adopted the Baltimore City Clean Air Act which establishes strict pollution limits on commercial solid waste incinerator facilities, such as the Wheelabrator Incinerator located in South Baltimore which receives proceeds through its production of RECs under the Maryland RPS. Beginning in 2022, the ordinance would require all facilities to have real time monitoring and disclosure of pollutants on a website and limits emissions such as mercury, sulfur dioxide and nitrogen oxides. In order to be in compliance, the Wheelabrator facility, which incinerates 1.2 million tons of garbage annually, would require significant investment. While the Wheelabrator's incinerator contract with Baltimore City concludes at the end of 2021, it has contracts with surrounding counties under which it burns approximately 500 tons of garbage. The Company that owns the Wheelabrator facility sued the City in April 2019, stating that emissions are regulated by state and federal agencies, not by city governments.

Table 3-6 Waste-to-Energy Facilities in Maryland

Facility Name (Location)	Project Status	Nameplate Capacity (MW)	Operator/Developer
Montgomery County Resource Recovery Facility (Dickerson, Maryland)	Operational	68	Covanta Montgomery
Wheelabrator Baltimore Refuse Facility (Baltimore, Maryland)	Operational	65	Wheelabrator Baltimore
Harford Waste-to-Energy Facility (Joppa, Maryland)	Shut Down in 2016	1.2	Energy Recovery Operations
Fairfield Renewable Energy Power Plant (Baltimore, Maryland)	Permit Revoked	140	Energy Answers International

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. 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. Both CO_2 and methane are greenhouse gases (GHGs); however, methane has 20 times the global warming potential of CO_2, so 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 instead to generate power makes use of this otherwise wasted energy and also reduces odors, contaminants, and GHGs. Table 3-7 lists the LFG-to-energy projects that are currently operating in Maryland. The 3.2 MW Millersville LFG project collects LFG and sells it directly to the Army's Fort Meade base to fuel operations at the base.

Table 3-7 Landfill Gas Projects in Maryland

Name and Location	Estimated Total Waste in Place (Tons)	Project Status	LFG Energy Project Start Date	LFG Energy Project Type	MW Capacity	Project Developer
Brown Station Road (Prince George's County)	6,964,110	Operational Operational Operational	1987 1987 2003	Reciprocating Engine Boiler Reciprocating Engine	2.6 Steam 3.5	PG County
Eastern/White Marsh (Baltimore County)	5,213,000	Operational	2006	Reciprocating Engine	2.5	Pepco Energy Services
Newland Park (Wicomico County)	1,238,743	Operational	2007	Reciprocating Engine	2.6	INGENCO
Central Landfill (Worcester County)	1,244,656	Shutdown	2008	Reciprocating Engine	2.0	Curtis Engine
Gude (Montgomery County)	4,800,000	Shutdown Operational	1985 2009	Reciprocating Engine Reciprocating Engine	2.0 0.8	Covanta SCS Engineers
The Oaks (Montgomery County)	6,874,060	Retired	2009	Reciprocating Engine	2.4	SCS Engineers
Quarantine Road (Baltimore County)	10,632,202	Retired	2009	Cogeneration	1.5	Ameresco Federal Solutions
Reichs Ford Landfill (Frederick County)	3,940,387	Retired	2010	Reciprocating Engine	2.1	Energenic-US
Sandy Hill (Prince George's County)	5,125,946	Operational Operational	2003 2011	Boiler Boiler	Steam Steam	Toro Energy
Millersville (Anne Arundel County)	2,888,404	Operational	2012	Reciprocating Engine	3.2	Northeast Maryland Waste Disposal Authority
Alpha Ridge (Howard County)	2,276,586	Operational	2012	Reciprocating Engine	1.1	Pepco Energy Services, Inc.

Notes: The Brown Station Road, Gude, and Sandy Hill landfills are closed and are no longer accepting waste, but the LFG facilities continue to operate. LFG from Sandy Hill is combusted to generate heat only, not electricity. The capacity rating of Newland Park reflects the capacity rating for single fuel/LFG mode landfill gas and not the maximum capacity rating of 6 MW which includes use of diesel fuel.

3.1.6 Energy Storage

Energy Storage

Energy storage allows for 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 systems (CAES), flywheels, and various types of batteries, e.g., lead-acid batteries, lithium-ion batteries, and zinc-bromide batteries. Each of the various technologies carries with it different benefits, economics, and operational characteristics. Hence, the various technologies can be used to serve multiple end uses. The principal end uses of electric storage include:

- **On-peak power supply** – Storage technology can be relied upon to provide electric power at times of high demand. For example, pumped hydroelectric (or pumped storage) entails pumping water up into a reservoir during periods when the demand for electric power (and hence price) is low and using that water to generate electricity when demand (and price) is high.
- **Electric grid support** – Storage can help support the transmission system by correcting for transient voltage anomalies. Additionally, storage can be used to help relieve transmission congestion and to relieve pressure on the local distribution system when periods of high, localized demand occur. Use of storage in this way can postpone the need to upgrade electric distribution facilities to accommodate those periods of high demand that occur only infrequently.
- **End-user cost management** – An end-user can benefit from energy storage by storing electric power during periods when market prices are low and drawing on that power when market prices are higher.
- **End-user reliability enhancement** – Electric storage can be relied upon for power supply during times when the electric grid is not available.
- **Variable renewable energy generation**– Electric storage can be used to reduce the variability of certain renewable electric generation technologies, such as wind and solar. For example, storage could be used to reduce the output fluctuations from a photovoltaic array due to passing clouds. Furthermore, storage can enhance the value of variable renewable energy production by effectively allowing generation produced in one-time period to be carried to a later time period when electricity prices are higher.

Historically, only pumped hydroelectric and CAES have been used to provide bulk energy services since these technologies can be sized at 100 MW or more and are capable of providing electric power to the grid for periods measured in hours rather than in minutes or seconds. Bulk energy service refers to: (a) the ability to significantly shift large amounts of energy between the time of generation and the time of use, and (b) the provision of generation capacity. Recent declines in the costs of battery storage have led to a number of hybrid solar and storage projects, predominately in the Western United States. As of 2019, a total of 38 hybrid solar and storage projects totaling 4.3 GW of solar capacity and 2.6 GW of battery capacity are either planned or are in operation, with all but five located in the Western United

States.[43] The duration of battery storage ranges from two to five hours and applications include shifting solar energy to late afternoon/early evening hours or to minimize or alleviate curtailment of solar generation. In the Mid-Atlantic region, battery systems and flywheels are providing transmission and distribution system grid support due to typical size and operational factors and can also be used to provide power quality and reliability at the end-use (retail) level.

Decreases in the prices of storage devices, particularly lithium ion battery storage which has benefited from research and development related to plug-in electric vehicles, have been significant in recent years and prices are generally expected to continue to decline over time. Based on the potential uses of storage, electric storage can be viewed, to some degree, as a substitute for certain types of generation (e.g., peaking generation) and for certain marginal investments in the distribution and transmission infrastructure.

At the conclusion of 2018, there was 23 GW of energy storage installed in the United States. In 2018, 760.3 MWh of energy storage was interconnected to the U.S. electric grid, which is 162 percent higher than the 336 MWh interconnected in 2016. In 2018, residential markets experienced the highest levels of growth, likely due to policies and mandates in California, Hawaii and Vermont. The overall growth in interconnected energy storage will likely continue due to the establishment of energy storage targets in states such as California, Massachusetts, New Jersey, New York and Oregon, coupled with the decrease in the cost of energy storage.

In the spring of 2017, the Maryland General Assembly enacted legislation that required PPRP to study regulatory reforms and market incentives that may be needed or may benefit energy storage in Maryland. The final report, released January 22, 2019, provides a review of the energy storage technologies, their applications, efforts by other states to promote storage, the current state of storage in Maryland and the barriers that discourage widespread implementation.[44]

Following the release of the report, the Maryland Senate introduced Senate Bill ("SB") 573 which requires the Maryland PSC to establish an energy storage pilot program with pilot projects ranging between 5 and 10 megawatts. The pilot is designed to evaluate energy storage ownership models and answer whether a utility can own storage in a deregulated electricity market. Under SB 573, which passed in April 2019, the state's four IOUs are required to solicit two energy storage projects for the PSC's approval by April 15, 2020 and September 15, 2020, with project operational dates by February 28, 2022. The projects must solicit offers which fall under two of the following four utility ownership models: utility-only, utility and third party, third party ownership, and a virtual power plant. Under the last ownership model, the utility would utilize services provided by energy storage devices owned by customers or a third party aggregator.[45]

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[43] The five projects not located in the Western United States are in Florida, Minnesota and Texas.

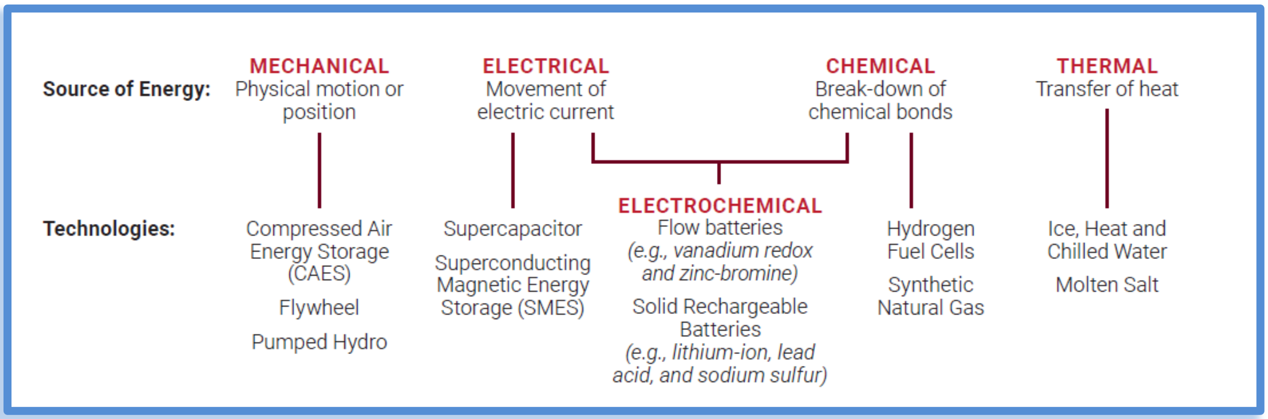
[44] https://dnr.maryland.gov/pprp/Documents/Energy-Storage-In-Maryland.pdf.

[45] http://mgaleg.maryland.gov/2019RS/bills/sb/sb0573T.pdf

Energy Storage Technologies

Energy for storage systems can come from four sources: mechanical, electrical, chemical and thermal. As noted in Figure 3-14, there's a wide variety of electricity storage devices currently in use, including pumped hydroelectric power, chilled water, batteries, and flywheels.

Figure 3-14 Energy Storage Sources of Energy and Common Technologies



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

Pumped hydro is the most widespread energy storage system in use today. With an efficiency rate of more than 80 percent, pumped storage provides for approximately 22.9 GW of energy storage in the United States. Water is pumped into an upper reservoir when electricity prices are low, generally during night-time off-peak periods, 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 to 60 minutes of energy storage as regulation service. Some energy companies are also testing the use of batteries for grid management and energy storage. As of 2019, Hornsdale Power Reserve, located in South Australia, holds the title of the world's largest lithium-ion battery. The battery, owned by Neoen Australia and built by Tesla, is 100 MW/129 MWh and cost $95 million to build. There are seven planned lithium-ion batteries, with commission dates ranging from 2020 to 2023, that are expected to meet or exceed the 100 MW threshold. The largest planned facility is the Florida Power and Light Manatee Energy Storage Center, projected to be online in late 2021, that will have a capacity of 409 MW/900 MWh. This facility is expected to replace two aging gas plants in the area.

A flow battery is a type of battery that uses 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. Prototype flow battery demonstration systems have been deployed throughout the world. VRB Energy is the process of installing the largest vanadium redox flow battery project in the World as part of the Hubei Zaoyang Storage Integration Demonstration project. The project, which is planned to reach 10MW/40MWh, successfully commissioned the first 250kW/1MWh vanadium redox flow battery module in late 2018 and a 3MW/12MWh vanadium redox flow battery in January 2019, thus completing Phase I of the project.

Flywheel systems utilize 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.

Warrior Run Battery Facility

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, since 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 upon the configuration, the facility can provide output ranging from 15 mins to four hours.

Source: AES FERC Registered Entities https://aesusgeneration.com/

Rail cars are also becoming a potential alternative for energy storage. In 2014, the Southeastern Pennsylvania Transportation Authority (SEPTA) piloted a battery storage network program that captures and stores energy from braking subway cars. In 2016, Constellation Energy (a subsidiary of Exelon) partnered with Viridian Energy to expand this pilot program to a 10 MW battery storage network at seven SEPTA stations. Similarly, a company called ARES recently developed a railcar test-system as an alternative to hydro-pumped storage in Southern California. The storage system moves weighted rail cars uphill when receiving excess energy from wind and solar generation, and releases the cars back down the hill to generate additional power during lulls in solar and wind production. ARES plans to build a 50 MW commercial-scale rail car storage system in Nevada with operations targeted for 2020.

Thermal storage reserves the energy that is produced in the form of heat or cold to be used at a later time. An example would be to create ice for an ice chiller during off-peak hours and utilize the chiller during peak hours to assist with cooling.

In addition to traditional storage devices, the electricity grid itself can be considered a mechanism for storing electricity. For example, a home powered by a solar PV installation may ship (sell) excess electricity generated to the grid during daylight hours and utilize (buy) electricity from the grid during evening hours and overnight.

Energy Storage Tax Credit

In May 2017, Maryland introduced a state income tax credit for the installation of energy storage systems, marking the first and only state to offer a tax credit for this type of technology. For systems installed between January 1, 2018 and December 31, 2022, the Maryland Energy Administration (MEA) will award tax credits for up to 30% of the total installed costs of the energy storage system for qualified systems installed on residential or commercial properties. The systems which qualify for the tax credit include chemical (batteries), thermal (ice/chilled water), electrical energy and mechanical (flywheels, compressed air). As of December 15, 2019, MEA had awarded $495,000 in tax credits out of the $750,000 allocated for the 2019 tax year.[46]

Energy Storage Pilots

As technology advances and the cost declines, the size and frequency of projects increase. Below are some energy storage pilots that have either been commissioned or will be implemented.

- **Solar plus storage**: The Municipal Light Department of Sterling in Massachusetts used a $1.5 million grant to purchase a 2-MW lithium-ion battery that is paired with a 3.4-MW PV system to provide 12 days of back-up power for the police headquarters. In addition to back-up generation, the battery is used to reduce monthly and annual peak demand charges. Excluding grants, the project is expected to have a seven year payback period.
- **Flow batteries**: In April 2019, the California Independent System Operator (ISO) indicated that it would initiate a four year pilot project to test flow batteries in the commercial wholesale market. The pilot will utilize a 2MW/8MWh vanadium redox flow battery that could provide power to 1,000 homes for four hours.
- **Alternative to grid infrastructure**: In August 2019, Dominion Energy filed an application with the Virginia State Corporation Commission to build four utility-scale battery storage projects with a total capacity of 16 MW. Two of the batteries will equal 12MW/48MWh that will be integrated at the Scott Solar plant. A 2-MW battery will be used to see how it could be used to improve reliability and serve as an alternative to grid infrastructure investments, such as transformer upgrades. Another 2-MW battery will be used to see how batteries can be used for maintaining grid stability, such as dealing with voltage and reverse energy flow issues.
- **Residential storage**: Green Mountain Power in Vermont implemented two pilots which provide a $850/kW incentive for residential customers that enrolled their batteries, including vehicle chargers, in a demand response type program. In exchange for the credit, Green Mountain power can draw the battery's stored energy during peak events over a period of 10 years. One pilot is designed for customers that opt to lease the Tesla Powerwall batteries, while the second pilot is considered a BYOD ("Bring Your Own Device") program, which allows or for customers that choose to use other approved provider batteries that are either owned or leased.

[46] https://energy.maryland.gov/business/Pages/EnergyStorage.aspx.

3.2 New and Proposed Power Plant Construction

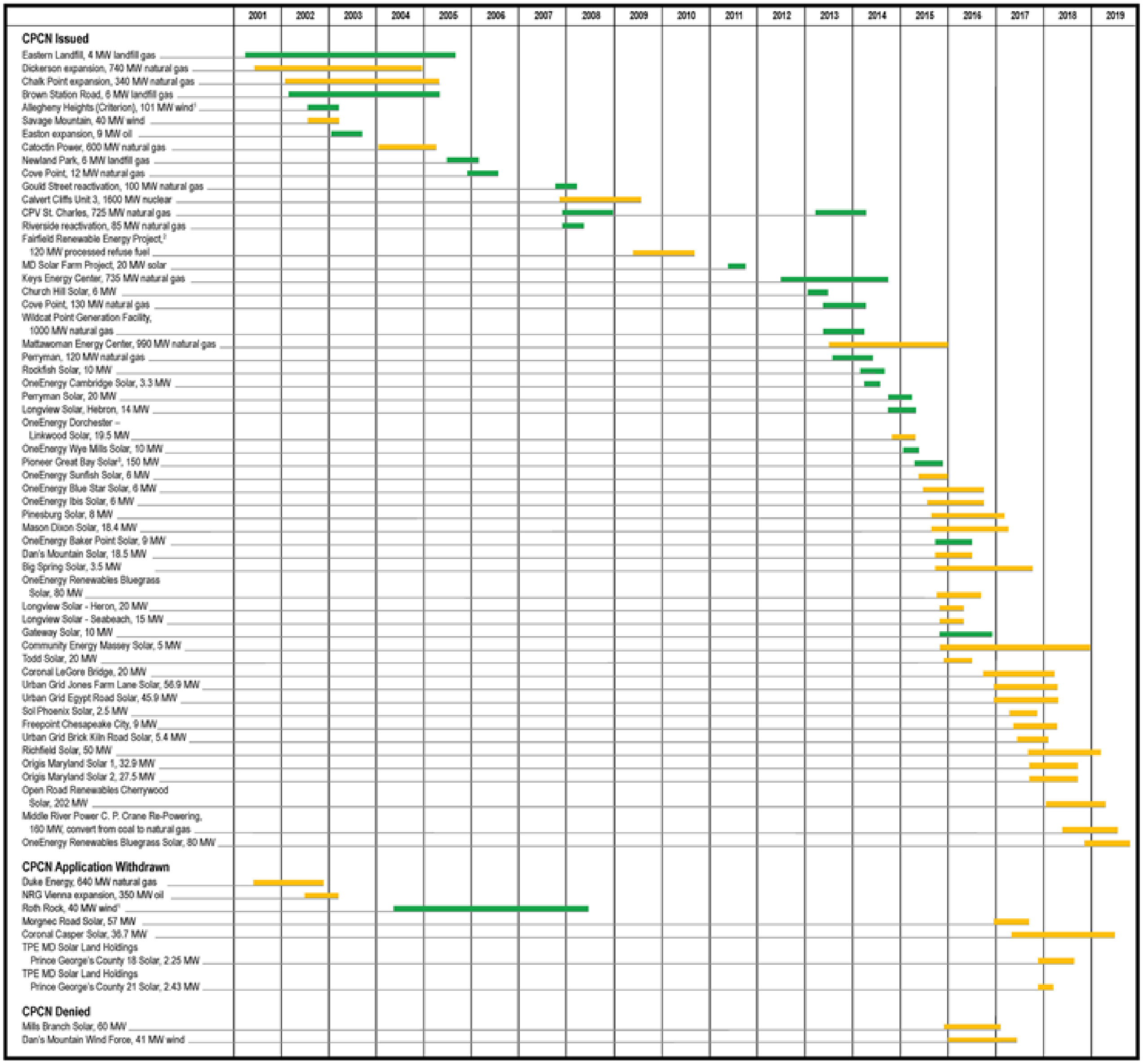
Since the start of 2015, the PSC has received 42 CPCN applications from developers of proposed new generating facilities - an unprecedented level of licensing activity. Over the past 18 years, the PSC has received 69 CPCN applications for new generation, representing several thousand megawatts of potential generating capacity at existing facilities and at greenfield sites with numerous application reviews ongoing (see Figure 3-15). While the majority of these proposed plants did obtain a CPCN, only 24 are now in operation. The remainder are under construction or have been delayed or abandoned because of various financial or commercial reasons.

Maryland has seen a sharp increase in utility-scale solar projects in recent years. Developers are proposing these solar projects to capitalize on Maryland state tax incentives and support the Maryland Renewable Energy Portfolio Standard (see Solar discussion in Section 3.1.5).

While renewable energy projects have made up the majority of licensing activity in the past decade, from a capacity perspective, the 2010s were dominated by new natural gas fired facilities in Maryland. Spurred by the abundance of natural gas (especially in the nearby Marcellus Shale basin) and low fuel prices, developers proposed and constructed several new gas-fired plants. The PSC has issued CPCNs to three new gas-fired power generation facilities in southern Maryland, a project in Cecil County and a repowering project at the existing CP Crane coal plant.

- The Competitive Power Ventures (CPV) St. Charles facility is located in Charles County, and received initial CPCN approval in 2008. A modified and amended CPCN was subsequently filed and approved in 2012. CPV began construction in December 2014 and became operational in March 2017. Originally filed as 640 MW combined cycle power plant, the project was updated with more efficient technology and now yields a 725 MW nameplate capacity.
- The 755 MW Keys Energy Center, located in Prince George's County, received CPCN approval in November 2014. PSEG Power acquired the project from Genesis Power, LLC in 2015. The facility began commercial operation in July 2018.
- Mattawoman Energy, LLC, a subsidiary of Panda Power Funds, LLC, is building the Mattawoman Energy Center near Brandywine in Prince George's County. The 990 MW project received CPCN approval in October 2015. Mattawoman recently modified its plans to include an air-cooled condenser in place of a wet cooling system, which will avoid the need for substantial amounts of cooling water.
- Old Dominion Electric Cooperative (ODEC) received its CPCN approval in April 2014 for a 1000 MW power plant in Cecil County. The Wildcat Point facility began operating in April 2018 and is located adjacent to the existing site of the Rock Springs Generation Facility.
- Middle River Power obtained a CPCN in June 2019 to build a 160 MW gas-fired facility at the site of the existing CP Crane coal-fired plant. The coal-fired units at Crane ceased operation in May 2018. Middle River Power expects to begin operating the natural gas units in 2020.

Figure 3-15 CPCN Requests, 2001 through November 2019



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:

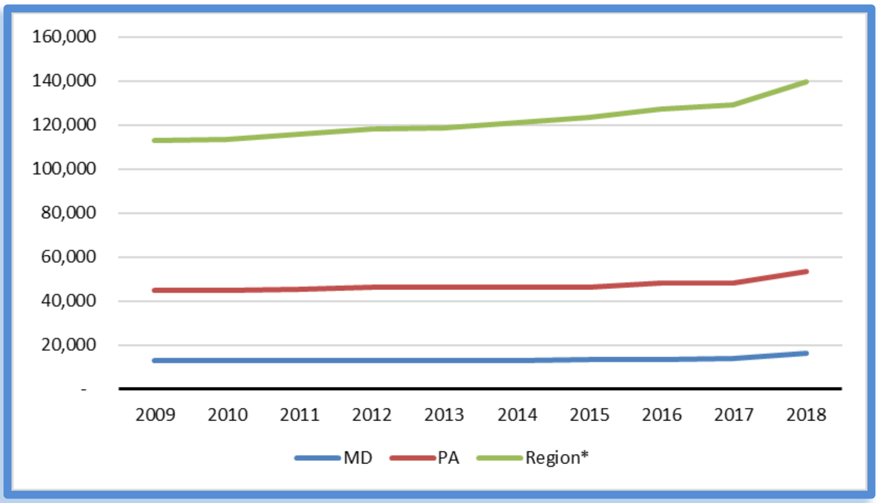
= Project is operational = Project is not operational

[1] Project was subsequently reconfigured, granted a CPCN exemption, and is now operational.
[2] Air permit denied.
[3] The CPCN is for 150 MW solar array; only 75 MW of the project are in operation as of October 2019.

Chart does not reflect CPCN cases ongoing as of October 2019 (all proposed solar projects): Biggs Ford, Perennial, Mattawoman, Citizens Union Bridge, Kieffer Funk, Morgnec Road, Spectrum, Whitetail.

As a market-based state, Maryland's electric generation resource planning resides with the competitive electricity market, driven by economics and price signals. High prices that result from tight supply markets are expected to attract investors, developers, and demand response providers; low prices that result from over-supplied markets are projected to discourage new generation development and demand response providers. However, substantial and sustained price differentials are required to elicit such market behaviors. The up-and-down movement of wholesale prices in PJM has resulted in a "boom-bust" cycle in the development of new generating plants in PJM. This trend produces a situation where many power plants are proposed and built in a short time frame followed by a period where few plants are built. Figure 3-15 demonstrates the recent increase in the number of CPCN requests in Maryland after a multiyear period with relatively few open applications but much larger individual projects. Figure 3-16 shows the amount of capacity on-line for Maryland, Pennsylvania and the region.

Figure 3-16 Maryland and Regional Capacity



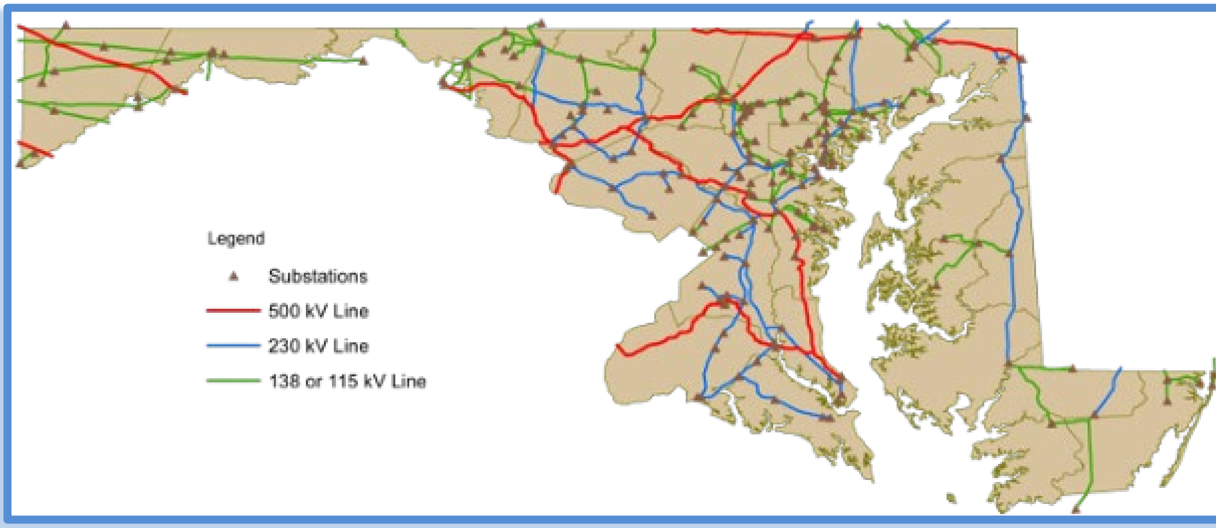
*Region includes Delaware, Maryland, New Jersey, Pennsylvania, Virginia, Washington, D.C., and West Virginia.
Source: Energy Information Administration, EIA-860, 2018 Final Release

Over the last decade, capacity growth has been stagnant in Maryland, Pennsylvania and the region as a whole. This "bust" period followed a brief period of growth in the early 2000s. Projects that had started construction prior to the decrease in wholesale market prices in 2002 went on-line by 2004, after which there was a slowdown in new facilities coming on-line in the region. Since then, a combination of several factors has suppressed the growth of capacity in the region, including energy efficiency and demand response efforts, transmission upgrades, capacity in excess of reliability requirements, and low load growth. Additionally, as coal plants have retired in recent years, natural gas power plants have come online resulting in a small net difference in capacity. These factors may likely continue to maintain a stagnant growth pattern in future years.

3.3 Electric Transmission

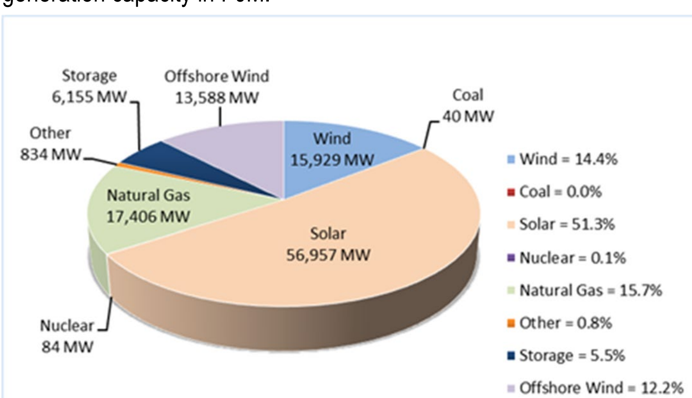
The network of high voltage lines, transformers, and other equipment that connects power-generating facilities to distribution systems is part of an expansive electric transmission system. In Maryland, there are more than 2,000 miles of transmission lines operating at voltages between 115 kV and 500 kV. Figure 3-17 shows a map of this high voltage transmission grid in Maryland.

Figure 3-17 Transmission Lines in Maryland (>115 kV)



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 January 2020, the PJM interconnection queue consisted of projects totaling nearly 111 GW of capacity (stated as winter net capacity). Solar is the dominant resource, followed by natural gas; the breakdown by fuel type is shown in the pie chart below. Renewable energy projects accounted for around 78 percent of the total capacity in the PJM interconnection queue. Although the majority of 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.

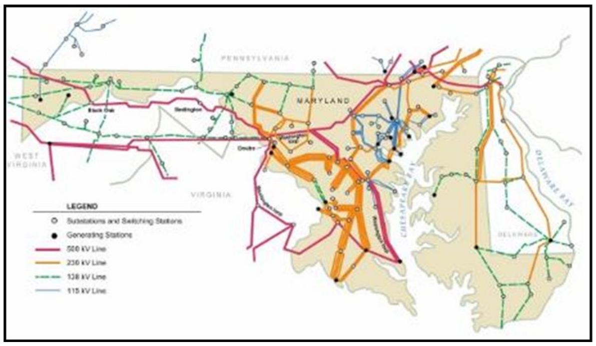


While the economic and environmental effects of generation are substantial, transmission also has major environmental and socioeconomic implications in Maryland, particularly since Maryland is a net importer of electricity. Building new transmission facilities is costly with significant environmental impacts and ratepayer costs. Upgrading existing heavily used facilities must be done quickly, often in 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.

Artificial Island Project on Delmarva Peninsula

The Delmarva Peninsula, consisting of Maryland's Eastern Shore, Delaware, and a portion of Virginia, experiences high congestion costs due to the isolation of the transmission system. As noted in the figure below, the entire Delmarva Peninsula relies upon a transmission interconnection at the northern part of the Peninsula in Delaware. The lack of transmission interconnection points elsewhere on the Peninsula causes increased transmission congestion. While projects, such as the Mid-Atlantic Power Pathway (MAPP), have been proposed in the past, none have come to fruition.

Maryland Transmission Lines



Proposed Artificial Island Transmission Project

Source: "PJM Staff Picks LS Power for Artificial Island Stability Fix; Dominion Loses Out," S. Herel, April 28, 2015, RTO Insider, http://www.rtoinsider.com/pjm-ls-power-artificial-island-14775/.

Instead, reliability improvements in surrounding areas, such as Central Maryland, serve to strengthen reliability on the Peninsula and reduce outage risk until the need for another transmission interconnection point to allow additional imported power onto the Peninsula is identified. One project, the Artificial Island project, proposes the construction of a new underwater 230 kV transmission tie from the Salem and Hope Creek nuclear power plants in New Jersey to the western side of the Delaware Bay. The project is ultimately expected to address stability issues at the plants while increasing their generation output. Since it was first introduced, the Artificial Island project has been contentious. A major point of contention for the project revolved around the solution-based distribution factor (DFAX) method which PJM used to assign cost responsibility between the three states involved. Use of the DFAX method resulted in allocation of approximately 90% of the project costs (roughly $220 million of the $278-million project) to Maryland and Delaware ratepayers which, in turn, would receive little of the project benefits. In April 2016 FERC rejected Maryland and Delaware regulators arguments that the costs for the Artificial Island project were unreasonably and unfairly distributed. However, after reviewing further complaints by the states' commissions, in July 2018 FERC reversed its April 2016 decision and granted a rehearing on the issue finding it was indeed, unjust and unreasonable to allocate costs to this particular project using the DFAX method. In the July 2018 order, FERC established paper hearing procedures to find a new cost allocation specifically focusing on two alternative methods, the Stability Deviation Method and the Stability Interface DFAX method. FERC explained that while DFAX works well when addressing flow-based reliability violations but not stability-related projects. In a Decision on February 28, 2019, the FERC denied requests for rehearings from New Jersey state regulators and PJM Transmission Owners and ruled that the Stability Deviation Method was just and reasonable replacement rate for PJM to apply cost allocation for the project. The new cost allocation for ratepayers on the Delmarva Peninsula resulting from the switch to the alternative method is around 10 percent. Construction began in May 2019 and will be completed by summer 2020.

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 if additional transmission facilities are needed to comply with applicable transmission planning standards and associated reliability criteria. PJM also periodically examines whether certain new transmission lines will produce economic benefits 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 is detailed in Section 4.3.3.

3.3.1 New and Proposed Transmission Projects

In early 2019, the PSC granted a CPCN to the Potomac Edison Company, a First Energy electric company, to modify the Ringgold-Catoctin transmission line in Frederick and Washington Counties. This modification will mitigate future thermal reliability criteria violations of both First Energy and PJM planning criteria that were identified as part of PJM's Regional Transmission Expansion Plan (RTEP) analysis related to construction of the PJM Market Efficiency 230 kV Transource Independence Energy Connection Project (PSC Case 9471), described below. This project is required only if the Transource Project is built.

Two ongoing transmission projects include:

- Transource Energy, LLC (Transource) is proposing to build two new 230 kV overhead transmission lines, one in Western Maryland (IEC West) and one in Eastern Maryland (IEC East), as part of the Independence Energy Connection Project. In August 2016, the project was selected by PJM as a solution to address transmission congestion on the AP-South Reactive Interface. The project will include the construction of two new transmission lines originating in Pennsylvania and terminating at two substations in Washington and Harford Counties in Maryland. Transource submitted its CPCN application on December 27, 2017. The PSC held public hearings on April 27 and May 18; the evidentiary hearing was held from June 3 through June 11, 2019. A settlement between Transource and the parties was filed in October 2019. Transource would construct the IEC West project as proposed, but instead of the IEC East project, BGE will add a second 230 kV circuit on the existing Otter Creek – Conastone 230 kV, and yet another 230 kV circuit on the Manor – Graceton 230 kV line. The PSC is holding hearings on the settlement proposal in February 2020. PPRP filed direct testimony in support of the Settlement Agreement in December 2019.

- Baltimore Harbor 230 kV Overhead Transmission Line Crossing Project is a new overhead transmission line adjacent to the Francis Scott Key Bridge that will replace the aging underwater electric cables that currently connect the Sollers Point and Hawkins Point terminal stations. BGE has indicated that this reinforcement project is a critical part of the networked electrical system around Baltimore. BGE filed its CPCN application on December 20, 2018.

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

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 and 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

The PSC granted a CPCN to the Southern Maryland Electric Cooperative (SMECO) for the construction of a new 230 kV transmission line from Holland Cliff in Calvert County to the Hewitt Road Switching Station in St. Mary's County in 2009. This was the last transmission project to include an underground construction component for a short segment of the project under the Naval Recreation Facility (see below for submarine construction component of this project). Underground transmission lines are typically implemented in locations where overhead lines are difficult to place or would create aesthetic or environmental issues. Several solar facility projects in Maryland have incorporated underground transmission cables for interconnection to the electrical system.

In this type of construction, underground transmission cables are typically placed four to five feet below ground surface in conduits or reinforced duct banks, or are directly buried in specially prepared soil, as shown in Figure 3-18. 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. Often times, the individual cables required to make up a circuit are placed in polyethylene, PVC or fiberglass conduits and are installed as a group.

Source: ABB, 2008.

Modern underground cables, such as cross-linked polyethylene (XLPE), do not require pressurized liquid or gas insulating and cooling systems that were predominant in earlier cable types, and therefore, no longer have the environmental contamination risk associated with coolant releases. The cables can be designed for AC or DC systems and are manufactured in finite lengths that need to be spliced together, on the order of every 1,000 to 2,000 feet.

The advantages of underground transmission include reduced visual impacts and narrower right-of-way width requirements due to the close spacing of the cables. For short distances, right-of-way widths of approximately 20 feet are possible, whereas in open country, a 30- to 50-foot width is preferred. Most of this width is to permit access for construction and maintenance equipment, since the duct bank itself is usually less than 10 feet wide. In some instances, these improvements may also coincide with reduced environmental impacts; however, in sensitive areas the installation of an underground transmission cable can be more disruptive than an overhead line.

Disadvantages of underground cables include thermal impacts during operation, significantly higher project costs versus comparable overhead installations, and longer cable repair times due to difficulties locating and accessing the cables and reinstallation. Despite the longer repair times, underground cables generally have a longer useful life, are not damaged as often and can be more secure.

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 top of the river bottom or seabed. These cables have been used sparingly historically, but are becoming more common for higher voltage transmission lines, as the reliability of the technology is being proven. The above 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 was completed in 2014 and was monitored by PPRP.

Submarine cables are typically manufactured and installed as one continuous 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 in order to allow the cable to sink down to the desired installation depth of approximately 6 to 15 feet, depending on specific site conditions.

The benefits of implementing a submarine system are 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.

DC Transmission Lines

According to the Department of Energy (DOE), several thousand miles of high voltage DC transmission lines are presently installed in the U.S., which is relatively small compared to the over 200,000 miles of total installed high voltage transmission lines (including hybrid AC and DC) in the U.S. However, the implementation of DC technology into project design is becoming increasingly more common. Direct current 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, high voltage DC (HVDC) systems can be more cost effective at long transport distances compared to high voltage AC (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 high voltage DC transmission, although it was an alternative considered within the MAPP project. This technology could be used to support of future offshore wind projects to meet the recent increases in the amended Maryland RPS (see Section 2.1.1).

Transource Independence Energy Connection Project (PSC Case 9471)

Transource Maryland, LLC proposed to construct the Maryland portions of two new 230 kV interstate electric transmission lines that cross the Pennsylvania-Maryland border into Washington and Harford counties. Transource has stated that the purpose of the Project is to alleviate persistent transmission congestion constraints, as identified by PJM Interconnection, LLC, on the AP-South Reactive Interface. The AP South Reactive Interface are four 500 kV transmission lines which originate in West Virginia and terminate in Maryland and Virginia to the east and south. According to Transource, this Project is a part of PJM's Market Efficiency Project 9A, also identified as Baseline Upgrade Numbers b2743 and b2752 and includes upgrades at existing substations in Maryland, two new substations in Pennsylvania, and two new interstate transmission lines between Maryland and Pennsylvania. The current PSC CPCN application has been under review since it was filed in December 2017.

3.3.4 Electricity Distribution

There are 13 utilities distributing electricity to customers in Maryland (see Table 3-8). Four of these are large, investor-owned electric companies organized as for-profit, tax-paying businesses: Potomac Edison (formerly Allegheny Power); Baltimore Gas and Electric (BGE); Delmarva Power and Light Company (DPL); and Potomac Electric Power Company (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 percent of the customers in the state.

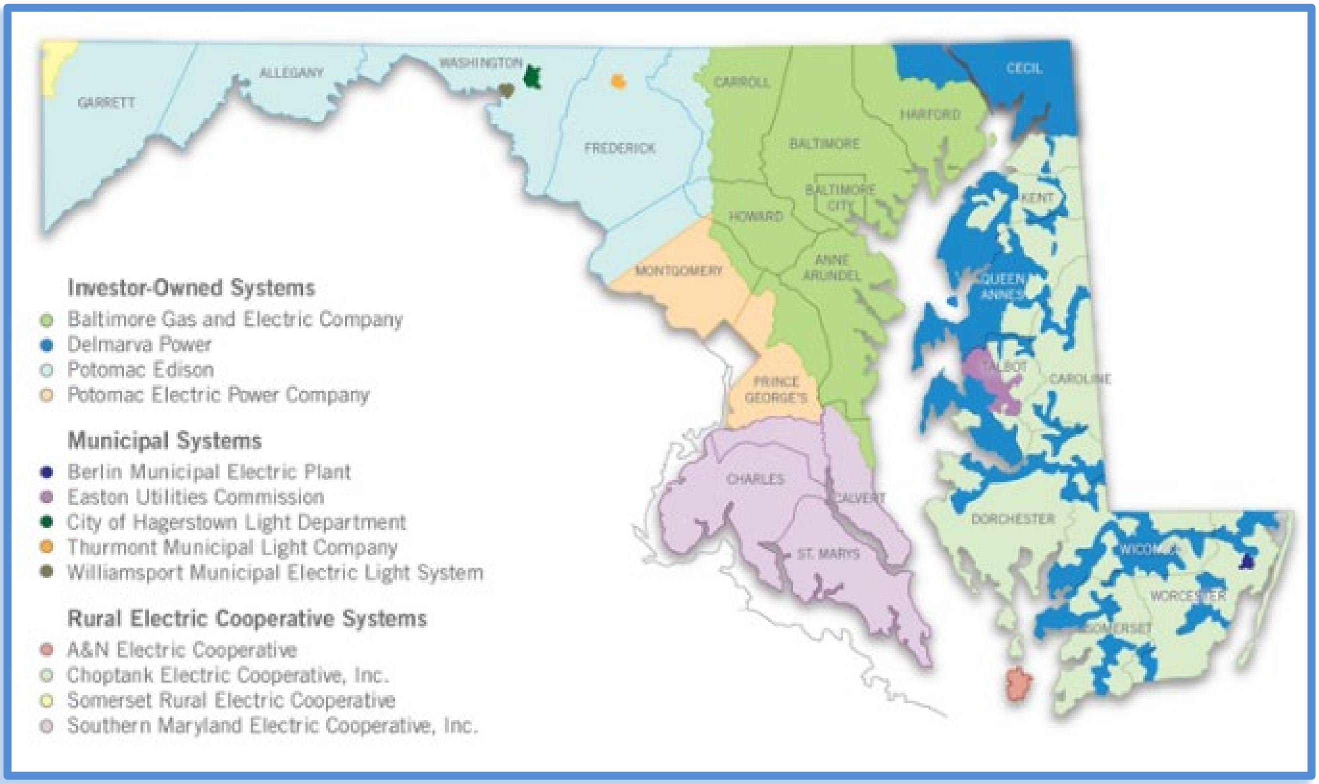
Five utilities are owned and operated by municipalities providing local electric distribution to a specific area. Four utilities are electric cooperatives, serving generally less populated rural areas. The service territories for the state's distribution companies are illustrated in Figure 3-19.

Table 3-8 Maryland Electric Distribution Companies, 2018

Company	Approximate Number of Maryland Consumers
INVESTOR OWNED*	
Potomac Edison (owned by First Energy)	273,719
Baltimore Gas & Electric (owned by Exelon)	1,299,409
Delmarva Power & Light (owned by Exelon)	211,708
Potomac Electric Power Company (owned by Exelon)	579,875
Subtotal	2,364,711
MUNICIPAL SYSTEMS**	
Berlin Municipal Electric Plan	2,538
Easton Utilities Commission	10,681
City of Hagerstown, Light Department	17,529
Thurmont Municipal Light Company	2,858
Williamsport Municipal Electric Light System	998
Subtotal	34,604
COOPERATIVE SYSTEMS**	
A&N Electric Cooperative***	274
Choptank Electric Cooperative, Inc. **	54,249
Somerset Rural Electric Cooperative****	804
Southern Maryland Electric Cooperative, Inc.*	164,968
Subtotal	220,295
Total Customers	2,619,610

* Source: Maryland Public Service Commission Electric Choice Enrollment Report December 2018.
** Source: Maryland Public Service Commission Ten-Year Plan for 2018-2027. Forecast number of customers. Actual 2018 data was not available for these utilities.
*** U.S. Energy Information Association EIA-861 2017.
**** Source: Somerset Rural Electric Cooperative Utility Annual Report for 2018 http://webapp.psc.state.md.us/utilityreport/Somerset%20Rural%20Electric%20Cooperative%20Inc/

Figure 3-19 Electricity Distribution Service Areas



3.4 Maryland Electricity Consumption

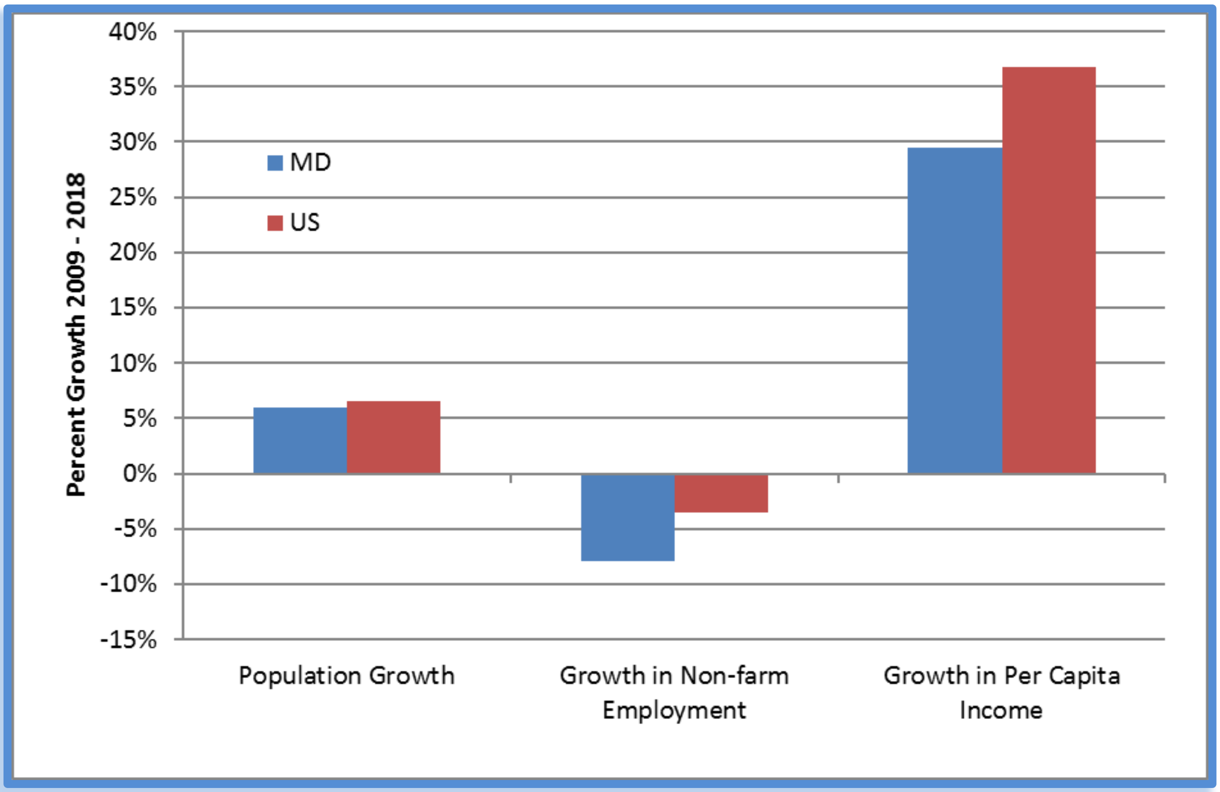
Maryland end-use customers consumed about 62 million MWh of electricity during 2018.[47] Between 2009 and 2018, the annual average growth rate in electricity consumption in Maryland was lower than in the U.S. as a whole - negative 0.18 percent in Maryland versus a positive 0.24 percent in the U.S. Figure 3-20 compares some of the key factors contributing to growth in electricity demand in Maryland and the U.S. from 2009 through 2018. Maryland's population growth accelerated between 2007 and 2010, slowed significantly between 2010 and 2016, and then increased between 2016 and 2018, as depicted in Figure 3-21. Despite growth in population and per capita income, electricity consumption has continued to decline. In general, slower population and per capita income growth will negatively affect electricity use, other factors held constant; however, the recent decline in electricity consumption can be attributed to businesses and households investing in more efficient energy technology, effectively reducing their energy usage.

The shares of electricity consumption in Maryland used by residential and commercial sectors exceeded the consumption levels of the United States as a whole (see Figure 3-22). Conversely, the industrial sector's electricity use in Maryland is significantly lower than the rest of the country—25 percent for the

[47] U.S. Energy Information Administration, "Retail Sales of Electricity," Maryland, Electricity Data Browser.

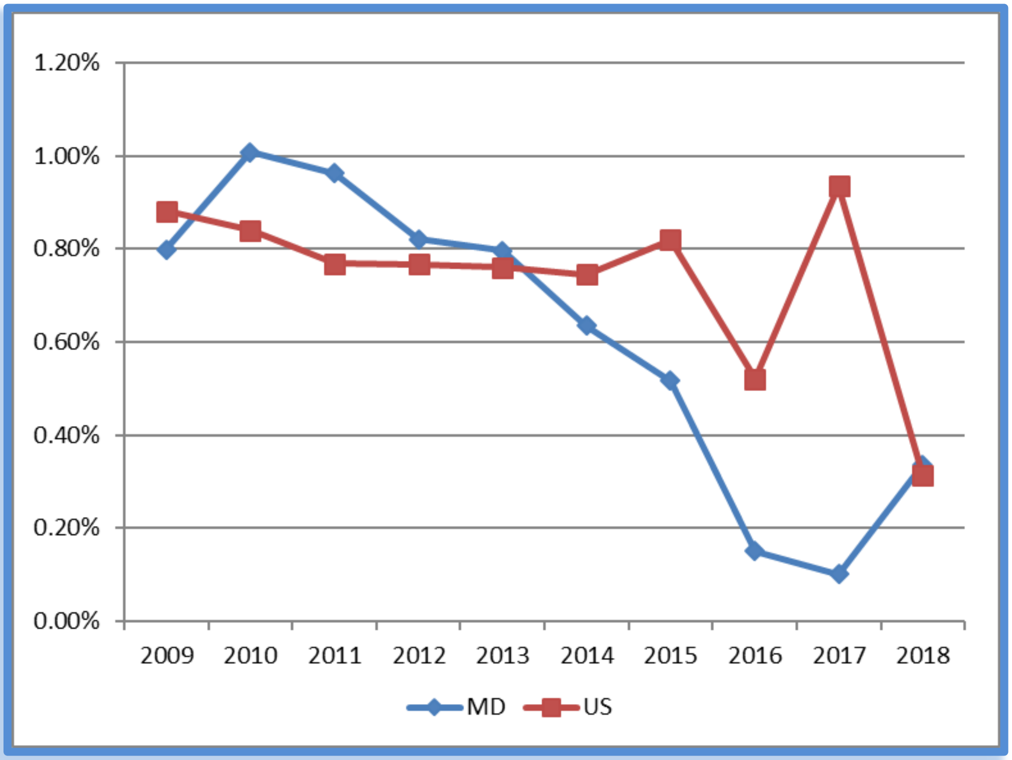
nation as a whole (953 million MWh). In 2009, the industrial sector accounted for 8 percent, or 5.3 million MWh, of Maryland's energy consumption; comparatively, in 2018, the industrial sector consumed approximately 3.8 million MWh, or 28 percent less electricity than in 2009.

Figure 3-20 Comparison of U.S. and Maryland Growth Factors Affecting Electricity Consumption (2009-2018)



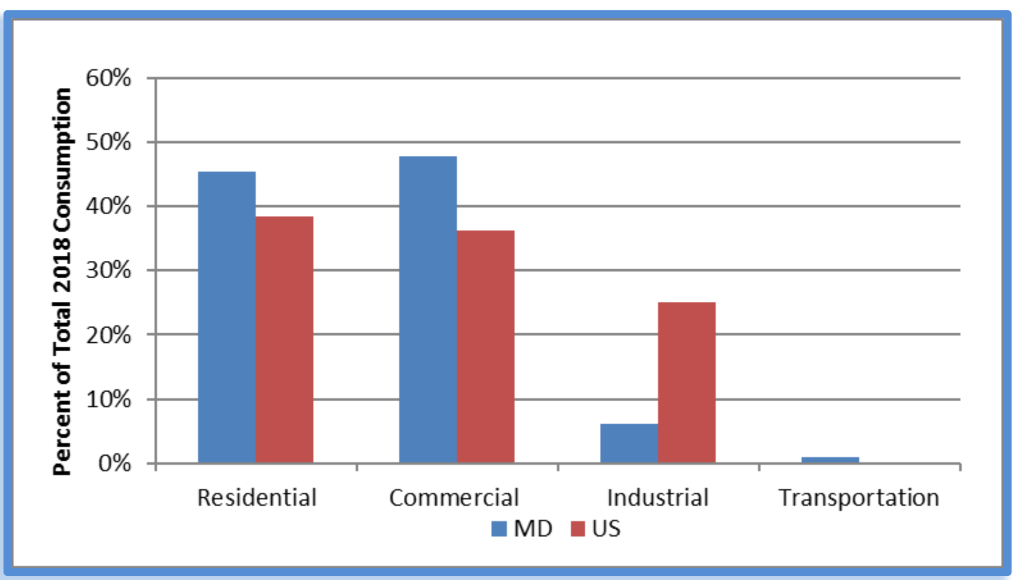
Source: Bureau of Economic Analysis Regional Data; Bureau of Labor Statistics.

Figure 3-21 Population Growth Trends in Maryland and the U.S. (2009-2018)



Source: Bureau of Economic Analysis Regional Data, SA1 Population.

Figure 3-22 Electricity Consumption by Customer Class for 2018



Source: U.S. Energy Information Administration, "Retail Sales of Electricity, Annually."

3.4.1 Maryland Electricity Consumption Forecast

The economic recession that began in 2008 resulted in a downward trend for electricity consumption in Maryland. While Maryland was not as seriously affected by the recession as many other states, it was not immune to the higher unemployment levels and lower levels of economic activity more generally. Electricity sales in 2009 were about 1 percent below 2008 levels, largely explained by the recession-induced declines in economic activity. As the economy began to recover in 2010, electricity consumption also increased in Maryland by 4.4 percent compared to 2009. However, electricity consumption fell every year in 2011-2017, and increased in 2018, though the 2018 value (61.9 MWh) is still below the 2009 value (62.5 MWh). This decline is largely due to the impact of the EmPOWER Maryland legislation. This law targeted a 15 percent reduction in per capita electricity consumption by 2015 from 2007 levels. For more information about EmPOWER Maryland, refer to Section 3.4.3. Table 3-9 compares the average change in electricity consumption by sector for both the United States and Maryland from 2016 through 2018. Recent increases in electricity consumption in Maryland have been slower than those in the United States in the residential sector. In the commercial sector, electricity consumption has fallen in Maryland but increased in the U.S. In the industrial sector, the decline in energy consumption is smaller in the U.S than in Maryland. In Maryland, the industrial and transportation sectors make minimal contributions to overall electricity consumption.

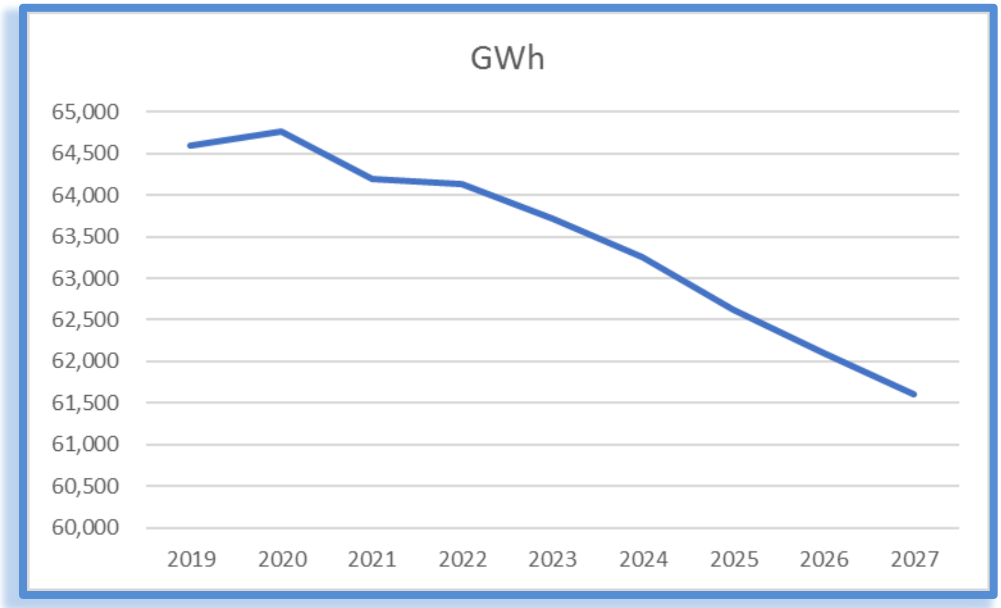
Table 3-9 Annual Change in Retail Sales of Electricity by Sector, 2016-2018

	All	Residential	Commercial	Industrial	Transportation
Maryland	0.50%	1.42%	-0.24%	-0.27%	-0.89%
United States	0.52%	1.84%	0.35%	-1.22%	-0.80%

Source: U.S. Energy Information Administration, “Retail Sales of Electricity, Annually.”

Figure 3-23 illustrates the most recent forecast for future electricity consumption in Maryland, as projected by the utilities serving loads in the state. The growth rate in electricity consumption in Maryland averages about a decline of 0.5 percent per year over the 10-year forecast period. By comparison, the average annual growth rate in electricity consumption in Maryland was around 2 percent during the 1990s and less than 1 percent between 2000 and 2010. The slower growth in recent and forecasted electricity consumption compared to historical growth during the 1990s is largely attributable to increases in the real price of electricity, slower growth in population and employment, and the impacts of EmPOWER Maryland. Higher electricity prices dampen the demand for electric power in two ways. First, the existing stock of electricity-consuming equipment and appliances is used less intensively because operation is more costly. Second, consumers replace their stock of electricity-consuming equipment and appliances with more energy-efficient appliance to reduce energy costs.

Figure 3-23 Maryland Forecasted Consumption (GWh), 2019-2027



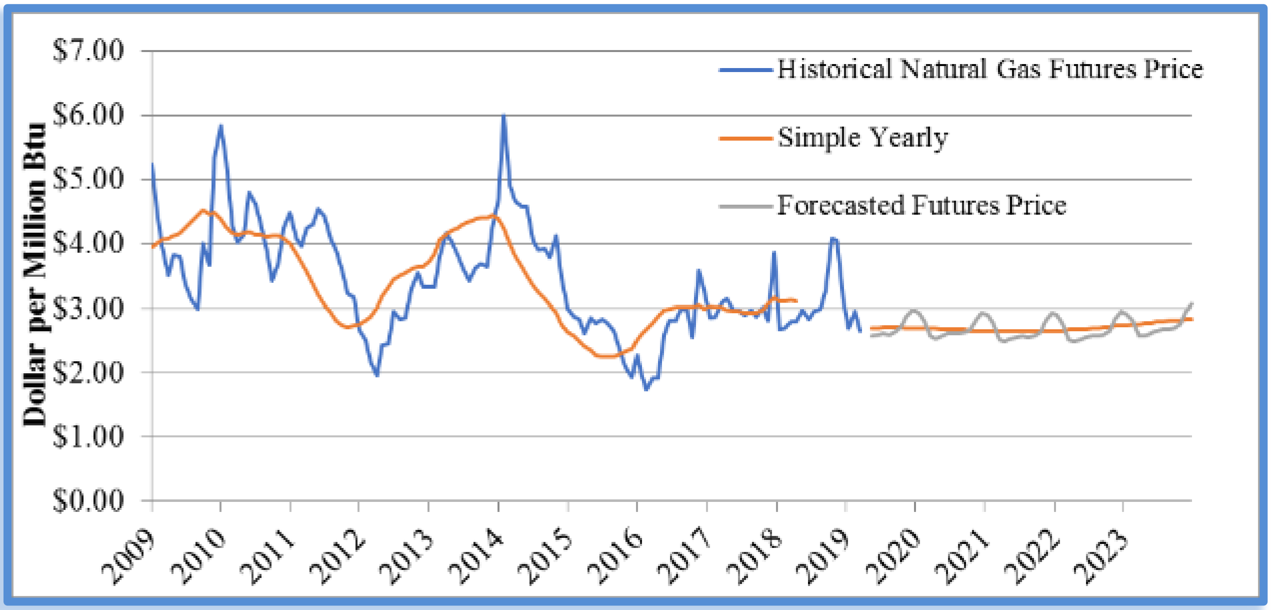
Source: Maryland Public Service Commission 2018 Ten Year Plan.
Note: Forecast based upon 2017 data.

PJM produces an independent forecast of electric energy consumption, and PJM's most recent forecast covers the 15-year forecast period of 2019 through 2034. The relatively slow growth in electricity consumption in Maryland is projected by PJM to persist throughout the PJM 15-year forecast period. Over this period, consumption in PJM's Mid-Atlantic region is expected to grow at an average annual rate of approximately 0.2 percent, whereas Maryland's forecast calls for a reduction in consumption over the 10-year period ending in 2027, as forecasted by the Maryland utilities.

Future electricity prices (and hence consumption of electricity) are affected by wholesale natural gas prices, in addition to a range of other factors. Wholesale natural gas futures contracts priced on the New York Mercantile Exchange (NYMEX) are based on the delivery price at the Henry Hub in Erath, Louisiana. Henry Hub is a major intersection of pipelines and the crossroads for a significant amount of natural gas moving to locations across the country. Wholesale natural gas is priced and traded at over 30 hubs throughout the country where major pipelines intersect. The difference between the Henry Hub price and another hub is based on supply and demand at that particular point.

As shown in Figure 3-24, natural gas prices peaked at around $6 per million British thermal units (MMBtu) in 2014 during the Polar Vortex, but declined shortly after, hovering between $3 and $4 per MMBtu or below since then. According to the Energy Information Administration (EIA), the price is forecast to remain below $3.00 per MMBTU for the next four years.

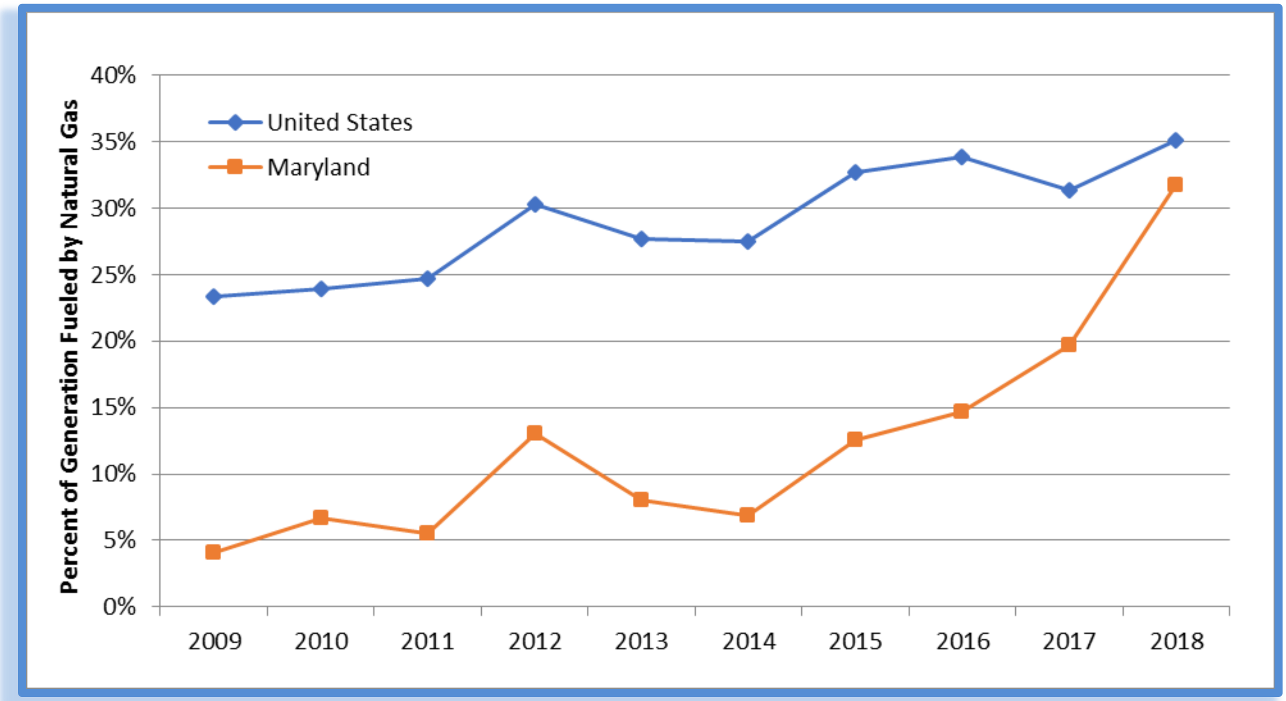
Figure 3-24 Historical and Future NYMEX Henry Hub Natural Gas Prompt Month Futures Prices, 2009-2023



Source: Historical prices: U.S. Energy Information Administration; futures prices: The CME Group.

As is shown in Figure 3-25, natural gas has been steadily growing as a share of fuels used for electricity generation in the United States. In 2012, the proportion of electricity generated from natural gas increased significantly in both the United States and Maryland, owing primarily to fuel switching, retirement of coal plants, and natural gas generating facilities operating for more hours of the year. In Maryland, there has been a significant increase since 2014 due to the addition of 3,470 MW of natural gas capacity since 2017. Natural gas futures show that wholesale natural gas prices may remain below $4.00 per MMBtu through 2020 or longer due to abundant supplies of shale gas (see Figure 3-24). Therefore, since natural gas-fired facilities are often the marginal resources within the PJM Interconnection region, and therefore often set the spot market prices in PJM, electricity prices are anticipated to show only modest increases through 2020. Refer to Chapter 4 for more information on natural gas and electricity markets.

Figure 3-25 Natural Gas Share of Fuel for Electricity Generation in Maryland, 2009-2018



Source: U.S. Energy Information Administration, "U.S. and Maryland Natural Gas Generation Data."

In addition to economic factors and EmPOWER legislation, future electricity consumption may be affected by additional energy conservation, fuel switching, and distributed generation. For example, achievement of the 2015 EmPOWER Maryland goals resulted in much of the state's street lighting inventory being upgraded.

The Maryland DNR also published the *Long-Term Electricity Report for Maryland* (LTER) in December 2016, which examines various approaches to meeting Maryland's long-term electricity needs through 2035 and provides another tool to examine future electricity consumption. The assessment considers how environmental regulation, land-use restrictions and the transmission infrastructure affect energy and capacity costs, fuel use, fuel diversity, emissions, power plant construction and retirements, and renewable energy credit prices. The LTER Reference Case, which represented then-current regulatory and economic conditions, was developed to evaluate load levels and fuel prices based on projections assessed to be most plausible. A total of approximately 13 alternative scenarios were also assessed to evaluate potential impacts of changes in legislation, fuel prices, load growth, power plant construction and various other factors. The LTER is a useful sensitivity analysis tool that can be used to evaluate current conditions compared to the Reference Case and how any differences may affect future electricity needs in Maryland going forward.

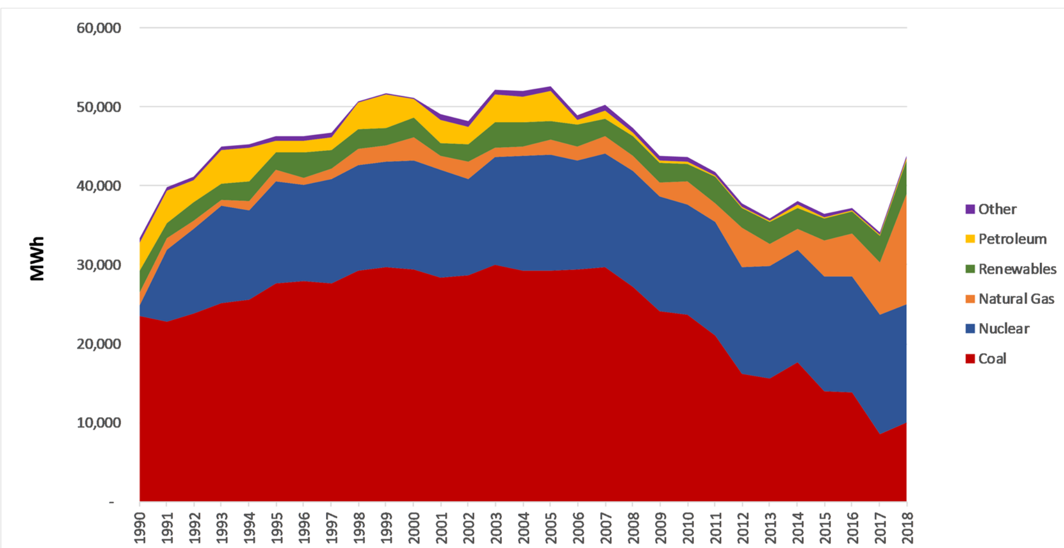
3.4.2 Generation: Comparison with Consumption

The provision of adequate levels of electric power generation for Maryland consumers does not require that the level of power generation within the state's geographic border match or exceed the state's consumption. Historically, Maryland's consumption of electricity has exceeded the amount of energy generated within the state, necessitating imports from out-of-state resources. Although there is sufficient generating capacity in Maryland to meet the state's electricity consumption needs, Maryland, as part of PJM, often relies on lower-cost generating resources from within PJM as a whole, as well as electric power that can be imported into the PJM footprint. Consequently, imbalances between Maryland consumption and generation should not be viewed as adversely affecting reliability or availability of electricity in Maryland.

Generation Fuel Mix Since 1990

Over the last several decades, the generation fuel mix in Maryland has shifted. The shifts in fuel mix are the results of various factors, including plant closures, economics, technology advancements, and environmental requirements. Since 1990, coal was the predominant generating fuel in Maryland; however, in the last five years its share of total generation has declined below nuclear generation. In 2018, natural gas surpassed coal to become the second highest generating fuel. In addition, the amount of electricity generated in Maryland has significantly declined since it peaked in 2005 with 52.6 million MWh, as Maryland generated 43.8 million MWh in 2018. Although this is 17 percent below 2005 generation, it is 20 percent higher than the average generation for 2012 -2017.

Maryland Generation Fuel Mix (Thousands of MWh)



Source: U.S. Energy Information Administration Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923).

With high import requirements, interregional transmission plays a much more critical role in sustaining reliable service. In addition, Maryland's high electric demand relative to instate generation supply can produce high electricity prices when transmission limits and congestion require the use of higher cost electricity resources located closer to load centers.

Electricity consumption in Maryland during 2018 exceeded electricity generation in the state by approximately 33 percent.[48] Table 3-10 compares electricity consumption and generation in Maryland over the past ten years. The significant decrease in net imports in 2018 coincides with three gas-fired power plants that came online in Maryland that year, which resulted in natural gas fired generation surpassing coal-fired power plants. In 2018, coal-fired power plants generated 10,067 GWh as compared to 23,668 GWh in 2010.[49] Comparatively, natural gas power plants generated 2,897 GWh in 2010 compared to 13,850 GWh in 2018.[50]

Table 3-10 Total Maryland Electric Energy Consumption and Generation (thousands of MWh), 2009-2018

	Retail Sales (Consumption)	Sales + T&D Losses*	Generation	Net Imports	Percentage of Sales Imported
2009	62,589	66,344	43,775	22,570	34%
2010	65,335	69,256	43,607	25,648	37%
2011	63,600	67,416	41,818	25,598	38%
2012	61,814	65,522	37.810	27,713	42%
2013	61,899	65,613	35.851	29,763	45%
2014	61,684	65,385	37.834	27,551	42%
2015	61,872	65,489	36.390	29,099	44%
2016	61,354	64,422	37,167	27,255	42%
2017	59,304	62,269	34,104	28,165	45%
2018	62,086	65,190	43,810	21,380	33%

*Assumes Transmission and Distribution (T&D) losses of 6 percent through 2013 and then 5 percent for 2014 through 2018.
Source: U.S. Energy Information Administration, "Retail Sales of Electricity, Annual" and EIA-923 Net Generation.

PJM's 2018 *Regional Transmission Expansion Plan* (RTEP) report notes that power plant deactivation notifications increased in 2018 compared to the prior five years, with retirements expected between 2018 and 2022. In 2018, PJM received deactivation requests totaling 12,279 MW, compared to the deactivation requests between 2004 and 2011 which collectively equaled 11,000 MW. Of the 63

48 U.S. Energy Information Administration, "Retail Sales of Electricity, Annual."

49 U.S. Energy Information Administration, "Net Generation by State by Type of Producer by Energy Source, EIA-906, EIA-920, and EIA-923."

50 Ibid.

notifications received, 14 were from plants in Maryland totaling 388 MW of capacity, with all but one located in the BGE zone. Since those 14 Maryland plants provided notification, four have retired and an additional nine are projected to retire in June 2020.

PJM noted that if all deactivation plans are carried out, more than 27,000 MW of coal-fired plants will retire between 2011 and 2020. PJM noted that over the last decade that deactivation requests are primarily the result if the economic impact of environmental regulations and age, as many of the plant deactivations are for plants more than 40 years old. In prior RTEPs, PJM also noted that competition from new generating plants fueled by Marcellus Shale natural gas, new renewable energy plants and market impacts from demand response and energy efficiency programs has impacted the decision by owners to retire plants.

3.4.3 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 percent by 2015. This initiative was codified by the EmPOWER Maryland Energy Efficiency Act of 2008 (EPM Act). The EPM Act[51] sought to achieve electric consumption and peak demand reductions as follows:

- Per capita electricity consumption: 5 percent reduction by the end of 2011 and 15 percent by the end of 2015, from 2007 levels; and
- Per capita peak demand: 5 percent reduction by the end of 2011, 10 percent by the end of 2013, and 15 percent by the end of 2015, from 2007 levels.

Under the EPM Act, utilities with more than 200,000 customers are responsible for the full 15 percent demand reduction and two-thirds of the consumption goal (i.e., a 10 percent reduction in consumption), with the remaining 5 percentage point reduction in per capita electricity consumption to be achieved through state-administered programs and changes to efficiency codes and standards. The utilities required to participate in EmPOWER Maryland included BGE, DPL, PE, Pepco, and SMECO.

As written, the EPM Act is inclusive of both electric and gas companies; however, the PSC has not established goals for gas energy efficiency programs. In 2014, Washington Gas Light (WGL) submitted a voluntary gas reduction program[52] for the 2015-2017 program cycle. On December 23, 2014, the PSC approved WGL's residential and demand response programs[53] which are designed to reduce gas consumption for heating and water heating in existing and new construction. As of early 2016, the PSC is in the process[54] of considering the development of natural gas efficiency goals, but as of 2019 no natural gas goals have been established.

On July 16, 2015, the PSC issued Order No. 87082 which established energy efficiency goals for the EmPOWER Maryland electric utilities beyond 2015. The PSC adopted an annual incremental gross

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[51] Maryland Public Utilities Article §7-211

[52] Maryland Public Service Commission Docket No. 9362, Mail Log No. 158098

[53] Maryland Public Service Commission Order No. 86785

[54] Maryland Public Service Commission Order No. 87082

energy savings reduction of 2 percent from a utility's weather-normalized gross retail sales baseline, which will be officially implemented for the 2018-2020 program cycle. The 2016 weather-normalized gross retail sales serve as the baseline for the 2018-2020 program cycle. The PSC did not set demand reduction goals but stated that utilities should continue to use the demand reduction targets established through the approved 2015-2017 plans for program years 2016 and 2017. In spring 2017, the General Assembly enacted legislation to codify the 2 percent goal, thus continuing the EmPOWER Maryland efforts for the 2018-2020 and 2021-2023 program cycles.

EmPOWER Maryland Energy Efficiency and Conservation Programs

The EPM Act directed EmPOWER Maryland utilities to develop plans for all customer sectors—residential, commercial and industrial. The PSC is directed to consider whether each program is cost-effective and adequate to achieve the EmPOWER Maryland goals, and also to assess the program's potential impacts on electricity rates, jobs, and the environment. The programs offered by the utilities include rebates for ENERGY STAR® products, energy audit and retrofit assistance, combined heat and power, and incentives for energy efficient new construction. In addition, all of the utilities have been directed by the PSC to include conservation programs targeting low-income consumers. To date, over 32,000 low-income customers have participated in EmPOWER Maryland.

EmPOWER Maryland Peak Demand Reduction Programs

While energy efficiency programs can result in demand reduction, the majority of demand reduction comes from demand response and dynamic pricing programs (see Section 3.1.4 for more information on demand response). The EmPOWER Maryland utilities, with the exception of PE, implemented these types of programs to meet these goals.

In regard to demand response programs, BGE implemented its Peak Rewards program, which is a voluntary program that cycles air conditioners, heat pumps and water heaters for residential customers. Pepco and DPL are operating an Energy Wise Rewards program and SMECO is running CoolSentry; each offers residential and small commercial direct load control programs for air conditioner cycling. PE cites a lack of any cost-effective mechanism to meaningfully reduce peak demand. Each program offers various cycling levels, including 50 percent, 75 percent and 100 percent. As the utilities have reached program saturation levels, the savings contributed by the demand response has plateaued. At the end of 2018, the four demand response programs were capable of providing a demand reduction of 616 MW.[55]

The installation of advanced metering infrastructure (AMI) meters allows for utilities to implement a dynamic pricing program, which is used to lower summer peak demand (see Section 3.4.4 for more information on AMI meters). Dynamic pricing is a voluntary program for all customers with an AMI meter, regardless of whether they have central air conditioning. The day before an event, the utility will notify customers that the following day will be a dynamic pricing day. On the day of a dynamic pricing event, for each kWh that a customer reduces his or her usage from its baseline between the hours of 1:00 p.m. and 7:00 p.m., the customer will receive a bill credit of $1.25. BGE customers that participated in

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[55] Maryland Public Service Commission Docket No. 9494, Individual utility EmPOWER Maryland semiannual reports filed February 15, 2019.

an event received, on average, a bill credit of $5 to $8 per event.[56] On average, BGE, DPL and Pepco customers have collectively reduced their loads by 499 MW annually in 2015, 2016 and 2017.[57] The annual dynamic pricing demand reductions, which fluctuate annually based upon customer engagement, are summarized in Table 3-11.

Table 3-11 Utility Dynamic Pricing Demand Reduction (MW)

	2013	2014	2015	2016	2017
BGE	0	209	309	336	330
Delmarva	0	0	143	39	31
Pepco	309	125	47	126	135
Total	309	334	499	501	496

Source: Maryland Public Service Commission, The EmPOWER Maryland Energy Efficiency Act Standard Report of 2018 with Data for Compliance Year 2017.

EmPOWER Maryland Reductions

At the conclusion of 2015, the utilities achieved 99 percent of their energy reduction goal, reducing energy usage by 5,394,256 MWh, and 100 percent of the demand reduction goal by lowering lowered electric demand by 2,117 MW. As the EmPOWER programs continue, the energy reduction savings has almost doubled, with the EmPOWER Maryland utilities recognizing over 9.4 million MWh of reduced energy savings from 2009 through 2018. Due to the fact that demand reduction is not additive or constant year-over-year, the level of demand reduction at the conclusion of 2018, 1,230 MW, is significantly lower than the demand reduction in 2015. A summary of the energy and demand reductions of the electric EmPOWER Maryland utilities to date are summarized in Table 3-12 and the natural gas reductions from WGL's efficiency program to date is summarized in Table 3-13.

[56] BGE Smart Energy Rewards, Baltimore Gas and Electric, http://www.bge.com/smartenergy/smart-energy-rewards/Pages/default.aspx

[57] Maryland Public Service Commission, The EmPOWER Maryland Energy Efficiency Act Standard Report of 2018 With Data for Compliance Year 2017.

Table 3-12 EmPOWER Maryland Program Results to Date

		Energy Reduction (MWh)			Demand Reduction (MW)		
		Goal/Forecast	Gross Reductions	Variance	Goal/Forecast	Gross Reductions	Variance
BGE	2009 - 2015	3,593,750	2,638,975	73%	1,267	1,156	91%
	2016 - 2017	1,149,791	1,335,350	116%	541	559	103%
	2018 - 2020*	1,430,944	738,589	52%	996	585	59%
	Total **	6,174,485	4,712,914	76%			
DPL	2009 - 2015	143,453	382,605	267%	18	147	815%
	2016 - 2017	213,471	202,421	95%	42	144	346%
	2018 - 2020*	286,332	91,414	32%	122	106	87%
	Total **	643,256	676,440	105%			
PE	2009 - 2015	415,228	529,519	128%	21	82	392%
	2016 - 2017	162,274	174,922	108%	24	35	147%
	2018 - 2020*	356,845	99,445	28%	48	16	32%
	Total **	934,347	803,886	86%			
Pepco	2009 - 2015	1,239,108	1,600,813	129%	672	640	95%
	2016 - 2017	686,546	786,428	115%	580	638	110%
	2018 - 2020*	816,442	441,771	54%	404	458	113%
	Total **	2,742,096	2,829,012	103%			
SMECO	2009 - 2015	83,870	242,347	289%	139	92	67%
	2016 - 2017	116,181	102,736	88%	28	17	62%
	2018 - 2020*	147,046	65,564	45%	87	66	76%
	Total **	347,097	410,647	118%			
Total	2009 - 2015	5,475,409	5,394,259	99%	2,117	2,117	100%
	2016 - 2017	2,328,263	2,601,857	112%	1,215	1,394	115%
	2018 - 2020*	3,037,609	1,436,783	47%	1,658	1,230	74%
	Total **	10,841,281	9,432,899	87%			

*Only includes 2018 savings, but goal is for 2019 and excludes savings from MD Department of Housing and Community Development Limited Income Programs
** Demand response savings is not additive.

Table 3-13 WGL Natural Gas Program Results to Date

	Reduction in Therms		
	Goal/Forecast	Gross Reductions	Variance
2015 - 2017*	2,224,955	1,698,312	76%
2018 - 2020**	3,652,714	248,972	7%
Total	5,877,669	1,947,284	33%

* For 2015 – 2017 program cycle, WGL only reported net reductions, not gross.
** For 2018 – 2020 program cycle, the goal/forecast is provided for the entire program cycle but the actual reductions are only for saving through 2018.

The EmPOWER Maryland utilities have collectively spent over $2.54 billion, consisting of $1.6 billion on energy efficiency and conservation and $744 million on demand response programs. Projected savings from EmPOWER Maryland is $7.7 billion over the life of the installed measures. The average monthly residential bill impact for 2018, by utility, is provided in Table 3-14.

Table 3-14 WGL Natural Gas Program Results to Date

	EE&C	Demand Response	Dynamic Pricing	Total
BGE	$4.34	$2.87	($0.11)	$7.10
Delmarva	5.87	1.56	(1.06)	6.37
Potomac Edison	6.93	N/A	N/A	6.93
Pepco	5.85	2.90	0.48	8.27
SMECO	5.91	3.79	N/A	9.70

*Bill impact assumes the average monthly usage of 1,000 kWh.
**N/A indicate that the utility does not offer that program.
Source: Public Service Commission of Maryland 2018 Annual Report for the Calendar Year Ending December 31, 2018.

3.4.4 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.

Advanced Metering Infrastructure (AMI) Initiatives

At the heart of a "smarter" electric grid lies the deployment of advanced technology at end-user locations. On the metering and communications front, these technologies are referred to as Advanced Metering Infrastructure, or "AMI." AMI has multiple benefits: utilities can "see" electrical outages based on clusters of unresponsive meters, costs for all parties are lowered as meters indicate (either directly or implicitly) the need for maintenance, and the meters themselves can be read remotely via wireless communications. However, the greatest potential benefit from AMI deployment comes from the new rate structures they enable. AMI provides the necessary technology for the dissemination of high-resolution (≤ 1 hour) prices to customers, who can then make decisions to curtail or defer electricity usage based on the prices and their personal preferences. These dynamic rates are expected to lower energy and capacity prices as customers shift energy use away from typical peaks to save money.

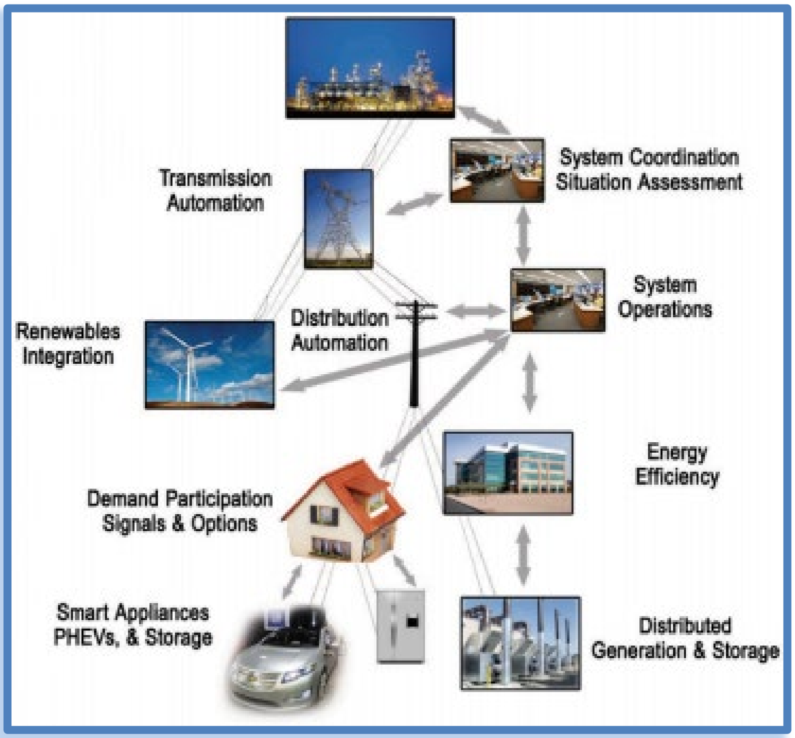
BGE, DPL, Pepco and SMECO have completed the installation of AMI meters in their respective service territories, and each has received Commission approval to recover AMI-related costs through base rates for each utility with exception of SMECO. In February 2017, the Commission denied SMECO's request to recover AMI costs stating that the Cooperative can seek recovery once it has delivered a cost-effective AMI system. SMECO has yet to file another request with the Commission for AMI cost-recovery. For customers who wish to opt-out of receiving the AMI meter, the PSC has established opt-out fees that vary by service territory. Until the AMI projects are proven cost-effective, each utility must defer incremental costs related to AMI in a regulatory asset. At this time, PE has not filed plans to install AMI meters.

Smart Grid Integration

AMI and smart grid are often used synonymously. However, while AMI is a necessary precondition for the realization of full smart grid benefits, the concept of smart grid extends far beyond remote and dynamic meter communications. A smart grid integrates advanced technologies and communication by consumer-based resources, distribution companies, and transmission systems (see Figure 3-26). Better integration of these traditional elements of the electrical system may one day serve to reduce utility and power plant operations and maintenance and capital costs by improving load factors, lowering system losses, and improving outage management performance.

On the consumer side, the smart grid will provide information, control and options that enable consumers to engage in new energy markets and allow for better home energy management. For example, intelligent control systems reading temperatures, weather forecasts, and real-time power system statistics, coupled with a high degree of automation for end-user electrical control (e.g., price-responsive thermostats, water heaters, lighting), can dynamically match customer price points with electrical system needs.

Figure 3-26 Smart Grid Integration



Cybersecurity

The increasingly digital and interconnected nature of the nation's electrical grid exposes these crucial systems to the threat of infiltration and attack. Addressing cybersecurity is critical to enhancing the security and reliability of the nation's electric grid. A resilient electric grid is a complex and critical component of the nation's infrastructure that is required in order to deliver essential services.

For the past several decades, a significant portion of generation dispatch has become automated or been outfitted for remote control using Supervisory Control and Data Acquisition (SCADA) systems. Through the SCADA infrastructure, system operators communicate instructions from a central control facility to the generating units via automated generator control (AGC). Owing to this level of automation, the grid has always faced some threat from cyberattacks. In particular, the protection of nuclear plants and large hydroelectric dams, and the potential large-scale consequences of their sabotage, has always been one of the key cornerstones of generating system infrastructure protection. However, the extension of grid intelligence beyond SCADA and AGC to the more robust network and ultimately more distributed smart grid increases these risks.

In February 2013, President Obama issued an Executive Order on "Improving Critical Infrastructure Cybersecurity" in response to failed attempts at passing federal cybersecurity legislation in Congress. The Executive Order encourages information sharing between the federal government and private industry and puts voluntary cybersecurity standards in place for critical infrastructure. Two years later, the President issued an Executive Order on "Promoting Private Sector Cybersecurity Information Sharing" in an effort to allow private companies and the federal government to work together when responding to threats. Further strengthening those two efforts, in February 2016, President Obama directed his administration to implement a Cybersecurity National Action Plan (CNAP) to enhance cybersecurity awareness and projections through near-term actions and long-term strategy. In November 2018, President Trump signed the Cybersecurity and Infrastructure Security Agency Act of 2018, which established the Cybersecurity and Infrastructure Security Agency (CISA). The agency, under U.S. Department of Homeland Security, utilizes resources in the public and private sectors to assist in defending against cyberattacks and to provide the federal government with the tools necessary to ensure "secure and resilient infrastructure for the American people."[58] CISA includes the National Cybersecurity and Communications Integration Center (NCCIC), which shares cyber and communications information with the cybersecurity community to assist in building awareness and understanding on how to mitigate cyber threats and vulnerabilities.

Over the last several years, FERC has adopted cybersecurity standards under the Critical Infrastructure Protection (CIP) standards. In early 2016, FERC Order 822 revised seven of the North American Electric Reliability Corporation's (NERC's) CIP standards. In addition, it requires the NERC to develop modifications to: (1) protect transient electronic devices used at low-impact bulk electric system cyber systems; (2) protect communication network components between control centers; and (3) refine the definition for low-impact external routable connectivity. In July 2016, FERC issued Order No 829 which directed NERC to develop a new or modified reliability standard that addressed supply chain risk management for BES operations. FERC Order No. 843, released in April 2018, adopted NERC's proposed Reliability Standard related to these matters, with one exception, a directive regarding controls for low impact bulk electric system cyber systems. In its denial of this directive, FERC directed NERC to complete a study within 18 months to assess whether the proposed directive provides adequate security.

On July 21, 2016, FERC issued a Notice of Inquiry (NOI) to address potential modifications to the CIP reliability standards as a result of lessons learned from the 2015 cyberattack on an electric grid in the Ukraine. The Notice sought comments on (1) whether there should be a separation between the internet and the Bulk Electric System (BES) control systems in control centers that perform transmission operator functions and (2) requiring computer administration practices that prevent unauthorized programs from running. In response to its NOI, FERC received 18 comments opposing modifications to CIP reliability standards. As a result, FERC terminated the proceeding, citing that the CIP reliability standards allow flexibility with implementing security controls.

In June 2019, FERC expanded the reporting requirements for cybersecurity incidents under the CIP Reliability Standards. Under the adopted standard, cybersecurity incidents which compromise Electronic Security Perimeters, Electronic Access Control or Monitoring Systems, or Physical Security Perimeters with associated cybersecurity systems and attempts to disrupt or the disruption of bulk electric system cyber systems. Incidents reports will be sent to the NCCIC and the Electricity Information Sharing and Analysis Center at NERC.

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[58] https://www.dhs.gov/cisa/about-cisa

In addition to these legislative and regulatory activities, most observers recognize that grid operators and equipment manufacturers play a pivotal role in making systems less vulnerable by adopting good security practices and building security into their products and systems. This topic will continue to be relevant to electricity reliability in Maryland and nationwide as smart grid technology is adopted throughout the nation.

The PSC recognized the risks associated with AMI meters, stating that “as our distribution systems become more automated, and private customer data is increasingly being used in electronic format, we are keenly aware of the risks and rewards related to smart meter infrastructure build-out in Maryland.” The PSC approved BGE’s, DPL’s, and Pepco’s respective Cybersecurity Plans filed in October 2012. In addition, the PSC approved a Cybersecurity Reporting Plan,[59] which establishes the protocols for reporting incidents and providing annual updates to the PSC and other parties, such as the Governor’s office and the Maryland Energy Administration (MEA). Additionally, the three utilities fund the PSC’s access to a cybersecurity consulting firm which serves at the discretion of the PSC. The firm provides independent advice to the PSC regarding the process and sufficiency of the AMI-related cybersecurity.

In 2018, the PSC issued a Notice of Initiating a Proceeding and Request for Comments on the Final Report of the Cyber-Security Reporting Work Group, a document that provided recommendations regarding “(i) cyber-security definitions, (ii) Maryland utilities periodic cyber-security reporting applicability, (iii) cyber-security reporting agenda, (iv) cyber-security reporting certification, (v) cyber-security briefing parties, (vi), cyber-security report briefing frequency, (vii) cyber-security breach reporting, and (viii) cyber-security briefing information handling protocols.” In Commission Order No. 89015, issued February 2019, the PSC adopted the Final Report’s recommendations, including:

- Expanding the definition of information technology systems to include “hardware and software related to electronic processing, and storage, retrieval, transmission;”
- Establishing triennial reporting requirements beginning 2019 for utilities with more than 300,000 customers; and
- All utilities must report cybersecurity breaches.

[59] Maryland PSC Order No. 85680.

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, 17 other states, typically states characterized by high electricity prices, 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, PJM (see Appendix B for a map of the PJM zones and additional information on PJM). Note that the State of Maryland retains regulatory control over siting for new generation (over two megawatts) and high voltage transmission development (over 69,000 volts) through the CPCN process (see Chapter 1).

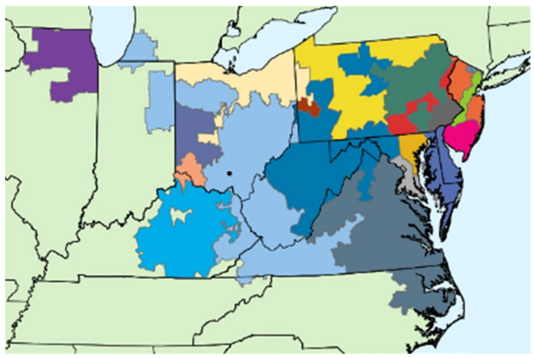
In states with restructured markets, such as Maryland, electricity is generated by a power company that is separate from the entity responsible for transporting and delivering power to end-use customers. Entities selling energy on the wholesale market include competitive suppliers and power marketers 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 re-sold several times before finally being consumed. These sales and re-sale 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 of time 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 Interconnection 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 $49 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 Co. formed the P.A. N.J. 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 P.A.-N.J. 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, would meet PJM reliability targets. The name was changed to the Pennsylvania-New Jersey Maryland Interconnection, or PJM, in 1956 when Baltimore Gas & Electric (now a subsidiary of the Exelon Corporation) and General Public Utilities (now a part of FirstEnergy) joined.

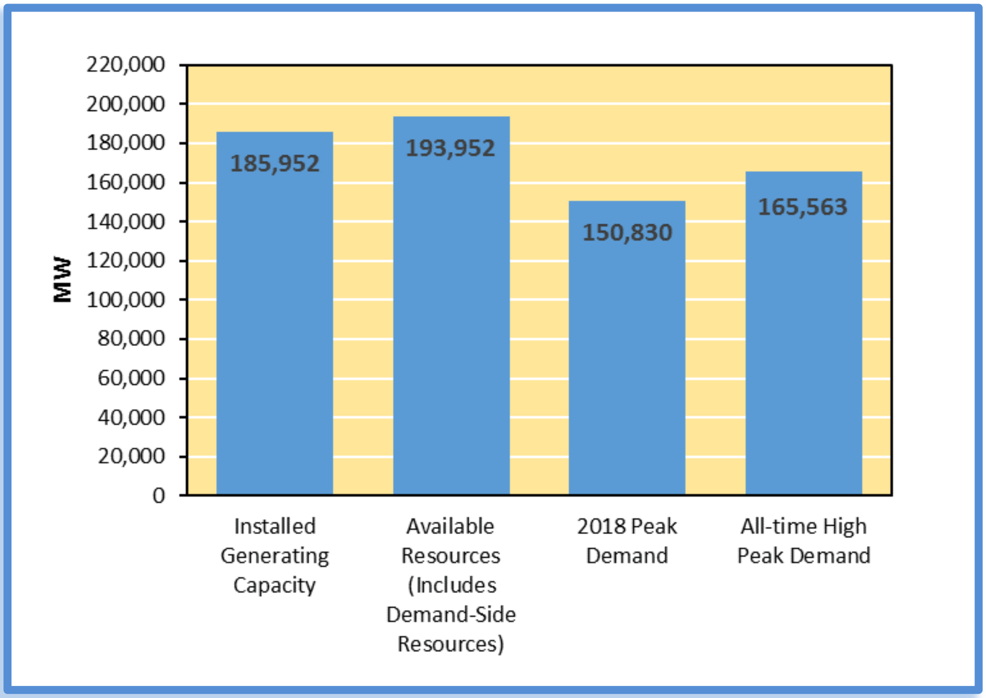
In 1997, FERC approved PJM as the first fully functioning independent system operators (ISO), which operate but do not own transmission systems and allow non-utility users access to the transmission grid. In an effort to develop competitive wholesale power markets and operate a multi-state transmission system, FERC encouraged PJM to form a regional transmission organization (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), CPP (2011), Duke Energy Ohio and Duke Energy Kentucky (2012), and East Kentucky Power Cooperative (2013). In addition, Ohio Valley Electric Corporation (OVEC) integrated in 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 2018,

https://www.pjm.com/-/media/about-pjm/newsroom/annual-reports/2018-annual-report.ashx?la=en "PJM History," PJM Interconnection, http://www.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 development of new generation capacity necessary to meet electricity demand. Figure 4-1 shows supply and demand in PJM in 2018.

Figure 4-1 PJM Supply and Demand for 2018 (MW)



Source: Installed Generating Capacity and 2018 Peak Demand: Monitoring Analytics, 2018 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 the names of the markets, 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 upon 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 also 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 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 on the basis of 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 is able to 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 2018 are shown in Table 4-1.

Table 4-1 PJM Off-Peak and On-Peak Hourly Locational Marginal Prices for 2018

	Day Ahead		Real Time	
	Off-Peak ($/MWh)	On-Peak ($/MWh)	Off-Peak ($/MWh)	On-Peak ($/MWh)
Average	30.70	41.41	31.33	40.81
Median	25.43	36.66	24.41	32.99

Source: Monitoring Analytics, *2018 State of the Market Report for PJM.*

Since 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. Based on real-time market outcomes, PJM estimates that in 2018, congestion added approximately $3.82/MWh to the average LMPs in the BGE zone, $2.98/MWh in the Pepco zone, and $3.16/MWh in the Delmarva Power & Light (DPL). Congestion accounted for 9 percent, 7 percent and 7 percent of load-weighted average, real-time LMPs in the BGE, Pepco and DPL zones, respectively.

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

PJM Zone	2017	2018	Variance
BGE	34.76	44.09	9.33
Pepco	33.70	42.65	8.95
DPL	33.39	43.82	10.43
APS	31.32	39.83	8.51

Source: Monitoring Analytics, *2018 State of the Market Report for PJM.*

In prior years the congestion costs and LMPs have dropped and the differences between LMPs between the eastern and western zones of PJM have declined; however, in 2018 the LMP costs increased significantly by 27 to 31 percent as compared to 2017. The increase in 2018 LMPs can be attributed to several factors such as record low LMP prices in 2016 and 2017, coal setting the electric price approximately one-quarter of the time (coal is more expensive than natural gas), and increased congestion costs. The biggest contributor to LMPs is the cost of fuel to generators. Fuel prices rose in 2018 due to increases in natural gas prices and emissions allowance costs and attributed to 35 percent of the increase in LMP between 2017 and 2018. The factors that affect LMPs are discussed at length in Appendix B.

Historically, coal plants were the least-cost generators due to the long-term availability of low-cost coal as a fuel, as well as the economies of scale arising from the construction of large, baseload coal plants. However, over the last several years, natural gas has increasingly been used in place of coal for baseload generation. Shale gas discoveries in the United States have increased natural gas supplies, which in turn have led to sharp decreases in wholesale natural gas prices. The decrease in wholesale prices has trickled down into reductions in wholesale electricity price and, subsequently, retail electricity prices. These conditions are expected to continue since natural gas supplies are plentiful and wholesale natural gas prices are expected to remain low for the next decade. As a result of lower wholesale electricity prices 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 reports that that it anticipates 44,684 MW of generation to retire between 2011 and 2022, approximately 70 percent of which is from coal fired steam units. In 2018, 5,522 MW of generation was retired, and 12,826 MW of new generation resources were added. PJM does not expect these retirements to result in degraded reliability since as of December 31, 2018 there was 114,953 MW of capacity in the generation queue, indicating that there is still sufficient capacity in the queue to compensate for retirement of generation units. In addition, PJM has a reserve margin of over 28 percent, or about 40,000 MW. PJM's required reserve margin is 16 percent of expected demand.

4.1.2 Power Plant Construction

Prior to electricity restructuring, Maryland, like other states, would identify a need for generating capacity as part of an Integrated Resource Planning (IRP) process. Capacity was constructed, typically by vertically integrated utilities, once a need was identified and a permit to construct was issued by the PSC. The cost of building and operating the new generation capacity was included in customer rates, which were regulated by the PSC. With the adoption of electric industry restructuring in Maryland, as well as in many other states, generation is now considered competitive, and the competitive market is now relied upon to provide new generation resources to meet load requirements. Capacity is constructed by independent power producers or the competitive affiliates of the regulated electric distribution companies in response to wholesale electricity market price signals. PJM established the Reliability Pricing Model (RPM) capacity auction to provide a three-year forward market for new and existing generation capacity. The RPM has undergone multiple rounds of changes to improve the operation of the capacity market and to help ensure the availability of needed capacity to meet load requirements. See Section 3.1.4 Demand Response and Appendix B for more information on the RPM.

From the late 1990s through mid-2010s, relatively little new generation was constructed in the Mid-Atlantic region even with the implementation of the RPM capacity market. The lack of new generating capacity in the Mid-Atlantic gave rise to concerns regarding the reliability of power supply in Maryland and other nearby states. Though RPM capacity prices have remained higher in eastern PJM than in western portions of PJM, no new large generation projects were constructed in Maryland. Independent power producers and competitive affiliates proposed various generation projects, but they were mainly expansions of existing sites. Without the financial assurances that were previously available through utility ownership and rate base cost recovery, and the inability of power plant developers to secure long-term contracts for generation, it became increasingly difficult for developers to obtain third party financing to build new generation.

In September 2009, the PSC opened Case No. 9214 to "investigate whether it should exercise its authority to order electric utilities to enter into long-term contracts to anchor new generation or to construct, acquire, or lease, and operate new electric generating facilities in Maryland." In September 2011, the PSC made a preliminary determination that new generation was needed to meet long-term, anticipated electricity demand in Maryland. Subsequently, the PSC directed the state's four investor-owned utilities to issue Request for Proposals for up to 1,500 MW of new, natural gas-fired generation in Maryland that will clear the RPM auction. In April 2012, the PSC issued an order accepting one of three bids for natural gas generation, a Competitive Power Ventures (CPV) bid for a 661 MW (later increased to 725 MW) combined cycle facility located in Charles County.

Also prompted by high RPM capacity prices and no new large generation development, New Jersey conducted an auction to develop new large generating plants. New Jersey selected two companies to build new natural gas plants, with the condition that each plant must clear the RPM auction. PJM and some existing generators considered the New Jersey auction to be anti-competitive since the new, state-supported generating capacity could bid into the capacity auctions at an artificially low price (i.e., below their cost of construction), thereby lowering the RPM clearing price. In fact, with the requirement that new capacity clear the PJM capacity auction, new generation would have been bid into the auction at a price of zero. All resources clearing the auction receive the market-clearing price rather than the offer price. In May 2013, PJM received Federal Energy Regulatory Commission (FERC) approval to change the RPM rules to remove the exemption for state-sponsored projects from the Minimum Offer Price Rule (MOPR). In essence, the MOPR requires that new generating projects bid a price into the RPM equal to or greater than the capacity price that is consistent with the cost of new entry. Maryland included a similar provision requiring the winning bidder to clear the RPM auction, thereby making the CPV project subject to the MOPR. This could have potentially led to the CPV project not clearing in the RPM capacity auction, making it ineligible for RPM capacity payments and to be counted towards resource adequacy requirements for Maryland utilities.

As a result of this conflict between Maryland's and New Jersey's desire to actively promote increased generation instate, and PJM's and existing generators' desire to maintain higher capacity prices, several lawsuits emerged. Maryland and New Jersey both challenged FERC's MOPR ruling. Additionally, several generators brought lawsuits against the Maryland PSC challenging its authority to require utilities to enter into contracts with CPV. In September 2013, the U.S. District Court for Maryland ruled that the Maryland PSC order directing the utilities to enter into contracts with CPV was unconstitutional based on the Supremacy Clause of the U.S. Constitution. (Separately, in October 2013, the Circuit Court for Baltimore County ruled that it is within the Maryland PSC's statutory authority to direct the utilities to enter into such contracts.) In November 2013, the Maryland PSC appealed the U.S. District Court's decision to the U.S. Court of Appeals for the Fourth Circuit, which upheld the earlier verdict in June 2014. The Supreme Court of the United States then agreed to hear the case. Oral arguments were presented in February 2016. Despite the legal controversy, CPV was able to clear the PJM Capacity Market auction and broke ground on the Charles County project in 2014 and came online in February 2017.

On April 19, 2016, the Supreme Court upheld the lower court's decision stating in its opinion that the PSC's ruling overstepped on FERC's authority as granted by the Federal Power Act. In its opinion, the Supreme Court noted[60] that in deregulated markets, power must be procured one of two ways: 1) through bilateral contracts where load serving entities agree to purchase power through a power purchase agreement or 2) through competitive wholesale auctions held by regional transmission operators. The contract for differences for the CPV plant would not transfer the ownership of power to the load serving entities and guaranteed the plant a contract price rather than the auction clearing price; therefore, the plant's contract does not meet either of the two power procurement methods. In an effort to not discourage states' efforts to develop new or clean generation, the Supreme Court clarified that the reason the contract for differences was invalid is that it violated the interstate wholesale rate required by FERC since it conditioned the payment of funds on the clearing the capacity market.

Separately, Old Dominion Electric Cooperative (ODEC) proposed to build a 1,000 MW natural gas power plant in Cecil County (See Section 5.2.1: Low-Flow Issues). In April 2013, ODEC asked the PSC for expedited approval of a CPCN for the project, so that it could bid into PJM's May 2014 capacity auction. ODEC expected significant increases in capacity requirements over the next few years, and stated in its application that this project would reduce its need for market purchases by about 30 percent. The project, called the Wildcat Point Generation Facility, was approved by the PSC in March 2014. It was completed and operation started in May 2018.

[60] Hughes v. Talen Energy, 578 U.S. 14614, 2016, https://www.supremecourt.gov/opinions/15pdf/14-614_k5fm.pdf

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 (the 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, ten years after the Act's enactment, only 2.8 percent of residential customers were being served by competitive suppliers. By January 2019, however, 21.3 percent of residential customers had signed with competitive suppliers. The majority of medium to large commercial and industrial customers are currently purchasing electricity from competitive suppliers (see Table 4-3).

Table 4-3 Percentage of Customers Served by Competitive Suppliers

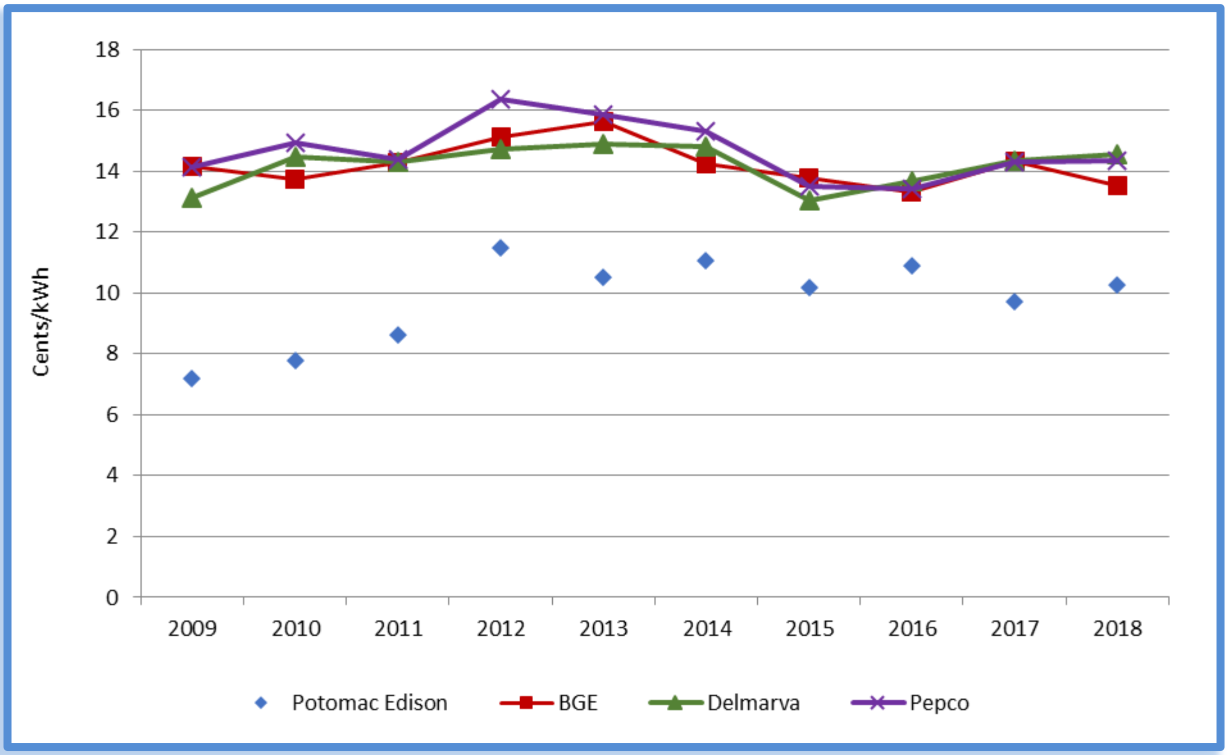
Residential	Small Commercial & Industrial	Mid-size Commercial & Industrial	Large Commercial & Industrial
19.4%	32.3%	52.5%	82.4%

Source: Maryland PSC, *Electric Choice Enrollment Monthly Report*, January 2019.

Residential and small commercial customers that cannot or do not choose to transact with a competitive supplier are provided with 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 utilities (IOUs) procure 25 percent 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 in Maryland rose significantly between 2005 and 2009, and as a result, residential customers saw substantial increases in their electric bills. Between 2009 and 2012, however, retail rates declined as wholesale energy prices decreased. Forward market prices have remained relatively stable since 2012. Figure 4-2 shows the average annual IOU residential rates in effect in the summer of 2009 and for each subsequent summer.

Figure 4-2 Average Annual Retail Electricity Rates for Maryland Residential Customers, 2009-2018 (cents/kWh)



Source: Edison Electric Institute (EEI), *Typical Bills and Average Rate Reports*

Note: Average annual rates were taken from EEI's summer editions of the Typical Bills and Average Rates Reports, except for BGE's 2012 rate and Potomac Edison's 2013 and 2015 rates, which were unavailable. EEI's summer editions take the average of the rates from the 12 months ending June 30 of the edition year.

4.2.2 Retail Electric Billing

Customers are billed for each of the three separate functions—generation, transmission, and distribution—although most customers receive just one consolidated electric bill. The PSC sets distribution rates through rate case proceedings. Generation rates are based on either SOS rates or a customer's contracted rate with a competitive supplier. Transmission rates are set by the FERC and administered by PJM. The local distribution utility is still responsible for directly billing customers with competitive generation and transmission components as direct pass-through components.

Also included in rates are several components referred to as "riders" which are used to recover costs for specific purposes or initiatives, such as energy efficiency costs under EmPOWER Maryland. These riders do not always appear on bills as separate line items but are sometimes rolled into the electric rate or charges. Riders are used to account for costs that are typically variable and can be adjusted periodically (usually quarterly, semiannually, or annually) through proceedings that are less intensive than a full rate case. Figure 4-3 shows a residential BGE bill with some details on billing components.

Figure 4-3 BGE Bill Detail Example

Electric Details Electric Choice ID:
Residential - Schedule R
Billing Period: Nov 18, 2015 - Dec 17, 2015 Days Billed: 29

Meter Read on December 17 Meter #

Current Reading		Previous Reading		kWh Used
14112	-	13805	=	307

BGE Elec Supply	307 kWh x .0946800	29.07
BGE Electric Delivery Service		
Customer Charge		7.50
EmPower MD Chg	307 kWh x .0048100	1.48
Distribution Chg	307 kWh x .0359500	11.04
RSP Chg/Misc Cr	307 kWh x .0035100	1.08
ERI Initiative Chg	307 kWh x .0001700	.05
State / Local Taxes & Surcharges		
MD Universal Svc Prog		.36
Envir Srchg	307 kWh x .0001510	.05
Franchise Tax	307 kWh x .0006200	.19
Total BGE Electric Amount		**$50.82**

The BGE customer profiled in Figure 4-3 is on Rate Schedule R, the standard residential service schedule. In this particular month, the customer used 307 kWh of energy and was charged a total of \$50.82. The BGE electric supply rate during this billing period was \$0.09468 per kWh. The electric supply rate consists of the SOS energy and capacity charges, a PJM transmission charge, and applicable taxes. The largest component of the delivery service charges is BGE's distribution charge (shown as \$11.04 on this sample bill) as approved by the PSC. Delivery charges also include the fixed monthly charge and riders that compensate BGE for the cost of EmPOWER Maryland programs; a Rate Stabilization Plan that insulates BGE from either revenue shortfalls or excess revenue collections only to factors such as weather conditions; miscellaneous credits; and an Electric Reliability Initiative Surcharge used to provide funds to enhance BGE's electric distribution system. Other elements in the bill include a universal surcharge as well as the environmental surcharge. Both of these surcharges are designed to support certain state programs, such as PPRP.

Paying for Power during Storm Outages – Bill Stabilization Adjustment

Maryland can experience severe storms that result in power outages for electricity customers. Power outages are caused by storm-related damage to transmission or distribution infrastructure, often from downed trees or falling branches.

During a power outage, a customer is not using electricity and, therefore, the customer might expect total electricity costs to be lower. However, the Bill Stabilization Adjustment (BSA) mechanism, approved by the PSC in 2007, removes the link between electricity use and utility revenue. The BSA is an adjustment that will lower rates if a utility is receiving more revenue than the PSC has approved, and will increase rates if the utility is receiving less revenue than the PSC has approved. Prior to the BSA, the traditional rate structure created a disincentive for the utility to encourage customers to conserve energy because that would reduce revenue for the utility. The BSA was implemented to remove this disincentive. Previously, the more electricity customers used, the more revenue a utility received, but through the BSA, the level of utility revenue is independent of the level of electricity consumption.

An unintended consequence of the BSA was that it also removes a utility's incentive to restore power quickly after an outage. In January 2012, the PSC issued an order to prevent utilities from using the BSA beginning 24 hours after the commencement of a major storm and continuing until all storm-related sustained interruptions are restored.

The largest component on the bill is the electric supply charge. For BGE, the winter 2016 SOS generation component of the supply charge was $0.08469 per kWh (this does not include taxes, fees, and PJM transmission charges that are also rolled into the total electricity supply charge). Therefore, the electric generation component makes up about $25.97 of this customer's entire bill, or 51 percent. Distribution charges comprise about 22 percent, while transmission charges only amount to about 6 percent of the total charges. The rest of the charges consist of the customer charge, riders, surcharges and taxes (about 21 percent). As noted earlier, the utilities contract for energy supply in the wholesale market and, therefore, the electric generation price of $0.08469 per kWh is reflective of the price of energy in the PJM wholesale energy markets at the time the contracts were signed, and includes various mark-ups for the companies that provide the firm energy contracts for two years. For customers who signed with competitive suppliers, the electric supply component would be the energy charge from their supplier, which is collected by BGE and then passed through to the competitive supplier.

Figure 4-4 profiles a residential Pepco customer with a consumption pattern slightly higher than that of the aforementioned BGE customer. Note that Pepco's Residential Service rate is distinct from BGE's residential Rate Schedule R, although the rates and charges are similar. The Pepco bill example shows how PJM transmission charges and taxes are rolled into the total electricity supply charge, which is the largest component of the bill.

Figure 4-4 Pepco Bill Detail Example

[redacted]

Your electric bill for the period
January 22, 2016 to February 18, 2016

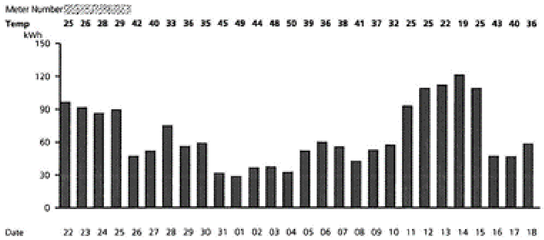
Account number: [redacted]

Supply Charges: These charges reflect the cost of producing electricity for you. You can compare this part of your bill to offers from competitive suppliers.
Supply Price Comparison Information: Standard Offer Service (SOS) electricity will cost 9.24 cents/kWh beginning on Oct 1, 2015 through May 31, 2016. The price for SOS electricity after May 31, 2016 has not yet been set. The weighted average price of SOS electricity will be 9.21 cents/kWh through May 31, 2016.

Type of charge	How we calculate this charge	Amount($)
Transmission Services:		
Energy Charge	1847 kWh X $0.0075100 per kWh	13.87
Gross Receipts Tax	at 2.0408%	0.28
Generation Services:		
Energy Charge	1847 kWh X $0.0847300 per kWh	156.50
Procurement Cost Adjustment	1847 kWh X $0.0010958- per kWh	2.02–
Total Electric Supply Charges		**168.63**
Total Electric Charges - Residential Service		**265.97**

Your daily electricity use for this bill period. Visit My Account at pepco.com to see your hourly electricity use.

Meter Number [redacted]



Details of your Electric Charges

Residential Service - service number [redacted]
Electricity you used this period

Meter Number	Energy Type	End Date	Start Date	Number Of Days	Total Use
[redacted]	Use (kWh)	Feb 18	Jan 22	28	1847

Your meter records hourly use. Total use is the sum of this hourly data.
Please visit My Account at pepco.com to view your energy use data.

Your next bill period is scheduled to end on March 18, 2016

Delivery Charges: These charges reflect the cost of bringing electricity to you.
Current charges for 28 days, **winter rates in effect.**

Type of charge	How we calculate this charge	Amount($)
Distribution Services:		
Customer Charge		7.39
Energy Charge	1847 kWh X $0.0269750 per kWh	49.83
Grid Resiliency Charge	1847 kWh X $0.0001400 per kWh	0.26
Franchise Tax (Delivery)	1847 kWh X $0.0006200 per kWh	1.15
Universal Service Charge		0.36
MD Environmental Surcharge	1847 kWh X $0.0001470 per kWh	0.27
Empower MD Chg	1847 kWh X $0.0087630 per kWh	16.19

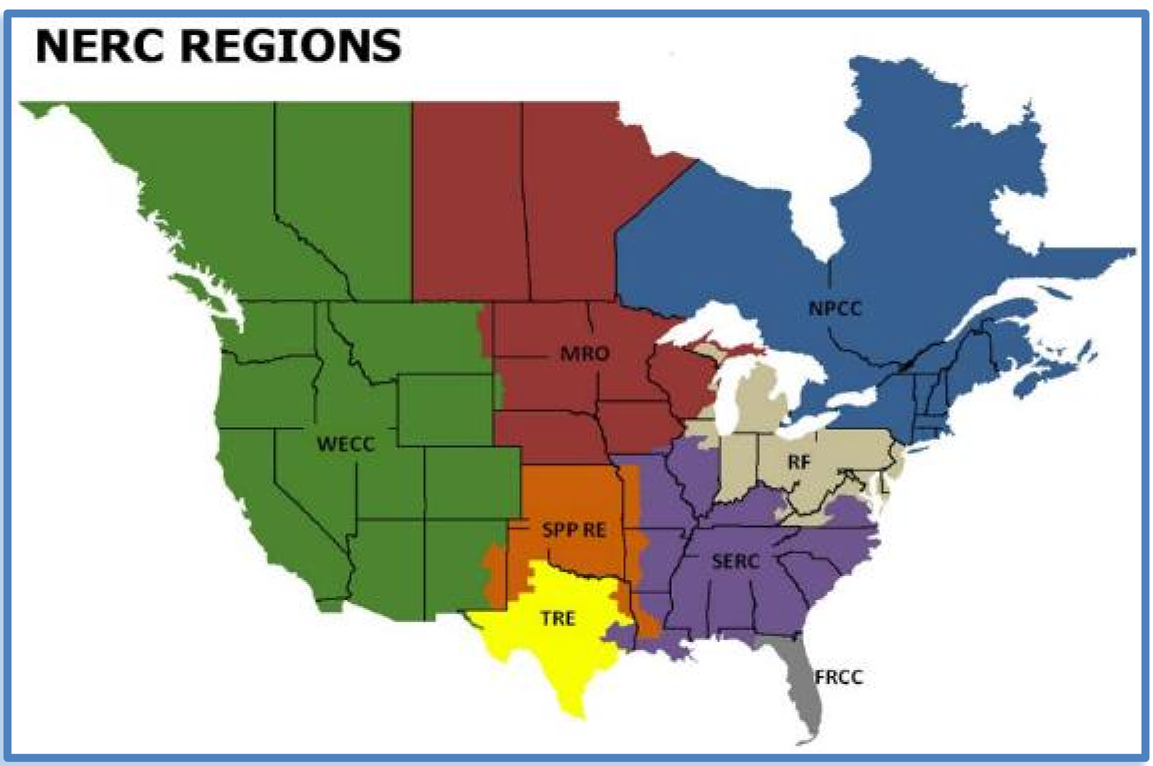
4.3 Transmission and Distribution System Planning and Reliability

Historically, transmission infrastructure enabled utilities to locate power plants near inexpensive sources of fuel and transmit electricity over long distances to consumers. By interconnecting different utilities' transmission systems, utilities were able to access additional sources of generation and back up each other's generating capacity, thus improving overall reliability and also reducing overall operating costs. Ultimately, the power grid grew into an interstate system subject to both federal and state regulation. Under the federal Energy Policy Act of 1992 and FERC Order 888 issued in 1996, any generator, independent or utility-owned, may request access to the transmission grid at rates and terms comparable to those that the owner-utility would charge itself. This access to the transmission grid led to the growth of wholesale power markets. Power generators were able to use the transmission system to send power to one another as needed to serve the loads of their customers, creating larger, more regional transmission networks. With the creation of regional transmission systems and competitive wholesale markets, utilities in many areas transferred the functional control of their transmission lines to independent system operators (ISOs) or regional transmission organizations (RTOs), such as PJM, while maintaining ownership and maintenance responsibilities over their lines. Utilities retain sole control for their distribution systems.

4.3.1 Reliability

The North American Electric Reliability Corporation (NERC) is charged with developing and implementing reliability standards and periodically assessing the reliability of the bulk power system. NERC, which is governed by a 12-member independent board of trustees, develops mandatory reliability standards that are reviewed and ultimately approved by the FERC. The Energy Policy Act of 2005 requires electricity market participants to comply with NERC reliability standards, or be subject to fines of up to $1 million per day per violation. NERC delegates enforcement authority to eight regional reliability councils, including the ReliabilityFirst Corporation (RF) that serves the PJM RTO (see Figure 4-5).

Figure 4-5 NERC Reliability Councils



Source: North American Energy Reliability Corporation.

One of the NERC reliability standards applicable to PJM is the Resource Planning Reserve Requirement. This standard requires that each load serving entity (LSE) participating in PJM has sufficient resources such that there is no loss of load more than one day in ten years. In order to maintain compliance under this reliability standard, PJM conducts annual resource planning exercises to ensure all LSEs have sufficient generation resources (either owned or contracted) to supply their peak electricity load, plus a specified annual reserve margin of approximately 15 percent.

4.3.2 Transmission Congestion

The economic impacts of transmission congestion are described in Section 4.1.1; however, congestion may also affect reliability if a transmission line nears or exceeds its transfer limit (the physical limit of the transmission system) and there are no supplemental generation resources downstream of the constraint. If this occurs, system operators might ask large customers to voluntarily curtail their loads or, in extreme situations, may even be forced to reduce electricity deliveries to consumers. Economic congestion that results in higher electricity costs is far more common than a loss of load, or a blackout event, caused by insufficient transmission or generation resources. Economic congestion results when a transmission path is unable to provide access to the lowest cost generation to serve load requirements in particular locations. This circumstance entails more expensive generation located along an uncongested path to be used to meet load requirements. The difference in generation cost between the lowest cost (but unavailable) generation and the higher cost (but available) generation represents the congestion cost.

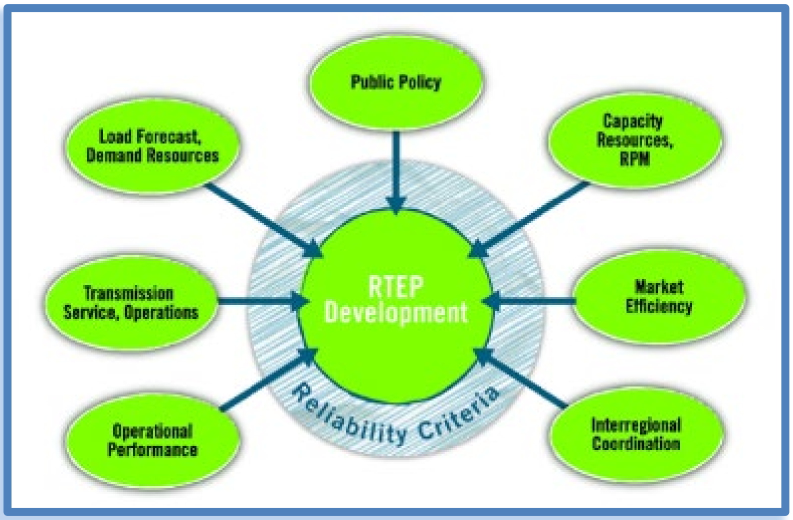
Eliminating or reducing key constraints can alleviate congestion. This may be achieved through construction of new transmission lines, building new generation within a load pocket, upgrades to existing facilities, or demand side management. PJM routinely conducts transmission planning to ensure reliability is maintained. In that regard, congestion that threatens reliability will be addressed in PJM's transmission planning process. Economic congestion, as described in Section 4.1.1, is congestion that produces localized increases in electricity prices, but does not trigger a reliability event. Economic congestion is not addressed in PJM's reliability planning since it is considered an economic decision rather than a reliability problem. However, depending on the total economic impact and benefits, PJM may suggest corrective projects as part of its competitive planning process to improve market efficiency.

4.3.3 PJM Transmission Planning

PJM conducts annual transmission planning to forecast and address potential reliability issues. PJM's Regional Transmission Expansion Planning (RTEP) process models future load and generation, and identifies and evaluates possible new transmission projects or upgrades. PJM has authority over the transmission system and an obligation to maintain reliability. However, PJM can only put forward transmission solutions in RTEP. PJM cannot impose generation or demand response solutions, and includes in the RTEP model only those generation projects that have requested interconnection to the PJM grid and are at a relatively late stage of development. Additionally, only demand response resources that have cleared in the RPM are recognized by PJM for purposes of reliability assessment.

PJM develops a 15-year Transmission Plan that includes upgrades to help alleviate constraints identified through the modeling exercise. Once a transmission constraint is identified, PJM authorizes construction and cost recovery of transmission upgrades to address the area of concern. PJM authorization does not supersede state regulation, so a CPCN may be required depending on state siting and permitting regulations. PJM also considers market efficiency upgrades designed to relieve economic congestion by reducing overall operating and supply costs for customers. Since the 2012 RTEP planning cycle, PJM has included public policy requirements (for example, state Renewable Energy Portfolio Standard policies) when considering transmission upgrades. (See Figure 4-6 for the RTEP planning criteria.)

Figure 4-6 PJM RTEP Transmission Planning Criteria



Source: PJM 2015 Regional Transmission Expansion Planning.

In February 2019, PJM released the 2018 RTEP report, which outlines planned system upgrades approved by the PJM Board through December 31, 2018. The PJM Board approved $37.1 billion in transmission enhancements since 1999. The 2018 RTEP summarizes the following high voltage backbone transmission projects not yet in-service or recently placed in service:

- Cloverdale-Lexington transmission upgrade – this project is for the reconductoring of the AEP portion of the Cloverdale-Lexington 500 kV transmission line. This project connects Botetourt and Rockbridge Counties in Virginia and was completed in June 2016.
- Dooms-Lexington transmission upgrade – this 500 kV rebuild project runs between Augusta and Rockbridge Counties in Virginia and was completed in January 2016.
- Surry to Skiffes Creek transmission line – this 500 kV project for a new transmission line that crosses the James River near Williamsburg, Virginia has an anticipated in-service date of December 2017.
- Loudoun-Brambleton- this 500 kV rebuild project was completed in May 2016.
- Byron to Wayne transmission line – this 345 kV project in northern Illinois was completed in April 2017.
- Bergen to Linden Corridor 345 – the Bergen-Marion 345 kV portion was placed in service in April 2016. The remainder of the facilities is under construction with an expected in-service date in 2018.

PJM Market Efficiency

As part of PJM's Regional Transmission Expansion Planning (RTEP) 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 over a 12- 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 does 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.

PJM's first market efficiency analysis was performed in 2013 and it is currently in its third market efficiency analysis cycle. The most recent proposal window was open from November 1, 2018 through February 28, 2019, during which time PJM received 22 proposals to address congestion on the Hunterstown-Lincoln 115-kV transmission line in Pennsylvania. One project approved during a previous market efficiency process is the Transource project, which will result in the construction of two east/west transmission lines, linking substations in Pennsylvania and Maryland. As indicated in Figure 1, Transource's West transmission line will run from a new substation in Shippensburg, Pennsylvania to an existing substation in Smithsburg, Maryland, while the East transmission line will run from a new substation in Airville, Pennsylvania to an existing substation in White Hall, Maryland. Both the Pennsylvania Public Utility Commission and the Maryland Public Service Commission are reviewing Transource's CPCN application.

Figure 1 Transource Transmission Line Map

(Source: https://www.transourceenergyprojects.com/IndependenceEnergyConnection/)

Maryland RTEP Upgrades

The 2018 PJM RTEP lists two baseline upgrades (equal to or greater than $10M) (shown in Table 4-4), and seven supplemental upgrades (equal to or greater than $10M) (shown in Table 4-5). Baseline projects ensure compliance with NERC, regional and local transmission owner planning criteria and to address market efficiency and congestion relief. Supplemental projects, known at one time as Transmission Owner initiated projects, are not required for compliance with system reliability, but could address equipment material condition performance and risk, operational flexibility and efficiency, infrastructure resilience and customer service. The cost of these baseline transmission upgrades is expected to total $59 million. PJM RTEP only lists transmission upgrades with cost estimates greater than $10 million that were approved by the PJM Board in 2018.

Table 4-4 Baseline Projects in Maryland (Greater than $10M) Included in 2018 PJM RTEP

<table>
<tr><th>Baseline Projects</th><th>Date</th><th>Cost $M</th><th>Zone</th></tr>
<tr><td>Reconnect the Crane-Windy Edge 110591 and 110592 115 kV circuits into the Northeast Substation with the addition of a new 115 kV three-breaker bay.</td><td rowspan="3">6/1/2018</td><td rowspan="3">12.00</td><td rowspan="3">BGE</td></tr>
<tr><td>Modify the Crane-Windy Edge 110591 and 110592 115 kV circuits by terminating Windy Edge Circuits 110591 and 110592 into Northeast Substation with the addition of new 115 kV breaker positions at Northeast substation.</td></tr>
<tr><td>Modify the Crane-Windy Edge 110591 and 110592 115 kV circuits by terminating Crane Circuits 110591 and 110592 into Northeast Substation with the addition of new 115 kV breaker positions at Northeast substation.</td></tr>
<tr><td>Reconductor the Conastone-Graceton 230 kV 2323 and 2324 circuits. Replace seven disconnect switches at Conastone Substation. Reconductor the Raphael Road-Northeast 2315 and 2337 230 kV circuits.</td><td rowspan="3">3/1/2021</td><td rowspan="3">39.60</td><td rowspan="3">BGE</td></tr>
<tr><td>Add bundle conductor on the Graceton-Bagley-Raphael Road 2305 and 2313 230 kV circuits.</td></tr>
<tr><td>Replace short segment of substation conductor on the Windy Edge-Glenarm 115 kV circuit.</td></tr>
</table>

Source: PJM 2018 Regional Transmission Expansion Planning.

Table 4-5 Supplemental Projects in Maryland

<table>
<tr><th>Supplemental Projects</th><th>Date</th><th>Cost $M</th><th>Zone</th></tr>
<tr><td>Reconfigure the Calvert Cliffs 500 kV switchyard, including the addition of four breakers in a new 500 kV bay. Two additional breakers will be installed for the current plant service transformers.</td><td>9/30/2020</td><td>$59.80</td><td>BGE</td></tr>
<tr><td>Create a new Loch Raven 115/13 kV substation.</td><td rowspan="4">6/1/2024</td><td rowspan="4">$130.00</td><td rowspan="4">BGE</td></tr>
<tr><td>Build a new Loch Raven 115/13 kV substation. Supply substation with underground 115 kV cables from Erdman Substation.</td></tr>
<tr><td>New Loch Raven substation, install 115 kV breakers and perform high side bus work to supply the distribution station.</td></tr>
<tr><td>At Erdman 115 kV substation, expand to a gas insulated substation, breaker-and-a-half configuration to connect new circuits that supply Loch Raven.</td></tr>
</table>

<table>
<tr><th>Supplemental Projects</th><th>Date</th><th>Cost $M</th><th>Zone</th></tr>
<tr><td>Network East Towson substation to Loch Raven Substation with underground 115 kV cross-linked polyethylene cables.</td><td rowspan="3">6/1/2024</td><td rowspan="3">$93.00</td><td rowspan="3">BGE</td></tr>
<tr><td>Build a 115 kV circuit between East Towson and Loch Raven stations with underground 115 kV cross-linked polyethylene cables.</td></tr>
<tr><td>Install 115 kV circuit breakers and equipment at East Towson and Summerfield substation to accommodate transmission network.</td></tr>
<tr><td>Rebuild line between Church and Chestertown substations. All structures, conductor and static wire will be replaced with new steel poles and conductor.</td><td rowspan="4">12/31/2022</td><td rowspan="4">$35.00</td><td rowspan="4">DPL</td></tr>
<tr><td>Rebuild the Church-Massey REA 69 kV circuit.</td></tr>
<tr><td>Rebuild Massey REA-Lynch 69 kV circuit.</td></tr>
<tr><td>Rebuild Lynch-Chestertown 69 kV circuit.</td></tr>
<tr><td>Rebuild line 6719 between East New Market and Cambridge substations. All structures, conductor and static wire will be replaced with new poles, conductor and optical ground wire.</td><td>5/31/2021</td><td>$17.90</td><td>DPL</td></tr>
<tr><td>Rebuild both Five Forks-Windy Edge 115 kV circuits using steel monopole, double circuit construction.</td><td>12/31/2022</td><td>$60.00</td><td>BGE</td></tr>
<tr><td>Build new 115 kV station to supply 34 kV and 13 kV distribution station. Provide diverse overhead transmission supplies from Riverside and Windy Edge substations to new 115 kV station.</td><td rowspan="4">12/1/2026</td><td rowspan="4">$45.00</td><td rowspan="4">BGE</td></tr>
<tr><td>Build new 115 kV ring bus station, Fitzell, and install two 115/34 kV and two 115/13 kV transformers.</td></tr>
<tr><td>Extend the existing Windy Edge-Riverside 115 kV double circuit to the new station.</td></tr>
<tr><td>Rebuild and extend the existing Riverside-North Point-Finishing Mill 115 kV double circuit to the new station.</td></tr>
</table>

Source: PJM 2018 Regional Transmission Expansion Planning.

4.3.4 State Distribution System and Reliability Planning

Following several incidents of storms and outages in Maryland during 2010 and 2011, the PSC initiated Rulemaking 43 (RM43) to consider revisions to state regulations in regard to electric company reliability and service quality standards, "including, but not limited to: service interruption, downed wire repair and service quality standards; vegetation management standards; annual reliability reporting; and the availability of penalties for failure to meet the standards." On April 17, 2012, new regulations were adopted, including the following:

- A requirement that utilities submit a Major Outage Event Report within three weeks following the end of the event. A "major outage" is defined as an event affecting more than 10 percent of a utility's customers or 100,000 customers in total, whichever is less.
- A set of reliability standards and a requirement to collect certain related data.
- Service interruption standards that require utilities to restore service within a defined period of time.

- Downed wire standards that require utilities to respond within four hours of notification by a fire department, police department, or 911 emergency dispatcher at least 90 percent of the time.
- A communications standard that requires utilities to answer calls within a certain period of time.
- Vegetation management standards that aim to keep power lines clear of potential hazards.
- A requirement for periodic equipment inspections.

Utilities must submit an annual report outlining their performance with respect to these regulations. In addition, the utilities are required to have a Major Outage Event Plan on file with the PSC providing a description of and procedures for its response to major events, as well as performance measures associated with the assessment of the implementation of the Major Outage Event Plan.

Being able to detect outages during storms or during normal operations has been a challenge for utilities. Historically, utilities have relied on customers to report local outages. With the advent of new technologies, being able to "see" conditions on the distribution grid in real-time is becoming a reality. Maryland utilities with PSC-approved advanced metering infrastructure (AMI) plans have either finished installing or are in the process of installing AMI in their respective service territories. While AMI allows for electronic reading of customer meter information, the communication network created by the advanced meters also serves to provide much needed information on the current status of the distribution grid. (For more information on AMI and smart grid capability, see Section 3.4.4.)

Damage from severe storms can be extensive and costly to repair. Some jurisdictions utilize a rider to fund storm-related repairs. In Maryland, the costs of storm repairs are included in the utility's overall revenue requirement which determines a utility's rates as approved by the PSC. In BGE's 2011 annual report submitted in its rate case filed in July 2012, the utility noted that incidental costs associated with Hurricane Irene totaled $41.1 million. In a PSC March 2011 rate order, BGE was authorized to defer, as a regulatory asset, $15.8 million in storm costs incurred during the winter storms that took place in February 2010. These costs were amortized over a five-year period that began in December 2010.

On December 2, 2015, the PSC adopted proposed regulations[61] regarding the reliability and service quality standards. The proposed regulations established numerical reliability standards in terms of allowable number of outage minutes for calendar years 2016 through 2019.

[61] Maryland Public Service Commission Mail Log No. 179783. Revisions to COMAR 20.50, Proposed Reliability and Service Quality Standards, January 12, 2011.

4.4 The Role of Federal Entities

Regulatory jurisdiction over the electricity system as a whole is shared between federal and state entities. This section describes federal authority over the generation and transmission of electricity in Maryland.

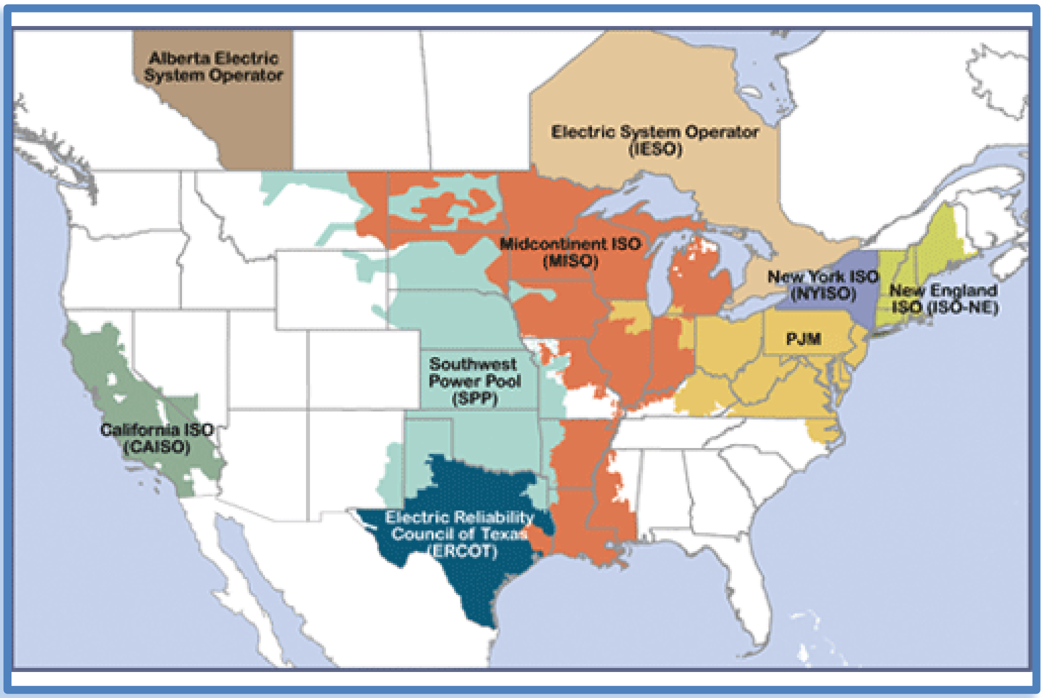
4.4.1 Federal Energy Regulatory Commission

The FERC is an independent regulatory arm of the U.S. Department of Energy (DOE). FERC authority derives from the Interstate Commerce Clause (Article I of the U.S. Constitution) and a large set of federal statutes, primarily the Federal Power Act, the Natural Gas Act, the Energy Policy Act of 2005, and the Interstate Commerce Act. FERC's authority specifically includes: hydroelectric projects on interstate waterways (those not otherwise regulated by other federal entities such as the U.S. Army Corps of Engineers); interstate natural gas pipelines and certain types of gas storage, transmission, and wholesale sales of electricity in interstate commerce; and import and export facilities for liquefied natural gas (LNG) (a responsibility shared with the U.S. Coast Guard). FERC also has authority over wholesale energy rates, natural gas pricing, interstate oil pipeline rates, electric reliability at a national level, and reviews of certain mergers and acquisitions by energy companies. FERC does not have authority over the following: local or otherwise non-interstate reliability; retail electricity and natural gas rates; mergers and acquisitions related to natural gas and oil companies; energy facilities; or energy issues regulated by state energy authorities (such as state public utility commissions) or regional energy authorities (such as the Tennessee Valley Authority).

Electricity Transmission

FERC jurisdiction over wholesale transmission applies to entities that own, control or operate interstate transmission facilities, primarily investor-owned utilities, but could include electric cooperatives, municipal utilities and public power agencies. In addition, FERC jurisdiction over federal agencies is limited and FERC jurisdiction does not extend to regions not engaged in interstate commerce, which includes the part of Texas under the Electric Reliability Council of Texas and the states of Alaska and Hawaii. FERC has primary jurisdiction over all U.S. ISOs and RTOs with respect to both the ISO/RTO-administered wholesale electricity markets and the ISO/RTO regional transmission planning activities (except in Electric Reliability Council of Texas). The North American ISOs and RTOs are shown in Figure 4-7. Regulation of transmission owners outside of an ISO/RTO varies on a case by case basis.

Figure 4-7 North American RTOs and ISOs



Source: FERC

Transmission Planning and Cost Recovery

FERC originally issued Order No. 888 in April 1996, establishing requirements for transmission use and planning on both a local and regional level. Within this order, FERC outlined several broad planning principles for transmission providers such as PJM, but these were mainly focused on meeting reliability needs and promoting wholesale competition through establishing open access transmission service on a nondiscriminatory basis to all wholesale customers. In February 2007, FERC issued Order No. 890, which strengthened the pro forma Open Access Transmission Tariff by requiring public utility transmission providers to participate in open transmission planning processes. Order 890 noted that transmission investment relative to load growth had declined in the decade following Order 888, and transmission constraints had become common occurrences. Order 890 also outlined new criteria for transmission planning. In July 2011, FERC issued Order No. 1000 to amend some of the transmission planning and cost allocation requirements established in Order 890. FERC noted that regional transmission planning processes had improved following the issuance of FERC Order 890 but some deficiencies remained. Order 1000 included several reforms with respect to transmission planning processes and cost allocation methods by FERC-jurisdictional entities, including:

- A requirement for all public (i.e., under FERC jurisdiction) transmission providers to participate in a regional transmission planning process that evaluates both transmission and non-transmission solutions and includes consideration of public policy requirements; and
- Each public utility is required through the regional planning process to coordinate with neighboring transmission planning regions and create an interregional transmission planning agreement.

Order 1000 also includes criteria that align cost allocation with transmission planning. Each public utility transmission provider is now required to have a method for allocating costs for new transmission facilities that follow principles that FERC sets out, with one set of principles for intraregional facility cost allocation within PJM and another for interregional facilities between PJM and adjacent transmission providers, such as the Midcontinent Independent System Operator (MISO). The methodology can include different cost allocation schemes for different types of projects driven by different needs; i.e., reliability, economics, and public policy goals.

PJM submitted its Order 1000 compliance plan in October 2012, outlining its proposed changes to its intraregional transmission planning process. PJM proposed to expand its current planning process to consider direct submissions by states of proposed public policies to be studied at the assumptions stage of the transmission planning process. These submissions would then form the basis for developing scenarios and ultimately could be factored into the selection of projects. PJM also proposed a new cost allocation methodology for large backbone transmission projects. Under PJM's proposal, the cost of new 500 kV or double-circuit 345 kV projects would be split evenly between the PJM system as a whole and the identified beneficiaries of the project. This method contrasts with the then-existing PJM cost allocation methodology whereby backbone transmission costs were assigned to the system as a whole, with direct beneficiaries bearing the same cost as entities receiving little, if any, benefit. The project costs assigned throughout PJM will be allocated *pro rata* to all LSEs based on their peak loads. The other half of project costs will be allocated to the beneficiaries of the new project as determined by PJM zonal modeling. On March 22, 2013, FERC conditionally accepted PJM's Order 1000 compliance filing, approving the new cost allocation methodology. FERC also ordered PJM to clarify its definition of "Public Policy Requirements" to include duly enacted laws or regulations passed by a local governmental entity, such as a municipal or county government.

In July 2013, PJM submitted to FERC its compliance filing for interregional transmission planning and cost allocation. Interregional planning by PJM and MISO is already provided for under their Joint Operating Agreement (JOA). The existing JOA is largely compliant with many of the requirements of Order 1000, but PJM and MISO worked with stakeholders to agree upon a number of enhancements to the JOA. However, PJM and MISO were not able to come to an agreement on the future treatment of cross-border cost allocation for reliability projects currently specified in the existing JOA, nor on the need to maintain the established reliability planning criteria in the existing JOA. Interregional planning between PJM and the New York Independent System Operator (NYISO) is also provided for through a JOA. While PJM and NYISO modified the JOA, PJM believes the enhancements only partially comply with Order 1000. Finally, PJM and the Southeast Region Transmission Planning entities filed an agreement on planning and cost allocation to meet the Order 1000 provisions. Compliance points were developed by PJM and Southeast Region Transmission Planning stakeholders, and tariff language (rather than a JOA) was filed with the FERC.

Various utilities and the National Association of Regulatory Utility Commissioners have sued FERC, arguing that some of the provisions in Order 1000 are beyond FERC's authority. In September 2013, FERC argued before the District of Columbia Circuit Court of Appeals that it does, in fact, have the authority to reform the planning of high voltage power transmission. FERC argued that the appeals court should dismiss claims against its requirement in Order 1000 which states that FERC-jurisdictional electric transmission providers must participate in a regional planning process that takes into account state and local public policy when outlining a regional plan, and requires them to also coordinate with other adjacent providers to find better ways to boost efficiency and reliability. FERC argued that its rule did not intrude on state authority and that its public policy directive to regulate in this area is sufficiently clear.

In November 2013, the Coalition for Fair Transmission Policy along with National Association of Regulatory Utility Commissioners and various other utilities, trade associations, and public power organizations filed two reply briefs with the U.S. Court of Appeals challenging FERC's defense of Order 1000. The first brief addressed controversial cost allocation provisions and asked that key provisions in Order 1000 be reversed. The second brief challenged FERC's assertion that Order 1000 was simply the last in a series of evolutionary transmission restructuring orders and also addressed the effect of Order 1000 on state utility regulators. The Court heard oral arguments in March 2014 and issued a decision in August 2014 to uphold Order 1000, stating that FERC acted within its authority and that the rule was not arbitrary and capricious.

The Eastern Interconnection

North America is comprised of two major and three minor alternating current (AC) power grids or "interconnections." The Eastern Interconnection, one of the major grids, reaches from Central Canada eastward to the Atlantic coast (excluding Québec), south to Florida and west to the foot of the Rockies (excluding most of Texas). All of the electric utilities in the Eastern Interconnection are electrically tied together during normal system conditions and operate at a synchronized frequency at an average of 60Hz. The other major interconnection is the Western Interconnection. The three minor interconnections are the Québec Interconnection, Alaska Interconnection and Texas Interconnection.

Source: http://www.powermag.com/the-odd-couple-renewables-and-transmission/?pagenum=2

Hydroelectric and Liquefied Natural Gas

Unless a project has a valid pre-1920 federal permit, nonfederal hydroelectric projects are subject to FERC jurisdiction if the project:

- Is located on navigable waters of the United States;
- Occupies public lands or reservations of the United States
- Uses surplus water or hydropower from a federal dam (such as an Army Corps of Engineers facility); and/or
- Is located on a body of water over which the U.S. Congress has Commerce Clause jurisdiction, and was constructed on or after August 26, 1935, and the project affects the interests of interstate or foreign commerce.

FERC issues licenses for projects for up to 50 years and has a complex licensing procedure that incorporates interagency processes such as the U.S. Fish and Wildlife Coordination Act and local public consultation.

FERC also has authority under the Natural Gas Act to authorize the siting of facilities used to import or export liquefied natural gas, which are constructed and/or operated inside the state waters limit. State waters are generally three nautical miles from shore, but this distance varies in some areas, such as the Gulf of Mexico and Puerto Rico where this limit is nine nautical miles.

4.4.2 The Role of the NRC

Under federal law, the Nuclear Regulatory Commission (NRC) is responsible for regulating commercial nuclear power plants and other uses of nuclear materials, such as in nuclear medicine, through licensing, inspection and enforcement. The NRC is charged with ensuring adequate protection of public health and safety, promoting the common defense and security, and protecting the environment. The NRC's relevance to power generation in Maryland stems from its role in overseeing the state's only nuclear power plant, Calvert Cliffs Units 1 and 2, located on the Chesapeake Bay in Calvert County. NRC staff monitor virtually every aspect of Calvert Cliffs' operation, including maintenance, security, training, and emergency response planning.

The Calvert Cliffs facility holds NRC licenses for each of the two operating units, as well as a separate license for the Independent Spent Fuel Storage Facility Installation (ISFSI) at the site. These licenses have finite periods, with the Calvert Cliffs facility receiving a license extension to 2034 for Unit 1 and 2036 for Unit 2, and through November 2052 for the ISFSI. When the NRC issues a license or a license renewal, it is required to do an environmental evaluation under the rules of the National Environmental Policy Act (NEPA). States have the option of participating in the NRC licensing process.

4.4.3 The Role of the EPA

In regards to generation, the U.S. Environmental Protection Agency (EPA) issues laws and regulations affecting air, waste, and water, as well as ensure compliance with standards such as coal ash. Laws and regulations enforced by the EPA include the Clean Power Plan (See Section 5.1.5), Cross-State Air Pollution Rule (CSAPR), National Emissions Standards for Hazardous Air Pollutants (NESHAP), Clean Water Act (CWA), Resource Conservation and Recovery Act (RCRA), and coal ash regulations. In addition to establishing the rules, the EPA issues permits or authorizes states to issue permits related to the environmental regulations.

The CAA is a federal law that defines the responsibilities of the EPA for protecting and improving the nation's air quality and the stratospheric ozone layer. Under the CAA, EPA has developed a complex set of regulations that govern construction of new pollution sources and modifications or expansions of existing sources. Collectively, these regulations are referred to as New Source Review (NSR). There are three types of NSR permitting requirements: Prevention of Significant Deterioration permits, Nonattainment NSR permits, and minor source permits. Major NSR permits cover the construction, modification or reconstruction of "major" stationary sources or "major" modifications of existing sources. In areas of the country where National Ambient Air Quality Standards are being met, known as "attainment areas," the NSR program is known as Prevention of Significant Deterioration (PSD). In nonattainment areas, the NSR program is referred to as Nonattainment New Source Review (NA-NSR). Construction and modification of "minor" sources are covered by "minor NSR" programs and the regulations covering these activities are established by state and local regulatory agencies. NSR permits outline what construction is authorized, emission restrictions and how the facility must be operated.

Under Maryland law, power plants in the state are required to obtain a CPCN prior to construction of or modification to an existing facility (See Chapter 1). The CPCN serves as the air quality permit to construct the proposed project, including PSD and NA-NSR permits. PPRP conducts a comprehensive review in coordination with the Maryland Department of the Environment (MDE) to provide consolidated recommendations and CPCN licensing conditions to the PSC. For all PSD or NA-NSR permits issued by the state, the EPA is provided the opportunity to review and comment on the licensing conditions during the CPCN process. Minor NSR permits do not require review by EPA, although representatives from EPA may be consulted on issues that are new or developing.

Additionally, facility-wide Title IV Acid Rain Permits and Title V Operating Permits for power plants in Maryland are issued outside the CPCN process. These permits are processed, renewed and submitted for public comment by MDE. The draft permits are submitted to the EPA for review. Final permits are issued by MDE. The conditions specified in the permits are federally enforceable and compliance with certain permit conditions requires submittal to the EPA Region III.

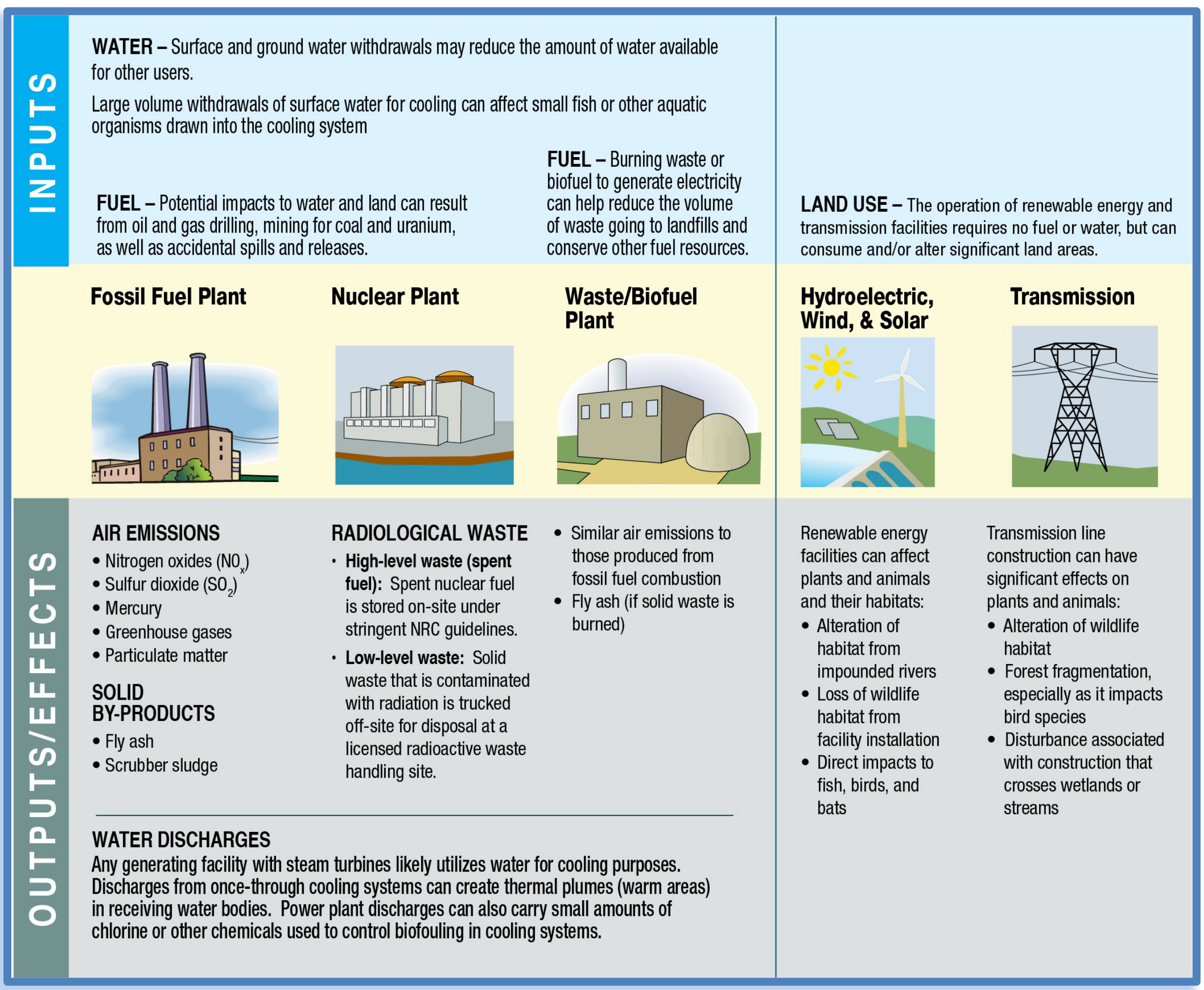
The CWA, enacted in 1948, regulates the discharge of pollutant discharge in water throughout the United States and established standards for water quality. Under the CWA, the EPA has enacted pollution control programs and standards for the electric generation industry. For example, Section 316(b) of the CWA required the EPA to issue regulations regarding the design and operation of cooling water intake structures (see Section 5.2.2). In August 2014, the EPA finalized its National Pollutant Discharge Elimination System (NPDES) requirements, which served to reduce the adverse impact of cooling water intake systems on marine life. Each cooling water intake system must receive a state issued NPDES permit. This rule impacts electric generating units, as well as pulp and paper mills, chemical manufacturing plants, iron and steel manufacturing, and food processing.

The EPA has issued several regulations under the RCRA, a national law which regulates solid waste, regarding fossil fuel combustion (FFC) waste produced from the burning of fossil fuels. The waste can include fly ash, bottom ash, boiler slag and particles removed from flue gas. Most recently, the EPA finalized a rule for the disposal of coal combustion residuals (CCR) from electric utilities. The purpose of the rule is to establish comprehensive requirements for the safe disposal of coal ash, including addressing contamination of ground water, blowing of containments in the air, and reporting requirements. The rule also supports responsible recycling of CCR.

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 socio-economic impacts associated with the construction, operation and maintenance of these facilities.

This chapter describes each of these impact areas in some detail, and discusses PPRP's efforts to better understand the magnitude of these impacts in Maryland and how they can be managed, minimized, or mitigated. Also critical to reducing environmental impacts is controlling the amount of electrical energy we use, and the amount of fossil fuel consumed to generate that electricity. Other chapters of this report provide more information on how Maryland is promoting energy efficiency and the development of more sustainable energy sources.



Note: This figure illustrates some of the primary environmental impacts associated with electricity generation and transmission in Maryland.

5.1 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. The CAA was passed in 1963, but Congress first approached air pollution issues in the mid-1950s with passage of the *Air Pollution Control-Research and Technical Assistance Act of 1955*. In the *Clean Air Act Amendments of 1965*, Congress divided regulation of air pollution into two titles, one to address pollution prevention in general, and one to address mobile sources. The first law to resemble air quality rules as we know them today was the *Clean Air Act Amendments of 1970*. These Amendments provided the framework for air quality regulation in the United States that remains in effect today. Importantly, these Amendments differentiated areas of the country with relatively good air quality (those meeting established ambient standards, known as "attainment" areas) from those with relatively poor air quality (known as "nonattainment" areas) and created different rules to regulate air pollution in these different areas. Congress again passed significant amendments to the CAA in 1977, which established increasingly stringent requirements on new and existing sources. Even with the 1977 Amendment's stringent requirements, many areas of the country continued to have trouble meeting the National Ambient Air Quality Standards (NAAQS). Despite this fact, Congress stalled development of new air quality legislation on the federal level for many years, until Congress passed the *Clean Air Act Amendments of 1990*.

Among other issues, the Amendments of 1990 addressed what Congress saw as four significant threats to the health and welfare of Americans, all of which have affected power plants and other sources of air pollution:

- Acid rain and regional haze (Title IV of the CAA)—For the first time, required cuts in sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emissions from fossil fuel-fired power plants to prevent acidic deposition and improve visibility. Title IV of the 1990 CCA Amendments established the first "cap and trade" program for SO_2 emissions designed to use market forces and pollutant trading to drive pollution control.
- Toxic or hazardous air pollution (Title III of the CAA)—Identified 189 Hazardous Air Pollutants (HAPs) and, for the first time, established control technology-based standards for various types of sources, most requiring at least 95 percent reduction in HAP emissions.
- Urban air pollution (Title I of the CAA)—In addition to the new toxics provisions, greatly expanded the number and types of pollutants and sources subject to regulation to address persistent "ozone smog" pollution in most metropolitan areas.
- Stratospheric ozone depletion (Title VI of the CAA)—Identified and regulated, for the first time, ozone-depleting substances (ODS) and provided a framework for US participation in the *1987 Montreal Protocol on Substances that Deplete the Ozone Layer*.

The Six Criteria Pollutants

Fossil fuel-fired power plants emit most of the six criteria pollutants for which the EPA has established National Ambient Air Quality Standards (NAAQS). The criteria pollutants are as follows:

Nitrogen dioxide (NO_2) – a product of fossil fuel combustion. The generic nitrogen-based exhaust product from power plants and other combustion sources is termed "NO_x" and is primarily composed of nitric oxide (NO) and NO_2. NO_x emitted by combustion sources is primarily in the form of NO, which is rapidly converted to NO_2 in the atmosphere. In the presence of sunlight and heat, NO_2 reacts with volatile organic compounds (VOCs) to form ground-level ozone (smog).

Sulfur dioxide (SO_2) – a product of combustion. SO_2 is released when sulfur-containing fuels, such as oil and coal, are burned.

Particulate matter (PM) – dust, soil and liquid droplets that form during the combustion of fossil fuels or in the atmosphere by chemical transformation and condensation of liquid droplets. Particulate matter is defined by the size of its particles. PM_{10}, for example, contains particles smaller than 10 microns in diameter. $PM_{2.5}$, also referred to as "fine" particulate matter, is composed of particles smaller than 2.5 microns in diameter.

Carbon monoxide (CO) – formed by incomplete combustion of carbon-based fuels during the combustion process.

Lead – a metal emitted into ambient air in the form of PM.

Ozone (O_3) – not emitted directly, but forms in lower levels of the atmosphere as "smog" when NO_X and VOCs react in the presence of sunlight and elevated temperatures.

Since the early days of air quality management in the US, regulators have based many air quality rules and regulations on the NAAQS that the CAA authorized the United States Environmental Protection Agency (EPA) to develop. 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 the public welfare by preserving visibility and preventing damage to crops, animals, vegetation and buildings. The CAA requires EPA to review and, if appropriate, revise the NAAQS every five years. Table 5-1 lists the current NAAQS.

Table 5-1 National Ambient Air Quality Standards as of June 2019

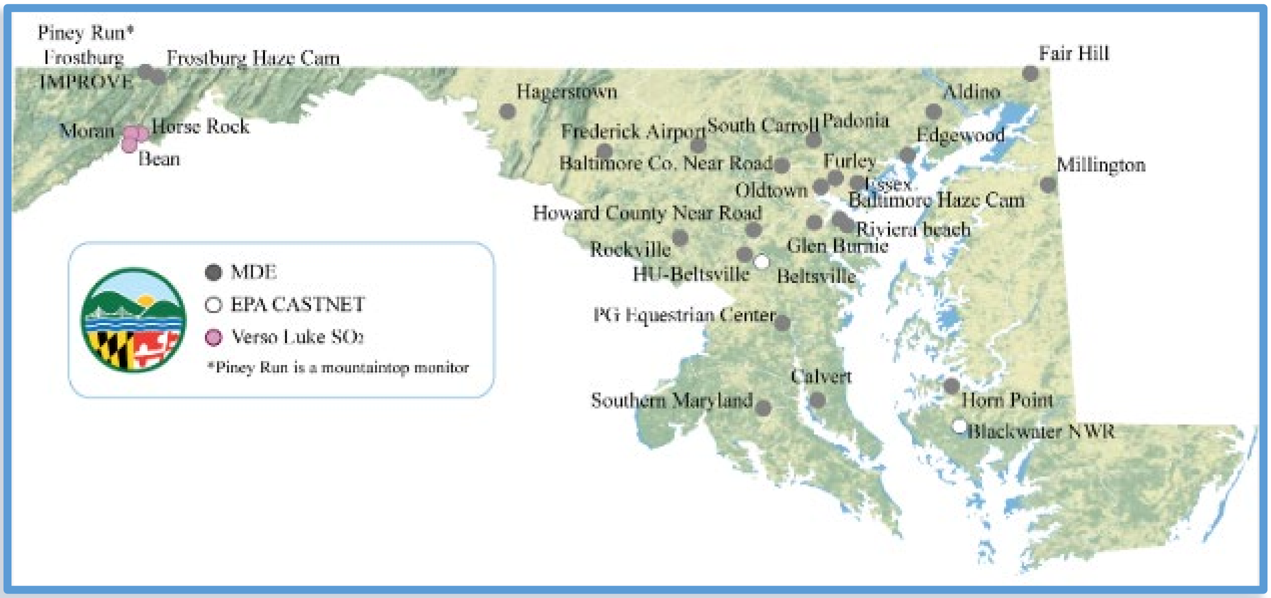
Pollutant	Primary/ Secondary	Averaging Time	Level	Form
Carbon Monoxide (CO)	Primary	8 hours	9 ppm	Not to be exceeded more than once per year.
		1 hour	35 ppm	
Lead (Pb)	Primary and Secondary	Rolling 3-month average	0.15 $\mu g/m^3$ (1)	Not to be exceeded.
Nitrogen Dioxide (NO_2)	Primary	1 hour	100 ppb	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	12.0 $\mu g/m^3$	Annual mean, averaged over 3 years.
	Secondary	1 year	15.0 $\mu g/m^3$	Annual mean, averaged over 3 years.
	Primary and Secondary	24 hours	35 $\mu g/m^3$	98th percentile, averaged over 3 years.
Particle Pollution (PM) - PM_{10}	Primary and Secondary	24 hours	150 $\mu g/m^3$	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: "National Ambient Air Quality Standards." Reviewing National Ambient Air Quality Standards – Scientific and Technical Information. EPA, 10 June 2019. https://www.epa.gov/criteria-air-pollutants/naaqs-table
ppm - parts per million
ppb – parts per billion
mg/m^3 - milligram per cubic meter
$\mu g/m^3$ - 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 submitted and approved, the previous standards (1.5 $\mu g/m^3$ 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. Revocation of the previous (2008) O_3 standards and transitioning to the current (2015) standards will be addressed in the implementation rule for the current 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 1 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 CFR 50.4(3)). A SIP call is an EPA action requiring a state to resubmit all or part of its State Implementation Plan to demonstrate attainment of the require NAAQS.

Across the country, EPA and state and local regulatory agencies monitor concentrations of the criteria pollutants near ground level. MDE's Ambient Air Monitoring Program handles ambient monitoring in Maryland. Figure 5-1 presents the locations of ambient air monitoring stations in Maryland. The EPA Clean Air Status and Trends Network (CASTNET) includes monitoring stations managed by EPA, and "Verso Luke SO_2" are SO_2 monitoring stations operated by the Verso Luke Mill (a paper mill located in Allegany County, Maryland).

Figure 5-1 Ambient Pollutant Monitoring Stations in Maryland



Source: http://mde.maryland.gov/programs/Air/AirQualityMonitoring/PublishingImages/MonitoringNetwork.png "Current Ambient Air Monitoring Network Map." Ambient Air Monitoring Network. MDE. Accessed 28 May 2019.

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.

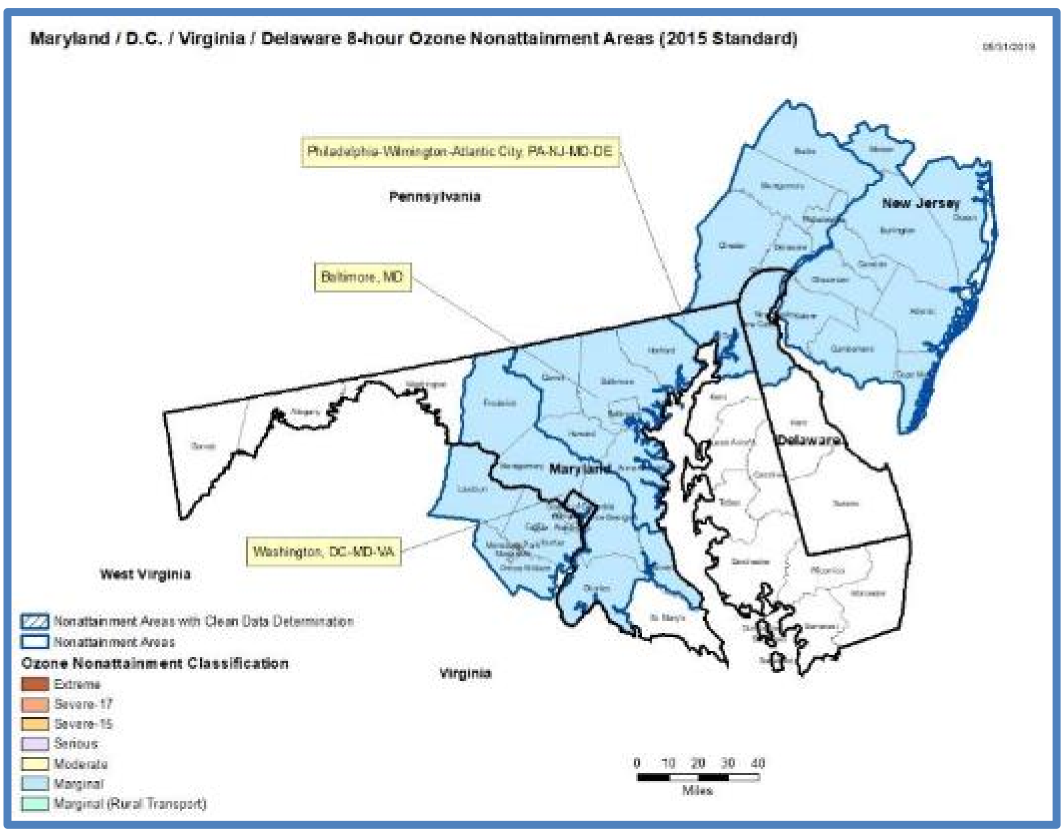
Currently, all of Maryland is in attainment with the NAAQS for most of the criteria pollutants (NO_2, $PM_{2.5}$, PM_{10}, CO, and lead). On December 14, 2012, EPA lowered the fine particulate matter NAAQS by revising the primary annual $PM_{2.5}$ standard to 12 micrograms per cubic meter ($\mu g/m^3$) from 15 $\mu g/m^3$ and retaining the 24-hour fine particle standard of 35 $\mu g/m^3$. All of Maryland is currently in attainment with the 2012 standard.

In June 2016, EPA designated areas in Anne Arundel and Baltimore Counties as nonattainment for the 2010 1-hour SO_2 NAAQS. This nonattainment designation was based in part on air quality modeling of SO_2 emissions from the Wagner and Brandon Shores power plants, which are located south of Baltimore in Anne Arundel County. With the June 2016 designation, Baltimore City is now identified as "unclassifiable/attainment" which is an interim designation in situations where there is insufficient data to make a final designation.

In addition to SO_2, 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 ppm went into effect. In 2018, EPA designated three areas in Maryland as "marginal" nonattainment with respect to the 2015 ozone NAAQS: the Baltimore, Philadelphia and Washington DC areas. As a result, these three areas must reach attainment status within three years of their designation or voluntarily reclassify to a higher nonattainment category. The latter approach would lead to a required attainment plan from the State of Maryland to the US EPA outlining how attainment will be achieved.

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 Amendments created the Northeast Ozone Transport Region (OTR), comprised 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. Figure 5-2 depicts current 8-hour ozone nonattainment area designations in Maryland.

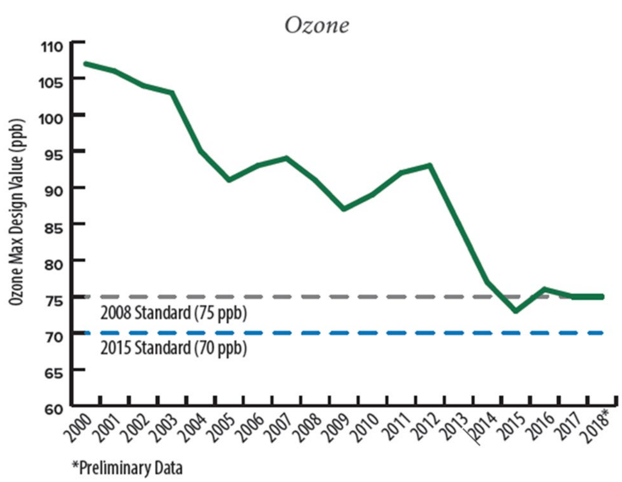
Figure 5-2 Ozone Nonattainment Areas in Maryland (2015 Standard)



Source: https://www3.epa.gov/airquality/greenbook/mddcvade8_2015.html "Maryland/Washington D.C./Virginia/Delaware 8-hour Ozone Nonattainment Areas (2015 Standard)." EPA Greenbook. EPA, 31 May 2019. Accessed 10 June 2019.

Maryland Clean Air Progress

According to the MDE *Maryland Clean Air 2019 Progress Report*, Maryland is in compliance with four out of six criteria pollutant standards. Particle levels in the state have continued to trend down each year since 2010 and are well below the annual and daily standards. And although Maryland has one area designated as nonattainment for SO_2, current measurements are showing concentrations well below the standard. Ground level ozone has been Maryland's most challenging air pollution problem for the past 30 years; however, there has been progress. Maryland has recently met the 2008 ozone standard, but has not yet been able to comply with the more stringent 2015 ozone standard. Maryland continues to reduce NO_X emissions from industry and mobile sources, but has been unable to achieve the 2015 ozone standard due to NO_X emissions and transported air pollution from other states. The figure below illustrates Maryland's progress in reducing ozone concentrations over the last 18 years. In 2018, Maryland recorded the second fewest number of bad ozone days ever recorded.



Source: Maryland Clean Air Progress Report 2019, https://mde.maryland.gov/programs/Air/Documents/GoodNewsReport/GoodNews2019.pdf

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 of 2015.

While the NAAQS themselves do not directly affect stationary sources, lowering of the ambient standards means that EPA and states must eventually establish more stringent emissions limits and control technology requirements for sources such as power plants to ensure that ambient standards are met statewide. This, in turn, likely means additional regulation at the state level of air emission sources in Maryland and throughout the United States.

5.1.2 Emissions from Power Plants

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*[62] (based on the June 2018 update), emissions of SO_2, NO_X, CO_2 and mercury have all decreased significantly in recent years. Power plant emissions of SO_2 and NO_X are 91 percent and 82 percent lower than in 1990 when the Clean Air Act amendments were passed, mercury emissions are 86 percent lower than they were in 2000, and CO_2 emissions decreased by 24 percent from 2005 to

[62] "M.J. Bradley & Associates. *2018 Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States.*

2016. 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.

Air emissions are often discussed in terms of three classes of pollutants: criteria pollutants, hazardous air pollutants (HAPs), and greenhouse gases (GHGs). This section discusses emissions of these classes of pollutants by Maryland's power plants and compares Maryland's power plant emissions to those in other states.

Criteria Pollutants: SO_2, NO_x, and PM Emissions

Of the criteria pollutants, SO_2 and NO_X from power plants are among the most stringently regulated by EPA because they are the principal pollutants that react with water vapor and other chemicals in the atmosphere to create ozone smog, cause acid precipitation, and impair visibility. Particulate matter less than 10 microns (PM_{10}) and particulate matter less than 2.5 microns ($PM_{2.5}$) are also pollutants of concern as EPA has recognized that airborne particulate matter is associated with adverse health effects, including premature mortality, cardiovascular illness, and respiratory illness. EPA continually attempts to understand better which attributes of particles may cause these health effects, who may be most susceptible to their effects, how people are exposed to PM air pollution, how particles form in the atmosphere, and what sources in different regions of the country contribute to PM. This research has allowed EPA to hone its focus over time from regulating emissions of total suspended particulates to PM_{10} and $PM_{2.5}$.

Emissions of SO_2, PM_{10} and $PM_{2.5}$ are dependent on the types and amounts of fuel combusted at each generating unit; the type, age, and configuration of the generating units; and the type, age and efficiency of their associated air pollution control equipment. Most coal-fired power plants in Maryland have installed state-of-the-art pollution control systems to meet requirements of the 2007 Maryland Healthy Air Act (HAA), which were required by a federal deadline of 2010. MDE has regulated NO_X emissions more stringently and for a longer period of time than SO_2 and particulates, and so there was a less remarkable decrease in NO_X with implementation of the HAA beginning in 2009 and 2010. NO_X emissions from power plants have declined in recent years due to installation of control equipment including selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) and due to process changes. MDE's "emergency NO_X" regulation approved May 1, 2015 reduced ozone season NO_X emissions in 2015. The final version of the regulation that was promulgated in December 2015 established additional requirements to reduce summertime ozone formation further by establishing more stringent NO_X emission requirements. This regulation may be contributing to some of the trend in NO_X reductions that were seen in Maryland through 2017 for coal-fired power plants. Section 5.1.4 describes in detail the implications for regulations with respect to Maryland's coal-fired power plants.

> **Coal to Natural Gas**
>
> On May 31, 2018, the Charles P. Crane Generating Station (C.P. Crane) submitted an application to the Maryland Public Service Commission (PSC) for a Certificate of Public Convenience and Necessity (CPCN) to permanently retire their two existing coal-fired units and install three new simple cycle combustion turbines. Following the application, on June 1, 2018, C.P. Crane shut down their two existing coal-fired units.

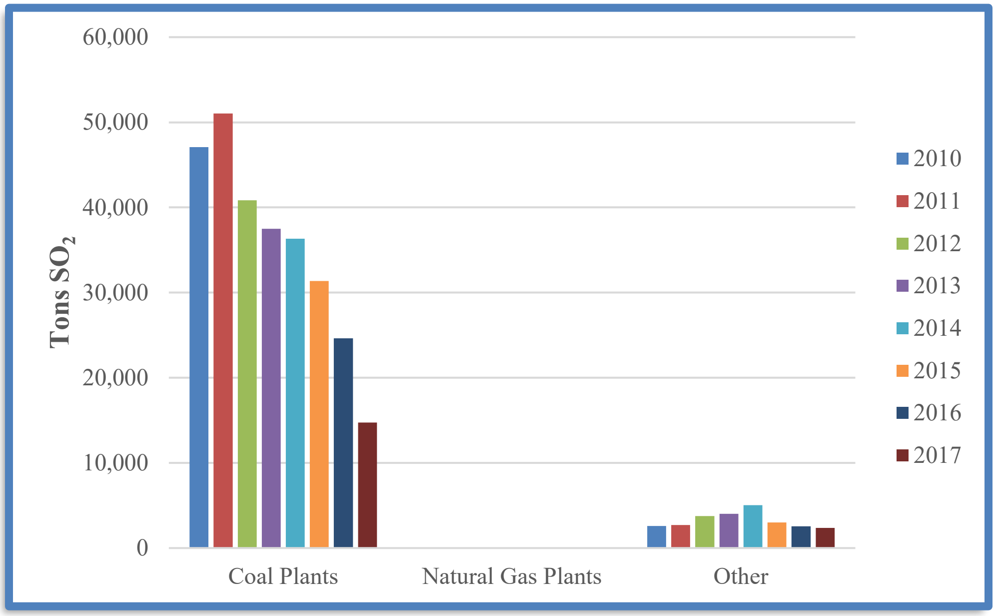
Figure 5-3 shows the type and location of the 108 power plants operating in Maryland as of March 2019, over half of which are renewable power sources with little to no air emissions. Power plant emissions in Maryland mostly come from the natural gas, petroleum, biomass and coal-fired plants. Maryland currently has six coal-fired power plants in operation after C.P. Crane retired its coal-fired units in 2018.

Figure 5-3 Map of Maryland Power Plants by Generation Type (March 2019)

Source: EIA's Electricity Data Browser, Plant level data for the State of Maryland. https://www.eia.gov/electricity/data/browser/

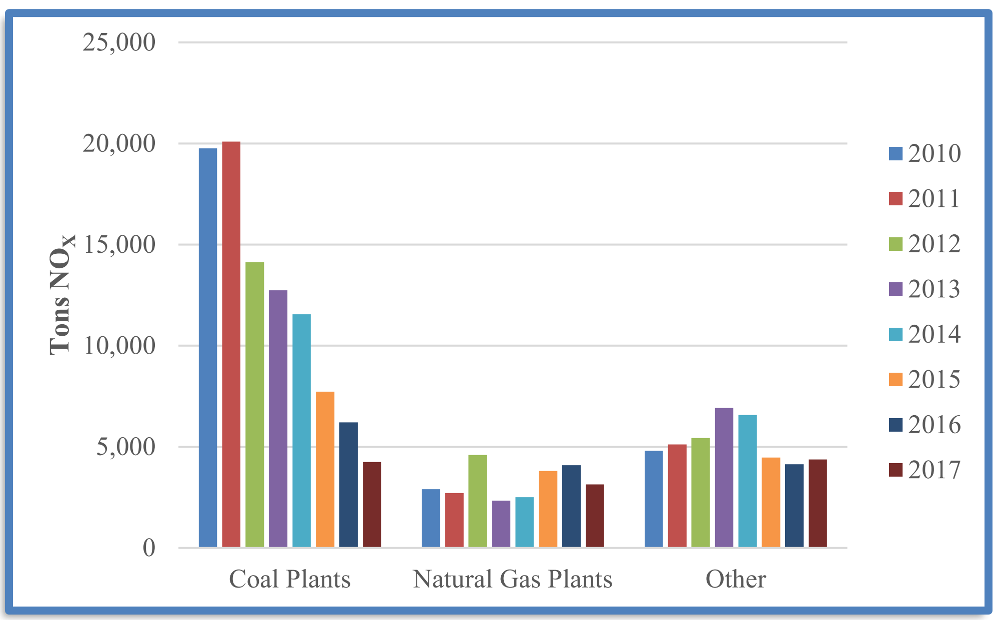
Trends in SO_2 and NO_X emissions from generating units in Maryland of different fuel types are shown in Figure 5-4 and Figure 5-5, respectively. Coal-fired power plants in Maryland dominate the annual SO_2 emissions, as typical coal being used in Maryland contains about 2 percent sulfur by weight. SO_2 emissions in Maryland have decreased over time due to Maryland's Healthy Air Act and the addition of flue-gas desulfurization (FGD) technology installed at Maryland's coal-fired power plants. SO_2 and NO_X emissions from coal-fired power plants have also decreased as the power sector continues to move away from coal and towards natural gas and renewable energy sources.

Figure 5-4 Annual SO_2 Emissions from Power Plants in Maryland



Source: Emissions reported in *Electric Power Industry Emissions Estimates Back to 1990, Maryland.xlsx* found on eia.gov

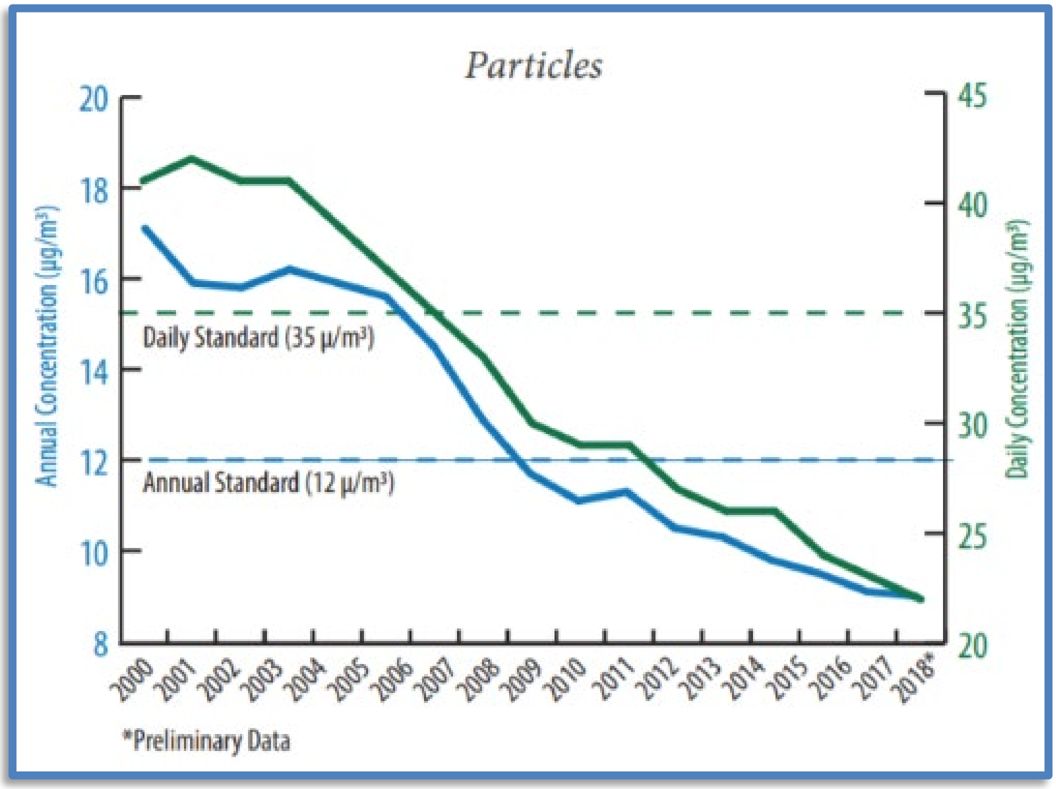
Figure 5-5 Annual NO_X Emissions from Power Plant Types in Maryland



Source: Emissions reported in *Electric Power Industry Emissions Estimates Back to 1990, Maryland.xlsx* found on eia.gov

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, and so $PM_{2.5}$ emissions data from power plants are not readily available. Figure 5-6 shows annual ambient $PM_{2.5}$ concentrations (rather than emissions) across Maryland over the last 18 years from the *Maryland Clean Air 2019 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.

Figure 5-6 Annual and Daily Ambient $PM_{2.5}$ Concentrations in Maryland



Source: Maryland Clean Air Progress Report 2019, https://mde.maryland.gov/programs/Air/Documents/GoodNewsReport/GoodNews2019.pdf

Hazardous Air Pollutant Emissions

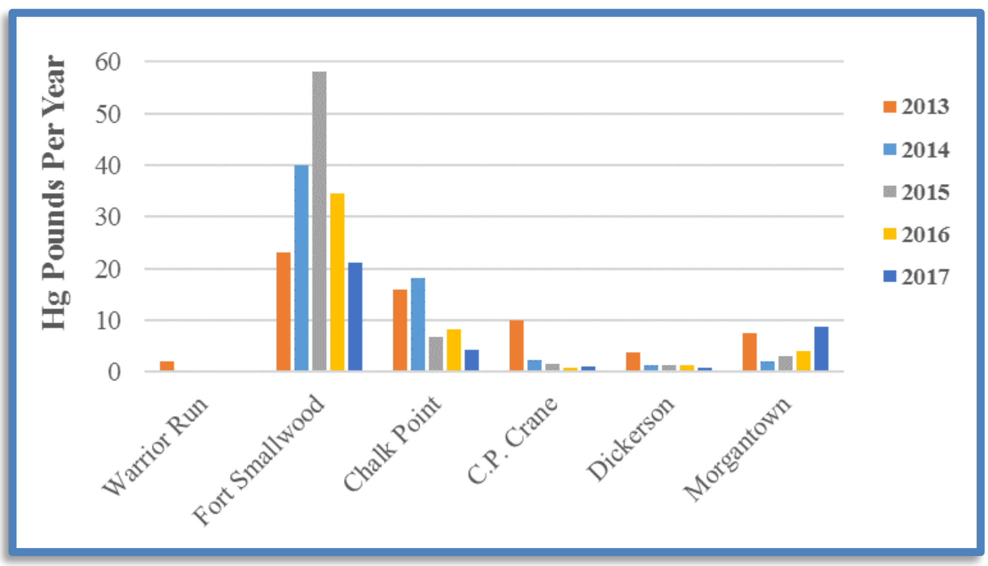
In 1990, Congress amended the CAA to regulate a class of pollutants that cause or might cause an adverse impact to health or the environment. These pollutants are referred to as hazardous air pollutants, or HAPs. There are currently 187 pollutants on EPA's list of CAA HAPs. Although some HAPs can occur naturally (such as asbestos or mercury), most HAPs originate from mobile or stationary industrial sources such as factories, refineries and power plants.

Although fossil fuel-fired power plants emit HAPs, chemical plants and petroleum refineries that use and emit highly toxic compounds have historically been considered more significant sources of air toxics than power plants. Prior to the CAA Amendments of 1990, EPA regulations did not apply to HAP emissions from power plants and even with passage of the Amendments of 1990, power plant HAP emissions were addressed differently by Congress than those from other industrial sources. While many states, including Maryland, have developed toxic air pollutant (TAP) regulations, fuel burning sources in Maryland are exempt from TAP regulations. EPA's Mercury and Air Toxics Standards (MATS), promulgated in 2011, regulate HAP emissions from power plants. Section 5.1.4 further discusses recent MATS standard developments.

Among the HAPs emitted by power plants, mercury is a pollutant of particular concern because of its significant adverse health effects.[63] Figure 5-7 presents annual emissions of mercury from Maryland's coal-fired power plants from 2013 through 2017 as reported in EPA's Toxic Release Inventory (TRI) for each facility. As illustrated in Figure 5-7, mercury emissions from Maryland's power plants do not show a clear trend.

Hydrochloric acid (HCl) is a HAP emitted in large quantities from coal- and oil-fired power plants. HCl is an "acid gas" like SO_2, so the pollution controls for SO_2 installed at coal plants in response to the Maryland HAA also reduced HCl emissions. Also, coal units at both the H.A. Wagner (which is included in "Fort Smallwood" in Figure 5-7) and C.P. Crane facilities installed dry sorbent injection (DSI) in 2015 in response to the MATS to control HCl.

Figure 5-7 Annual Mercury Emissions from Coal-fired Power Plants in Maryland



Notes: Emissions reported in EPA's Toxics Release Inventory. As of June 12, 2019, the mercury emissions data is only available through 2017. Fort Smallwood consists of the combined Brandon Shores and Wagner generating stations.

Maryland is also home to two waste-to-energy incinerators. While these incinerators are considered renewable energy plants in Maryland's Renewable Portfolio Standard, they produce significantly more criteria pollutant and HAP emissions than the other types of renewable power sources.

63 Environmental Health & Engineering, "Emissions of Hazardous Air Pollutants from Coal-fired Power Plants, www.lung.org/assets/documents/healthy-air/emissions-of-hazardous-air.pdf

Greenhouse Gas Emissions

A greenhouse gas (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: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). Section 5.1.5 describes the status of recent, federal GHG regulations. The principal GHGs that enter the atmosphere due to human activities are:

Carbon dioxide (CO_2): Carbon dioxide enters the atmosphere through the burning of fossil fuels (oil, natural gas and coal), solid waste, trees and wood products, and also as a result of other chemical reactions (e.g., manufacture of cement).

Methane (CH_4): Methane is emitted during the production and transport of coal, natural gas and oil. Methane emissions also result from livestock and agricultural processes and from the decay of organic waste in municipal solid waste landfills.

Nitrous oxide (N_2O): Nitrous oxide is emitted during agricultural and industrial activities, as well as during combustion of fossil fuels and solid waste.

Fluorinated gases: HFCs, PFCs and SF_6 are synthetic, powerful GHGs that are emitted from a variety of industrial processes. Fluorinated gases are sometimes used as substitutes for ozone-depleting substances (i.e., chlorofluorocarbons (CFCs), hydrochlorofluorocarbon (HCFCs), and halons). These gases are typically emitted in smaller quantities, but because they are potent GHGs, they are sometimes referred to as High Global Warming Potential gases.

Emissions of GHGs are reported on a "carbon dioxide equivalent" (CO_2e) basis under EPA's GHG Reporting Rule. CO_2e emissions are determined by multiplying the mass amount of emissions in tons per year (tpy) of each of the six individual greenhouse gases by each gas's "global warming potential" or GWP.

Figure 5-8 presents GHG emissions from fossil-fuel fired power plants in Maryland for the years 2010 through 2017. 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 annual GHG emissions data show a decrease in coal and an increase in natural gas generation over time.

Global Warming Potentials

Global warming potential (GWP) is a measurement of how "effective" individual greenhouse gases are in contributing to warming relative to the most common greenhouse gas, carbon dioxide (CO_2). GWP includes the period of time the gas remains in the atmosphere (lifetime) and its ability to absorb energy (radiative efficiency). CO_2, by definition, has a GWP of 1 since it is the gas used as reference. Methane is estimated to have a GWP of 28-36 over 100 years. Even though methane emissions last about a decade in the atmosphere, which is less than CO_2, it absorbs much more energy than CO_2. The GWP reflects both the net effect of the shorter lifetime and higher energy absorption. N_2O has a GWP of 265-298 times that of CO_2 because it remains in the atmosphere for over 100 years. The GWP for fluorinated gases is in the thousands or tens of thousands because they trap substantially more heat than CO_2. EPA's *Major Long-Lived Greenhouse Gases and Their Characteristics* table below shows the GHG average lifetime and the 100-year GWP of individual compounds.

Global Warming Potentials

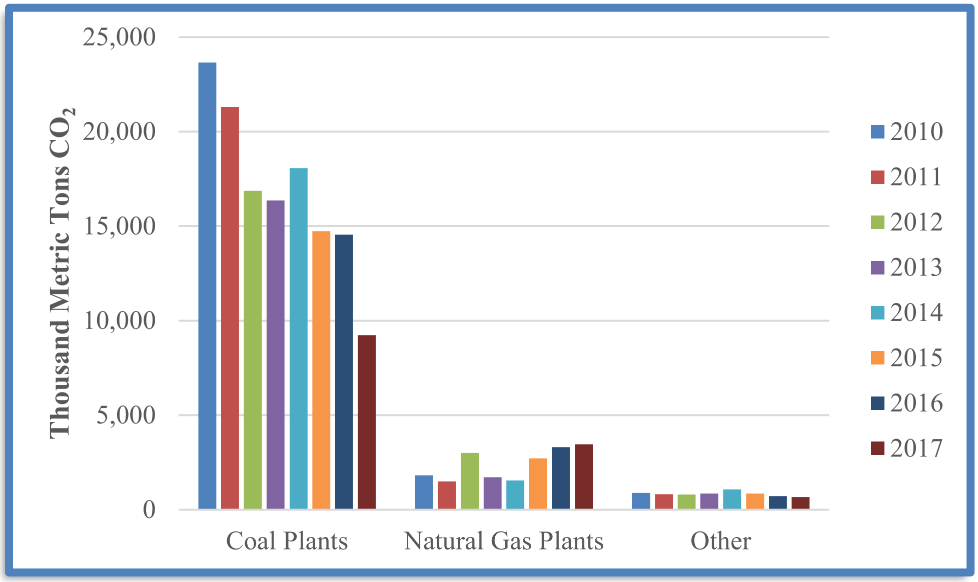
Greenhouse gas	How it's produced	Average lifetime in the atmosphere	100-year global warming potential
Carbon dioxide	Emitted primarily through the burning of fossil fuels (oil, natural gas and coal), solid waste, and trees and wood products. Changes in land use also play a role. Deforestation and soil degradation add carbon dioxide to the atmosphere, while forest regrowth takes it out of the atmosphere.	see below[1]	1
Methane	Emitted during the production and transport of oil and natural gas as well as coal. Methane emissions also result from livestock and agricultural practices and from the anaerobic decay of organic waste in municipal solid waste landfills.	12.4 years[2]	28–36
Nitrous oxide	Emitted during agricultural and industrial activities, as well as during combustion of fossil fuels and solid waste.	121 years[2]	265–298
Fluorinated gases	A group of gases that contain fluorine, including hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride, among other chemicals. These gases are emitted from a variety of industrial processes and commercial and household uses and do not occur naturally. Sometimes used as substitutes for ozone-depleting substances such as chlorofluorocarbons (CFCs).	A few weeks to thousands of years	Varies (the highest is sulfur hexafluoride at 23,500)

1 Carbon dioxide's lifetime cannot be represented with a single value because the gas is not destroyed over time, but instead moves among different parts of the ocean–atmosphere–land system. Some of the excess carbon dioxide is absorbed quickly (for example, by the ocean surface), but some will remain in the atmosphere for thousands of years, due in part to the very slow process by which carbon is transferred to ocean sediments.

2 The lifetimes shown for methane and nitrous oxide are perturbation lifetimes, which have been used to calculate the global warming potentials shown here.

Source: https://www3.epa.gov/climatechange/science/indicators/ghg/
Climate Change Indicators: Greenhouse Gases. EPA Climate Change, 22 February 2017. Accessed 10 June 2019.

Figure 5-8 Annual CO_2 Emissions from Power Plant Types in Maryland



Notes: Emissions reported in *Electric Power Industry Emissions Estimates Back to 1990, Maryland.xlsx* found on eia.gov

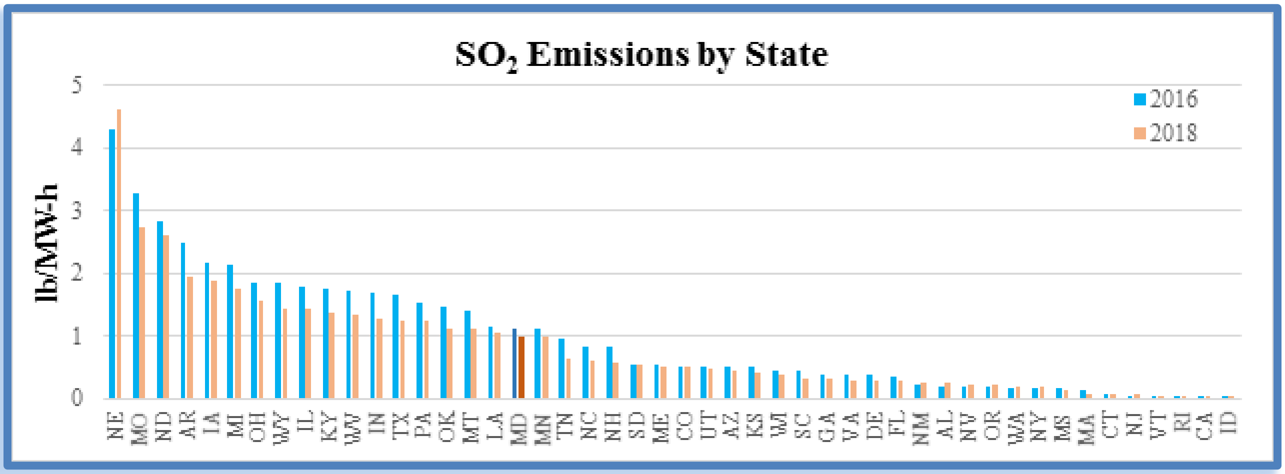
Maryland Power Plant Emissions Relative to Other U.S. Power Plant Emissions

To put Maryland's power plant emissions in perspective, Figure 5-9 and Figure 5-10 present a comparison of SO_2 and NO_X emissions from all power plants in Maryland to emissions from power plants in other states for the years of 2016 and 2018. These figures represent the emissions (in pounds per megawatt-hour of electricity generated) from the lower 48 states as reported in EPA's Air Markets Program Data (AMPD).

As seen in Figure 5-9, SO_2 emissions from Maryland's power plants are comparable to the nation-wide median. Although SO_2 emissions declined from 2016 to 2018, the rate at which they declined was slower in comparison to the SO_2 emission rate in other states.

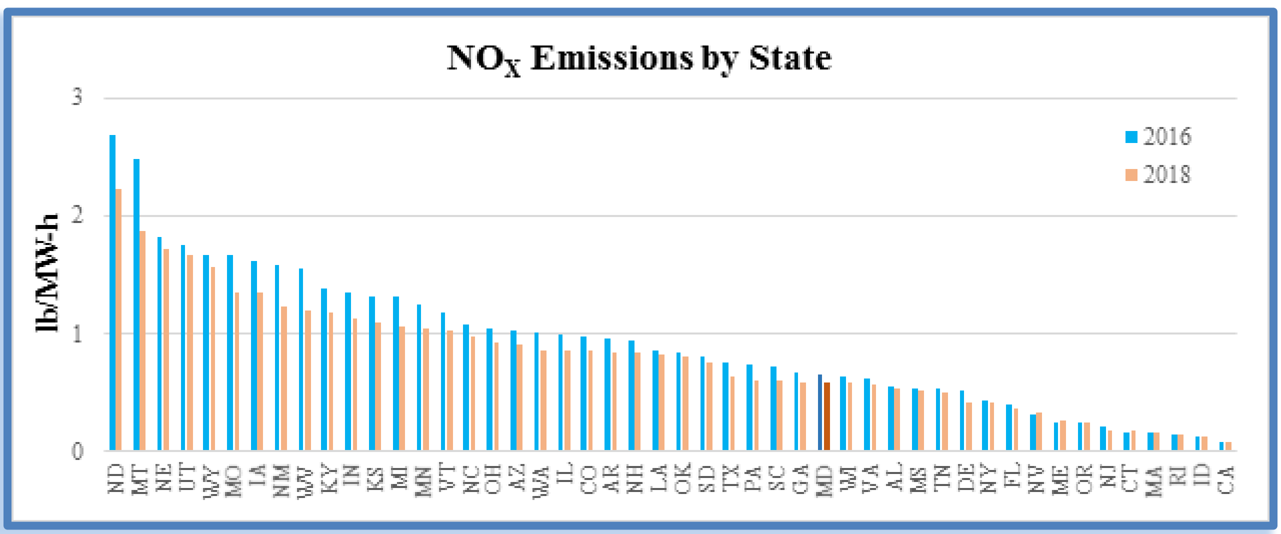
NO_X emissions from Maryland power plants were around the nation-wide median in 2016 and declined in 2018 to a lower emission rate than most other states (Figure 5-10). This decrease in NO_X emissions is likely due to the move away from coal-fired power plants and toward the lower NO_X emitting natural gas-fired plants, as well as the installation of control equipment such as SCR and SNCR.

Figure 5-9 SO_2 Emissions from Maryland Power Plants Compared to SO_2 Emissions from Plants in Other States



Note: Emissions reported in AMPD (http://www.epa.gov/airmarkets).

Figure 5-10 NO_x Emissions from Maryland Power Plants Compared to NO_x Emissions from Plants in Other States



Note: Emissions reported in AMPD ((http://www.epa.gov/airmarkets).

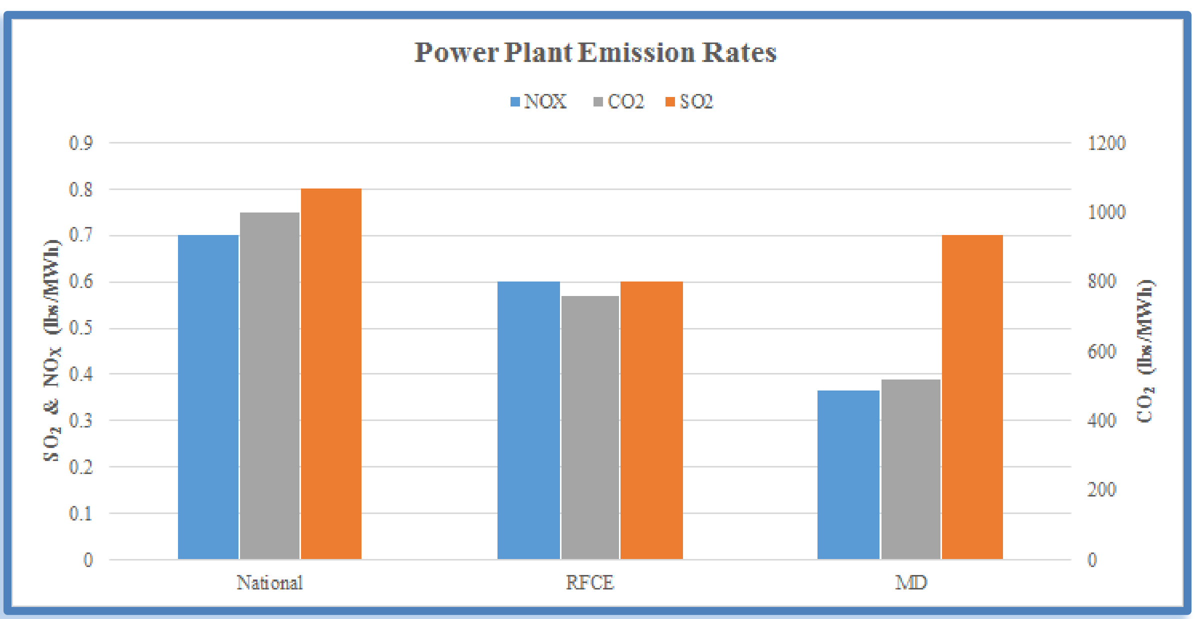
5.1.3 Impacts from Power Plant Air Emissions

Impacts from Out-of-State Emissions

While this report has so far analyzed emissions from power plants located in the State of Maryland, emissions may also be transported from sources located outside of the state. EPA's "good neighbor" provision, Section 126 of the Clean Air Act, addresses the issue of interstate pollution transport by requiring each state to manage emissions that may significantly contribute to NAAQS violations in a downwind state in its State Implementation Plan (SIP). If the state does not resolve the issue, then the EPA may step in on its own or at the state's request. On November 16, 2016, the State of Maryland submitted a petition to the EPA over ozone nonattainment concerns due to NO_X contributions from out-of-state sources. More specifically, the petition cites 36 power plants in Indiana, Kentucky, Ohio, Pennsylvania and West Virginia as significant contributors of upwind NO_X emissions. The EPA denied Maryland's petition in a decision that was published in the Federal Register on October 5, 2018. The State of Maryland submitted a petition for judicial review to the US Court of Appeals on October 12, 2018.

Maryland may also be connected to out-of-state emissions because of its import of electricity from the PJM grid. As mentioned in Section 3.4, Maryland's consumption of electricity has historically exceeded the amount of energy generated within the state. Out-of-state resources through PJM help to provide a lower-cost resource to meet electricity consumption needs. Maryland's reliance on out-of-state power plants raises an interest in the emissions from these out-of-state facilities. An online EPA tool provides a comparison of average emission rates for the Reliability First Corporation East (RFCE) eGRID region, which covers most of the PJM domain, to the national average emission rates. These emission rates are compared with the average emission rates from power plants in Maryland in Figure 5-11. This figure helps to show that energy imported into Maryland is likely associated with relatively higher NO_X and CO_2 emissions and lower SO_2 emissions.

Figure 5-11 Average Power Plant Emission Rates



Source: National and RFCE data from EPA Power Profiler (https://www.epa.gov/energy/power-profiler); Data Year 2016; downloaded 6/10/19. Maryland data from EIA State Energy Data System (primary energy production) and State Profile Data (electric power industry emissions), Data Year 2016.

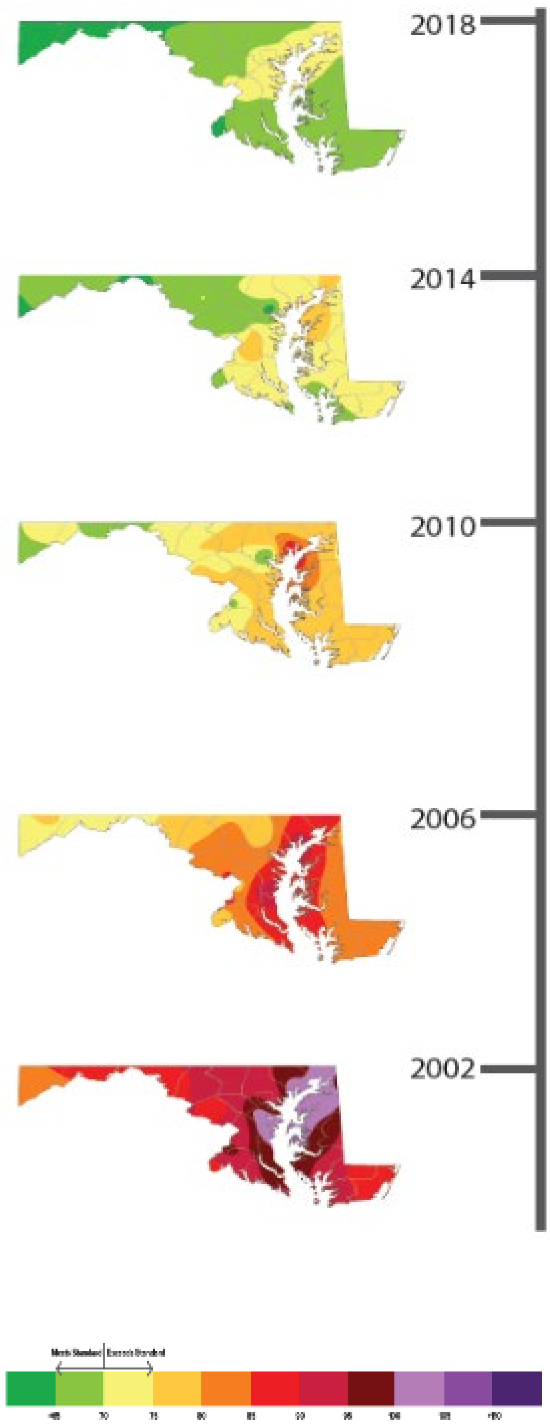
Ozone

The persistent ozone "smog" problem in many areas of the country has been one of the most important drivers for regulation of power plant NO_X emissions over the past two decades. Ozone exists naturally in the upper levels of the atmosphere (from 6 to 30 miles above the Earth's surface) and protects the Earth from harmful ultraviolet rays. Although ozone is helpful in the stratosphere, it is harmful when it occurs in the troposphere, the layer closest to the Earth's surface. 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 it instead forms through chemical reactions in the atmosphere. Ground-level ozone is formed when the precursor compounds — NO_X from both mobile and stationary combustion sources (such as automobiles and power plants, respectively), and VOCs from industrial, chemical, and petroleum facilities and from natural sources — react in the presence of sunlight and elevated temperatures. Ozone levels are consequently highest during the summer months when temperatures are higher, the hours of daylight are greater and the sun's rays are more direct.

Weather plays such an important role in the formation of ozone that EPA has established an "ozone season" for each of the states, and has developed regulations that require power plants to restrict NO_X emissions during the summer months. Maryland's ozone season extends from April through October.

Ground-level ozone has the potential to cause adverse human health effects. Breathing air with high ozone concentrations can cause chest pain, throat irritation and congestion; it can also worsen preexisting conditions like emphysema, bronchitis and asthma. Children and the elderly are especially vulnerable to health problems caused by ground-level ozone. Recent action in 2015 by EPA reduced the level of ozone standard (8-hour) from 75 ppb to 70 ppb, introducing additional challenges for states including MDE to develop a plan to achieve the standard. Maryland is required to be in compliance with this standard by 2020. Figure 5-12 shows the positive trend in ozone concentrations in Maryland over the last 16 years.

Figure 5-12 Maryland's Shrinking Ozone



Source: MDE Report on the Environment, "Clean Air Progress Report 2019"
https://mde.maryland.gov/programs/Air/Documents/GoodNewsReport/GoodNews2019.pdf

Since the mid-1990s, there have been a series of federal NO_X reduction regulations, implemented at the state level, that have resulted in significant reductions in summertime ("ozone season") emissions of NO_X from power plants in Maryland and surrounding states. One of the most significant, referred to as the "NO_X SIP Call" because it called for affected states to update their State Implementation Plans (SIP) to address ozone issues, is based on a NO_X cap-and-trade program that allows sources to acquire "allowances" to emit a certain quantity of pollutants. Sources can reduce emissions or purchase allowances from other plants who have reduced emissions below their caps. In some states, including Maryland, emissions exceeded statewide NO_X allocations for many years in the first decade of the 2000s, meaning that some plants in these states were buying NO_X allowances rather than reducing plant-level NO_X emissions. The allocation exceedance in Maryland is likely attributable to the fact that not many sources had installed state-of-the-art controls such as SCR systems over the period. Maryland's Healthy Air Act led to the installation of controls for some of Maryland's largest power plants. NO_X reductions were further aided by Maryland's 2015 NO_X regulation for coal-fired power plants. Of the major coal fired plants in Maryland, all have installed SCR systems, Selective Auto Catalytic Reduction (SACR) or Selective Non-Catalytic Reduction (SNCR) technology. [64]

CAMNET Visibility Haze Cams

Regional haze cameras (haze cams) have been set up as part of CAMNET, a project of the Northeast States for Coordinated Air Use Management (NESCAUM) to evaluate the effects of air pollution on visibility. Maryland has haze cams located in Baltimore and Frostburg. The Baltimore haze cam provides an enhanced wide angle view of the Francis Scott Key Bridge and Baltimore City. The Frostburg haze cam positioned on top of a mountain peak provides a view towards the northeast across Maryland and into the Mt. Davis area of Pennsylvania. The CAMNET website, http://www.hazecam.net/, provides real time images every 15 minutes. The photo below from the Baltimore haze cam is dated May 28, 2019 at 12:15PM.

Source: https://www.hazecam.net/ "Realtime Air Pollution & Visibility Monitoring."

Visibility and Regional Haze

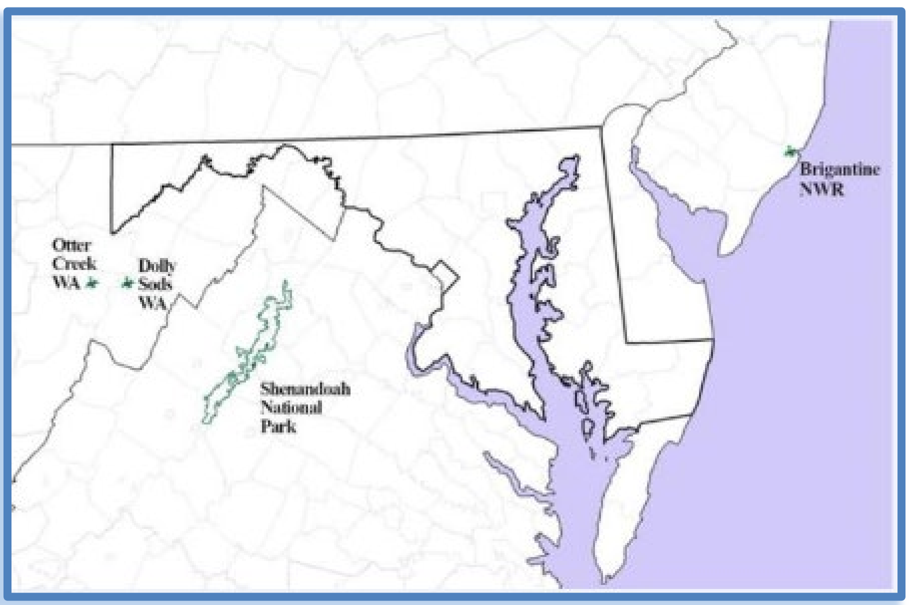
Fine particulate matter, or $PM_{2.5}$, consists of particles that are about 1/30th the diameter of a human hair. $PM_{2.5}$ can be emitted directly from stacks or created when gases react to form particles during transport in the atmosphere. $PM_{2.5}$ is different from many other air pollutants in that it is not a chemical compound itself, but is comprised of various compounds in particle form. Common sources include:

[64] TSD for NOx control, "Technical Support Document for COMAR 26.11.38 – Control of NOx Emissions from Coal – Fired Electric Generating Units", https://mde.maryland.gov/programs/Regulations/air/Documents/TSD_Phase1_with_Appendix.pdf

- Smoke and soot from forest fires,
- Wind-blown dust,
- Fly ash from coal burning,
- Particles emitted from motor vehicles,
- Hydrocarbons associated with vehicles, power plants, and natural vegetation emissions,
- SO_2 and NO_X emitted from fossil fuel combustion.

Aside from $PM_{2.5}$, or fine particulates, certain gases and larger particles can also interfere with visibility. In general, visibility refers to the conditions that can facilitate the appreciation of natural landscapes. The national visibility goal, established as a part of the CAA Amendments of 1977, requires improving the visibility in federally managed "Class I areas." These areas include more than 150 parks and wilderness areas across the United States that are considered pristine air quality areas. Figure 5-13 shows the location of Class I areas near Maryland. Since 1988, EPA and other agencies have been monitoring visibility in these areas.

Figure 5-13 Designated PSD "Pristine" Areas near Maryland



Source: https://www.epa.gov/sites/production/files/2016-02/npsmap_basemap_classi_11x17.jpg "Mandatory Class I Areas". EPA. Assessed 6 June 2019.

Since 2004, PPRP has participated in a coordinated effort with the Northeast States for Coordinated Air Use Management (NESCAUM) and the State of Vermont to evaluate impacts of visibility-impairing sources in the eastern United States. The studies have evaluated the tools and techniques currently available for identifying contributions to regional haze in the Northeast and Mid-Atlantic regions. PPRP was involved with the application of a dispersion model, CALPUFF, for estimating visibility degradation in Class I areas. The model identified the contributions of sources in different states in the eastern United States to visibility impairment in various Class I areas in the region. PPRP also evaluates the impacts of new power plants on Class I visibility to ensure that growth in the electrical generating sector does not contribute to impairment in these important areas.

Nitrogen Deposition

The Chesapeake Bay is the largest estuary in the United States. Protection and restoration of living resources in the Bay has been the goal of the Chesapeake Bay Program since its inception in 1983. The program is a regional partnership that comprises the States of Maryland, Pennsylvania and Virginia, the Chesapeake Bay Commission, EPA and other participating advisory groups.

Reducing nitrogen input from controllable sources is a high priority because excess nitrogen is one of the major sources of eutrophication in the Chesapeake Bay. Eutrophication is a process whereby water bodies, such as lakes or estuaries, receive excess nutrients that stimulate excessive plant and algal growth, and ultimately reduces the dissolved oxygen content in the water, thus limiting the oxygen available for use by aquatic organisms. The 1987 Chesapeake Bay Agreement established a goal of reducing controllable nitrogen by 40 percent compared to 1985 levels, and program participants reaffirmed that goal in their 2000 agreement. The Chesapeake Bay partners reaffirmed these goals in the 2010 Agreement, but have acknowledged that they would not meet the goals. EPA has initiated a process of developing a total maximum daily load (TMDL) target for the Bay. The Chesapeake Bay TMDL is a federal "pollution diet" that sets limits on the amount of nutrients and sediment that can enter the Bay and its tidal rivers to meet water quality goals.

On June 16, 2014, representatives from each of the watershed's six states signed the Chesapeake Bay Watershed Agreement, committing to create a healthy Bay by accelerating restoration and aligning federal directives with state and local goals. This agreement contains ten interrelated goals that work toward advancing the restoration and protection of the Bay, its tributaries and the land that surround them.

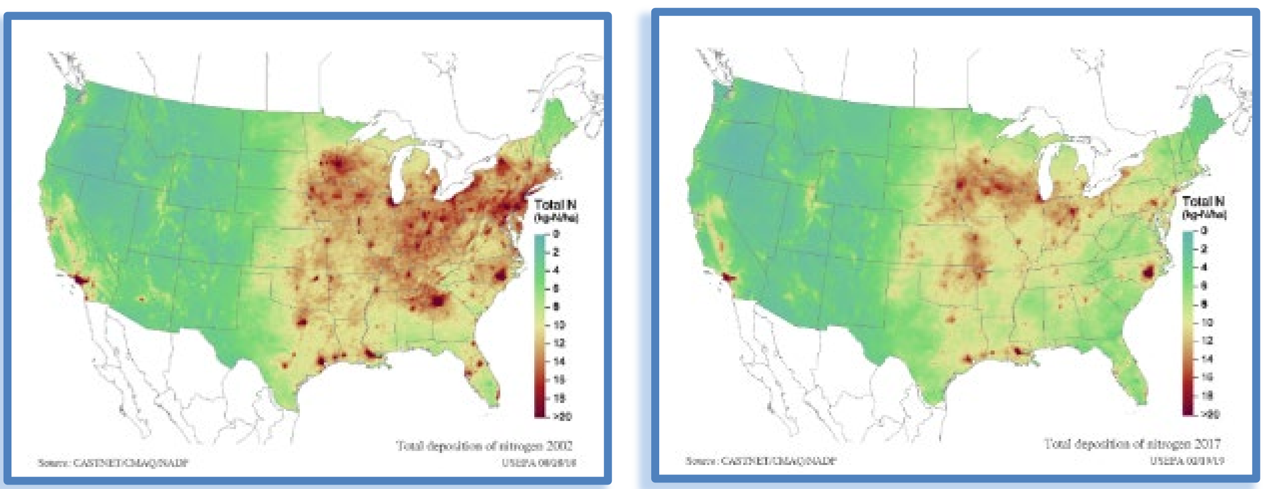
The Chesapeake Bay Program estimates that approximately 30 percent of the nitrogen load to the Bay comes from atmospheric deposition and subsequent transport of nitrogen through the watershed. Much of this loading comes from NO_X emissions from power plants, industrial sources and mobile sources. MDE recently devoted increased efforts to the role of ammonia in the deposition processes.

PPRP has previously evaluated the regional sources of NO_X emissions and their impacts on the Chesapeake Bay. As a part of this effort, scientists used advanced computer models to simulate the transport and subsequent deposition of emissions from these regional sources to the Chesapeake Bay. The actual loading to the Bay was calculated using a methodology similar to that used by the United States Geological Survey for its land-to-bay models. The model allowed PPRP to evaluate the relative contribution of Maryland sources and other regional sources to deposition totals. As a part of this study, PPRP developed a screening tool in 2010 to evaluate the potential reductions in nutrient loading to the Bay waters due to different emission control policies in different states. This tool is available to the public for free upon request to PPRP. By increasing the access to this reliable data, regional and local planning agencies can better develop emission reduction strategies to meet Bay restoration goals.

EPA has developed an advanced nitrogen deposition source apportionment technique, based on the photochemical grid model CMAQ, which is a refinement of the screening tool developed by PPRP. While much of the work related to deposition estimates and source apportionment going forward will be based on the CMAQ-based methodology, the screening tool is still available and can be used for developing first cut estimates of the effects of emissions changes on nitrogen loading. PPRP continues to work on updates to the underlying model (CALPUFF) and investigations of the newer SCICHEM model, to improve the accuracy of the modeled deposition rates.

The National Atmospheric Deposition Program (NADP) has developed total deposition maps for nitrogen and total sulfur for use in critical loads and other ecological assessments. The total deposition estimates are determined from the sum of both wet and dry deposition. Wet deposition values are the combined NADP/National Trends Network (NADP/NTN) measured values or precipitation chemistry with precipitation estimates from the Parameter-elevation Regression on Independent Slopes Model (PRISM). The PRISM model estimates precipitation across the U.S. based on elevation and slope. Dry deposition values are combined air concentration data with modeled deposition velocities. Figure 5-14 is a national map of total nitrogen deposition in 2002 and 2017. As shown in this figure, while total nitrogen deposition increased in some parts of the country, in the eastern U.S. it decreased significantly from 2002 to 2017.

Figure 5-14 Total Nitrogen Deposition in 2002 and 2017



Source: ftp://ftp.epa.gov/castnet/tdep/images/n_tw/
"Total Deposition Maps." National Atmospheric Deposition Program. Accessed 28 May 2019.

Mercury Impacts

The primary stationary sources of mercury in the U.S. are, in order of decreasing emissions, coal-fired power plants, industrial boilers, gold mining, hazardous waste incineration, chlor-alkali plants, municipal waste incinerators, and medical waste.[65] Emissions from some source categories, notably medical waste incinerators, have decreased dramatically due to stringent EPA regulations. Additionally, as shown in Figure 5-7, mercury emissions from power plants in Maryland have decreased significantly since the implementation of the Maryland Healthy Air Act (HAA).

[65] EPA's Roadmap for Mercury, EPA-HQ-OPPT-2005-0013, July 2006, https://www.epa.gov/nscep.

Due to the significance of power plant mercury emissions (including emissions from out-of-state sources), PPRP plays an important role in supporting scientific research on this topic. PPRP has been actively involved in the study of regional sources of mercury emissions and their impacts on Maryland and the Chesapeake Bay. In cooperation with the University of Maryland, PPRP has sponsored several deposition monitoring programs and continues to evaluate the impacts of toxic emissions from power plants in Maryland. PPRP has also supported a project to measure ambient air mercury concentrations at the Piney Run monitoring site in Garrett County, Maryland, using a continuous mercury monitoring instrument. This state-of-the-art monitoring effort provides valuable data to the mercury research community.

PPRP is also involved with other projects related to the effects of mercury emissions. The first project involves working with the Smithsonian Environmental Research Center (SERC) and the University of Maryland Center for Environmental Science (UMCES) – Chesapeake Bay Laboratory to investigate the biogeochemistry of the processes involved with the fate of atmospheric mercury and how it ends up in fish tissue. In a cooperative project with MDE, researchers are monitoring mercury tissue burden in young fish, a long-term effort that will hopefully lead to a better understanding of trends in mercury tissue burden in response to federal and state regulations aimed at reducing mercury releases to the environment. The 2018 data report[66] for this study concludes that while mercury loading and mercury deposition are slowly decreasing over time, it is not so easy to draw a conclusion about mercury loading in fish populations. Mercury concentrations in rain are showing a significant downward trend, but a trend for loading, which also relies on precipitation data, is still uncertain. The average amount of mercury in fish has largely not changed at freshwater sites, and the overall reduction in mercury loading that one might have expected over the years has not yet materialized. This is likely due to the complexity of mercury loading in fish, which is a factor of fish age, precipitation amount, local and/or regional effects, and selenium loading to name a few. Further research and monitoring are needed to investigate statistical relationships between mercury deposition and emissions and to track/develop trends. PPRP also participates in discussions and planning sessions with NADP regarding the Mercury Deposition Network (MDN) that measures wet deposition of mercury across the U.S. and Canada, and the Atmospheric Mercury Network (AMNet) that collects data consisting of speciated mercury concentrations and meteorological data. AMNet supplements the wet measurement network and improves understanding of total (wet plus dry) mercury deposition patterns.

In 2002, Maryland issued a statewide fish consumption advisory for lakes, reservoirs, and other impoundments due to high mercury levels in fish and has since continued to update this advisory over the years.[67] PPRP has been involved for many years in conducting complex modeling studies to estimate the quantity of mercury from Maryland and other regional sources that are deposited in water bodies

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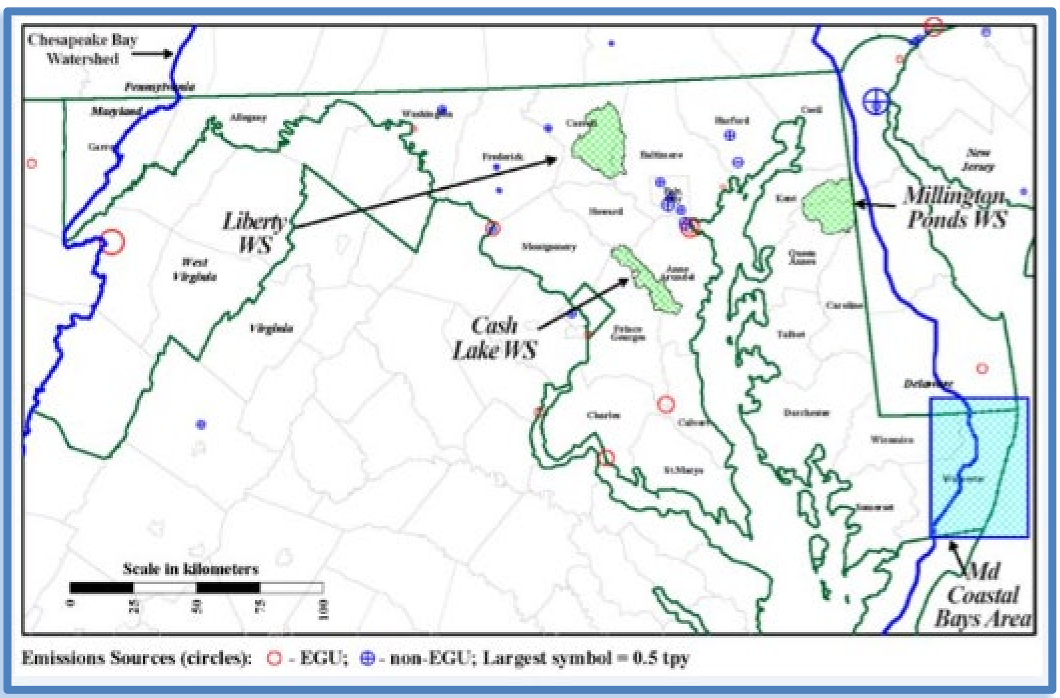
[66] Maryland Department of Natural Resources "Young of the Year Fish Monitoring in Maryland Freshwaters and Estuaries: A Means of Observing Change in Hg Availability" Data Report: September 01, 2018. University of Maryland Center for Environmental Studies.

[67] Maryland Department of the Environment, "Statewide Fish Consumption Guidelines for All Ages." March 17, 2016, http://mde.maryland.gov/programs/Marylander/fishandshellfish/Documents/Fish%20Consumption%20Docs/Maryland_Fish_Advisories_2014_March17.pdf

throughout the state. Figure 5-15 depicts the location of sources of mercury emissions close to Maryland, and the location of some of the water bodies and watersheds evaluated in PPRP's study.

As a part of the continuing effort to evaluate impacts of regional sources of mercury emissions on mercury loading to Maryland water bodies, PPRP conducted a study to determine the reduction in mercury loads to the state's water bodies due to implementation of Maryland HAA mercury controls. PPRP based this analysis on the projected reductions in emissions from Maryland power plants, which was approximately 90 percent from 2007 base year levels. This analysis predicted that Maryland's HAA emission reductions would potentially reduce mercury deposition to these water bodies contributed by Maryland power plants by an average of more than 75 percent. The analyses also compared the reductions in loading to the total loading from regional sources of mercury and global background levels. The modeling analysis predicted that the reduction in emissions at Maryland power plants would potentially reduce the mercury load to water bodies by 1 to 28 percent, the lower estimate being for the Western Maryland water bodies, which are influenced predominantly by sources from outside Maryland. An analysis of the reductions in load due to actual emissions reductions achieved is currently underway. PPRP is developing an updated mercury emissions inventory, and is working in cooperation with scientists from the National Oceanic and Atmospheric Administration (NOAA) to complete this analysis.

Figure 5-15 Location of Larger Watersheds (WS) and Mercury Sources within Maryland



Source: ERM "Garrison, Mark, Anand Yegnan and Jenifer Flannery. "Mercury in Maryland: Modeling to Assess Impacts and Effects." Maryland DNR PPRP. June 2010.

5.1.4 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 actually 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 located in Anne Arundel and Baltimore Counties. 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 FGD systems since 2010; coal units at Wagner began using lower sulfur coal and operating dry sorbent injection pollution control systems in 2015 and 2016. 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 in June 2018), Chalk Point, H.A. Wagner, Verso Luke Mill and Morgantown. Upon further evaluation of the SO_2 modeling, MDE will develop regulations to bring the SO_2 nonattainment areas into attainment status.

Recent Maryland GHG Regulation

On May 12, 2015, the Maryland Climate Change Commission Act of 2015 became law. The 2015 Act expanded the Maryland Commission on Climate Change (MCCC) originally created in 2007. MDE worked with the MCCC on the 2015 Greenhouse Gas Emissions Reduction Act Plan Update. In 2016, the Greenhouse Gas Emission Reduction Act Reauthorization was signed into effect which added a new benchmark requiring 40 percent reduction in emissions from 2006 by 2030. Along with this goal, the reauthorization of the Act reinforces and reaffirms that Maryland will meet the Intergovernmental Panel on Climate Change goal of reducing 80-95 percent of 1900 GHG levels by 2050. MDE will continue to work with MCCC to address climate change in Maryland and track the state's progress toward the goals of GHG reduction. The MCCC has various workgroups to address climate change issues including Mitigation; Adaptation and Response; Scientific and Technology; and Education, Communication, and Outreach.

Senate Bill 323, the Greenhouse Gas Emissions Reduction Act of 2016, also became law in April 2016, accelerating Maryland's efforts to reduce GHG emissions. The bill proposes a 40 percent reduction in statewide GHGs from 2006 levels by 2030.

Recent Maryland NO_x Regulation

In April 2015, MDE petitioned the Administrative, Executive and Legislative Review (AELR) Committee of the Maryland General Assembly requesting "emergency status" to reduce NO_X emissions during the 2015 summertime ozone season. The AELR Committee approved this emergency action on May 1, 2015 and projected it would reduce NO_X emission by 10 tons on the worst "ozone days" each summer. On December 10, 2015, a final version of the emergency action was promulgated establishing new NO_X emission requirements beyond 2015 designed to reduce ozone formation in the summer. The regulation requires that all coal-fired electric generating units must implement one of four options to reduce NO_X emissions by June 1, 2020. The fourth option is only available for a "system" of sources, which currently includes the three coal-fired generating units: Chalk Point, Dickerson and Morgantown.

1. Install SCR to meet a NO_X emission rate of 0.09 lbs/MMBtu during ozone season;
2. Permanently retire the unit;
3. Switch fuel permanently to natural gas; or
4. Meet a system-wide daily NO_X cap of 21 tons per day during the ozone season, or 0.13 lbs/MMBtu as a 24-hour block average. This option required reductions in emission rates starting in 2016 and further reducing rates biannually until 2020.

Utility Mercury and Air Toxics Standard (MATS)

On December 21, 2011, the EPA promulgated a Maximum Achievable Control Technology (MACT) standard, referred to as the Mercury and Air Toxics Standard, or the "Utility MATS" that will reduce emissions of hazardous air pollutants (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 MW. The rule is intended to reduce emissions of heavy metals (mercury, 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.

Subsequent to 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 Cost Finding for the MATS rule, which then determined that it is in fact *not* "appropriate and necessary" to regulate HAP emissions from power plants under Section 112 of the CAA. The MATS rule will remain in place, since 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 Act.

As the MATS rule currently stands, for new and existing coal-fired generating units, the Utility MATS establishes numerical emission limits for mercury, PM (as a surrogate for toxic non-mercury 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 start-up.

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

5.1.5 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 twentieth century, record high levels of atmospheric concentrations of GHGs sparked national debate about the responsibility to reduce human contribution to global climate change.

Some of the potential impacts associated with increased GHG levels in the atmosphere are global temperature increases, sea-level rise that may gradually inundate coastal areas and increase shoreline erosion, flooding from coastal storms, changes in precipitation patterns, increased risk of severe weather events and droughts, threats to biodiversity, and challenges for public health and wellness.

The electricity sector is particularly vulnerable to the effects of extreme weather events. As global temperatures continue upward, sea levels will also rise and extreme weather events are likely to occur more frequently. Renewable energy and transmission grid investments are necessary to make our electricity systems more resilient and reliable.

As published in Chapter 1 of "A Sustainable Chesapeake,"[68] by The Conservation Fund, historic tide-gauge records indicate that Maryland's coastal waters have increased by one foot in the past 100 years and are projected to continue to rise by over 1 meter by 2100[69], with a subsequent loss of approximately 580 acres of land per year along the Maryland coast. As sea levels continue to rise, coastal floods reach higher lands, threatening the reliability of power plants in the affected regions and increasing the number of electric facilities put at risk. "Maryland and the Surging Sea" reports that seven generating stations in Maryland are sited less than nine feet above local high tide, and three facilities are sited less than five feet above high tide.[70] According to MDE's GHG Reduction Plan updated in October 2015, among U.S. states, Maryland is the third most vulnerable to sea level rise.

Another effect of climate change is more frequent heat waves. In Maryland, mean annual temperature increased from 1977 to 1999 by 2°F according to the Comprehensive Assessment of Climate Change Impacts in Maryland.[71] The study also indicated that in the late 20th century, there was an average of 30 days per year with maximum daily temperatures greater than 90°F. The number of days with the daily temperature greater than 90°F is expected to double by the end of the century. These trends suggest that

[68] The Conservation Fund, "A Sustainable Chesapeake: Better Models for Conservation," https://www.conservationfund.org/our-work/cities-program/resources/a-sustainable-chesapeake

[69] Bradley, R., Karmalkar, A., and Woods, K. Climate Change State Profiles Maryland. Climate System Research Center, University of Massachusetts Amherst. https://www.geo.umass.edu/climate/stateClimateReports/MD_ClimateReport_CSRC.pdf

[70] Strauss, B., C. Tebaldi, S.Kulp, S. Cutter, E. Emrich, D. Rizza and D. Yawitz (2014). Maryland and the Surging Sea: A vulnerability assessment with projections for sea level rise and coastal flood risk. Climate Central Research Report. {http://sealevel.climatecentral.org/uploads/ssrf/MD-Report.pdf}

[71] Comprehensive Assessment of Climate Change Impacts in Maryland, Chapter 2. www.mde.state.md.us/programs/Air/ClimateChange/Documents/FINAL-Chapt%202%20Impacts_web.pdf

extended heat waves in Maryland are likely to occur more frequently and last longer. Extreme heat creates periods of high energy demand due to increased use of air conditioning and cooling equipment, while at the same time, warmer ambient temperatures in surface water bodies can reduce efficiency at power plants that rely on cooling water.

To increase resilience of the electricity sector, certain measures can be taken, including the following as provided in the U.S. Climate Resilience Toolkit:

- Diversify supply chains to address multiple types of disruptions
- Strengthen and coordinate emergency response plans to minimize magnitude and length of disruptions
- Develop flood and stormwater management plans to address extreme weather events and sea level rise
- Develop drought management plans to address the potential for decreased water supplies
- Develop hydropower management plans to address the potential for hydrologic extremes
- Build redundancy into facilities to allow for continued operation during partial disruptions
- Storm-harden energy infrastructure and/or elevate water-sensitive equipment to address high water levels
- Build coastal barriers using green, grey, or hybrid infrastructure to address high water levels
- Improve reliability of grid systems through back-up power supply, intelligent controls, smart grid, micro-grids, and distributed generation to better respond to disruptions
- Implement air-cooled or low-water-use cooling systems for thermoelectric power plants to address drought and increased temperatures for water cooling
- Expand the use of non-water-intensive energy technologies (for example, wind, photovoltaic solar)
- Relocate vulnerable facilities out of locations that may be inundated
- Relocate facilities to areas that have more sustainable water supply
- Add peak generation and power storage capacity to minimize disruptions
- Add back-up power supply for grid disruptions
- Add regional fuel product reserves to address vulnerable fuel supply disruptions
- Increase transmission capacity within and between regions to overcome localized disruptions.
- Improve demand-response capabilities of energy infrastructure (for example, a smart grid)

Burying transmission lines or elevating or relocating equipment can help reduce the risk of outages, but these options can be capital intensive and may not be a cost-effective, long-term solution. Renewable energy tends to be smaller-scale generation that reduces impact on the grid when upsets occur. Renewable resources can also be less vulnerable to fuel supply risks, thus reducing vulnerability to the fuel supply chain and providing price stability for consumers. Further research and investment in renewable energy will improve Maryland's understanding of the impacts as well as the risks associated with implementing renewable technology in the power sector.

Maryland has been working to reduce the state's impact on the climate. Maryland formed the Maryland Commission on Climate Change (MCCC) 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 Maryland 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 has since been updated in 2015. The GGRA requires a 25 percent reduction in statewide GHG emissions from 2006 levels by 2020. The state is on track to exceed the 25 percent reduction by 2020. 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.

The latest regulatory development in Maryland regarding GHGs is the Maryland Greenhouse Gas Emissions Reduction Act of 2016. This and other local and federal climate initiatives are discussed in the following sections.

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 (HAA), joined RGGI in 2007, the same year as Massachusetts and Rhode Island. Under the RGGI program, 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 188.1 million tons, based on projected 2006-2007 emissions levels. The annual cap was 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. Emission reductions of 2.5 percent per year are required from 2015 through 2020, for a total reduction of 10 percent. This phased approach was designed to provide regulatory certainty for electricity generators to begin planning for, and investing in, lower-carbon alternatives without creating dramatic electricity price impacts.

Table 5-2 lists the CO_2 budget allocations for each RGGI member state. There are 18 power plants in Maryland that are covered by RGGI. Maryland's 2019 RGGI budget allowance is 12.96 million tons of CO_2, or 22 percent of the 2019 regional CO_2 budget of 58.47 million tons. Contrary to what was expected when the CO_2 state apportionments were negotiated, emissions in the power sector have fallen over the last several years due to plant closures, the economic downturn, mild weather patterns, shifts to natural gas-fired generation, increased generation from renewable energy sources, and increases in conservation and demand response. At the conclusion of the third control period, the RGGI power sector recognized a 65 percent decline in emissions since 2005. Since 2005, emissions from Maryland's power sector have declined 66 percent, or by 24.58 million tons of CO_2.

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 percent reduction in the regional emissions cap to 91 million tons starting in 2014. Other revisions include the establishment of interim control period requirements, cost containment reserves to help alleviate spikes in allowance prices, and changes in the handling of offsets as described below. 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 percent from 2020 to 2030, effectively eliminating 22,750,000 tons of CO_2 from 2021 through 2030.

It should be noted that of the thirteen states (plus the District of Columbia) that are included in whole or in part in the PJM footprint, only Maryland and Delaware are participants in RGGI. To some degree, therefore, "emissions leakage" may occur: 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 covered plants in Maryland and Delaware is subject to the RGGI emissions cap while generation in PJM states not participating in RGGI (e.g., Pennsylvania) are not subject to the emissions cap. The extent of emissions leakage depends upon numerous factors including energy consumption levels, power plant running-cost differentials, the price of RGGI emission allowances, the level of the emissions caps, and transmission congestion.

Table 5-2 CO_2 Emissions from RGGI Sources

State	Annual Historic Emissions 2005 - 2008 (million tons of CO_2)	Annual RGGI Emissions (million tons of CO_2)			
		Compliance Period 1 2009-2011	Compliance Period 2 2012 - 2014	Compliance Period 3 2015-2017	Compliance Period 4 2018-2020[a]
Maryland	32.38 – 37.26	25.57 – 27.96	18.68 – 20.90	12.68 – 18.33	3.24 – 17.17
Connecticut	8.99 – 11.32	7.15 – 8.53	7.12 – 7.46	6.83 – 8.15	1.93 – 8.74
Delaware	7.56 – 8.30	3.71 – 4.30	3.93 – 4.84	3.52 – 4.04	0.39 – 2.72
Massachusetts	21.44 – 26.64	15.63 – 19.80	11.79 – 13.68	10.89 – 12.04	1.66 – 8.11
Maine	3.37 – 4.59	3.34 – 3.94	2.25 – 2.94	1.07 – 1.78	0.23 – 1.18
New Hampshire	7.10 – 8.97	5.53 – 5.90	3.57 – 4.64	1.98 – 3.82	0.42 – 2.30
New Jersey	20.60 – 22.07	16.36 – 19.68	N/A (see note b)	N/A (see note b)	N/A (see note b)
New York	48.35 – 62.72	37.15 – 42.11	33.48 – 35.64	24.58 – 32.55	6.06 – 27.21
Rhode Island	2.69 – 3.29	3.42 – 3.95	2.77 – 3.74	2.83 – 3.21	0.52 – 3.54
Vermont	0.0026 – 0.0078	0.0020 – 0.0065	0.0023 – 0.00276	0.0012 –.0043	0.00008 – 0.00207
Original RGGI 10 State Total	153.5 – 184.6	118.56 – 135.74	N/A	N/A	N/A
Current RGGI 9 State Total	132.9 – 162.5	N/A	86.53 – 92.73	64.49 – 82.99	14.46 – 70.97

Source: http://www.rggi.org/
Notes:
(a) Data for this control period only includes 2018 through June 2019.
(b) New Jersey withdrew from the RGGI program at the end of 2011.
NA – Complete emissions data are not available. Some facilities in Connecticut and Delaware are shown as having incomplete data in the RGGI emissions reporting database.

RGGI Allowance Auctions

Each 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, so that the individual state CO_2 budget trading programs, in aggregate, form one regional compliance market for CO_2 emissions. A power plant within a 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 percent) 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.

Allocation of the Maryland Strategic Energy Fund

The RGGI member states have agreed that a minimum of 25 percent of the revenue from each state's emissions allowances are to be used for consumer benefit or strategic energy purposes. As of the June 2019 auction, Maryland has raised $655.9 million in RGGI proceeds. This revenue is directed to the Maryland Strategic Energy Investment Fund (SEIF), which is administered by MEA. The Maryland legislature has directed MEA to allocate the SEIF as follows:

- Up to 50 percent — Energy bill assistance for low-income residents;
- At least 20 percent — Energy efficiency, conservation, and demand response programs (of which half must be used on low and moderate income families);
- At least 20 percent — Clean energy and climate change programs, outreach, and education; and
- Up to 10 percent, 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 percent 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 percent per year. However, beginning with the March 2014 auction, the reserve price was adjusted to $2 and increases by 1.025 percent each year. Allowance clearing prices have ranged from $1.86 per ton to $7.50 per ton, as shown in Figure 5-16.

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 reserve minimum. In September 2017, the price began to increase reaching $5.62 per ton as of the June 2019 auction. In total, RGGI has resulted in $3.2 billion in revenues to the nine member states as of the June 2019 auction. Maryland has raised $656 million (see Table 5-3), the majority of which has been used for low-income energy assistance.

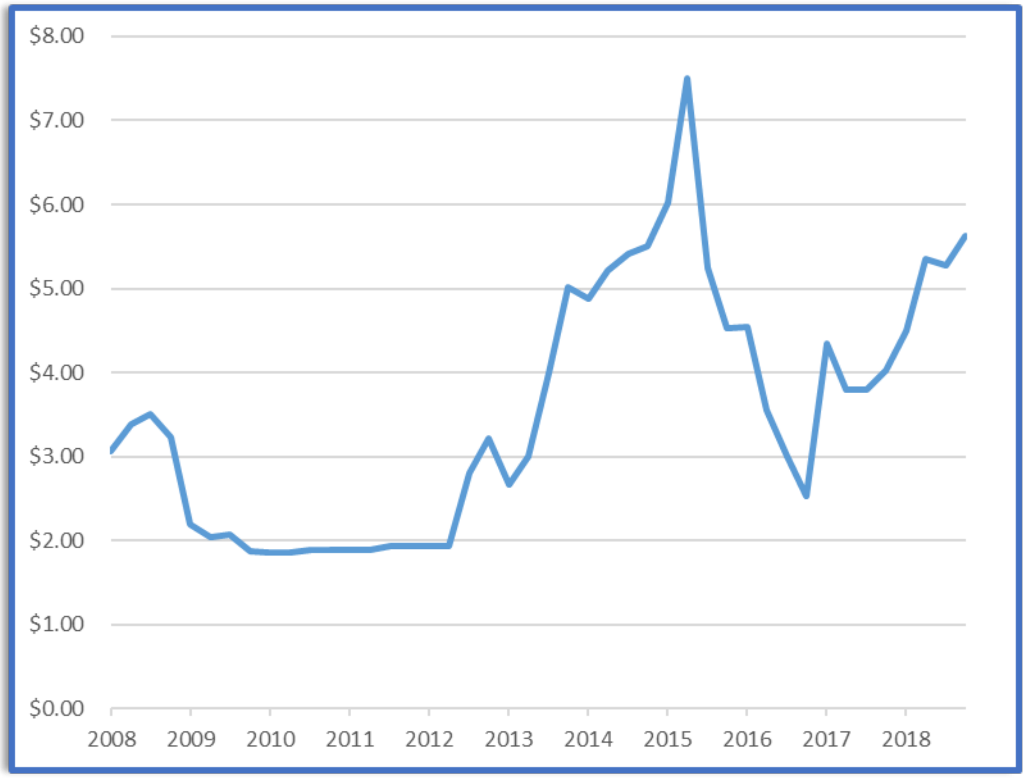
Table 5-3 RGGI Allowance Auctions, 2008-2019

Auction Date	Auction Offering	Total RGGI Allowances Sold	Clearing Price Per Ton	Maryland Allowances Sold	Maryland Revenues (million USD)
Sep-08	Current	12,565,387	$3.07	5,331,781	$16.37
Dec-08	Current	31,505,898	$3.38	5,331,781	$18.02
Mar-09	Current	31,513,765	$3.51	5,331,783	$19.93
	Future	2,175,513	$3.05	399,884	
Jun-09	Current	30,877,620	$3.23	5,331,782	$18.05
	Future	2,172,540	$2.06	399,884	
Sep-09	Current	28,408,945	$2.19	5,331,782	$12.42
	Future	2,172,540	$1.87	399,884	
Dec-09	Current	28,591,698	$2.05	5,331,782	$11.48
	Future	2,172,540	$1.86	294,317	
Mar-10	Current	40,612,408	$2.07	7,878,873	$16.99
	Future	2,137,992	$1.86	368,169	
Jun-10	Current	40,685,585	$1.88	7,528,873	$14.85
	Future	2,137,993	$1.86	3,767,444	
Sep-10	Current	45,595,968	$1.86	5,681,334	$10.99
	Future	2,137,992	$1.86	231,008	
Dec-10	Current	43,173,648	$1.86	4,316,922	$8.41
	Future	2,137,991	$1.86	206,358	
Mar-11	Current	41,995,813	$1.89	7,528,873	$14.94
	Future	2,144,710	$1.89	376,444	
Jun-11	Current	12,537,000	$1.89	2,245,541	$4.60
	Future	943,000	$1.89	190,346	
Sep-11	Current	7,487,000	$1.89	1,336,077	$2.53
	Future	0	--	0	
Dec-11	Current	27,293,000	$1.89	5,669,520	$10.72
	Future	0	--	0	
Mar-12	Current	21,559,000	$1.93	4,410,931	$8.51
Jun-12	Current	20,941,000	$1.93	4,458,850	$8.61
Sep-12	Current	24,589,000	$1.93	6,222,230	$12.01
Dec-12	Current	19,774,000	$1.93	5,011,529	$9.67
Mar-13	Current	37,835,405	$2.80	9,579,963	$26.82

Auction Date	Auction Offering	Total RGGI Allowances Sold	Clearing Price Per Ton	Maryland Allowances Sold	Maryland Revenues (million USD)
Jun-13	Current	38,782,076	$3.21	9,579,963	$30.75
Sep-13	Current	38,409,043	$2.67	8,739,921	$23.34
Dec-13	Current	38,329,378	$3.00	8,739,920	$26.22
Mar-14	Current	23,491,350	$4.00	4,842,487	$19.37
Jun-14	Current	19,062,384	$5.02	3,725,941	$18.70
Sep-14	Current	17,998,687	$4.88	3,725,942	$18.18
Dec-14	Current	18,198,685	$5.21	3,725,942	$19.41
Mar-15	Current	15,272,670	$5.41	3,051,680	$16.51
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
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
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
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
Jun-19	Current	13,221,453	$5.62	2,389,718	$13.43
Total					$655.95

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

Figure 5-16 RGGI Allowance Clearing Prices, 2008-2019



RGGI Offsets

The RGGI program allows covered entities to use qualifying offset projects to reduce the total number of allowances they are required to secure. Offset projects or emission credit retirements are awarded one CO_2 offset allowance for every ton of CO_2 reduced or sequestered. A source may cover up to 3.3 percent of its CO_2 emissions with offset project allowances. There is currently one offset project, the New Beulah Landfill Gas Reconstruction Project, in Maryland that was awarded 48,237 offsets.[72]

Offset projects that currently qualify under the RGGI program are:

1. Landfill Methane Capture and Destruction – applicable to municipal solid waste landfills that are not subject to New Source Performance Standards (NSPS).
2. Sequestration of Carbon Due to Reforestation, improved forest management, or avoided conversion – sequestering carbon through the conversion of land that has been in a non-forested state.
3. Avoided Methane Emissions from Agricultural Manure Management Operations – destroying methane generated by anaerobic digesters and uncontrolled storage of manure or organic food.

[72] RGGI CO2 Allowance Tracking System, RGGI CO2 Budget Trading Programs, https://rggi-coats.org/eats/rggi/index.cfm?fuseaction=search.project_offset&clearfuseattribs=true (viewed on January 8, 2020).

Forestry Carbon Sequestration

Biological processes can capture and sequester carbon, providing an offset to carbon emissions from fossil fuel power generating facilities. Restoring or planting forests is one approach to enhancing these carbon sequestration services. One method suggested to protect or expand the natural sequestration services provided by such ecosystems is to create trading markets that place a value on carbon in a way that results in economic incentives and payments for removing carbon from the atmosphere and storing it in biomass.

To understand the requirements and potential of applying such an approach in Maryland, PPRP has been evaluating previously restored forest sites. Data have been collected at the ODEC Patapsco and Seneca Creek restoration sites to measure the carbon content of soils and vegetation, and estimate changes over time. These studies helped develop carbon measurement methodologies and establish baseline values for determining the rate of carbon storage by such systems.

A second initiative has been developing models that can use the field data to project the amount of carbon that will be sequestered over the lifetime of the project (which may be several decades). PPRP has adapted the Graz-Oak Ridge Carbon Accounting Model (GORCAM) for use in terrestrial and wetlands carbon sequestration projects in Maryland. The GORCAM model has been used to characterize the sequestration benefits of different management regimes in Maryland's state-owned forests and to estimate the range of results expected using different mixes of species in the DNR's carbon sequestration demonstration project.

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 harvest 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.

The RGGI Model Rule issued in December 2017 did not include three categories that previously qualified for offsets including the Afforestation sub-category, Sulfur Hexafluoride Reduction category, and the End-Use Efficiency category. Two states, Massachusetts and Rhode Island, have completely terminated accepting all offset project applications.

Maryland Offset Projects

In Maryland, two additional offset project categories are being pursued, specifically terrestrial sequestration through urban forestry and the restoration of salt marshes. Maryland is promoting the development of programs within urban communities to plant and grow trees, which reduces GHG emissions in two ways. First, CO_2 is removed from the atmosphere by growing trees as their biomass increases. Second, GHG emissions are avoided through energy conservation, as the trees can provide shade with a natural cooling effect for residences and other buildings in the community. Several state agencies and community groups are interested in pursuing urban forestry projects as an alternative or supplement to other more traditional afforestation projects.

Salt marshes are prevalent in Maryland and are of critical importance for estuarine ecosystems, such as those associated with the Chesapeake Bay, by serving as habitats for wildlife and buffers to large storms. In addition, salt marsh soils have the capacity to sequester large amounts of CO_2 by accreting carbon-containing sediments and organic matter. Marsh decline, however, is occurring throughout the region as sea level increases and land areas subside. Raising the elevation of the marsh beds by supplementing natural sediment (e.g., depositing clean dredged material) can restore the tidal fluctuations required to support the marsh systems and promote carbon storage. Over the last several years, PPRP has assisted with an effort by Restore America's Estuaries to develop a formal offset protocol for salt marsh systems (see sidebar).

Maryland has considerable potential for reducing GHG emissions through sequestering carbon in

"Coastal Blue Carbon" Wetlands Restoration and Conservation Offsets

Research focusing on "Blue Carbon" in coastal wetland ecosystems suggests that some coastal wetlands can sequester carbon at rates 3 to 5 times greater than temperate forests, making them particularly valuable as carbon sinks that can offset carbon emissions by human activities. Unfortunately, current estimates indicate that 50 percent of U. S. coastal wetlands have been lost since the 1800s, and that coastal wetlands are being lost globally at a rate of 0.7 to 2 percent per year. Efforts to preserve and restore coastal wetlands can now be financed by payments for the additional carbon that the wetlands sequester.

Restore America Estuaries, with support from PPRP, developed a GHG offset category for measuring and crediting climate benefits from a broad range of wetlands, including freshwater tidal coastal wetlands, salt marshes, seagrasses, floodplains, peatlands, and other wetland types. The Wetlands Restoration and Conservation category, which received approval under the Verified Carbon Standard (VCS) in October 2012, allows increased private investment in wetland restoration and conservation projects through the issuance of internationally recognized carbon credits. VCS is the majority holder in the voluntary carbon market with a 58 percent global and U.S. share and is widely considered the leading certification available globally.

In late 2015, VCS approved the specific methodology for implementing tidal wetland and seagrass restoration projects in the Wetlands Restoration and Conservation offset category. The methodology, which is applicable throughout the world, details the procedures required to calculate, report, and verify the GHG reductions from these projects and thereby obtain "carbon credits" that can be traded in the VCS or other carbon markets.

restored wetlands and marshlands around the Chesapeake Bay. Maryland's Department of Natural Resources (DNR) has identified three focus areas to promote wetland carbon sequestration with the potential to reduce the state's net emissions by an estimated 0.5 to 0.65 million metric tons CO_2 equivalent (CO_2e):

<u>Blackwater Tidal Marsh Sequestration Project</u> – PPRP, the U.S. Department of Energy (DOE) and several other partners are collaborating with the University of Maryland to restore up to 20,000 acres of tidal marshes using clean dredged material. Determinations of the carbon storage rate and the effect of management practices on the process, as well as the development of a sampling protocol for CO_2 validation in restored marshes, will lead to projects that produce carbon offsets. The restoration project is storing an estimated 24,550 metric tons of carbon each year, a rate above the national average. In addition, the restored marsh will provide habitat for native and migratory birds, terrestrial animals and aquatic life.

<u>Dorchester County Wetlands Study</u> – PPRP conducted a study of wetlands in Dorchester County to demonstrate the potential carbon sequestration opportunities that may result from protecting and restoring wetlands. Areas for potential restoration were identified within Dorchester County's extensive coastal marshes. Satellite-derived net primary productivity of the wetlands was used to estimate gross sequestration, and net accumulation was estimated based on the current understanding of carbon dynamics in coastal wetlands.

<u>Sea Level Affecting Marshes Model</u> – DNR utilized this model to identify areas known as wetland transition zones, or areas projected to convert into wetlands. These identified areas will become targets for wetland restoration and land conservation efforts to help maintain coastal wetlands into the future.

Over the last several years, Maryland has enacted several pieces of legislation that will help the state, both directly and indirectly, meet its goals related to climate change. These bills target emissions from power plants and vehicles, spur development of renewable energy, and set energy efficiency and conservation goals.

During the 2009 session, the legislature passed the Greenhouse Gas Emissions Reduction Act (GGRA) via House Bill 315/Senate Bill 278. This law sets a statewide GHG emissions reduction goal of 25 percent from a 2006 baseline by 2020. The GGRA also requires that Maryland prepare a plan to meet a longer-term goal of reducing its GHG emissions up to 90 percent by 2050, while promoting new "green" jobs, protecting existing jobs and positively influencing the state's economy. A GGRA 2012 Plan (Plan) was designed to achieve the goals identified in the 2009 GGRA. The Plan describes 65 control measures for reducing GHG emissions, including reinforcement of Maryland's participation in RGGI and programs to support terrestrial and geological carbon storage. In addition to achieving GHG reductions, the Plan was designed to create jobs and improve Maryland's economy, and will also assist in advancing other environmental priorities of the state, including restoration of the Chesapeake Bay, improving air quality, and other critical energy and national security issues. MDE released a GGRA Plan Update in October 2015 that will provide additional environmental benefits by helping the state further Chesapeake Bay restoration efforts, continuing improving air quality, and working to preserve agricultural and forest lands.

In May 2015, the Maryland Climate Change Commission Act of 2015 was signed into law to expand the MCCC originally created in 2007. MDE worked with the MCCC on the 2015 GGRA Plan Update and will continue to work with MCCC to address climate change in Maryland. The MCCC has various workgroups to address climate change issues including mitigation; adaptation; science and technology; and education, communication, and outreach.

The Maryland Senate passed Senate Bill 323 in February 2016, accelerating Maryland's efforts to reduce GHG emissions. The bill proposed a 25 percent reduction in statewide GHGs below 2006 levels by 2020, and a 40 percent reduction in statewide GHGs by 2030. This bill was passed by the House and signed by the Governor in April 2016, as the Reauthorization of the Greenhouse Gas Emissions Reduction Act.

Clean Power Plan and the Affordable Clean Energy (ACE) Rule

The Clean Power Plan (CPP), finalized in 2015, was a comprehensive federal program mandating reductions in GHG emissions from large existing sources, including power plants, and potential new sources of GHGs. The CPP was rooted in Section 111 of the Clean Air Act, which laid out distinct regulatory approaches for new and existing sources of emissions. Section 111(b) covered federal programs to address new, modified and reconstructed sources by establishing emissions standards. Section 111(d) mandated a series of state-based programs covering existing sources; under Section 111(d), EPA established guidelines for states to design programs that fit within those guidelines to achieve target emissions reductions. In October of 2017, EPA issued a notice proposing to repeal the CPP. While tied up in litigation, EPA proposed changes to the CPP which would then become known as the Affordable Clean Energy (ACE) rule.

The Affordable Clean Energy (ACE) rule was proposed on August 21, 2018 as a replacement for the CPP. Centered on Section 111(d) of the Clean Air Act which governs how an agency issues emission guidelines and plans, the ACE rule establishes new guidelines for state regulation of coal-fired power plant emissions, shifting the responsibility away from federal programs and agencies, and provides the states with added time and flexibility. The ACE rule defines the “best system of emission reduction” for GHG emissions from existing coal-fired power plants as onsite improvements to heat-rate efficiencies. The ACE rule additionally provides incentives for efficiency improvements at existing power plants, and provides the states with a list of technologies to establish standards of performance for incorporation into their state plans. This rule has the potential to affect roughly 300 coal-fired power plants. The final ACE rule was published in the Federal Register on July 8, 2019, along with the final repeal of the CPP. This publication was quickly followed by a petition for review of the ACE rule by multiple parties.

5.1.6 Fossil Fuel-fired Generation and CO2

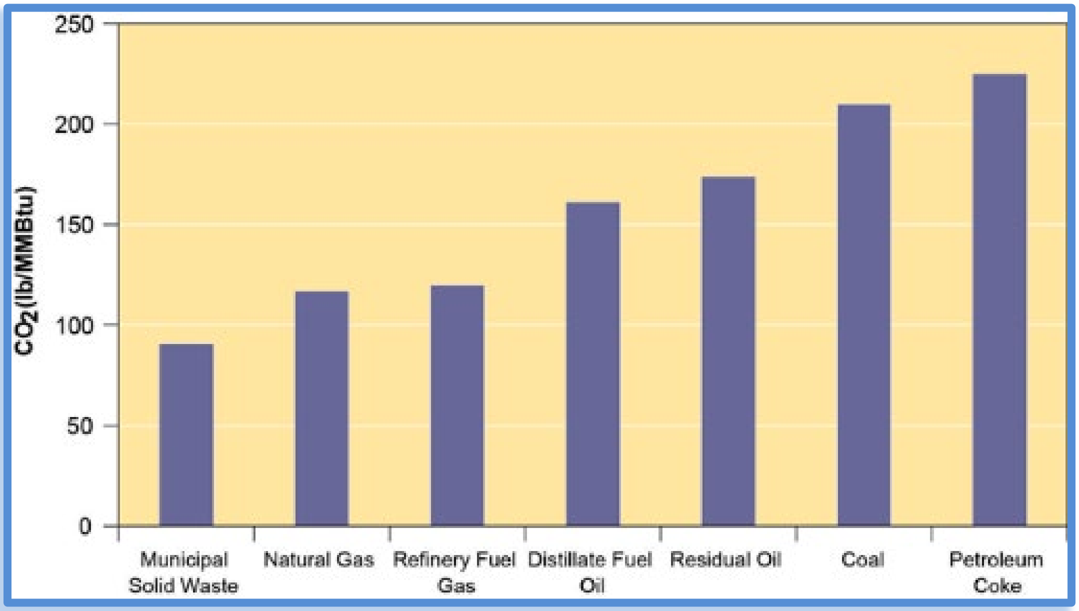
Background and Definition

Coal-fired power plants historically have supplied over half of Maryland’s net electricity generation and been effective in meeting baseload, intermediate load and peak demands given their high reliability. However, availability of vast reserves of economically viable, domestic unconventional gas has changed the face of the electric generation fuel mix in the United States and in Maryland. Since 2012, the sources of Maryland’s net electricity generation have changed substantially, with coal falling to only 14% of the total while natural gas-fired generation has increased to 46%. The increased gas supply incentivizes power plants to switch from distillate oil to natural gas at existing combustion turbines, or install new high efficiency natural gas-fired combustion turbines to replace older coal- and oil-fired units. Whether through fuel switching or the development of new natural gas-fired units, the Maryland electric power industry has experienced a shift as natural gas resources displace coal resources throughout the PJM region. The U.S. Energy Information Administration predicts that total domestic production of natural gas will continue to grow through 2050, and with relatively low natural gas prices, natural gas-fired electric generation grows steadily and remains the dominant fuel in the electric power sector through 2050.

All fossil fuels, including both natural gas and coal, contain substantial amounts of fuel-bound carbon that is oxidized into carbon monoxide (CO) and CO_2 during combustion. CO_2 emissions from conventional coal combustion technologies amount to approximately 1 ton per MWh of electricity generated, compared to 0.4 to 0.6 ton per MWh from natural gas-fired generation (e.g., combined cycle/simple cycle gas turbines). Figure 5-17 shows the approximate level of CO_2 formed when combusting various fossil fuels.

While CO_2 emissions related to gas fired plants are lower on a per-unit-of-energy basis relative to those generated from coal-fired plants, the increase in natural gas fired power generation in Maryland, highlights the fact that carbon emission mitigation cannot be limited to coal-fired plants. Furthermore, for coal to have an environmentally acceptable future, CO_2 emissions from new and existing coal-fired power plants will need to be mitigated to as low a level as feasible given regulatory drivers the electric utility industry may be facing in upcoming years. See Section 5.1.5 of the CEIR for more information on regulatory considerations.

Figure 5-17 CO_2 Emissions from the Combustion of Fossil Fuels



CO_2 emission mitigation for fossil fuel-derived power has been a debated topic in recent years and includes several alternatives. These CO_2 emission reduction strategies may include improvements to generation efficiency through the development of new plants or upgrades to existing facilities/equipment or substituting a fraction of the fossil fuel consumed with a carbon-neutral fuel, such as biomass (biomass co-firing). Some modern coal-fired boiler designs are currently capable of co-firing up to 30 percent biomass. One additional alternative that has received significant recent attention, especially at the federal level, is CO_2 capture, utilization and geological storage (CCUS).

CCUS is a term that encompasses the methods and technologies associated with removing CO_2 from flue gas (and therefore the atmosphere), followed by recycling the CO_2 for utilization followed by the safe and permanent subsurface storage of the CO_2. Thus, the full CCUS process includes CO_2 capture, CO_2 transportation, and the final use and storage of that CO_2. Recent federally funded projects and technological advances have proven that carbon capture from fossil fuel fired plants is an available technology that can be scaled for commercial application.

CO_2 Capture

Currently, three general methods are available to capture CO_2 from power plants before it reaches the atmosphere:

- *Post-combustion capture, in which CO_2 is separated from flue gases typically using sorbent or solvent systems;*
- *Pre-combustion capture, in which CO_2 is captured prior to combustion and generally involves a shift reaction to convert synthesis gas to CO_2 and hydrogen; and*
- *Oxyfuel firing, in which the fuel is fired with an oxygen or oxygen/ CO_2 mixture, thus producing a CO_2-rich flue gas that facilitates capture.*

Located in Cumberland, Maryland, the AES Warrior Run power plant has been capturing a small portion of its CO_2 emissions since 2000 for use in the food and beverage industry. This 180 MW circulating fluidized bed generating unit uses a post-combustion monoethylamine flue gas scrubber system to remove approximately 110,000 metric tons of CO_2 annually from a 2 to 3 percent slipstream of the plant's flue gas. The extracted CO_2 is then purified to a 99.99 percent purity level using carbon filters and molecular sieves. The CO_2 is stored under pressure in steel tanks until it can be shipped offsite via tanker trucks for beneficial use primarily in the food and beverage industry.

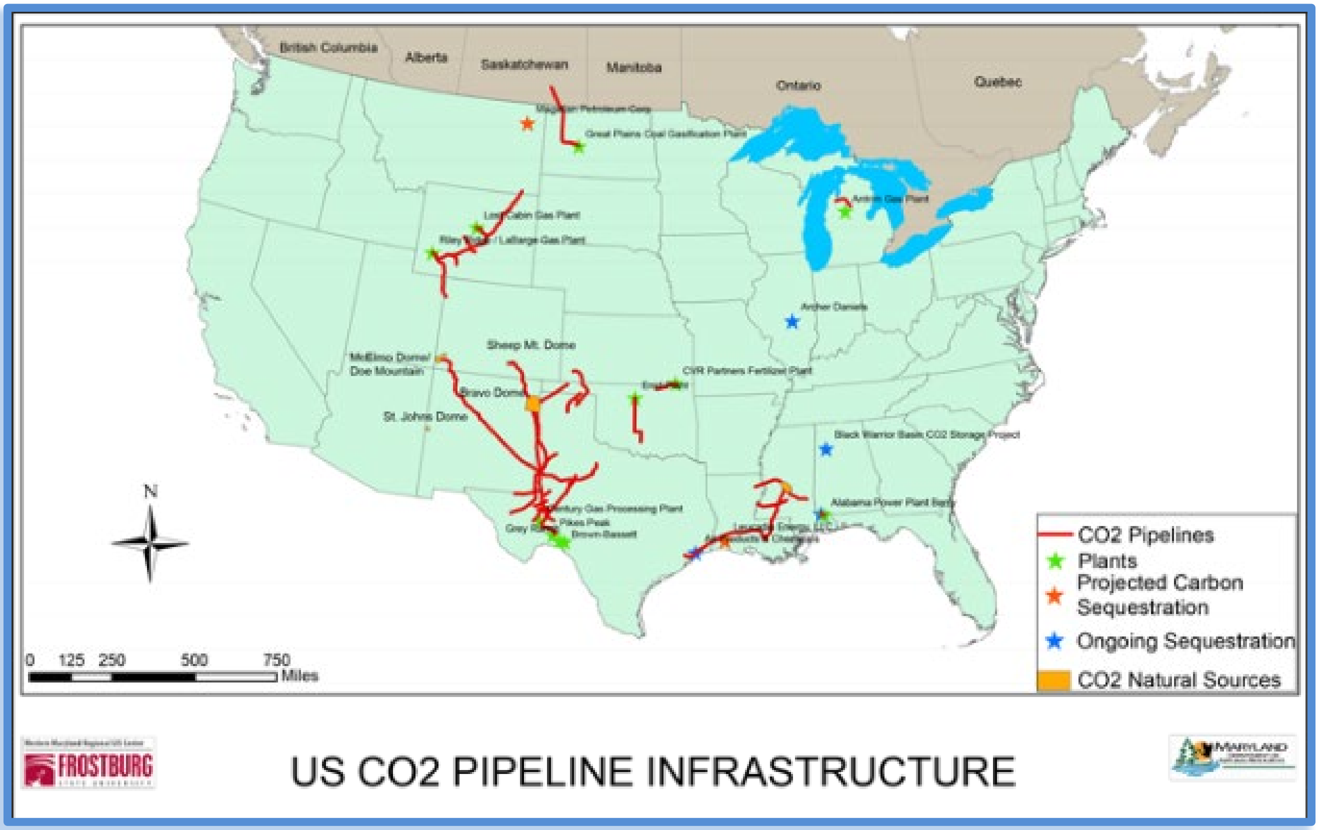
Outside of Maryland, several carbon capture demonstration projects are currently under various stages of development in the U.S., most of which are funded by the U.S. Department of Energy (DOE) National Energy Technology Laboratory. These projects incorporate the full range of existing carbon capture technologies, as well as test the viability of emerging innovative methods, such as cryogenic, phase-changing, and enzyme-based sorbent capture. A few commercial-scale industrial CO_2 capture projects are under construction or have commenced preliminary operations; however, most of the projects involving gas-fired power plants have not yet completed commercial-scale testing. The key barrier to carbon capture technology implementation for new and existing power plants is the substantial capital and operating costs. The beneficial use of captured CO_2 prior to storage to create value-added products or services may alleviate some of the economic burden.

Transporting CO_2

Typically, once CO_2 is captured, it must be highly pressurized and transported via one of several methods, including pipelines, trucks, or shipping vessels. Despite potentially being more cost-effective than pipelines for small-scale applications, trucking and shipping transport methods have inherent limitations of volume constraints and intermittency. Thus, for larger scale CO_2 projects, pipelines may be the most ideal transport method.

To implement carbon capture on the scale necessary to reduce atmospheric CO_2 concentrations, the transportation network of CO_2 from industrial sources to beneficial use or storage sites via pipeline must be greatly expanded beyond current capacities. The U.S. has a 40-year history of transporting CO_2 via pipelines for the purpose of CO_2 use in enhanced oil recovery (EOR) projects. Around 50 million metric tons of CO_2 is transported in the U.S. each year through approximately 4,500 miles of pipelines, with approximately 75-80 percent of the CO_2 in these pipelines derived from natural (geologic) sources (Figure 5-18). If currently planned CO_2 capture facilities and pipelines are built, the portion of CO_2 from industrial sources could come close to matching natural sources by 2020.

Figure 5-18 Existing CO_2 Pipeline Network in North America



While the pipeline transportation infrastructure for CO_2 is growing in certain regions of the country, there are no CO_2 pipelines in the Eastern U.S. Maryland has, however, an extensive network of natural gas pipelines (see Figure 3-3) that are concentrated in the central portion of the state, where the majority of Maryland's power plants and other large CO_2 emission sources are located. These existing gas lines offer a potential opportunity for co-location of CO_2 pipelines should Maryland pursue carbon sequestration in the future.

CO_2 Use and Storage

Even in light of Maryland's multiple projects in the areas of carbon offsets, terrestrial sequestration, renewable energy and switching from coal firing to natural gas, further mitigation of atmospheric CO_2 emissions could be achieved via CCUS. While CO_2 is not a hazardous substance, it is an aggressive gas that carries certain risks and geological sequestration must be approached carefully to achieve the permanent, safe storage of this industrial gas.

Geological Storage and Use of CO_2

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). The ultimate goal of long-term, permanent storage of CO_2 is more likely achieved through reactions involving the chemical adsorption of CO_2 due to the potential for CO_2 leakage associated with structural storage. Chemical reactions involving injected CO_2 include capillary attraction in small fractures, physical adsorption of CO_2 known to occur on the surface of rock containing organic material and chemical adsorption of CO_2 known to occur on the surface of some rocks and with some brines. Unfortunately, the first two reactions are not reliable in the long term since they are reversible when subject to pressure swings such as may occur in seismic events. Thus, the only ultimately secure CO_2 storage is that achieved with chemical adsorption. Within a candidate geologic formation, the most promising strategy appears to be the use of capillary attraction and physical adsorption to saturate the formation with CO_2 and thus foster chemical adsorption, which is expected to occur over a longer period of time.

The primary types of target geological reservoirs are depleted oil and gas fields, unmineable coal seams and deep saline formations. A potential utilization of CO_2 occurs with geological sequestration in oil and gas fields when pressurized CO_2 can be used to displace residual oil and gas, allowing greater extraction volume. A similar technique utilizes CO_2 injection into unmineable coal seams to displace and recover coal bed methane. Another potential sequestration option involves injecting CO_2 into (otherwise unused) deep saline reservoirs. Deep saline reservoir injection has two important advantages — potential storage capacity in the U.S. is very large and many reservoirs are close to major point sources of CO_2.

One additional promising means of storing (and using) Maryland CO_2 may be carbon mineralization using fly ash from power plants that does not meet the appropriate chemical specifications for use in industry. This process is an emerging technology that involves reacting coal ash from power plants with CO_2 in the flue gas of coal-fired power plants to ultimately create a solid that can be transported and stored permanently.

Beneficial Use of CO2

Large-scale regional CO_2 use, in addition to sequestration, could help offset the high costs associated with CO_2 capture and transportation, as demonstrated in many studies.[73,74,75] In response to its demonstrated effectiveness in enhanced oil and gas recovery, the acceptance of CO_2 as a commodity has been encouraged by the DOE as well as the oil industry.

Most proposed and existing CCUS projects in the U.S. involve EOR and are located in the southern and western states, where mature oil fields are prevalent. DOE has also recently funded extensive research and ongoing projects related to CCUS, also in EOR applications. These projects include new integrated gasification combined cycle (IGCC) facilities, a new oxy-combustion power plant and the retrofit of existing facilities with post-combustion capture technology. While these projects have demonstrated

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[73] Mikunda, Tom, Kober, Tom, Coninck, Heleen de, Bazilian, Margan, Rosler, Hilke, Van der Zwaan, Bo. 2014. Designing Policy for Deployment of CCS in Industry. Climate Policy. Vol 14 Issue 5: 665-676. 28 April 2014.

[74] Middleton, Richard S., Levine, Jonathan S., Bielicki, Jeffrey M., Viswanathan, Hari S., Carey, J. William, Stauffer, Philip H., 2015. Jumpstarting Commercial-Scale CO2 Capture and Storage with Ethylene Production and Enhanced Oil Recovery in the US Gulf. Greenhouse Gases Science and Technology. 5: 1-13. 2015.

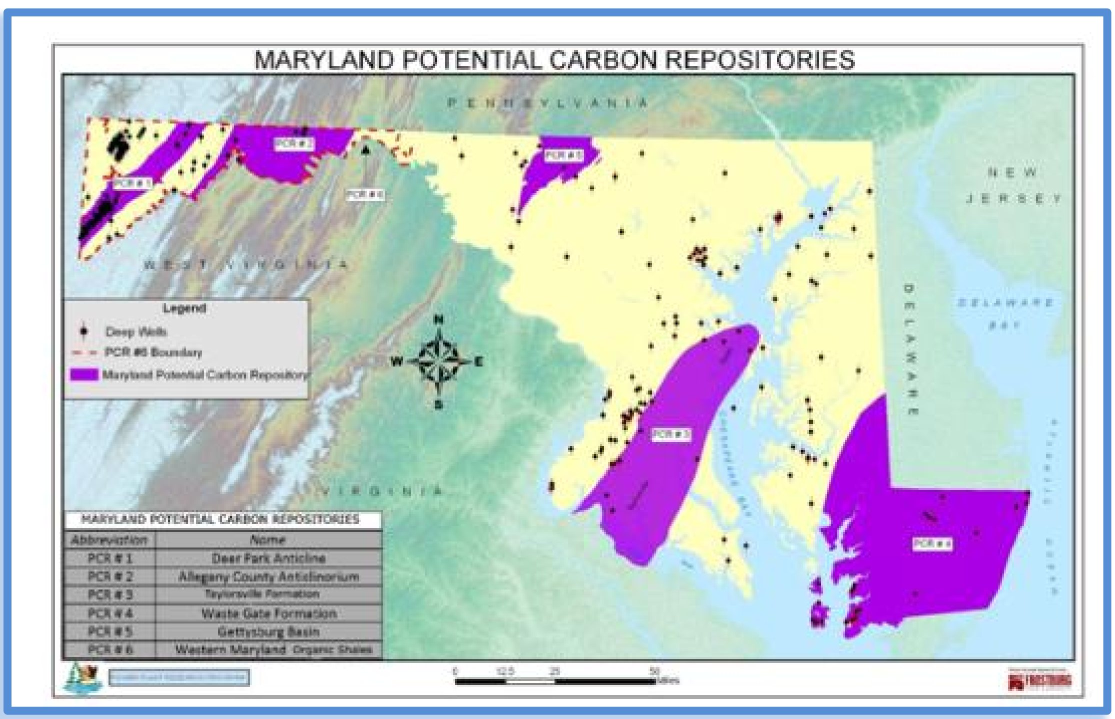
[75] Rubin, Edward S., Davison, John E., Herzog, Howard J., 2015. The Cost of CO2 Capture and Storage. *International Journal of Greenhouse Gas Control* (2015). 23 pp. http://dx.doi.org/10.1016/j.ijggc.2015.05.018

great potential for CCUS, funding and other technical difficulties have often resulted in delayed start dates or modified project scopes. The single largest barrier to further expanded use of CO_2 in EOR continues to be the lack of available, affordable CO_2 supplies. Of the total CO_2 currently used in EOR, about 25 percent (12 million metric tons) is anthropogenic in origin – i.e., produced by human activities, such as oil refining or fertilizer manufacturing. The rest is extracted from naturally occurring deposits. The CO_2 utilized in the oil recovery process is captured from the production well and recycled, so CO_2 emissions are negligible if injected CO_2 is stored in the reservoir when production is complete.

Applicability to Maryland

Since long-term carbon use and storage potential is associated with several geological formation types found in Maryland, including deposits of "unconventional" natural gas, deep saline aquifers, and Triassic age sedimentary basins, Maryland could technically both use and store its power plant CO_2. PPRP has identified six potential formations that could serve as carbon repositories in Maryland (see Figure 5-19). Some geologic and geochemical information is known about these sites from previous oil and gas or other drilling activities. The characteristics of these formations in terms of their potential for adsorption storage of CO_2, however, requires further study. Many of the identified repositories are located in proximity to large natural gas fired power plants that will remain in use in the future, and would avoid issues related to transportation of their CO_2 to the potential Appalachian Basin.

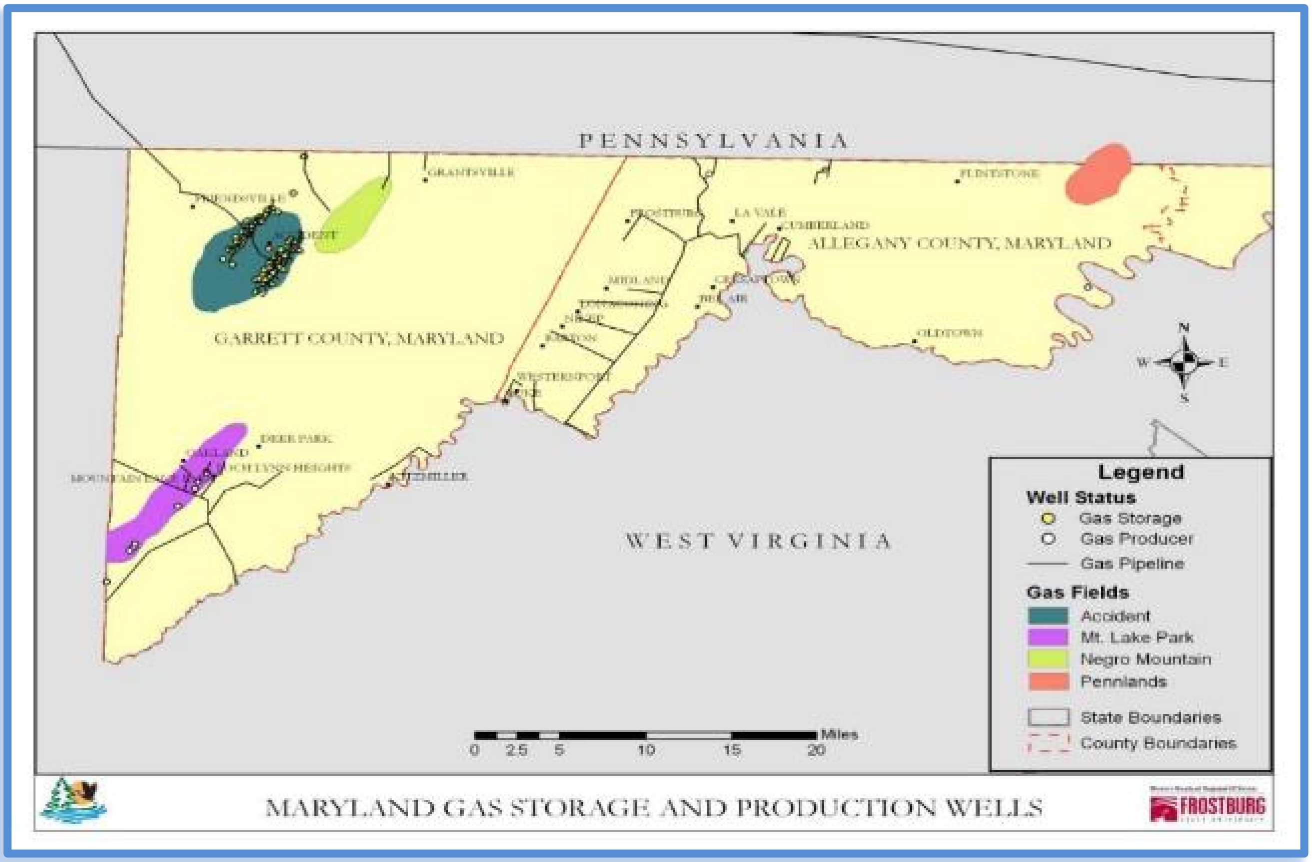
Figure 5-19 Maryland Potential Carbon Repositories



Source: "Marcellus Shale Safe Drilling Initiative Study," Prepared by Maryland Department of the Environment and Maryland Department of Natural Resources, December 19, 2014.

As shown in Figure 5-19, the geology of the western portion of Maryland is particularly attractive for the possible storage and use of CO_2. Figure 5-20 shows the location of gas fields in Western Maryland that could potentially be used for enhanced recovery of gas and associated CO_2 storage, with the future potential economic use of the stored CO_2 in enhanced gas recovery. Maryland also has several coal beds in Western Maryland that could potentially be used for enhanced recovery of coalbed methane and associated CO_2 storage.

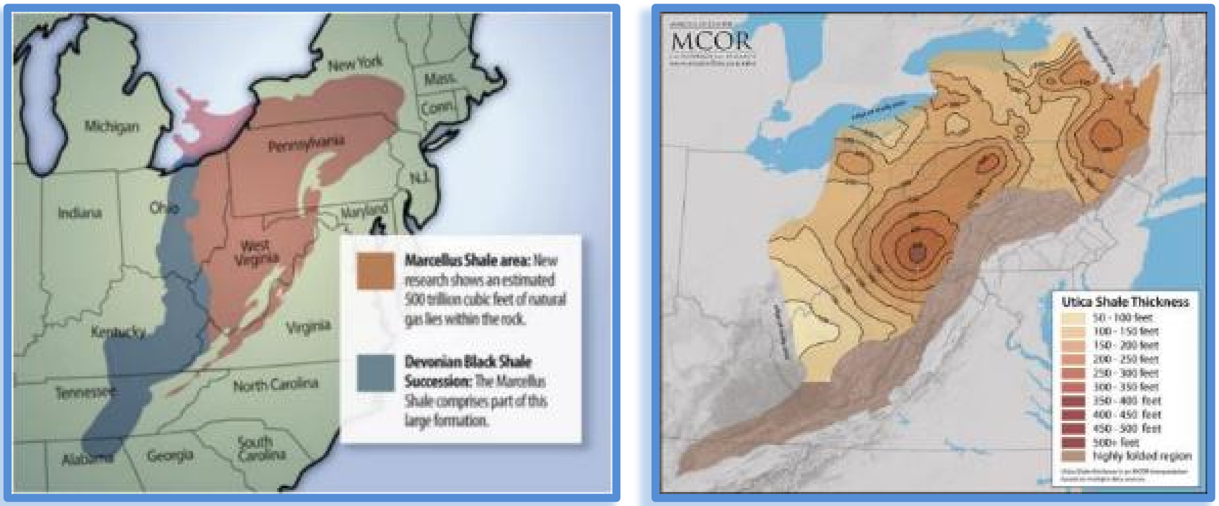
Figure 5-20 Maryland Gas Storage and Production Wells



Source: "Marcellus Shale Safe Drilling Initiative Study," Prepared by Maryland Department of the Environment and Maryland Department of Natural Resources, December 19, 2014.

Other natural gas resources exist in Western Maryland in the Marcellus Shale formation, a geologic feature in the Appalachian Range that stretches from West Virginia into central New York, and the Utica Shale formation (see Figure 5-21). Both of these organic shale formations provide the opportunity for permanent, irreversible CO_2 sequestration through adsorption in black, organic-rich shales – also called "sticky storage" – and this adsorption of CO_2 may displace additional natural gas. Although production wells will not be drilled into these formations in Maryland due to Maryland's 2017 law banning hydraulic fracturing, potential could exist for pipelining Maryland-generated CO_2 to Pennsylvania, Ohio and West Virginia, states that are currently producing gas from of these formations.

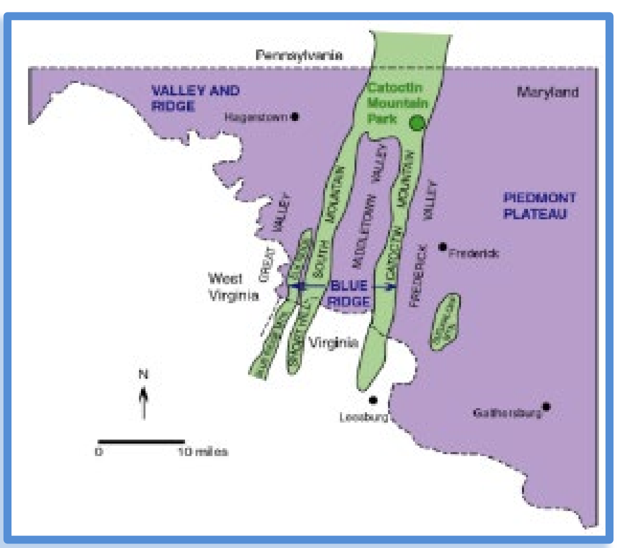
Figure 5-21 Location of the Marcellus and Utica Shale Formations



Source: "Marcellus Shale Safe Drilling Initiative Study," Prepared by Maryland Department of the Environment and Maryland Department of Natural Resources, December 19, 2014.

Basalt formations in Maryland have also been identified as potentially effective CO_2 adsorption sites. Dense interior layers function to trap the injected CO_2. Laboratory studies show that within a matter of months, CO_2 chemically reacts with minerals in the basalt to begin forming calcium carbonate crystals. DOE estimates the US and portions of Canada have potential capacity in basalts to store as much as 5,700 years of CO_2. Figure 5-22 shows the location of the Catoctin Formation, comprised of a metabasalt breccia, which potentially could store CO_2 from Maryland's point sources.

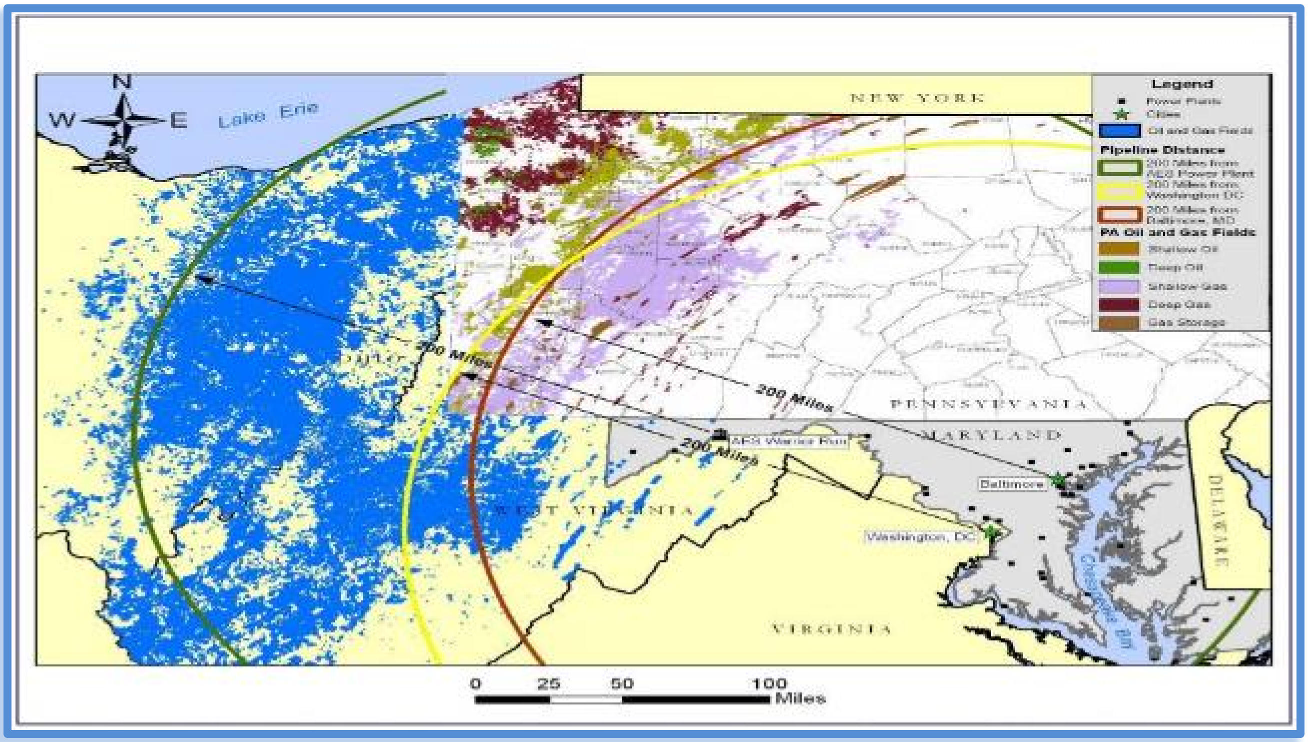
Figure 5-22 Location of the Catoctin Formation, a Regional Basalt Formation



Source: "Marcellus Shale Safe Drilling Initiative Study," Prepared by Maryland Department of the Environment and Maryland Department of Natural Resources, December 19, 2014.

If and when the local CO_2 market develops, Maryland could also potentially consider pipelining its captured CO_2 to regional EOR projects a bit further away, such as those shown in Figure 5-23. An example of a possible EOR project requiring CO_2 is the East Canton oil field located in Eastern Ohio, which the State of Ohio has identified as a potential CO_2 use candidate. This oil field has the potential to produce significant additional oil via EOR using CO_2 flooding. While a host of significant economic and environmental issues would warrant thorough investigation and evaluation prior to initiating a CO_2 pipeline project from Western Maryland power plants to Ohio, such a project could be worth considering if it were shown to be economically viable.

Figure 5-23 Regional Oil and Gas Fields



Source: "Marcellus Shale Safe Drilling Initiative Study," Prepared by Maryland Department of the Environment and Maryland Department of Natural Resources, December 19, 2014.

Maryland Geological Survey Research

<u>Regional Collaboration</u>

The Maryland Geological Survey (MGS) Department of Natural Resources represents Maryland in the Midwest Regional Carbon Sequestration Partnership (MRCSP), which it joined in 2004 to expand its regional sequestration involvement. The MRCSP was established and funded by DOE to assess the technical potential, economic viability, and public acceptability of carbon sequestration within a ten-state region — Delaware, Indiana, Kentucky, Maryland, Michigan, New York, New Jersey, Ohio, Pennsylvania, and West Virginia. Through its Phase I and Phase II research, the MRCSP determined the estimated carbon sequestration capacity of black shales in the Appalachian Basin may range from 2.2

billion tons to 29.68 billion tons, respectively (2010), based on the assumed storage efficiencies of either saline aquifers (3 percent) or continuous coals (up to 40 percent).

The final Phase, Phase III of the MRCSP work is nearly complete and involved a large-scale test of CO_2-EOR and associated storage at Core Energy's oil fields in northern Michigan, and the field data are being used to simulate CO_2 injection in several fields. A series of detailed reports and peer reviewed papers are being prepared to disseminate research findings related to potential storage capacity, modeling of subsurface geology, formation monitoring techniques, and information that provides a better understanding of similar rock formations throughout the region.

Local Research

The MGS has performed local research related to geologic carbon sequestration, and coordinates with its regional partners to frame the research into a broader context. Within the past year, MGS has performed two main geologic investigations, the first involving Triassic-age sedimentary basins and the second relating to younger Cretaceous sediments within the state. The Triassic basins were studied as a whole for sequestration and to determine characteristics for creating permanent seals that would contain injected carbon dioxide. The Cretaceous sediments of the Coastal Plain were also investigated for their sealing potential should offshore sequestration targets be desired.

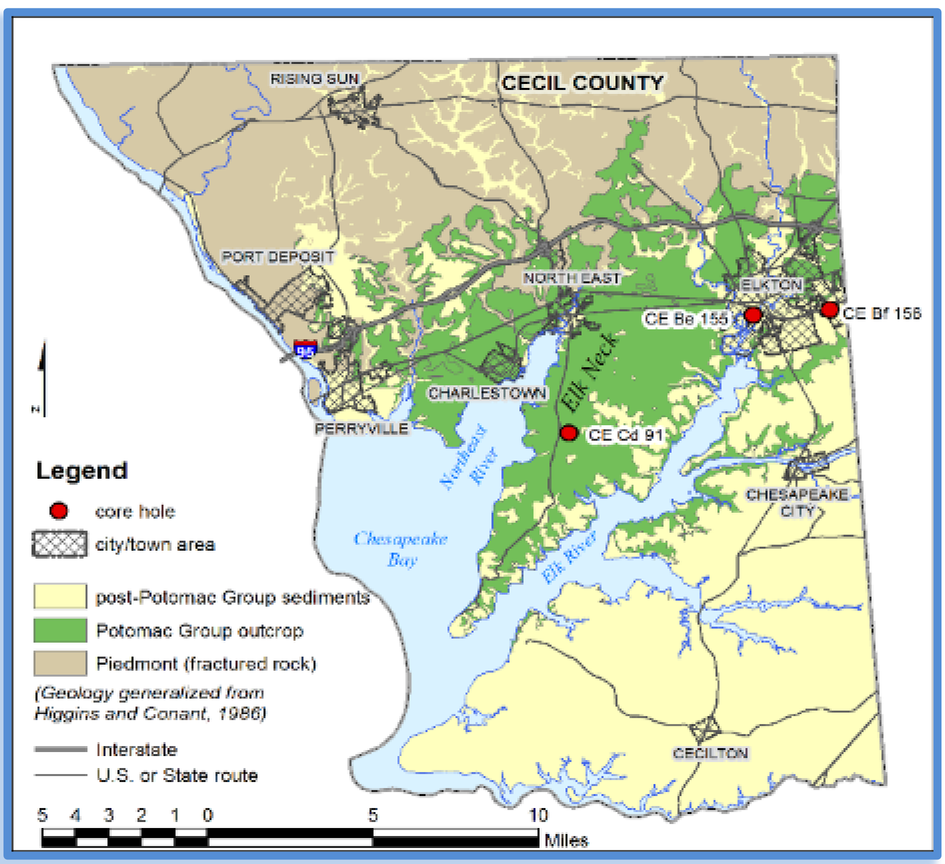
The study of the stratigraphic architecture, or layer characteristics, and the mappable subdivisions of these layers, within two Triassic Basins, the Culpeper and Gettysburg Basins, resulted in the identification of five distinct assemblages of rock types. These assemblages were formed by alluvial fan, braided and meandering streams, and marginal and distal lake depositional processes. These formation associations were then applied to the 8,000 feet of Triassic rocks that are concealed beneath the Cretaceous and Tertiary Coastal Plain sediments. Analysis of the rock assemblages indicates that the Taylorsville basin, one of Maryland's primary Triassic Basins, was filled asymmetrically by fluvial processes to the east and alluvial fan processes to the west. The center of the basin was subject to extensive lake sedimentation. Only high energy fluvial deposits, such as those found in the eastern side of the Taylorsville, appear to be consistent with the characteristics of an effective, conventional CO_2 reservoir.

The presence of thick, consistent intrusive and extrusive formations within the Triassic basins also serve as potential target locations for long-term CO_2 storage. These formations are potentially suitable for sequestration because they provide primary porosity in the form of lava flow top vesicles, are extensively fractured and contain mafic minerals, which may provide sequestration opportunities through carbonate remineralization. Additionally, extrusive and intrusive igneous rocks are preserved within fine-grained lake deposits that could provide effective sealing potential.

The second sequestration-related study includes an investigation of the Potomac Formation/Group, which is present in the Coastal Plain of Maryland, Delaware and New Jersey and appears to extend some distance offshore. Deep subsurface portions of the Potomac Formation/Group are being studied to assess the potential for structural carbon sequestration (both storage and confinement characteristics). Limited information exists about the deep subsurface portions of the Potomac Formation/Group, especially in offshore areas, and much the available data relies heavily on geophysical logs. Members of the Mid-Atlantic Offshore Storage Resource Assessment Project, primarily in New Jersey, have been researching the application of sequence stratigraphy and concepts of delta-fluvial "aggradation cycles" to interpret and correlate units within the Potomac Formation/Group with the prospect of developing better methods to predict the continuity of reservoir and capping units regionally, particularly where data are limited. Evaluation of these stratigraphic techniques, however, relies upon sections or boreholes where there are multiple lines of evidence for correlation, in addition to geophysical logs, and commonly these locations are in updip sections of the unit.

In this study, data from three coreholes in Cecil County, Maryland (an updip section, see Figure 5-24), were used to help fill data gaps and test previously identified correlations. Results indicate some of the previous correlations, derived largely from geophysical log interpretations, need to be revised. This study underscores the difficulty of interpreting the original relationships of Potomac Group layering across distances without corroborating data (e.g., biostratigraphy) to tie ages to sediments. As a result, use of such interpretative techniques to correlate strata across data-limited areas and predict the extent and/or continuity of storage or capping units in the Potomac Group is speculative in nature and will require further study to establish more defined relationships.

Figure 5-24 Study Area Showing Location of MGS Cores



Source: Maryland Geological Survey, 25 June 2019

Summary

Although the concept of CO_2 as a commodity has gained recognition, there are unresolved issues regarding CCUS projects. The issues of technology, infrastructure and economics related to CCUS require continued research. The risks associated with geological sequestration of CO_2 have been the subject of considerable study in the past decade and must be thoroughly evaluated when considering CO_2 storage. Global policy issues involve the debate over CCUS as a worthwhile investment, and whether CO_2 used for economic gain, such as in EOR, would be considered eligible for carbon credits. Technological issues suggest the need for further study to ensure that carbon is permanently sequestered and that the potential for future leaks is minimized.

Additional regional economic and other markers factors are important to consider for CCUS viability. Shell is constructing a massive new polyethylene plant in Monaca, Pennsylvania, and it is difficult to predict the impact this plant could have on the CO_2 capture and use market in the Appalachian Basin. Based on the premise that Maryland can wait for a market to develop for Maryland-generated CO_2 to be sold to the EOR and EGR industries in the Appalachian Basin, PPRP CO_2 research is severely constrained. It is anticipated that fuel switching and other measures will continue to reduce CO_2 production in Maryland.

5.2 Impacts to 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, consumption, and discharges in Maryland from power plant operations. It also describes potential resource impacts and methods for minimizing any adverse impacts. 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 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.[76] Together, these rivers and the 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

Most electricity produced in Maryland is generated by one of four types of generating technologies: steam-driven turbines, combustion turbines, combined cycle facilities (a combination of steam and combustion turbine units), and hydroelectric facilities. Power plants utilizing steam have significant water withdrawals because of the need to cool and condense the recirculating steam.[77] Typically, a power plant will obtain cooling water from a surface water body. The other, much smaller water needs of the power plant, such as boiler makeup water, are usually met by onsite wells or municipal water systems.

Cooling water withdrawals at steam electric facilities represent the majority of surface water usage in Maryland. In 2018, combined water withdrawal for all steam generating power plants in Maryland was estimated at approximately 4.9 billion gallons per day. All other non-power plant users in the state had a combined appropriation of less than 4 billion gallons per day. By comparison, the Potomac River has an average discharge of roughly 7 billion gallons per day, and the Susquehanna River discharges an average of about 18 billion gallons per day (actual daily flows in both the Susquehanna and the Potomac fluctuate greatly, both seasonally and from year to year).

Table 5-4 lists all major steam-generating power plants in Maryland (excluding self-generators) and quantifies their water withdrawals and consumption for 2017 and 2018. The plants are grouped into two categories: those that use once-through cooling, and those with closed-cycle cooling systems.

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[76] The Youghiogheny is the one river that drains to the Ohio water basin.

[77] 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.

Table 5-4 Surface Water Appropriations and Use at Maryland Power Plants with Steam Cycles

Power Plant	Surface Water Appropriation (average, mgd)	2017 Actual Surface Withdrawal (average, mgd)	2018 Actual Surface Withdrawal (average, mgd)	Estimated Consumption (mgd)	Water Source
Once-Through Cooling					
Calvert Cliffs	3,500	1,740	3,350	13.9	Chesapeake Bay
Chalk Point (a)	720	240	268	1.04	Patuxent River
C.P. Crane (b)	N/A	84.9	61.7	0.510	Seneca Creek
Dickerson	400	180	159	0.695	Potomac River (nontidal)
Gould Street	11.3	2.79	3.33	0.00643	Patapsco River
H.A. Wagner	940	209	239	1.28	Patapsco River
Morgantown	1,500	786	819	1.71	Potomac River
Riverside	30	0	0.00	0	Patapsco River
Wheelabrator	50	39.6	37.8	0.205	Gwynns Falls
SUBTOTAL	**7,151**	3,282	4,938	19.35	
Closed-Cycle Cooling					
AES Warrior Run (c)	0.021	0.164	0.183	0.11	City of Cumberland
Brandon Shores	35	7.94	7.990	5.18	Patapsco River (Wagner discharge)
CPV St. Charles	N/A	[awaiting data]	[awaiting data]	[awaiting data]	Mattawoman WWTP
Montgomery Co. Resource Recovery Facility	1.342	0.692	0.693	0.45	Potomac River (Dickerson Station's discharge canal – nontidal)
KMC Thermo - Brandywine	N/A	0.580	0.731	0.426	Mattawoman WWTP
Vienna	2.0	0.0107	0.0188	0.009	Nanticoke River
SUBTOTAL	**38.4**	**9.39**	**9.62**	**6.18**	
TOTAL	**7,189**	**3,291**	**4,948**	**25.5**	

Source: MDE WMA
mgd = million gallons per day
N/A = not applicable

(a) Chalk Point has two units on once-through cooling and two on closed-cycle cooling. The appropriation of 720 mgd covers all four steam units; the plant does not report data to MDE WMA on each cooling system separately.
(b) C.P. Crane's permit was deactivated on January 10th, 2019
(c) AES Warrior Run purchases its water from the City of Cumberland. The surface water appropriation of 0.021 mgd is for backup surface water withdrawals only.

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 percent of the water evaporates from the cooling tower and does not return to the source, thus representing a consumptive use. Closed-cycle cooling systems typically consume 1.5 to 2 times more water per MWh than once-through systems. Values are shown in units of millions of gallons per day (mgd).

Six steam power plants in Maryland – AES Warrior Run, Brandon Shores, CPV St. Charles, Montgomery Co. Resource Recovery Facility, KMC Thermo and Vienna – use closed-cycle cooling (cooling towers) exclusively instead of once-through cooling. Chalk Point has multiple steam boilers: two that use once-through cooling and two that use closed-cycle cooling. In Table 5-4, the estimated consumption values for closed-cycle systems are calculated assuming 65 percent of the surface water withdrawals are lost to evaporation. One more recently constructed steam power plant – Wildcat Point in Cecil County – also uses closed-cycle cooling, but it obtains water via direct withdrawal from the Susquehanna River in Pennsylvania and thus is not subject to Maryland appropriations permitting.

Nuclear power plants also fall within the steam generating category; however, they use nuclear reactions instead of fossil fuel combustion to create the needed thermal energy. The typical nuclear power plant operating today requires 10 to 30 percent more cooling water, on a per-MWh basis, compared to a fossil fuel plant since nuclear stations generally operate at a lower steam temperature and pressure compared to fossil fuel-fired generating plants. This results in a somewhat lower efficiency in the conversion of thermal energy to mechanical and, ultimately, electrical energy. Consequently, more waste heat is created per MWh generated than would occur in a fossil fuel plant, and more cooling water is needed to absorb that waste heat.

Calvert Cliffs Nuclear Power Plant (CCNPP) withdraws an average of 3.3 billion gallons per day directly from the Bay. This is the largest single appropriation of water in Maryland and is roughly 13 times larger than the municipal supply for the Baltimore City metropolitan area (250 mgd). While the majority of the water withdrawn by Calvert Cliffs is returned to the Bay, an estimated 14 mgd is lost to evaporation as a result of the heated discharge (see Table 5-4).

While the quantity of water withdrawn from a source is fairly straightforward to determine and well-documented by individual facilities, calculating the net or consumptive use is a more complex analysis. By definition, consumptive use is water that is withdrawn but not returned directly to the surface or ground water 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 allocation and under what conditions competing uses have to be curtailed or prioritized.

For power plants with closed-cycle cooling systems, the evaporative losses to the atmosphere can be calculated as the difference between water withdrawn and water discharged. However, most steam plants in Maryland use once-through cooling, in which cooling water is continuously drawn from a water source, used and then continuously returned to (usually) the same source. While water losses within the cooling system itself are negligible, 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 assessment of consumptive use is largely 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 percent of a plant's total discharge volume during the summer and 0.5 percent during the winter.

When assessing the significance of water withdrawal impacts, the nature of the source water body is a key factor. In estuaries such as the Chesapeake Bay, and the tidal portions of 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.

In addition to cooling systems, air pollution control systems at power plants can also require water appropriations. As a result of the Healthy Air Act, Maryland's four largest coal-fired power plants – Brandon Shores, Chalk Point, Dickerson, and Morgantown operate wet flue gas desulfurization (FGD) systems. Two of these facilities, Dickerson and Morgantown, use surface water for their wet FGD systems, Brandon Shores uses reclaimed wastewater and Chalk Point uses ground water. Table 5-5 lists water withdrawals and consumption for 2017 and 2018 associated with these FGD systems.

Table 5-5 Water Use for Wet FGD Systems at Maryland Power Plants with Steam Cycles (excluding ground water)

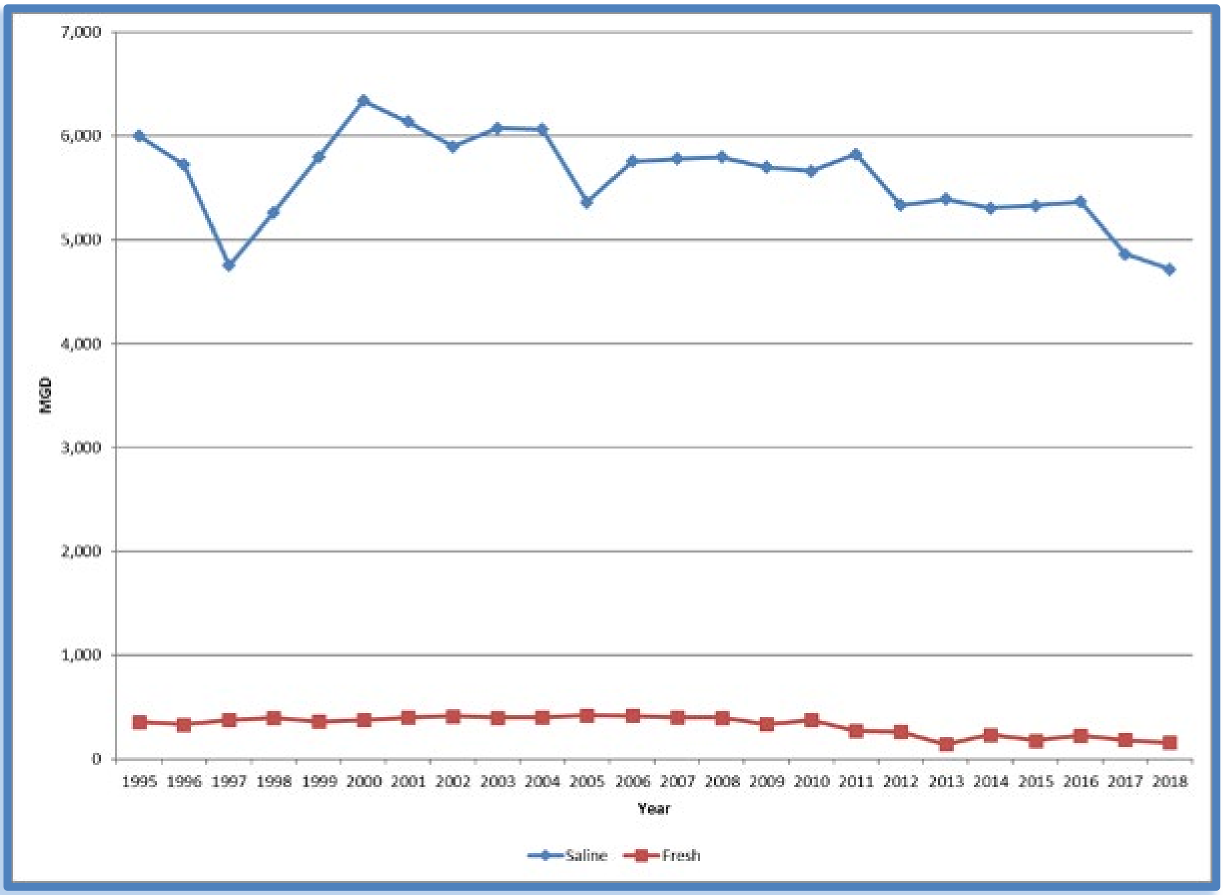
Power Plant	Surface Water Appropriation (average, mgd)	2017 Actual Surface Withdrawal (average, mgd)	2018 Actual Surface Withdrawal (average, mgd)	Estimated Consumption (mgd)	Water Source
Dickerson	0.98	0.14	0.14	0.12	Potomac River (nontidal)
Morgantown	3.4	0.652	0.653	0.555	Potomac River
Brandon Shores	N/A	1.65	1.90	1.51	Cox Creek WWTP
TOTAL	**4.38**	**2.44**	**2.69**	**2.19**	

mgd = million gallons per day
Note: Chalk Point is not reported because the water used for its wet FGD system is ground water, not surface water.

Typically, about 85 percent of the water used in these pollution control systems is consumptively lost through evaporation out of the stack. Operation of the FGD systems at Maryland's coal-fired power plants results in an additional evaporative loss of approximately 2.7 mgd combined. This additional loss is not significant in the tidal estuarine environments at Brandon Shores and Morgantown. NRG, the operator of the Dickerson plant located on a nontidal reach of the Potomac River, is required to provide onsite water storage to mitigate the potential impacts of its FGD system's water use on other users of the Potomac River (see discussion of low-flow issues in the next section).

Figure 5-25 below summarize average surface water withdrawals per year. Withdrawals are summed by fresh water and saline water sources, inclusive of all surface water sources used by the power plants in Table 5-4.

Figure 5-25 Average Daily Surface Water Withdrawals (1995-2018), in million gallons per day



Surface water withdrawals from saline sources far exceed those from fresh water sources in Maryland. The largest saline withdrawals come from the Chesapeake Bay and are associated with Maryland's one nuclear facility, Calvert Cliffs (see additional discussion of trends by fuel type). Other significant water sources include the Potomac, Patuxent, and Patapsco Rivers, as well as Seneca Creek. For each of these water bodies, other than the Potomac, all withdrawals are from saline portions of the rivers. For the Potomac, typically more than 70 percent of the annual withdrawals are from saline portions of the river.

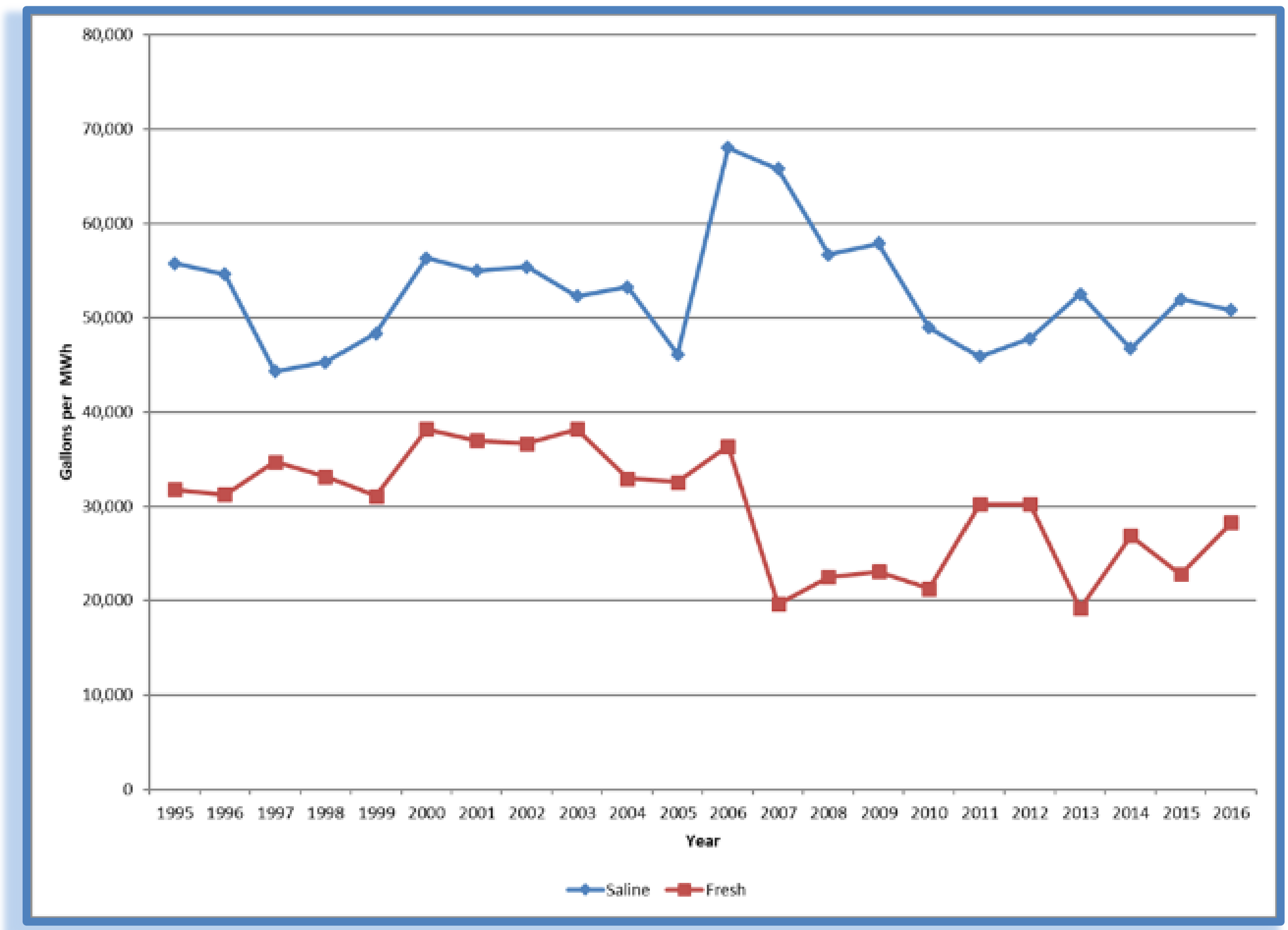
For those direct surface water withdrawals included in this section's evaluation, only two are fresh (nontidal) sources. Nontidal withdrawals from the Potomac River (which generally account for 30 percent or less of all Potomac withdrawals) are associated with Dickerson and Montgomery County Resource Recovery Facility.

Other water sources used by Maryland power plants include collected stormwater at the Rock Springs facility, water from the City of Cumberland for the AES Warrior Run facility, and reclaimed water from the Mattawoman Wastewater Treatment Plant (WWTP) and the Cox Creek WWTP. In Figure 5-25, these sources have been grouped together with the freshwater withdrawals from the Potomac River.

Saline withdrawals have been more variable than fresh water withdrawals over the 20-year period. The most notable shifts in saline withdrawals occurred in 1997-1998, 2005, and 2012 (see Figure 5-25 above). The 1997-1998 and 2005 decreases in withdrawal volume are primarily related to temporary shutdowns at Morgantown during those periods. The 2012 decrease is primarily due to the shutdown of the R.P. Smith facility. Other than these dips, saline surface water withdrawals have shown a gradual decline over the last 20 years. The total annual volume of fresh water withdrawals has been less variable over the study period, but has declined slightly over the past 12 years (2005-2018).

Another important consideration in evaluating Maryland's surface water withdrawals is to evaluate them relative to the net electricity generation of the associated power plants. Figure 5-26 below shows the average surface water withdrawals per year per MWh of net electricity generation.

Figure 5-26 Average Surface Water Withdrawals per MWh (1995-2016)



Far fewer power plants use fresh water sources, so after normalizing for net generation, the saline and fresh water withdrawals are more similar in magnitude.

The U.S. Geological Survey (USGS) develops water use reports for the United States every five years. The latest USGS water use report, published in November 2014, details national water usage data for the year 2010, as well as trends in water use from 1950 through 2010. USGS estimates that, in 2010, 161 billion gallons per day was withdrawn from surface freshwater sources for thermoelectric power generation in the US. Maryland accounts for about 3% of that withdrawal volume.

Fuel Type Trends

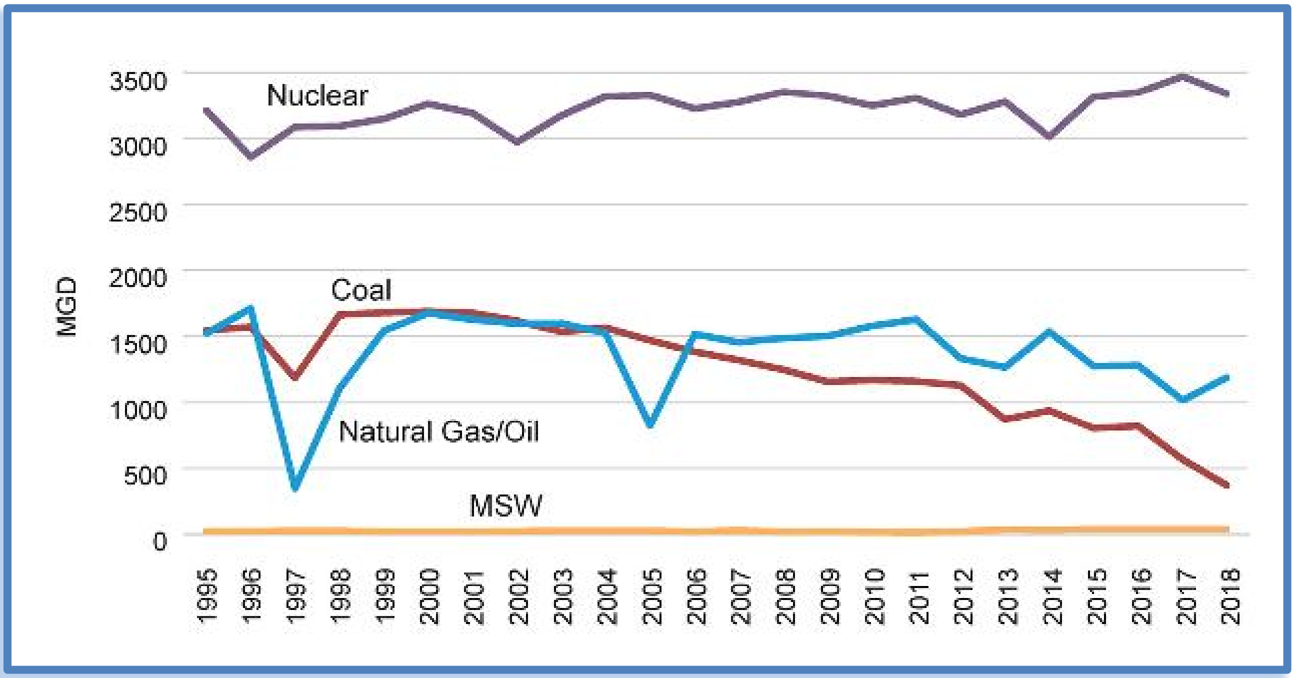
This section looks at trends relative to different fuel types, namely nuclear, coal, fossil (natural gas and fuel oil), and municipal solid waste (MSW). Table 5-6 below summarizes average withdrawals per year by fuel source. Values are first shown in units of MGD and then on a percent basis. The withdrawals include only surface water.

Table 5-6 Average Surface Water Withdrawals by Fuel Type (1995-2018)

Year	Volume Rate (MGD)				Percent Contribution			
	Nuclear	Coal	Natural Gas/Oil	MSW	Nuclear	Coal	Gas/Oil	MSW
1995	3,221	1,553	1,530	23	50.92%	24.54%	24.2%	0.36%
1996	2,866	1,577	1,716	25	46.34%	25.60%	27.9%	0.41%
1997	3,095	1,192	349	27	66.36%	25.72%	7.5%	0.58%
1998	3,102	1,668	1,111	27	52.51%	28.36%	18.9%	0.46%
1999	3,157	1,683	1,550	22	49.24%	26.34%	24.3%	0.35%
2000	3,271	1,693	1,681	23	49.06%	25.48%	25.3%	0.34%
2001	3,201	1,680	1,633	22	48.98%	25.78%	25.1%	0.34%
2002	2,980	1,622	1,603	25	47.83%	26.14%	25.8%	0.40%
2003	3,183	1,541	1,605	29	50.06%	24.34%	25.4%	0.45%
2004	3,327	1,571	1,531	28	51.53%	24.43%	23.8%	0.44%
2005	3,338	1,476	827	29	58.87%	26.17%	14.7%	0.51%
2006	3,235	1,389	1,523	21	52.45%	22.60%	24.8%	0.34%
2007	3,284	1,326	1,461	31	53.81%	21.85%	24.1%	0.51%
2008	3,363	1,254	1,492	20	54.88%	20.52%	24.4%	0.32%
2009	3,333	1,162	1,508	23	55.32%	19.35%	25.1%	0.38%
2010	3,258	1,175	1,585	17	53.99%	19.52%	26.3%	0.28%
2011	3,315	1,165	1,633	15	54.09%	19.05%	26.7%	0.25%
2012	3,189	1,134	1,339	22	56.10%	20.02%	23.7%	0.39%
2013	3,287	875	1,272	38	60.06%	16.10%	23.4%	0.70%
2014	3,019	943	1,543	36	54.49%	17.13%	28.0%	0.64%
2015	3,324	807	1,280	39	60.99%	14.91%	23.7%	0.71%
2016	3,359	823	1,286	39	60.99%	15.05%	23.5%	0.71%
2017	3,482	568	1,021	40	68.12%	11.21%	20.1%	0.79%
2018	3,350	374	1,193	38	67.60%	7.60%	24.3%	0.78%

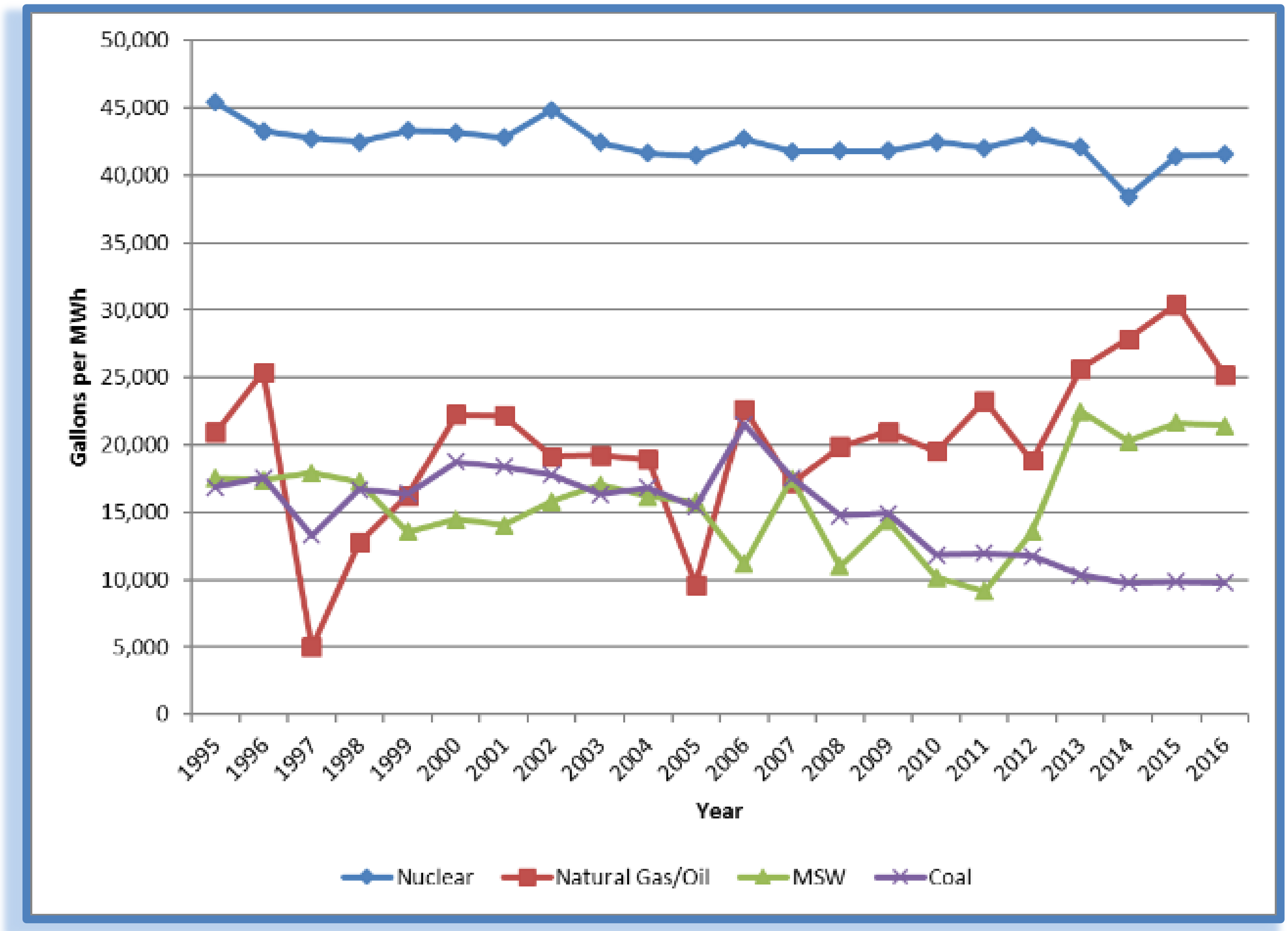
Figure 5-27 provides a visual depiction of the trends over time for power plant water withdrawals, broken down by fuel type. The notable decline in water withdrawals associated with coal-fired generation reflects the decreasing utilization of coal plants in Maryland.

Figure 5-27 Average Surface Water Withdrawals by Fuel Type (1995-2018)



These withdrawals can also be evaluated relative to the associated power plants' net electricity generation. Figure 5-28 shows withdrawals relative to net generation, in units of gallons per MWh. Nuclear withdrawals from Calvert Cliffs are significantly greater, in part because nuclear generation creates more waste heat than fossil fuel combustion, and also because the other fuel types in Figure 5-28 represent a combination of once-through and closed-cycle cooling systems.

Figure 5-28 Average Surface Water Withdrawals per MWh, by Fuel Type (1995-2016)



Low-Flow Issues

Consumptive users of water in the nontidal portion of the Potomac River must comply with Maryland's consumptive use regulations for the Potomac River Basin (COMAR 26.17.07). The intent of this regulation is to ensure that during low-flow periods, upstream users allow sufficient water to continue downstream to supply water demands in the Washington, D.C., metropolitan area.

The consumptive use regulations require users consuming more than 1 mgd of water from the Potomac River to maintain low-flow augmentation storage, and release water from this storage to offset their consumption during low-flow periods. Alternatively, users can comply with the rules by reducing consumptive use to less than 1 mgd during low-flow periods. The consumptive use regulations specify the amount of augmentation storage that must be secured to avoid the potential for curtailment of water withdrawals during low-flow periods.

A power plant developer can build ponds or tanks to store cooling water, which could carry the facility through a short-term drought. However, it is typically not feasible for plant developers to construct onsite storage that could supply enough water to support operations through a prolonged period of withdrawal restrictions. Plants that propose to withdraw cooling water from nontidal waters of the Potomac, therefore, accept the risk that severe drought conditions may require them to curtail their operations. It is recognized that severe drought conditions correlate quite well with conditions of heavy electricity consumption, but the goal of providing onsite water storage is to reduce the risk of curtailment, not entirely eliminate it. An example of this approach is the CPCN issued to Mirant (now NRG) for construction of the FGD system at Dickerson, which includes a requirement to construct an onsite pond capable of storing 4.5 million gallons to serve the facility during low-flow periods. This large storage capacity also would reduce the potential conflict between environmental issues and needed electricity.

Similar regulations and policies have been established by the Susquehanna River Basin Commission (SRBC), which was created in 1970 to coordinate the water resource efforts of the Susquehanna River Basin Compact between the States of Maryland, New York and Pennsylvania. The SRBC's consumptive use regulation requires users of surface or ground water within the basin to provide mitigation during low flow events, protecting both aquatic resources and other water users. Alternatively, users are allowed to pay a fee to the SRBC in lieu of conducting physical mitigation. The SRBC uses such fees to undertake large-scale storage projects that will offset consumptive water use by those paying the fee.

Cooling System Alternatives and Advances

With increasing pressures to minimize water withdrawals, power plant developers are finding more efficient means of cooling. Once-through cooling, the original standard for power plants, is no longer a viable option for new power plants, particularly in light of EPA's current regulations for new facilities under the Clean Water Act (CWA) Section 316(b), designed to reduce ecological effects of cooling water withdrawals. Closed-cycle cooling towers have become standard on new steam generating power plants, reducing water withdrawals substantially compared to once-through cooling systems. As noted previously though, their consumptive use per MWh is higher than that for once-through cooling.

MDE Guidelines for Use of Reclaimed Water

Under §9-303.1(a) of the Annotated Code of Maryland, MDE is directed to encourage use of reclaimed water as an alternative to discharging treated sewage effluent to surface waters of the State. Two power plants in Maryland – KMC Thermo and Brandon Shores – have been utilizing high quality reclaimed wastewater for many years, avoiding the need for large volume surface water withdrawals to provide cooling water and, in the case of Brandon Shores, makeup water for air pollution control systems.

In 2015, MDE finalized new guidelines for commercial, residential and industrial applications of highly treated effluent, designated as Class IV reclaimed water, and in 2016, the guidelines were revised. The new guidelines pertain to the production and distribution of reclaimed water, design of systems, and standards for monitoring. The most notable implications are:

- Establishment of minimum water quality thresholds,
- Requirement that a WWTP obtain a discharge permit from MDE before supplying Class IV reclaimed water,
- Requirement that a WWTP obtain a construction permit from MDE before constructing or expanding current facilities for the distribution of Class IV reclaimed water, and
- Physical infrastructure requirements (e.g., pipe color, installation process).

WWTPs providing Class IV reclaimed water to industrial users must now meet these new guidelines. The standards are generally consistent with conditions that PPRP and MDE have recommended in past CPCN licensing cases, and that the PSC has included when approving new or modified facilities that use reclaimed water for cooling.

The reuse of effluent from wastewater treatment plants (WWTPs) is becoming an acceptable and viable water supply option. This grants some flexibility in siting plants close to sources of reclaimed wastewater for cooling water supply, rather than relying on direct surface water withdrawals. The KMC Thermo combined cycle facility, located near Brandywine in Prince George's County (formerly owned by Panda), currently utilizes about 0.5 to 1 mgd of treated effluent from the Mattawoman WWTP for its cooling water needs. CPV Maryland in Charles County, another combined cycle gas-fired plant, began operating in 2018 and also utilizes Mattawoman WWTP effluent. In 2010, Constellation began using treated effluent from Anne Arundel County's Cox Creek WWTP to supply the FGD system now in operation at the Brandon Shores power plant.

Effluent reuse has been established as an alternative that can be economically attractive and technically viable for sites located near large WWTPs. With respect to environmental impacts, effluent reuse still represents a consumptive loss of water resources, since the treated effluent that is used and evaporated in the cooling towers would otherwise be discharged to surface water. However, overall aquatic impacts are reduced because effluent reuse does not involve direct withdrawals from a surface water body.

Dry cooling systems, or the use of air-cooled condensers, are also making significant inroads in the power industry. Because of their large size, parasitic power use, required land and capital outlay, dry cooling towers are more expensive to construct and operate compared to conventional wet cooling systems. However, with increasing constraints on siting and water appropriations, dry cooling is becoming a more attractive option. It is a much more viable technology option in the western United States compared to the East Coast. The Keys Energy Center combined cycle facility in Prince George's County became the first major power plant in Maryland to use dry cooling, when it began operating in July 2018. Mattawoman Energy Center also plans to operate with dry cooling.

Ground Water Withdrawals

The use of ground water for process cooling is severely restricted in Maryland, but some of Maryland's power plants are significant users of ground water for other purposes. Ground water is used for boiler feedwater in coal-fired power plants, inlet air cooling, emissions control in gas- and oil-fired combustion turbines, and potable water throughout the power plants. High-volume ground water 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 ground water are available in the Coastal Plain aquifers, withdrawals must be managed over the long term to ensure adequate ground water supplies for the future.

The impact of these withdrawals has been a key issue in southern Maryland, where there is a significant reliance on ground water for public water supply. Currently, five power plants withdraw ground water from southern Maryland coastal plain aquifers for plant operations: Exelon's Calvert Cliffs Nuclear Power Plant, NRG's Chalk Point and Morgantown power plants, Southern Maryland Electric Cooperative's (SMECO) combustion turbine facility (located at the Chalk Point plant), and KMC Thermo's combined cycle power plant (formerly owned by Panda). These five plants have historically withdrawn ground water from three aquifers in Southern Maryland: the Aquia, the Magothy and the Patapsco. Chalk Point began withdrawing ground water from the deeper Patuxent Aquifer in 2009.

Four additional power plants utilize ground water, but these facilities withdraw ground water from sources other than the Coastal Plain aquifers: Dickerson, located in Montgomery County; Perryman, located in Harford County northeast of Baltimore; Rock Springs, located in Cecil County; and Vienna, located in Dorchester County on the Eastern Shore.

Figure 5-29 shows the ground water withdrawal rates expressed as daily averages from 2000 to 2018 for each of the power plants. The withdrawal rates and associated appropriation limits are also listed in Table 5-7.

Figure 5-29 Average Daily Ground Water Withdrawal Rates at Maryland Power Plants (in mgd)

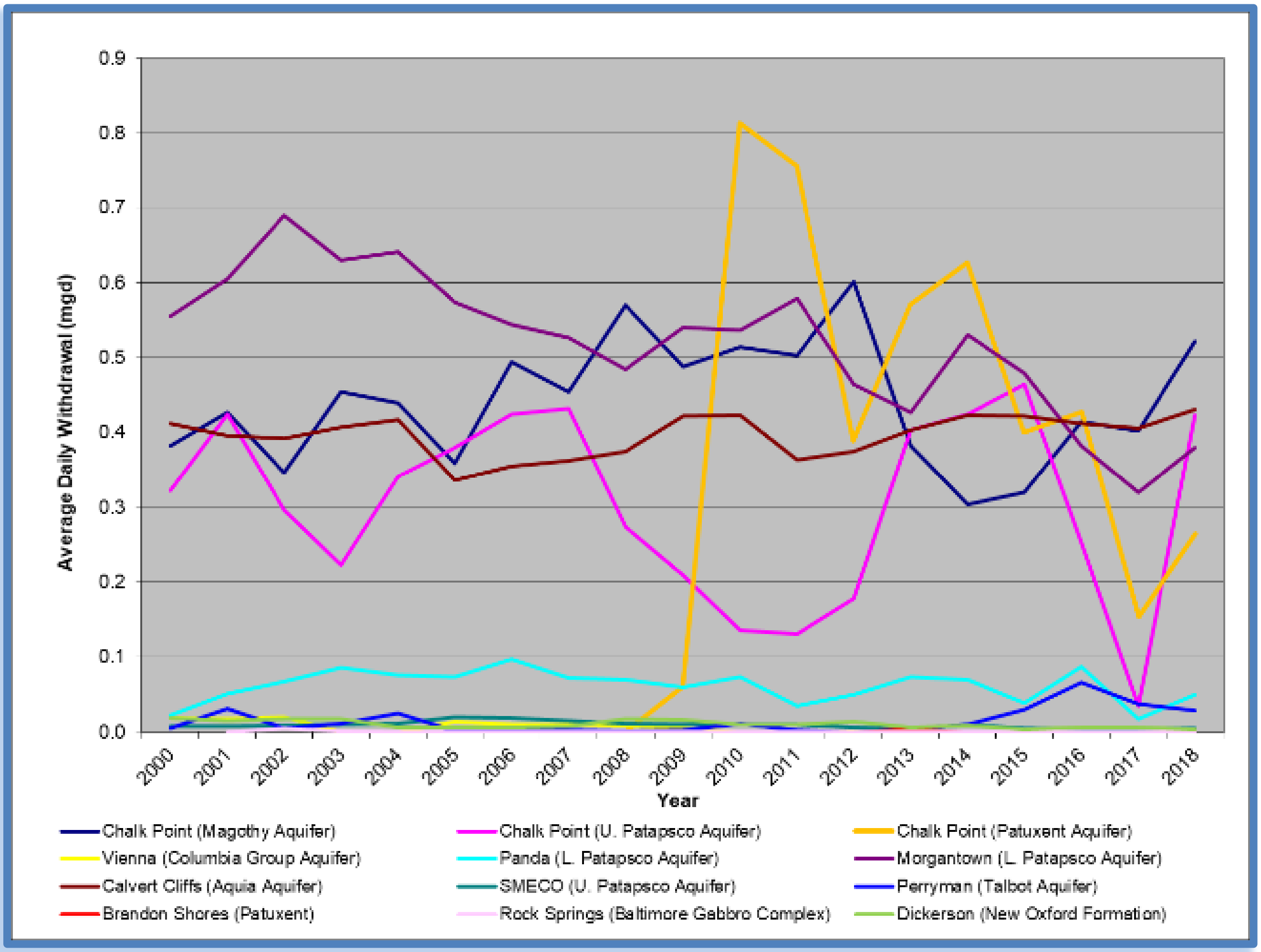


Table 5-7 Average Daily Ground Water Withdrawal Rates at Maryland Power Plants (in mgd)

	Chalk Point (Magothy Aquifer)	Chalk Point (U. Patapsco Group Aquifer)	Chalk Point (Patuxent Aquifer) See Note (a)	Vienna (Columbia Aquifer)	Panda (L. Patapsco Aquifer)	Morgantown (L. Patapsco Aquifer)	Calvert Cliffs (Aquia Aquifer)	SMECO (U. Patapsco Aquifer)	Perryman (Talbot Aquifer)	Brandon Shores (Patuxent)	Rock Springs (Baltimore Gabbro Complex)	Dickerson (New Oxford Formation)	Total Average Daily Withdrawal
Current Appropriation Limit	0.66	1.02	0.66	0.035	0.074[b]	0.7	0.45	0.02	0.942	0.0099	5.5 E-3	0.0055	3.9
2000	0.382	0.322		0.019	0.022	0.555	0.412	0.008	0.005			0.018	1.7
2001	0.427	0.425		0.018	0.051	0.605	0.396	0.007	0.031		0.00000	0.015	2.0
2002	0.346	0.296		0.020	0.067	0.689	0.392	0.009	0.004		0.00463	0.017	1.8
2003	0.454	0.222		0.023 See Note (b)	0.086	0.630	0.407	0.009	0.010		0.00070	0.017	1.9
2004	0.439	0.341		0.008 See Note (c)	0.075	0.641	0.416	0.011	0.025		0.00011	0.006	2.0
2005	0.359	0.379		0.013	0.074	0.574	0.336	0.020	0.001		0.00008	0.006	1.8
2006	0.494	0.425		0.009	0.097	0.543	0.354	0.018	0.002		0.00011	0.007	1.9
2007	0.454	0.432	0.000	0.009	0.072	0.526	0.362	0.015	0.002		0.00010	0.007	1.9
2008	0.570	0.274	0.000	0.008	0.069	0.485	0.375	0.011	0.001		0.00010	0.017	1.8
2009	0.488	0.209	0.060	0.005	0.059	0.540	0.422	0.010	0.002		0.00012	0.015	1.8
2010	0.514	0.135	0.813	0.000	0.073	0.536	0.423	0.010	0.011		0.00012	0.009	2.5
2011	0.502	0.131	0.756	0.000	0.035	0.579	0.364	0.010	0.002		0.00010	0.010	2.4
2012	0.601	0.178	0.389	0.001	0.049	0.465	0.375	0.006	0.000	0.00000	0.00011	0.014	2.1
2013	0.382	0.403	0.571	0.000	0.073	0.426	0.404	0.004	0.003	0.00384	0.00009	0.006	2.3
2014	0.304	0.425	0.626	0.000	0.070	0.530	0.423	0.010	0.010	0.00011	0.00005	0.009	2.4
2015	0.320	0.464	0.400	0.000	0.038	0.479	0.422	0.005	0.030	0.00015	--	0.003	2.2
2016	0.415	0.253	0.428	0.000	0.087	0.382	0.412	0.003	0.065	0.00009	--	0.006	2.1
2017	0.402	0.035	0.153	0.0002		0.320	0.406	0.003	0.037	0.00009	--	0.006	1.4
2018	0.522	0.423	0.264	0.000		0.379	0.431	0.005	0.029	0.00005	--	0.004	2.1

Source: U.S. Geological Survey, MDE WMA
Note (a): Well was installed in 2007. Routine withdrawal did not occur until approximately 2009.
Note (b): No report was submitted to MDE for the period July-December 2003. The amount shown was estimated using the total volume withdrawn of 4,131,683 gallons reported for the period January-June 2003.
Note (c): No report was submitted to MDE for the period January-June 2004. The amount shown was estimated using the total volume withdrawn of 1,505,770 gallons reported for the period July through December 2004.

As noted in Table 5-7, power plants typically withdraw ground water at rates well below their appropriation permit limits. The average withdrawal for seven power plants in 2016 was 2.1 million gallons per day (mgd) compared to a combined daily appropriation limit of 3.9 mgd. The total amount of ground water withdrawn by power plants has fluctuated between about 1.6 and 2.5 mgd over the past 40 years.

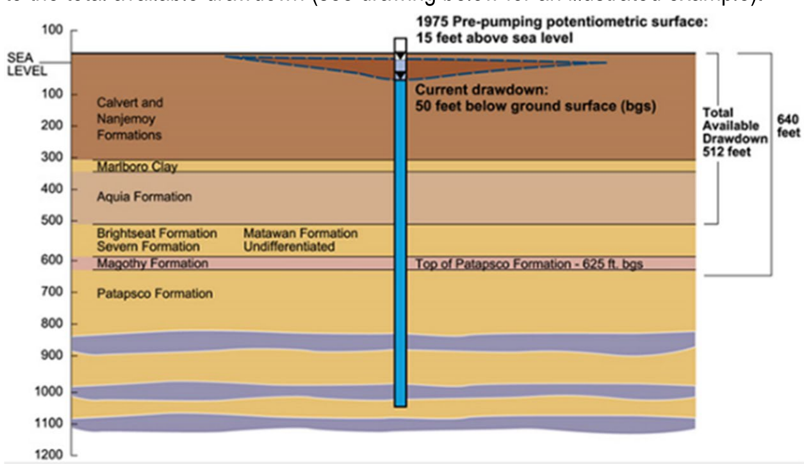
Three government agencies – the Maryland Geological Survey (MGS), the USGS and PPRP – jointly operate a ground water monitoring program to measure the water levels in the Coastal Plain aquifers of Southern Maryland to ensure the long-term availability of ground water. MDE Water Management Administration (WMA), the permitting authority for all ground water 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. However, these declines are not solely due to withdrawal by power plants, and are considered acceptable by MDE WMA when compared to the amount of water available in the aquifers. The amount of water available is expressed as the aquifer's "available drawdown," which is defined in MDE regulations as 80 percent of the distance from the historic pre-pumping water level to the top of the pumped aquifer.

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. To minimize impacts to municipal supplies, MDE WMA has required industrial users to utilize the deeper aquifers for new withdrawals.

Evaluating Drawdown Impacts

Long-term monitoring data show how pumping from a ground water aquifer affects the water level over time. MDE regulations define "available drawdown" in an aquifer as 80 percent of its historic pre-pumping level. The significance of the current drawdown can then be estimated by comparing current drawdown to the total available drawdown (see drawing below for an illustrated example).



Water quantity impacts to each of the coastal plain aquifers are summarized below.[78]

- **Aquia Aquifer at Calvert Cliffs** – Water levels in the Aquia Aquifer at Calvert Cliffs declined approximately 80 feet from 1982 to 2015, with most of the decline occurring post 1990. This acceleration in water level decline is due to withdrawals from municipal well fields at Lexington Park in St. Mary's County and Solomons Island in Calvert County. The water levels at Lexington Park and Solomons Island have declined nearly 116 feet and 103 feet, respectively, since 1982. The impacts from the water level decline are considered acceptable given the estimated 325 feet of available drawdown in the Aquia Aquifer at Calvert Cliffs (based on MDE's available drawdown criteria described above).

[78] Andrew W. Staley, David C. Andreasen, and Stephen E. Curtin, *Potentiometric Surface and Water-Level Difference Maps of Selected Confined Aquifers in Southern Maryland and Maryland's Eastern Shore, 1975-2015*, Maryland Department of Natural Resources, www.mgs.md.gov/reports/OFR_16-02-02.pdf

- **Magothy Aquifer at Chalk Point** – MDE WMA has required industrial users of the Magothy Aquifer to use deeper aquifers like the Patapsco to allay concerns over water level declines in the Magothy. As a result, the Chalk Point power plant reduced its ground water withdrawals from the Magothy Aquifer from 1990 to 2015 by about 45 percent compared to its withdrawals prior to 1980. This reduction has resulted in a commensurate decrease in the rate of water level decline in the portion of the aquifer near the facility during this same period. However, water levels continue to decline in the aquifer as a whole due to its extensive continued use in Annapolis, Easton and Waldorf. The drawdown at Chalk Point has been approximately 41 feet between 1975 and 2015, and a total of about 81 feet since pumping at Chalk Point began in 1964. Prior to pumping in 1962, the elevation of the potentiometric head in the Magothy Formation at Chalk Point was 28 feet above mean sea level; thus, the available drawdown is 80 percent of 600 feet plus 28 feet, approximately equivalent to 500 feet. Consequently, the total drawdown of 81 feet is small compared to the estimated total available drawdown of approximately 500 feet for the Magothy Formation in the vicinity of Chalk Point.

- **Upper Patapsco Aquifer at Chalk Point** – The water level surface in the Upper Patapsco Aquifer has declined 51 feet in the vicinity of Chalk Point since 1990. This decline will not impact the approximately 550 feet of available drawdown for the Upper Patapsco Aquifer in the vicinity of Chalk Point.

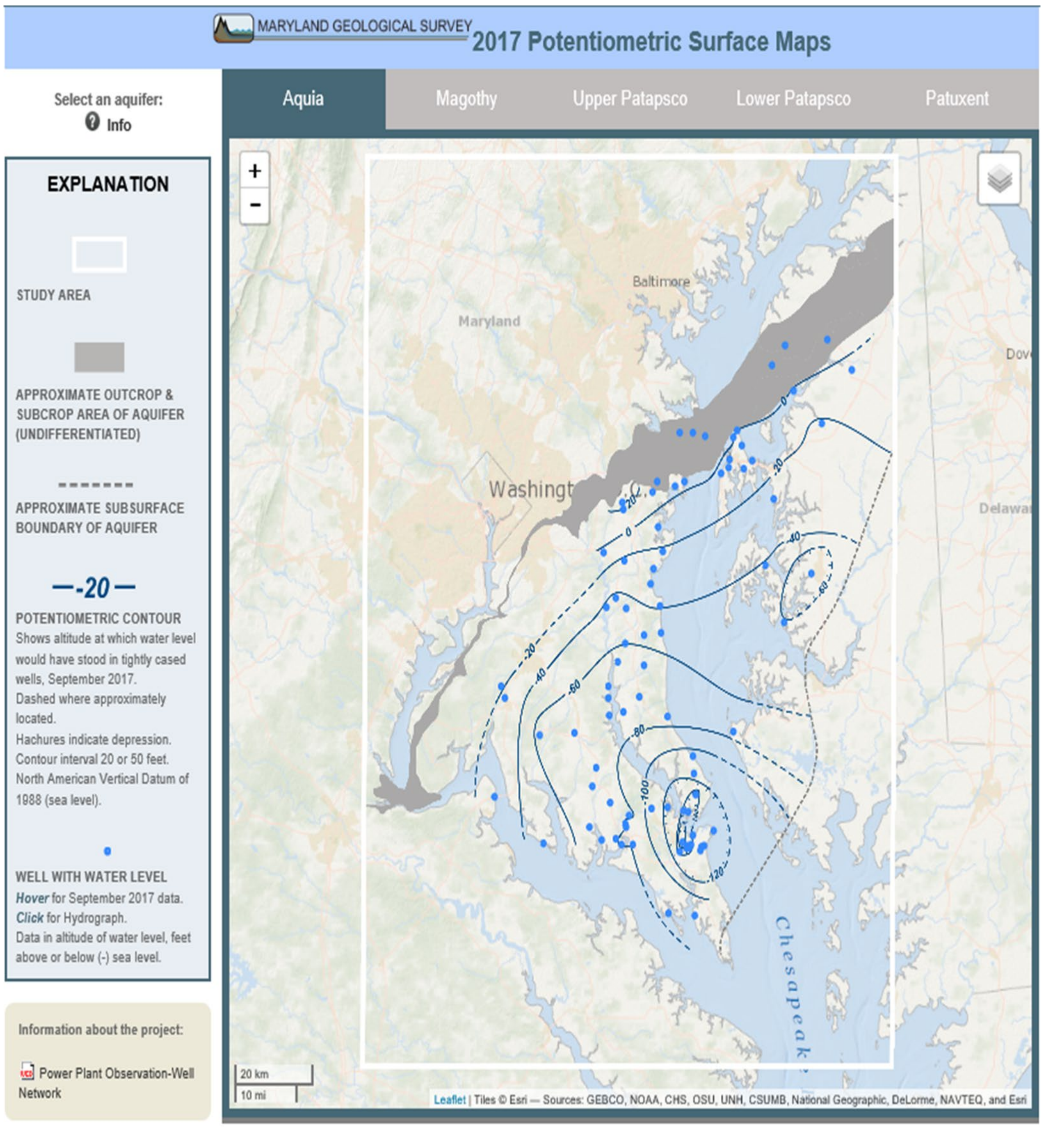
- **Lower Patapsco Aquifer at Morgantown** – The water level surface of the Lower Patapsco Aquifer in the vicinity of the Morgantown power plant has declined 30 feet since 1990. The increased water demands at Morgantown following the installation of FGD scrubbers in 2010 is likely to cause further declines in recent years. However, this decline is small compared to the available drawdown, which is approximately 600 feet.

- **Patuxent Aquifer at Chalk Point & Brandon Shores** – The water level surface of the Patuxent Aquifer has declined approximately 75 feet as a result of withdrawal at the Chalk Point power plant. Water levels in the immediate vicinity of the power plant have declined approximately 10 feet per year since 2007, which is one of the highest rates of water decline in the coastal plain aquifers of Maryland over that period. However, this decline is small compared to the approximately 1,450 feet of available drawdown in the Patuxent Aquifer at Chalk Point. The Brandon Shores power plant has only recently (i.e., since 2012) started withdrawing water from the Patuxent Aquifer. This is a very small quantity withdrawal for emergency use only.

Based on data from USGS monitoring well surveys from 2017 to 2018, the rate of drawdown is not changing significantly; thus, the impacts continue to be acceptable.

MGS Online Potentiometric Surface Maps

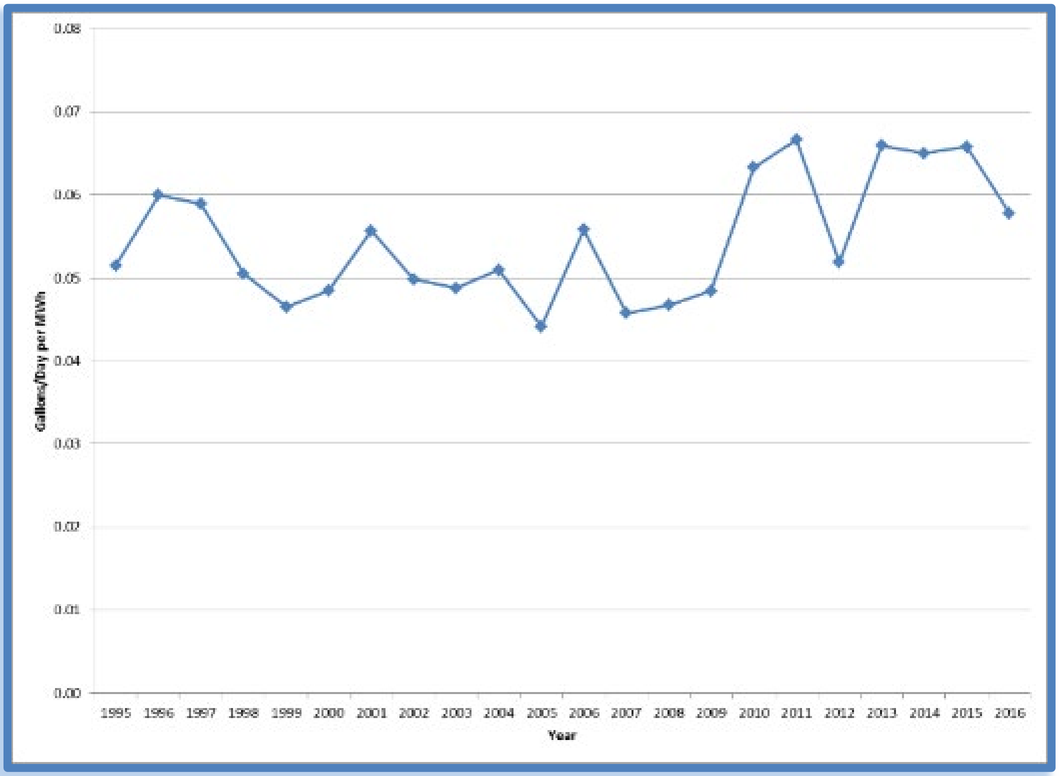
The Maryland Geological Survey (MGS) has now made available on its website the potentiometric surface maps previously included in published biannual reports. The service allows users to view the study area of five different aquifers, their latest potentiometric contour updates, and access the well data that defines the contours. It also defines the study area and subsurface boundaries of the aquifers.



http://www.mgs.md.gov/groundwater/2017_pot_maps.html

Figure 5-30 shows the average ground water withdrawals per year per MWh. Values are shown in units of gallons per day per MWh.

Figure 5-30 Average Ground Water Withdrawals per MWh (1995-2016)



In general, ground water withdrawals are less closely related to actual electricity generation (compared to surface water cooling system withdrawals). When electricity generation drops, ground water demands do not decline nearly as much as cooling water demands do.

Contaminated Ground Water Impacts

In several recent licensing cases, PPRP has worked with MDE to address issues related to ground water contamination. These instances of contamination were not caused by power generation or transmission activities; however, the applicants in these licensing cases had to take measures to avoid exacerbating the negative impacts. PPRP has conducted indepth evaluations in each of these cases and developed CPCN conditions to establish requirements for the applicants.

Perryman

Ground water quality in the vicinity of the proposed Perryman 6 Project facility has been impacted by a release of fuel to the subsurface. The source of the contamination was a leaking No. 2 fuel oil line immediately west of combustion unit No. 4. Results of initial investigations identified an area roughly equivalent to five acres of free phase oil within the property boundaries. In an effort to mitigate the plume migration, skimmers were installed and adsorbents were used to recover as much oil as possible.

Currently, ground water monitoring is conducted as part of an active MDE Oil Control Program case that includes monitoring of oil and water level measurements and dissolved phase petroleum-related contaminants. Recent monitoring results indicate that the residual dissolved petroleum plume extends towards the west and is elongated in a northeast-southwest direction. Based on current total petroleum hydrocarbon diesel range organic concentrations measured in monitoring wells, the current area of the plume is approximately 2.5 to 3.0 acres. The results of investigations conducted in 2011 and 2012 indicate that the majority of the remaining liquid phase hydrocarbon is present at residual, immobile saturation, and is therefore trapped in isolated pores in discontinuous pockets by capillary forces.

The withdrawal of ground water is required for the operation of the Perryman plant. However, pumping ground water from the Upper Aquifer has the potential to cause impacts to the ground water quality if the reduction in the water table elevation or an alteration in the ground water flow directions disperses the oil plume. Aquifer modeling results were used to evaluate the potential for these water quality impacts to be realized. Steady-state model results indicated that drawdown ranging from 0.1 feet to 0.15 feet could occur in the area of the oil plume. This slight drop in the water table would not alter the ground water flow direction, indicating that the pumping would not disperse the oil plume. Therefore, the model results indicate that lowering the water table will not alter the extent of the oil plume.

Mattawoman

The planned generator lead line for Mattawoman will traverse the Brandywine Defense Reutilization and Marketing Office (DRMO) Superfund site, which is owned by Joint Base Andrews (JBA). Chlorinated volatile organic compounds (VOCs) are present in ground water at the DRMO Superfund site and were observed to be migrating offsite into a residential area. JBA is currently operating a groundwater extraction and treatment system at the DRMO Superfund site to capture and treat a chlorinated VOC plume that is migrating offsite.

JBA raised concern that dewatering activities at the Mattawoman site will influence groundwater flow at the DRMO site and adversely impact plume capture/migration and their ongoing remediation. As a part of the CPCN review process, Mattawoman conducted a dewatering evaluation to determine potential affects to the DRMO remediation system caused by construction dewatering associated with the reclaimed water pipeline at the proposed Mattawoman site. PPRP also conducted an independent analysis to evaluate the findings of “no significant impact” to the DRMO system from Mattawoman construction activities.

License conditions imposed on Mattawoman were created to assure protection of human health during transmission pole installation for the generator lead line. The conditions also specified requirements to reduce/minimize further releases of contaminated soil or ground water to nonimpacted areas such that the surrounding community would not be affected.

Dewatering for Pipeline Construction

Dewatering of saturated materials during the construction of power plants, including pipelines, 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, such as streams and ponds, and nearby ground water users. PPRP has conducted analyses in recent licensing cases to ensure that proposed pipelines associated with generating facilities will not deplete ground water resources or affect nearby water users.

The information needed to estimate the rate of dewatering in areas where pipes are placed below the water table, particularly in areas adjacent to or under streams, includes the following:

1. The estimated length of pipeline segments that will be installed beneath the water table;
2. An estimate of the depth that the excavations will extend below the water table (i.e., saturated thickness); and
3. Duration of pipeline construction and average construction duration of each segment.

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

This dewatering approach was applied to the Mattawoman Energy Center project. An 8-mile gas and a 10-mile reclaimed water pipeline were proposed for installation as part of the Mattawoman natural gas-fired power plant. Mattawoman calculated the duration and rate of dewatering for the first mile of the reclaimed water pipeline. The mile-long pipeline route was segregated into four segments, with the boundaries of each segment corresponding to major stream crossings. These segments were then evaluated using the methodology described above to determine if dewatering would be necessary for each segment, and if dewatering was deemed necessary, the amount of dewatering that would occur for each segment. Based on Mattawoman's calculations (confirmed by PPRP), all four segments needed an appropriation approval through a CPCN amendment. In February 2016, the Public Service Commission granted the CPCN amendment to Mattawoman to modify the ground water appropriation permit to accommodate construction dewatering for the first mile of reclaimed water pipeline. In December 2016, Mattawoman requested an amendment to its CPCN for construction dewatering of the remaining portion of the reclaimed water pipeline. After significant review by MDE Water Management Administration and PPRP, it was concluded that construction dewatering would not have an adverse impact on the aquifer, nearby groundwater users, adjacent streams or wetlands, provided that Mattawoman comply with additional conditions. However, in May 2019, Mattawoman proposed a design change to convert the method of cooling from wet mechanical draft cooling tower to air-cooled condenser. This design change will eliminate the need to construct the remaining nine miles of the reclaimed water pipeline, resulting in a significant reduction in the amount of construction dewatering required onsite and offsite. PPRP and MDE reviewed the proposed design change and concur with the requested amendment. During the next phase of construction design, Mattawoman will conduct a similar dewatering evaluation to determine the potential effects associated with the construction of the natural gas pipeline.

Pepco Burtonsville to Takoma Park Transmission Rebuild Project

Pepco filed an application for the rebuild of an existing 230 kV transmission line originating at the Burtonsville substation and terminating at the Takoma substation. In its application, Pepco acknowledged that there are three areas along the right-of-way (ROW) that could contain petroleum-contaminated soil or areas where hazardous substances may be present in soil or groundwater. The presence of oil-contaminated soil or hazardous substances is the result of releases caused by entities other than Pepco whereby such substances have migrated onto the Pepco ROW.

However, to ensure the safety of its workers, Pepco committed to conduct investigations to determine the presence of soil and/or ground water contamination at the structure locations to the depths of proposed excavations prior to initiation of construction and to use the results of the investigation to determine the course of action to mitigate potential risks from contamination during construction.

License conditions were imposed on Pepco to address concerns regarding worker health and safety, as well as the management and disposal of excavated materials impacted with hazardous substances, and ensure Pepco delivers on the commitments set forth in the CPCN application. To achieve the license conditions, Pepco was required to conduct necessary analytical testing of the soil and groundwater near the structure locations that could be affected by subsurface contamination. Pepco was also required to prepare plans for soil and groundwater management to include plans for health and safety, excavation, containment and disposal. The license conditions also require that Pepco compare the results of the analytical data collected as part of the investigation to MDE's Cleanup Standards for Soil and Groundwater. Analytical data for soil must be compared to residential cleanup levels to ensure protection of residents living adjacent to the Project ROW. Should analytical data for soil exceed the MDE standards for residential soil, Pepco must adhere to proper disposal of impacted soil at a licensed solid waste facility in accordance with MDE's solid and hazardous waste laws and regulations. Impacted soil may not remain within the Project ROW. If groundwater is determined to contain hazardous substances exceeding MDE's standards, procedures may be developed and implemented to ensure that impacted groundwater is either treated or disposed of in accordance with all applicable local, state and federal laws and regulations.

5.2.2 Impacts to Aquatic Biota

Conventional Facilities

Conventional electric power generation facilities have the potential to affect the state's water resources from water withdrawal, consumption and discharge during plant operations. 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, as well as mortality of aquatic organisms because of entrainment in the cooling system, and impingement of larger organisms on cooling system intake screens as mentioned above. Elevated temperatures of receiving waters from a plant's discharge may also have an effect on aquatic resources. Impacts to fish in streams include the potential loss of habitat due to lower water levels or altered water temperature particularly 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 (see Section 5.2.4 – Cumulative Effects on Aquatic Biological Resources).

In addition to minimizing impacts, several power plants once instituted cooperative aquatic enhancement measures at their facilities, such as constructing and operating game fish hatcheries in cooperation with the Maryland Department of Natural Resources (DNR). Other power plants established funds to remove fish migration obstructions caused by low-head dams no longer in use. The types of impacts identified by PPRP, along with the steps taken to minimize and mitigate these impacts are discussed in detail below. The impacts associated with cooling water withdrawals in the state are being reevaluated by MDE with technical assistance from PPRP for regulatory compliance over the next several years because of EPA's revised Section 316(b) regulations of the Clean Water Act (CWA) for existing power plants.

Cooling Water Systems

<u>Withdrawal Impacts</u>

Cooling water withdrawals can cause adverse ecological impacts in three ways:

- Entrainment – drawing in of plankton and larval and/or juvenile fish through plant cooling systems;
- Impingement – trapping larger organisms on barriers such as intake screens or nets; and
- Entrapment – accumulation of fish and crabs (brought in with cooling water) in the intake region.

In the 1970s and early 1980s, PPRP evaluated impacts to aquatic organisms at eleven major power plants to evaluate the relative impacts of power plant operations on the aquatic environment, with special emphasis on the Chesapeake Bay. Results of the studies showed that while power plant operations affected ecosystem elements, the cumulative impacts to Maryland's aquatic resources were not ecologically significant.

Measured entrainment losses of aquatic organisms did not reveal consistent depletions of populations. Even then, some power plants modified their operating procedures and one constructed onsite hatchery facilities for fish stocking operations. They also provided funding to remove blockages to migratory fish and developed improved intake technologies and other modifications to reduce entrainment or impingement. Section 316(b) of the federal Clean Water Act requires power plants to use cooling water intake structures (CWIS) that reflect the best technology available for minimizing adverse environmental impacts. After several decades, the U.S. EPA implemented a final rule on requirements for CWIS at existing facilities (see sidebar).

Clean Water Act Section 316(b)

EPA's implementation of Clean Water Act (CWA) Section 316(b) has resulted in updated assessments of the impacts of cooling water withdrawals. EPA's regulation included three phases of implementation: Phase I applied to new facilities constructed after January 2002 with cooling water intake; Phase II, effective September 2004, applied to existing power-producing facilities, with cooling water intake designed for greater than 50 mgd (the regulations would be applied at the time the facility renewed its National Pollutant Discharge Elimination System (NPDES) discharge permit); and Phase III applied to non-power producing facilities.

Maryland has eleven existing steam electric power plants with an NPDES permit and a cooling water intake and discharge. Of these, two plants were below the 50 mgd design threshold for Phase II facilities (Warrior Run and Vienna), one was classified as exempt from the new regulations (Wheelabrator/Baltimore RESCO), and the remaining eight (Calvert Cliffs, Chalk Point, C.P. Crane, Dickerson, Gould Street, Morgantown, Riverside, and Wagner-Brandon Shores) conducted Phase II evaluations.

The Phase II regulations established specific performance standards for reduction of impingement and entrainment, and identified five compliance alternatives for using best technology available to minimize adverse environmental impact at facilities. However, as a result of a lawsuit by several environmental groups, states, and industry groups, the U.S. Court of Appeals made a ruling on Phase II, rejecting many of its provisions (Riverkeeper et al. v. USEPA, decided in 2007). Several industry groups and the Riverkeeper appealed a portion of this ruling with respect to the cost-benefit test to the U.S. Supreme Court. The court ruled in 2009 that the cost-benefit test is allowed; specifically, the court stated: "The EPA permissibly relied on cost-benefit analysis in setting the national performance standards and in providing for cost-benefit variances from those standards as part of the Phase II regulations." EPA proposed a revised rule for public comment in 2011, addressing the other issues required by the Riverkeeper case and the U.S. Supreme Court ruling on cost-benefit testing. PPRP submitted comments on the proposed rule. The EPA finalized the standards in 2014.

The new rule includes the following requirements, which facilities in Maryland that withdraw at least 2 million gallons per day will need to address in the coming years; some facilities have already started studies to address these issues:

- Facilities are required to choose one of seven options to reduce fish impingement.
- Facilities that withdraw at least 125 million gallons per day (mgd) must conduct studies to help their permitting authority determine whether and what site-specific controls, if any, would be required to reduce entrainment of aquatic organisms.
- New units added to an existing facility are required to reduce both impingement and entrainment that achieves one of two alternatives under national entrainment standards.
- Power plant owners must conduct one year of impingement studies and 2 years of entrainment studies (for facilities withdrawing greater than 125 mgd) within the last 10 years. Some facilities already conducted some or all of these studies while others need to conduct additional studies.
- All facilities subject to the new rule will need to conduct economic and engineering studies to comply with the new rule as their NPDES permits are renewed.

Discharge Impacts

Impacts to aquatic biota from power plant cooling water system discharges include elevated temperatures, discharge of chemicals used for biofouling treatment (e.g., chlorine), discharge of metals eroded from internal plant structures (e.g., copper), and, in the case of Maryland's only nuclear power plant, discharge of radiological materials (see Section 5.5 for more information). Each of these impacts is discussed below.

Thermal Changes

Biological impacts from heated effluents depend upon the magnitude and duration of the temperature difference between discharge water and receiving water. Small organisms that pass through a plant's cooling system experience the greatest temperature stress, both in magnitude and duration. Exposed organisms in the receiving waters are more likely to experience smaller increases in temperature of shorter duration due to dispersion of the thermal plume and mobility of most of the exposed aquatic biota (e.g., fish, blue crabs). PPRP and plant owners conducted studies to determine the effects of thermal discharges at each existing power plant in the state. Because different aquatic biota occupy different salinity regimes in Maryland waters, study results are presented here according to the habitats where power plants are located (see Figure 5-31). Below is a brief summary of the findings in those studies.

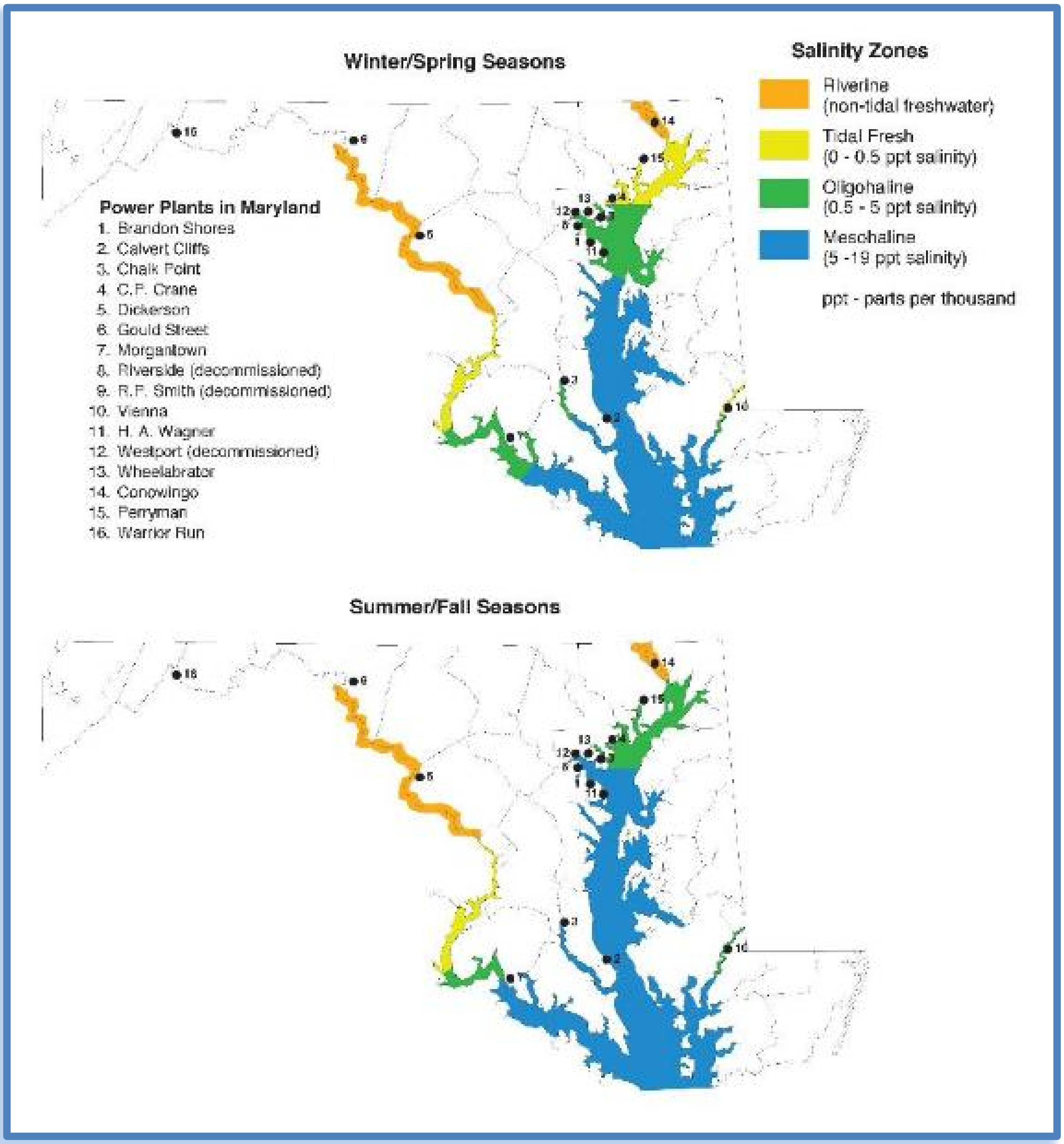
Mesohaline Habitat – The five largest power plants in the state by generating capacity (Chalk Point, Calvert Cliffs, Morgantown, Brandon Shores and H.A. Wagner) discharge into mesohaline habitat (5-19 parts per thousand (ppt) salinity) during all or part of the year. PPRP studied thermal discharges from the Chalk Point, Morgantown, Calvert Cliffs and H.A. Wagner power plants as part of extensive fieldwork in the 1970s and 1980s. Thermal plume dimensions for these power plants varied with season, tidal stage, wind velocity and direction, and plant operating levels.

The effects of thermal discharges from the power plants located in the mesohaline habitats of the Chesapeake Bay are localized and not considered significant. PPRP found no cumulative adverse impacts to the habitats of the Chesapeake Bay ecosystem. However, PPRP will continue to evaluate the habitats if additional power plant discharges are proposed and consider new technologies to reduce thermal discharges. More recently, PPRP studies have evaluated the potential effects of power plant discharges on diving ducks and their food resources.

Tidal Fresh and Oligohaline Habitat – Two plants, Vienna and C.P. Crane, once discharged into tidal fresh (0-0.5 ppt) and oligohaline waters (0.5-5 ppt). Chalk Point, Morgantown, Brandon Shores and H. A. Wagner also discharge into the oligohaline zone during part of the year. PPRP studies showed that the thermal plume at Vienna was small and its discharge effects were negligible. The thermal plume at C.P. Crane (coal units now retired) affected about 40 percent of the volume of the receiving water embayment. C.P. Crane effluents also resulted in a slight increase in nearfield salinity due to plant-induced changes in the nearby bay circulation pattern, but these factors did not affect nearfield dissolved oxygen.

Data collected in 2003-2005 and in the 1979-1980 studies reflect long-term changes in the upper Bay fish community and were not suggestive of a plant discharge effect. The results also suggest that the thermal discharge did not consistently affect the fish community's composition or distribution.

Figure 5-31 Salinity Zones of the Maryland Chesapeake Bay



In the early 2000s, MDE required studies at C.P. Crane to repeat some of the historical fishery surveys conducted in the late 1970s, as a condition for NPDES permit renewal. The purpose of the surveys was to demonstrate if the fish populations near the C.P. Crane power plant remain unaffected by its thermal discharge. The study showed that differences in the fish community apparent between the findings at the plants in these tidal fresh and oligohaline habitats were consistent with those at facilities in mesohaline areas. Thermal discharge effects were small and localized. PPRP studies found no evidence that thermal plumes in the plants' receiving waters in these particular habitats blocked fish movements. C.P. Crane has retired their coal-fired units and has applied for redevelopment as a simple-cycle natural gas-fired plant.

Nontidal Freshwater Habitat – Dickerson is the only Maryland power plant that uses once-through cooling that is located in nontidal riverine habitat. PPRP conducted a long-term freshwater benthic study over an eight-year period in the 1980s, and assessed the thermal impact of power plant discharges on the Potomac River ecosystem. While this long-term study documented that the thermal discharges from Dickerson had an adverse impact on benthic communities in the immediate area of the discharges, these effects were localized. The affected percentage of the total river bottom was very small. To assess whether these localized impacts on benthic communities may be affecting fish populations within the river, the discharge permit for the Dickerson facility included a requirement for a multiyear study of growth and condition of several fish species near the plant. Based on data on fish condition collected over a 21-year period near the plant discharge and at a reference location 8 miles above the discharges, there was no indication that the localized discharge effects on benthic communities affected fish near the plant.[79]

Discharge of Chemical Contaminants

Concerns regarding the impacts of copper and chlorine discharged from cooling water systems into sensitive waters of the Chesapeake Bay watershed in the late 1970s and early 1980s led to extensive studies by PPRP as well as others.

Copper – In the late 1970s and early 1980s, PPRP found that oysters near the Chalk Point, Calvert Cliffs and Morgantown power plant discharges were bioaccumulating copper that was present in the effluent discharge. The copper resulted from corrosion of the copper condenser tubes within the plants' cooling systems. While PPRP studies showed that oyster growth and survival were not adversely affected, the elevated levels of copper concentrations in oysters posed a potential risk to the health of individuals who might consume them. Power plants in Maryland replaced the copper condenser tubes with titanium tubes where this problem was most significant, primarily in estuarine waters. The titanium tubes eliminated the metals corrosion, which also resulted in less maintenance on the condenser tubes. Currently, NPDES permitting for all power plant discharges includes an evaluation of maximum discharge levels for copper (as well as other metals) to protect human health and the environment.

Chlorine – This substance is sometimes used by power plants to control biofouling of condenser tubes in cooling water systems. While it may be an effective means of controlling biological organisms within the cooling system, it can also cause mortality in the aquatic biota of the receiving water body. Presently, the NPDES permits for all power plants in Maryland require that they may not discharge chlorine into the state's waters for more than two hours in any one day from any one unit, and no more than one unit may discharge at any one time. MDE may grant an exception if a facility demonstrates that it needs more chlorination to control macroinvertebrates. MDE has determined that chlorinated discharge impacts are resolved and need no further action.

[79] Loos, J.J. and E.S. Perry. 1991. Dickerson Station graphical analysis of fish distribution relative to the Dickerson Station thermal discharge. 1979-2000. Permit Compliance Support, Mirant Mid-Atlantic.

Wastewater Discharges

Wastewater discharged from coal ash ponds, air pollution control equipment, and other equipment at power plants can contaminate drinking water sources, impact fish and other wildlife, and create other detrimental environmental effects. Although air pollution controls have made great strides in reducing emissions from power plants, some of the equipment used to clean air emissions does so by "scrubbing" the boiler exhaust with water ("wet" flue gas desulfurization (FGD) systems), which then can pollute rivers and other receiving water bodies. Treatment technologies are available to remove these pollutants before they are discharged to waterways, but these systems have been installed at only a fraction of the power plants. Types of treatment systems for FGD systems include settling ponds, chemical precipitation, biological treatment, constructed wetlands and zero-liquid discharge.

In 2009, EPA completed a multiyear study of power plant wastewater discharges and concluded that current regulations, which EPA issued in 1982, have not kept pace with changes that have occurred in the electric power industry over the last three decades. As part of this multiyear study, EPA measured the pollutants present in the wastewater and reviewed treatment technologies, focusing mostly on coal-fired power plants. Many of the toxic pollutants discharged from these power plants come from coal ash ponds and the FGD systems used to scrub SO_2 from air emissions. In 2009, EPA announced plans to revise the existing standards for water discharges from coal-fired power plants to reduce pollution and minimize its adverse effects. EPA published a report later that year that provides more information about that study.

EPA issued a proposed rule to amend guidelines and standards for the steam electric power generating industry in 2013 and took final action in 2015. However, in 2017 EPA announced the compliance dates would be postponed until November 1, 2020 while it conducts a rulemaking to potentially revise the regulations affecting discharge of FGD wastewater and bottom ash transport water.

In addition to the contaminants covered under EPA's effluent guidelines, and as a result of the implementation of the Chesapeake Bay TMDL, all dischargers with NPDES permits, including industrial dischargers such as power plants, will have reduced limits on total nitrogen, total phosphorus and sediment.

Hydroelectric Facilities

Maryland has only two large-scale hydroelectric projects (with capacities greater than 10 MW): Conowingo Dam (see discussion below) on the Susquehanna River and Deep Creek Lake in Western Maryland; however, four additional small-scale facilities also generate electricity within the state and one additional one (Jennings Randolph Hydroelectric Project) has been permitted by the Federal Energy Regulatory Commission (see map and table in Section 3.1.5). Hydroelectric facilities may present special environmental concerns that operators do not encounter at steam electric power plants. Development and operation of hydroelectric facilities causes three main types of impacts:

Changes in water quality – Impoundments created for hydroelectric dams significantly alter river flow from free-flowing streams to deepwater flow. This alteration causes changes in natural water clarity, thermal stratification, and lower dissolved oxygen concentrations upstream of the dam, which, in turn, may result in low dissolved oxygen levels in the water discharged from the hydroelectric dam. In addition, because dams slow moving water, suspended sediment often drops out and settles on the bottom behind the dam rather than continuing downstream, as would occur if the dam were not present. Normally, these materials would be carried and deposited throughout the entire river system. Downstream of dammed rivers, it is common to see receding riparian zones and wetlands due to the loss of transported sediment. This change and other effects influence the types of organisms that can live there. In addition, the river channel or path a river takes can be changed as a result of the existence of a dam. Habitats downstream from a dam are in general less diverse than those of free-flowing rivers and streams. Absent the dam, the river would be guided by the surrounding landscape, not a dam.

The existence of a dam fundamentally alters water quality and aquatic life upstream of the dam (i.e., in the reservoir). The creation of a reservoir essentially replaces a flowing, dynamic, and varied aquatic habitat with a lake with fundamentally different habitat that in turn results in a different assemblage of aquatic species than would otherwise be present without the dam.

The change from a riverine system to a lentic system also changes the fate and transport of pollutants such as sediment and nutrients. The existence of a dam often alters species diversity and the number of fish in the water behind the dam as well as the types of fish there, with riverine species of fish being replaced by reservoir-adapted fish that like slow-moving warm water and insects that like silt and sandy bottoms. The slow moving warmer water in a reservoir combined with inputs of nutrients from upstream sources and/or from project lands can also contribute to algal blooms, particularly during the summer, which can impact aquatic life as well as drinking water and recreational uses.

When reservoirs contain deposited sediment, large storm events can scour the deposited sediment and nutrients from the reservoir floor and move them downstream, adversely impacting water quality and aquatic life. In some cases, this material has been shown to impact water quality 40 miles or more from a dam.

Changes to flow regime and resultant changes to aquatic life and habitat downstream – The flow regime downstream of a hydroelectric dam plays a large role in defining the physical and biological characteristics of the river below the dam. Hydroelectric operations alter the flow regime of a river and disrupt the cycles that many aquatic organisms depend on. Accordingly, without the hydroelectric dam, one would expect increased biodiversity and population densities of native aquatic species downstream.

Hydroelectric facilities operating in a peaking mode (in response to peak electrical demand) produce unnatural and frequently extreme water level fluctuations in impoundments and the river downstream of the impoundment. Additional small-scale projects may also divert some flow away from the natural streambed. Fluctuations in water level and flow can reduce fish abundance as well as important food sources essential to fish growth and survival. In addition, as discussed in the section above on water quality, large hydroelectric dams allow suspended sediments to accumulate in the impoundment resulting in reduced storage, reduction in navigational waters, and changes in the timing and distribution of sediment and associated nutrients downstream of the dam.

Direct adverse effects on fish populations – Dams prevent the natural upstream and downstream movement of both resident and migratory fish species. Entrainment of fish attempting to move downstream past the dam may cause mortality due to the turbines. Factors that affect fish mortality include the type of turbine, the proportion of flow diverted through the turbine, and the size of fish.

Susquehanna River Migratory Fish Restoration

Historically, the Susquehanna River supported large spawning runs of migratory species such as American shad (shad), river herring, striped bass and American eel. The massive diadromous fish migrations extending 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 Holtwood, Safe Harbor, and York Haven dams in Pennsylvania).

By the year 2000, restoration programs had been operating for nearly 30 years, and fish passage devices had been installed at all four hydroelectric facilities, partially reopening the Susquehanna River to migratory fish. This has created the potential for shad and other migratory fishes to move as far upstream as New York State, representing renewed access to well over 400 miles of historic habitat. However, fish passage has only been partially successful to date and the hydroelectric licensees on the Susquehanna River are conducting additional 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. Upstream passage peaked in 2001, when nearly 200,000 American shad were passed over the Conowingo Dam; however, annual passage has declined since then for reasons that are the subject of ongoing studies and potential mitigation measures (see Figure 5-32). The 2019 fish passage data showed less than 6,000 American shad passed Conowingo and less than 12 percent of what passed Conowingo passed the next upstream dam (Holtwood). The Holtwood numbers have historically been low, but improvements to their fish passage system that were made in conjunction with recently added generation capacity were expected to result in an increased percentage of fish passing Holtwood. Long term (2000-2019), Safe Harbor has passed 74 percent of what passed Holtwood, but York Haven only passed 13 percent of what 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 as well as safe downstream passage of juveniles through operational and/or engineering modifications.

Similar to shad, American eels likely occupied the majority of the Susquehanna Basin, but have been restricted from accessing the majority of the Susquehanna 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 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 loss 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, but its abundance in the Susquehanna River is lower than other regional watersheds (i.e., 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 their disappearance from the watershed has likely played a significant role in the limited abundance, size, age and recruitment of their populations.

From 2009 to 2016, the U.S. Fish and Wildlife Service (USFWS) operated an eel ramp[80] to capture juvenile eels below Conowingo Dam and move them upstream. The goal of this program was to move 1 million eels to designated locations within the watershed to not only help restore mussel populations but to restore the ecological balance. Eels quickly bring balance back to the ecosystem by their predation on small fishes and crayfish.

The collected number of elvers (young eels) increased from 2009 through 2013 (Table 5-8), then decreased from 2014 to 2016. The decline in elvers could be related to the unusual weather conditions in 2015 and 2016, or this trend could be related to natural variability in eel numbers. However, 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 was required to construct a new eel ramp and transport system at Conowingo in 2017. Numbers increased greatly in 2017 compared with 2016 although numbers declined in 2018, possibly due to high river flows that year, but rebounded in 2019.

Table 5-8 Total Number of Elvers Collected, by Year, at Conowingo Dam, Maryland

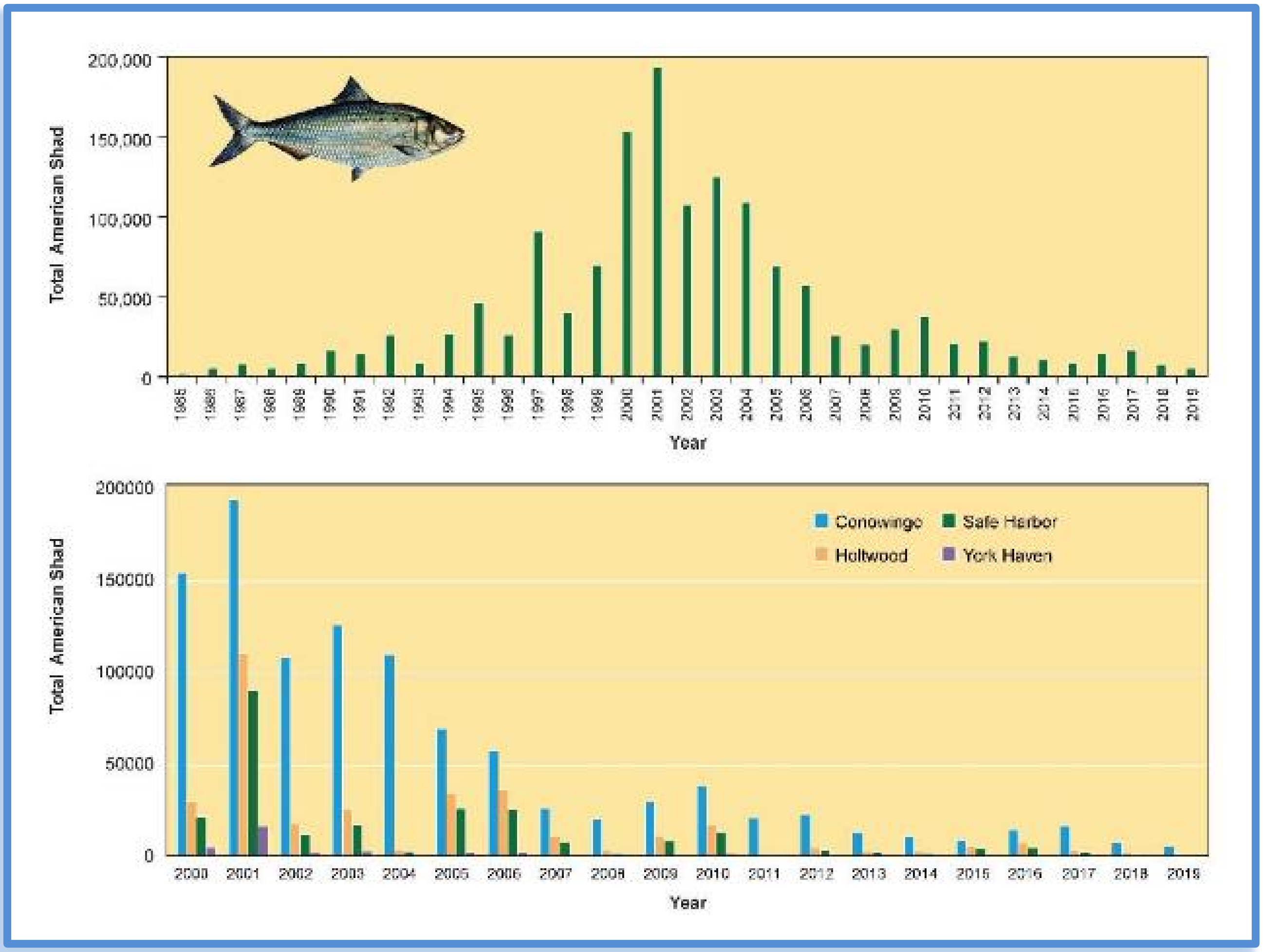
Year	Total elvers collected
2005	42
2006	19
2007	3,837
2008	42,058
2009	17,437
2010	23,856
2011	84,961
2012	127,013
2013	293,141
2014	185,628
2015	58,444
2016	2,684
2017	122,300
2018	67,949
2019	126,181

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.

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

The FERC licenses for Muddy Run and York Haven were renewed in 2015. Conowingo is currently undergoing relicensing (see further discussion below). Holtwood and Safe Harbor project licenses expire in 2030.

Figure 5-32 Number of American Shad Passed at Conowingo Dam from 1985 – 2019 and at Conowingo, Holtwood, Safe Harbor, and York Haven Dams from 2000 – 2019



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

Conowingo Hydroelectric Project Relicensing

The Conowingo Dam completed in 1928 created the 8,500 acre Conowingo Pond (reservoir); additional generating units added in the 1960s and upgrades in the recent decade resulted in the current capacity of 572 MW at the Conowingo Hydroelectric Project. In addition to the types of impacts mentioned that are generally caused by hydroelectric facilities, impacts specific to Conowingo also include increased evaporation and sedimentation, as well as periodic dewatering downstream of the dam. The Conowingo Pond supports other generating facilities nearby in Pennsylvania, including the 2,770 MW Peach Bottom Atomic Power Station (units 2 & 3), the 1,072 MW Muddy Run Pumped Storage Project and the 1,100 MW York Energy Center, as well as municipal water supply for Baltimore City and Chester, PA. The new 1,000 MW Wildcat Point facility in Cecil County also withdraws water from the Conowingo Pond, at a withdrawal point in Pennsylvania.

The federal license (issued by the Federal Energy Regulatory Commission or FERC in 1980) to operate the Conowingo Project (now owned by Exelon) expired in August 2014. Since 2014, the Conowingo Project has been operating under annual FERC licenses, while FERC completes the relicensing process. Exelon submitted to FERC a Pre-Application Document in 2009 for continued operation of the Conowingo Project. PPRP coordinated all Maryland agency reviews of the FERC Pre-Application Document and provided input on various studies and the license application for FERC to consider as part of its review. Principal issues that were the subject of multiyear studies based on recommendations from PPRP and other state and federal agencies include sediment and nutrient management, upstream and downstream fish passage (for migratory species such as American shad, river herring and American eel), flow and water level management, dissolved oxygen (DO) levels, debris management, land conservation and recreation. Under Section 401 of the federal Clean Water Act (CWA), before relicensing can occur, the MDE must certify that the operation of and discharges from the Conowingo Project under the new license will meet Maryland Water Quality Standards and Requirements. MDE issued a Water Quality Certification (WQC) under Section 401 in 2018. MDE and Exelon in 2019 proposed a settlement agreement to FERC which laid out licensing conditions for Conowingo, resolving issues between them. The proposed settlement (subject to approval by FERC) includes 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.

Fishway prescriptions issued by the USFWS were the subject of negotiations between the USFWS and Exelon. In 2016, the USFWS issued a fishway prescription that was the subject of extended negotiations between the USFWS and Exelon. In that prescription, Exelon agreed to implement improvements to the existing fish passage facilities within three years of the renewal of its federal license. The initial items to be constructed include:

- Modifying the East Fish Lift to provide 900 cubic feet per second of attraction flow.
- Replacing the current 3,300-gallon hopper at the East Fish Lift with two 6,500-gallon hoppers.
- Reducing cycle time at each hopper at the East Fish Lift to be able to lift fish four times per hour.
- Completing modifications to the East Fish Lift structure to allow for trapping and sorting fish at the East Fish Lift facility and transporting them to the western side of the dam to a truck for transport upstream.
- Modifying the West Fish Lift to facilitate trap and transport.
- Constructing and maintaining structures, implementing measures, and/or operating the Project to provide American shad and river herring a zone of passage to the fish passage facilities.
- Evaluating potential trapping locations for American eel on the east side of Conowingo Dam including Octoraro Creek starting in May of the first calendar year after license issuance or immediately if license issuance occurs during the upstream American eel migration period.

In addition to these initial construction items, Exelon will trap and transport American shad and river herring from Conowingo to above the York Haven Hydroelectric Project beginning the first fish passage season after license issuance. Exelon also has committed to trap and transport American eels at the west side of Conowingo Dam. Exelon has already started design work to implement many of the fish passage improvements required in the USFWS prescription.

Exelon will also conduct periodic efficiency tests of migratory fish passage through its improved facilities. If the project does not achieve specified passage goals, Exelon will implement additional mitigation measures from a tiered list of items to make further improvements in passage efficiency throughout the term of its license.

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. A number of additional U.S. projects have been proposed, most in shallow waters (<30 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. This could affect bird migration routes as well as breeding and feeding areas. 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.

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. Both lead lines from individual projects to shore substations and a large submarine "backbone" line parallel to the coast have been proposed. Burying cables in either configuration will create disturbed swaths across the seabed, which will become warmer than the surroundings during transmission operations from heat dissipated by the cables. Underwater electric transmission cables within and from wind farms also generate electromagnetic fields (EMF) which are known to affect the 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, the applicants must affirm plans to conduct an environmental review in compliance with applicable statutes, such as the National Environmental Policy Act. Because of the potential for impacts to 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 regulations and guidelines for surveying natural resources (including, but not limited to avian species, benthic habitats, 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 of 2016. After review, the PSC approved both applications, with conditions, in May 2017 (PSC Order No. 88192). Before construction starts, PPRP will conduct studies to identify potential environmental impacts from any submarine transmission cables that cross Maryland's offshore waters. The Bureau of Ocean Energy Management approved Site Assessment Plans in 2018 and the applicants are currently conducting site assessments for these projects.

In Maryland's 2019 Legislative Session, additional offshore wind project ORECs were authorized through the Clean Energy Jobs Act. These ORECs are to support the development of at least an additional 1,200 MW of wind energy by 2030 from applications for "Round 2" of offshore wind development (which started as of July 1, 2017). This amount of offshore wind energy, which is similar to the amount of generation approved for the Round 1 applications, will more than double the offshore wind contribution to the state's renewable energy portfolio.

Solar

While solar generation facilities are generally not built near large bodies of water, there are instances when the facility is located on property containing a freshwater stream or is located in an area where drainage to 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 based on the design of the facility. In some cases, this may actually 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 nonjurisdictional drainage ditches, leading to flooding both on- and offsite. In addition, consideration must be made to the interconnection process as well. For example, PPRP evaluated a proposed horizontal directional drilling (HDD) line at the proposed Casper Solar Facility that would have been installed under a Tier II stream and may have caused heat transfer to the stream, affecting the quality of life for aquatic biota. However, the proposed Casper Solar project was withdrawn in 2019.

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. Primary direct effects are caused by construction or maintenance vehicles crossing or working within stream beds, floodplains or bank areas, which may release sediment, construction debris and contaminants into the stream. Vulnerable aquatic or riparian zone species may also be disturbed by noise, dust and construction-caused changes in drainage patterns or soil. Tree removal during construction can result in immediate as well as long-term soil erosion that increases sediment loads in streams.

Large rivers may be too wide to avoid placing towers directly adjacent to the water or within the river itself. For example, the 500-kV line crossing the lower Potomac River near Moss Point, shown in Figure 5-33, includes six towers in the river. All of Maryland’s major rivers, both tidal and nontidal, are crossed by transmission lines. At present, only SMECO’s transmission line between St. Mary’s County and Calvert County near the mouth of the Patuxent River avoids the visual and physical impacts of towers by employing a cable beneath the river. Potential impacts from transmission support structures placed in the riverbed include disturbance to fish and bottom dwelling organism habitat, redirection of water currents and erosion patterns, and potential hazards to navigation and commercial fishing. Above the waterline, the towers may provide nesting and roosting opportunities for some birds, while other birds may collide with the towers or the wires between them.

Special care must also be taken to protect and enhance small streams located in the upper parts of watersheds. Any effects that propagate downstream, such as warmer water temperatures or increased sediment load, will also be detrimental. In lower reaches of the watershed, the synergistic effects could cause a shift in water quality, initiate changes in aquatic species composition or modify the configuration of the drainage channel. For this reason, protection of headwater streams – including small swales, creeks, vernal pools, wetlands, etc., that are the origins of most rivers – has been emphasized by state agencies. To minimize effects to streams, the state agencies typically recommend that towers be located as far from stream banks and their buffers as possible and require vegetation and construction management practices that minimize the movement of disturbed soil and construction debris toward streams.

Figure 5-33 Existing 500-kV Transmission Line Crossing of the Potomac River

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 due to clearing and runoff from maintenance treatments also elicit concern. Good practices can minimize these effects. In areas where streams are already degraded, effective maintenance practices can assist restoration, particularly with landowner and community participation.

Removing trees in or adjacent to a transmission line ROW may be necessary to maintain adequate clearance between taller vegetation and transmission line conductors. It also allows equipment to access the ROW during construction and maintenance. Such clearing can affect streams in a variety of ways, but soil erosion is the most damaging. The root systems of trees are important for preventing erosion and slumping of the banks of rivers and streams. Soil erosion resulting from removing trees often produces increased sediment loads in streams, leading to changes in stream morphology and diminished water quality, which ultimately degrade the biological resources of the stream.

Removing vegetation from the riparian area reduces stream shading and decreases the amount of leaf litter, woody debris and root wads present in the stream system. This may result in increasing water temperatures and a reduction in habitat and food sources that threaten survival and reproduction of cold water species, including brook trout. While studies have not documented a strong effect of a single transmission line ROW on average stream temperature, protection of coolwater or coldwater habitat is advisable as a cautionary measure. In most cases, placing transmission line towers sufficiently far enough from the stream that the wires span the stream and associated riparian area can minimize long-term effects. This configuration is particularly effective at reducing impacts when natural vegetation is maintained in the riparian area. However, many ROWs that have been managed in traditional ways or that have towers or poles on the stream banks are entirely cleared to the edges of the stream.

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. In order to manage the vegetation in the ROW after the construction phase is completed, pesticides and herbicides may be applied to the vegetation in the vicinity. Excessive application, wind-blown spray and uncontrolled runoff of these chemicals may deposit them in streams and degrade water quality and, ultimately, damage the biological resources that are present. The PSC requires that utilities use EPA-approved substances for vegetation management that degrade quickly and that have minimal side effects.

Impacts to Groundwater

Transmission line structures have a small potential to affect ground water resources, particularly in areas where the water table is close to the surface. Potential impacts to ground water would occur mainly during the construction or installation of the structures, whether above ground 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 open access channels to deeper aquifers. For example, typical estimated drilling depths required for new structures for 230 kV transmission line projects such as the recent SMECO Holland Cliffs to Hewitt Road are approximately 40 feet below ground surface. In many areas of the state, potable water supplies are much deeper than this and would not be at risk. However, the depth to ground water is much less in some areas, such as the Eastern Shore, where many utility upgrade projects are being conducted. Higher voltage overhead transmission lines require deeper drilling depths, therefore PPRP must carefully compare the tower foundation design to the depth to ground water for these projects.

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 ground water flow associated with the construction of underground duct banks and splice boxes or backfilling the trenches with material of differing porosity. Another potential effect could be an increase in ground water temperature due to the heating of an underground cable during its operation. The existence and magnitude of these impacts will be dependent upon several site-specific factors, including the project location, installation depth, construction technique employed, soil type, and depth to ground water.

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 species (RTE) need to be considered for every project. For example, the state endangered Northern Map Turtle (*Graptemys geographica*) occurs only in the lower Susquehanna River in Harford and Cecil Counties in Maryland, which is the eastern edge of its range. Impacts from habitat modification and human recreation are of special concern for Map Turtles in Maryland. The generation of electricity from the Conowingo Hydroelectric Dam influences flow of the lower Susquehanna River, which citizens use for recreational activities. Given the potential impacts of the Conowingo Hydroelectric Dam and associated human recreational use of the river, the Maryland DNR funded a three-year study to examine the status, distribution and ecology of Northern Map Turtles in Maryland.[81] A full list of the state's RTE species can be found at http://dnr.maryland.gov/wildlife/Pages/plants_wildlife/rte/espaa.aspx.

Additionally, while solar facilities are generally not located on or near large bodies of water, construction and operation of these facilities may impact aquatic RTE species. For example, the proposed Bluegrass Solar Facility drains entirely to tributaries of Southeast Creek, known to contain the federally endangered Dwarf Wedge Mussel. Dwarf Wedge Mussels require very high, sediment-free water quality. If disturbance were to occur to this stream from construction, or due to increased erosion or poor runoff control during operations, the population of mussel in that stream could be imperiled.

Offshore generation facilities could potentially affect federally listed threatened and endangered species that occur in the Chesapeake Bay and coastal waters of Maryland, including fish, whales, and sea turtles (see http://www.fws.gov/chesapeakebay/EndSppWeb/LISTS/specieslist-md.html for complete list). Except for sea turtle nesting habitat, the National Oceanic and Atmospheric Administration Fisheries Service has principal responsibility for these species.

Transmission Facilities

Rare, threatened and endangered (RTE) species are subject to the same impacts from the construction and maintenance of transmission line ROWs as other wildlife but must be protected to the maximum extent possible. Aside from avoiding the area containing the habitat of RTE species, time of year

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[81] R. Seigel, T. M. Richards, K. Anderson, and N. Byer, *Interim Report: Nesting and Basking Ecology of Northern Map Turtles in the Susquehanna River: Impacts of Human Disturbance and Effectiveness of Mitigation Measures*, Department of Biological Sciences, Towson University, December 2012

restrictions may be applied to activities within the ROW to avoid times when the species is breeding or especially active.

The 138 kV Piney Grove to Wattsville line is an example of a project that cannot avoid impacts to numerous RTE floral species, due to more than 20 species of RTE plants occurring along the more than 20-mile ROW. There are locations along this line where matting for access roads and equipment laydown will cause direct impacts on these RTE locations. To this end, PPRP has included a licensing condition in the CPCN that requires monitoring of RTE locations before, during and after construction to detect any changes in species composition, including expansion of invasive species populations into the RTE community.

5.2.4 Cumulative Effects on Biological Resources

Although permit requirements and regulations may not require an assessment of cumulative effects, the impact of multiple influences determines the health of the contiguous ecosystem. PPRP has conducted aquatic impact assessment studies at all of Maryland’s existing conventional power plants and has identified no measurable cumulative adverse impacts on water resources. MDE issues discharge permits, in accordance with the CWA, and uses aquatic impact assessment data to monitor continued performance of power plants to minimize these impacts. Cumulative effects of additional generation facilities such as offshore wind and solar will need to be considered.

As mentioned in previous sections, construction and maintenance of transmission lines and their associated ROWs affect freshwater streams through the loss of vegetation and shading, bank erosion and sedimentation during construction and herbicide contamination during maintenance activities. Many aquatic wildlife species may suffer without BMPs. For example, the brook trout (*Salvelinus fontinalis*) is an aquatic species that was historically prevalent in Maryland waters. Decreases in water quality and habitat degradation have placed this species in decline in Maryland. The brook trout is a coldwater species, dependent on streams with maximum water temperatures of 22°C. Removal of riparian vegetation at a brook trout stream, such as what would occur during the maintenance of a transmission line ROW, would decrease stream shading, thereby increasing the water temperature. This increase in the temperature could drive the brook trout out of a stream, leaving a habitat niche available for a nonnative species such as the brown trout (*Salmo trutta*) to compete for resources.

Because the health of an ecosystem depends on functional interactions between its components, impacts to multiple resources can have a cumulative effect much greater than a simple tally of the individual impacts would suggest. It is important to assess and address such multiple impacts. In addition to specific areas of multiple impacts, many small impacts to a single resource along a ROW can add up to a significant overall impact to that resource. It is also necessary to minimize such effects if they occur. For example, Maryland’s Wild and Scenic Rivers Act applies to the natural resources of state-designated Scenic Rivers and their tributaries, thus limiting any combination of activities within the watershed that would degrade the condition and quality of the designated river.

Transmission lines that cross numerous streams and rivers within a single watershed may degrade the overall biological health of that watershed. Any local effects that propagate downstream, such as warmer water temperatures or increased sediment load, will accumulate in lower reaches of the watershed. The summed effects could cause a shift in water quality, initiate changes in aquatic species composition or modify the configuration of the drainage channel. Evaluating the potential for such effects is always included in the reviews of proposed transmission line projects.

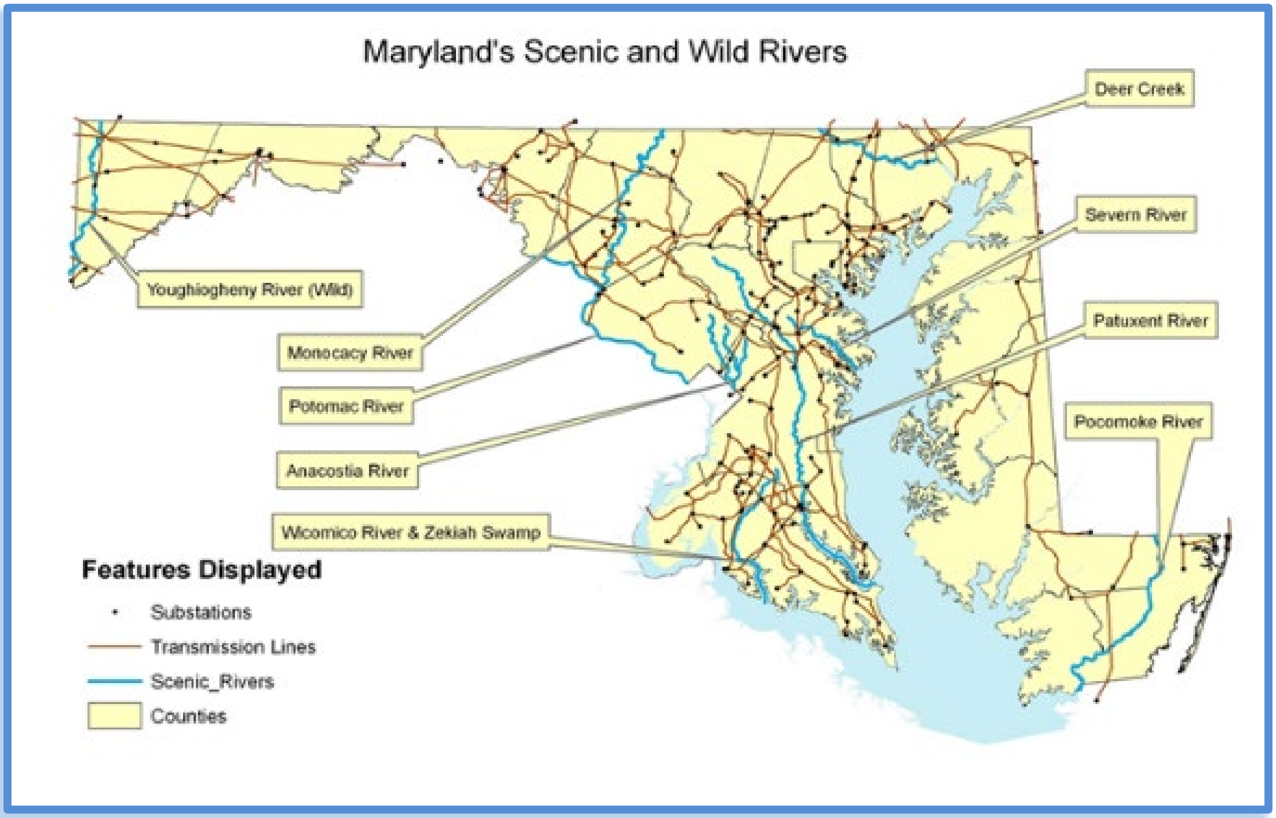
Impacts to High Quality Waters

The State of Maryland recognizes some streams and rivers as having particular natural values that deserve additional regulatory protection. These high quality waters include Scenic Rivers and Tier II streams, both of which may be affected by transmission line ROWs. Figure 5-34 illustrates Maryland's Scenic and Wild Rivers and the transmission line corridors in the state. During the CPCN review, PPRP evaluates the potential impacts of proposed transmission lines to ensure that projects avoid or minimize impacts on these resources.

Scenic and Wild Rivers

Maryland's Wild and Scenic 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." The Act mandates the preparation of river resource management plans for any river designated scenic and/or wild by the General Assembly. These plans identify river-related resources, issues and existing conservation programs, and make recommendations on the recreational use of the river and protection of special riverine features. Each unit of state and local government, in recognizing the intent of the Act and the Scenic and Wild Rivers Program, is required to take whatever action is necessary to protect and enhance the qualities of a designated river and its tributaries. In many cases, a Scenic River will also have a Watershed Restoration Action Strategy (WRAS), which is a means of implementing the recommendations set forth in the river's management plan.

Figure 5-34 Scenic and Wild Rivers and transmission line corridors in Maryland



Recent transmission projects that cross Maryland Scenic Rivers and their watersheds include DPL's Piney Grove to Wattsville new 138 kV line (Pocomoke River), the portion of the Transource project located in Harford County (Deer Creek), and the rebuild of the Ringgold to Catoctin project (the Monocacy River). PPRP's reviews of such projects include focused attention to all river and stream crossings in the associated watersheds, with particular attention to the potential for riparian buffer vegetation loss and erosion leading to downstream sedimentation.

In addition, transmission structures may significantly degrade the visual environment along the river. Several Maryland designated scenic rivers, including the Pocomoke River, the Patuxent River, the Monocacy River, and portions of the Potomac River, have incurred viewshed impacts from existing transmission line crossings. Where possible, underground crossings may eliminate or minimize such visual impacts (see Section 5.4.2 for additional details).

Tier II Streams

Maryland's antidegradation policy protects particularly high quality streams from impacts that would degrade them. The policy is laid out in three regulations: COMAR 26.08.02.04, which sets out the policy itself; COMAR 26.08.02.04-1, which provides for implementation of the antidegradation policy for Tier II (high quality) waters; and COMAR 26.08.02.04-2 which describes Tier III (Outstanding National Resource Waters or ONRW), the highest quality waters. Tier I waters meet only the minimum standards. There are Tier II streams in every county (23), but they are not evenly distributed throughout the state, and there are none located in Baltimore City. Maryland has no designated Tier III waters to date.

Maryland regulations provide Tier II designated streams with enhanced protection against degradation of water quality and habitat, including limiting sediment loads. Areas upstream of Tier II segments are also considered vital to the protection of the Tier II segment. All development that affects Tier II waters, including transmission line and solar project construction, is subject to review by MDE to eliminate any potential degradation resulting from the proposed activities.

Recent transmission line projects that cross or are located in the vicinity of Tier II waters include the Piney Grove to Wattsville upgrade (Nassawango Creek) and the portion of the Transource project located in Harford County (Island Branch). In addition to the protection of water quality and habitat by stringent best management practices (BMPs) for sediment and erosion control, PPRP recommended specific Integrated Vegetation Management (IVM) plans in areas upstream of Tier II waters in these cases. PPRP also recommended relocating poles that are in sensitive areas such as wetlands or riparian buffers.

The Shugart Valley and Ripley Road Solar Facilities in Charles County Maryland involve the cutting of nearly 500 acres of forested land in Tier II watersheds. This action triggered further involvement by MDE, requiring a condition that stream buffers upstream of the Tier II waters be buffered 100 ft., on average from the Limit of Disturbance. In addition, MDE is requiring pre- and post-construction stream monitoring at or near the Tier II segments, in accordance with Maryland Biological Stream Survey (MBSS) protocols. This monitoring will consist of benthic macroinvertebrate and fish sampling in order to assess any potential change in water quality due to the construction and operation of the solar facilities. [82]

[82] Subsequent to the award of CPCNs with this Licensing Condition, on August 28, 2019 MDE denied the Shugart Valley project a Wetlands and Waterways construction permit, determining that the Applicant had "failed to demonstrate that the project's impacts to a high quality (Tier II) water, which lacks assimilative capacity, are acceptable and justifiable under applicable laws and regulations." Simultaneously, MDE filed a letter with the PSC for the Ripley project indicating that "MDE has determined that the Report does not adequately demonstrate the social and economic needs for the project or provide an adequate justification for lowering water quality in the watershed of Mill Run 3 Charles County. Accordingly, it is MDE's position that MD Solar 2, LLC has not satisfied Condition 13.e of the CPCN." As of the time of this writing, it was unknown whether the Applicant would address this deficiency and be allowed by MDE and the PSC to continue with construction of the Ripley facility.

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 resuspend contaminated sediments, disrupt benthic 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 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, with in-water transmission towers found in the Potomac River (6 structures near Quantico), the Patuxent River (8 structures near Chalk Point), and Bear Creek (5 structures, near Sollers Point). 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 sampling and hydrodynamical modeling prior to construction.

Recently, BGE has proposed a new overhead transmission line across the Patapsco River, near the Key Bridge. This project would place 5 transmission structures in the River, with potential effects similar to those described above. The two largest towers would span 2200 feet across the Baltimore Harbor navigation channel and be protected by football-field sized collision protection barriers, made of concrete and mounted on an underwater wall of steel piles driven into the river bottom. PPRP is carefully evaluating the potential loss of bottom habitat and the effects of these proposed structures on natural resources, including aquatic vegetation, blue crabs, oysters, fish, migratory waterfowl and birds.

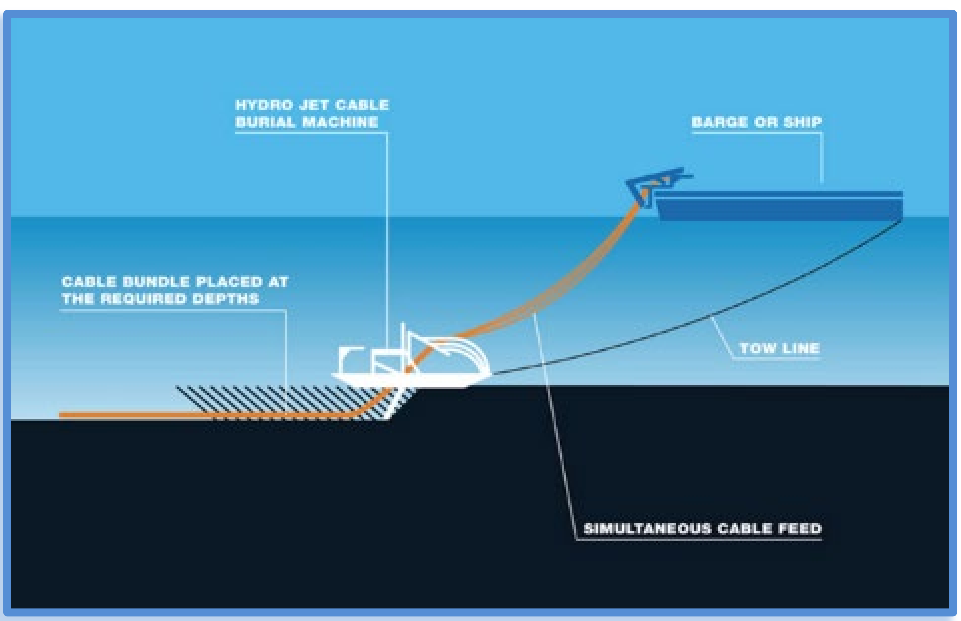
Impacts to the Chesapeake Bay and Coastal Waters

The prospect of offshore wind turbines and the need for more power on Maryland's Eastern Shore have resulted in past proposals for transmission lines across (under) large expanses of the Chesapeake Bay or the waters off Maryland's Atlantic Coast. Technological advances have significantly improved the feasibility and cost-effectiveness of long-distance submarine cable installations that are required for such projects. Underwater cables already exist in several areas of the United States, including Long Island Sound, Raritan Bay and San Francisco Bay. Submarine cables offer visual and engineering advantages compared to overhead lines across water bodies. In any specific area, PPRP must compare these advantages to the impacts to the biological communities that inhabit the bottom, and the food chains that depend on them. A submarine transmission line will cause multiple short-term, acute impacts resulting from installation activities, and long-term impacts from construction disturbance, maintenance activities, and, ultimately, the operation of the electric power line.

Utilities typically install underwater transmission cables several feet deep in the bottom sediments. Under some circumstances, such as rocky hard bottom, a utility will place the cable directly on the bottom. This latter technique affords the least protection from currents and manmade disturbance, such as being hooked by an anchor or damaged by commercial fishing operations. There are several methods for installing cables, including horizontal directional drilling (HDD), the use of a jet plow, trench excavation, or a combination of these techniques. The HDD technique can accidentally release pressurized drilling muds if there are weaknesses in the overburden, thereby contaminating sediments and increasing turbidity in the surrounding area. Jet plowing involves several steps to clear the area of debris prior to cable installation (e.g., grapnel dredging, pre-jet plowing), resulting in multiple sediment disturbances and the direct loss of benthic habitat along the cable corridor before the utility contractor can place the cable in the trench. Figure 5-35 illustrates a jet-plow installation, where a large sled is pulled along the cable corridor with high-pressure water jets fluidizing the sediment into which the cable sinks. Direct trench excavation creates the most impact due to removal and replacement of excavated materials.

SMECO's Holland Cliff to Hewitt Road 230 kV Transmission Line Project included a crossing at the Patuxent River using HDD under the riverbed. The crossing is parallel to and upriver from the Rt. 4 Bridge between Johnstown and Town Creek, Maryland, with end points at Point Patience and Patuxent Beach Road. A portion of the line also traverses the Navy Recreation Center (NRC) in Solomons through underground duct banks (concrete-lined trenches used to place power cables underground, then covered with vegetation or pavement). Because the termination point is within the Chesapeake Bay Critical Area, SMECO selected a previously developed site. The underground cable crossing is in an area of the river that is rich in biological resources including oysters, habitat for overwintering ducks, tidal wetlands, and submerged aquatic vegetation. SMECO completed the environmental studies required to comply with conditions of the CPCN concerning HDD beneath the Patuxent River, including a sampling plan to establish the river bottom baseline conditions using geotechnical and biological surveys of the river bottom with provisions for additional sampling if an inadvertent release of drilling fluids ("frac-out") occurred during the HDD process. CPCN licensing conditions recommended by PPRP required SMECO to develop a Contingency Plan using both pollution history and sampling data to help protect the living resources of the Patuxent River in the event of a frac-out. SMECO completed the HDD under the Patuxent River without incident in October and November of 2013.

Figure 5-35 Illustration of an Underwater Cable Installation Using Jet Plow Technology



Source: http://hudsonproject.com/project/description/

In Maryland, the laws that protect the "Critical Area" around the Chesapeake Bay and the Atlantic Coastal Bays require thorough environmental evaluations before building these types of underwater transmission lines. The Critical Area includes, in addition to the waters of the Chesapeake Bay and the Atlantic Coastal Bays and the submerged land below them, all land within 1,000 feet of either the mean high water line of tidal waters or the landward edge of tidal wetlands. The Critical Area Act (1984) authorizes state and local governments to assess impacts caused by construction disturbances, run-off and activities within the 1,000-foot buffer zone. Any project that directly or indirectly affects 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).

During project review, impacts evaluated include effects on turbidity, alterations of nutrient and dissolved oxygen concentrations, thermal changes, electromagnetic fields produced by the cables, salinity, and the creation of physical barriers on or in the bottom sediments. Continuously operated buried cables typically reach internal core temperatures of 90°C and may create zones of elevated sediment temperature above ambient conditions, depending on sediment thermal characteristics. Heat released during the operation of the cable could create a permanently warm area, affecting benthic habitats, spawning times of sessile species, and water mixing patterns. Long-term heating of the sediment could also create refuges for or increase the rate of growth of bacteria such as *Vibrio vulnificus* and *E. coli*.[83,84] Oysters and other shellfish that ingest these bacteria pose a human health risk.

Aquatic habitats may be affected by resuspension of sediments during construction or maintenance of the cables by the release contaminants or nutrients into the water column. Depending on the depth profile and tidal influences, disturbances that resuspend sediments or contaminants could have effects well beyond the immediate physical footprint of the cable path, such as nearby oyster and clam beds. An underwater cable could therefore affect the benthic habitat and the species that depend upon it for food, spawning, or juvenile development, including oysters, softshell clams, crabs, resident and migratory fish, overwintering sea ducks, and many other sensitive species.

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.

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[83] Jacobs, J.M., M. Rhodes, C.W. Brown, R.R. Hood, A. Leigh, W. Long and R. Wood. 2010. 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. 12 pp.

[84] Blaustein, R. A., Y. Pachepsky, R. L. Hill, D.R. Shelton and G. Whelan. *Escherichia coli* survival in waters: Temperature dependence. Water Research. Volume 47, Issue 2, 1 February 2013, Pages 569-578.

5.3 Impacts to Terrestrial Resources

Maryland's physiographic diversity, geology, and climate have produced a variety of ecoregions that foster numerous, and sometimes unique, habitats ranging from ocean barrier islands in the east through salt marshes, fields and forests on the coastal plain, into rolling piedmont hills, and on to forested mountains with remnant alpine glades to the west. While human activities (agriculture, urban/suburban development, etc.) have altered all these areas to some extent, the majority of the landscape still consists of a wide variety of habitats that support diverse communities of flora and fauna. Many of these communities help define their regions and may contain rare, threatened or endangered (RTE) species.

The State of Maryland enforces a suite of regulations (COMAR Titles 08, 26 and 27) that protect habitats and species in terrestrial and wetland environments, including regulations governing:

- Waterway Construction;
- Water Quality and Water Pollution Control;
- Erosion and Sediment Control;
- Nontidal Wetlands;
- Tidal Wetlands;
- Forest Conservation;
- Threatened and Endangered Species; and
- Critical Area of the Chesapeake Bay and Atlantic Coastal Bays.

The construction and operation of power generation facilities can have significant effects on terrestrial environments, including wetlands. Power plant infrastructure, including production units, pipelines to transport water, oil and natural gas, electrical transmission lines, and roadways and railways, can occupy extensive areas on the landscape. Notably, these facilities can:

- Physically alter or eliminate existing natural habitats;
- Disturb or result in the loss of wildlife species;
- Affect landscape ecology through atmospheric emission and deposition of particulate matter (PM) and other air pollutants; and
- Degrade habitats by the permitted discharge of pollutants or from accidental spills.

Impacts from new generation projects on Maryland's landscape depend on the mode of power production. Power plants using traditional resources such as coal and natural gas are generally confined to relatively small, intensively developed installations and their associated linear facilities, whereas renewable energy projects using wind turbines or solar panel arrays may occupy hundreds of acres. PPRP has reviewed more than 30 proposed solar generation facilities. These projects are located throughout the state and raise several environmental issues, many related to their size. For example, projects located near the Chesapeake Bay may include development in the Critical Area, and projects in agriculturally zoned areas may remove designated prime farmland out of production. Many of the projects require mitigation under the Forest Conservation Act, either for clearing trees or for developing land previously used for agriculture. 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 traditional 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. Recent examples highlighting the scope of impacts to terrestrial resources include two projects in Prince George's County – Keys Energy Center, which began operating in July 2018, and Mattawoman Energy Center, currently under construction.

Keys Energy Center is a combined cycle, natural gas-fired plant on a 180-acre parcel of land formerly used for a sand and gravel mining operation. The permanent electric power generation and support facilities require approximately 30 acres of the parcel. The site is adjacent to Pepco's existing 500 kV transmission line right-of-way located on the western side of the property. The associated gas pipeline is situated on the previously vegetated side of the existing 500 kV transmission line which required clearing many acres of forested habitat. The gas pipeline route also crosses sensitive areas such as wetlands and streams, including the headwater streams of Zekiah Swamp.

The Mattawoman Energy Center project site is an industrially zoned previously cleared 88-acre plot on Brandywine Road in Prince George's County. Linear facilities associated with the Project initially included an approximately 10-mile-long reclaimed wastewater pipeline to bring treated effluent from Piscataway WWTP, an approximately 7.4-mile-long natural gas pipeline and a 2.3-mile-long generation lead line extending from the power plant site north to Pepco's Burches Hill to Talbert 230 kV transmission line. The developer has modified plans to include a dry cooling system, eliminating the reclaimed water pipeline. The proposed substation site is located on Cherry Tree Crossing Road, adjacent to the Pepco 230 kV transmission line corridor. The site contains approximately 8 acres of predominately upland forest. The gas pipeline will widen the existing corridor of the Pepco/SMECO transmission line ROW, requiring clearing many acres of forest. A portion of the ROW, at the Mattawoman Creek crossing, runs directly adjacent to the proposed gas pipeline route for the Keys Energy Center. The last 1-mile segment of new ROW required for the gas pipeline runs parallel to Jordan Swamp.

Maryland has more than two thousand miles of electric power transmission line and natural gas pipeline rights-of-way. Constructing and maintaining these rights-of-way creates long, mostly linear corridors that are often quite different from the surrounding environment. These corridors can affect nearby areas, including terrestrial habitats and wetlands, in a variety of ways, either temporarily during construction or over the long term. To provide appropriate oversight and opportunity for public input, and to ensure that environmental and other concerns are addressed, new transmission line corridor construction or modifications in existing corridors require applications to the Public Service Commission to issue a CPCN.

Transmission line corridors may affect specific environmental features, alter the landscape over long distances or change the way people use nearby residential, commercial or agricultural land. For each right-of-way modification or construction proposal, PPRP reviews the potential impacts of the proposed project on streams, floodplains, wetlands, forests, rare species, historical and archeological sites and surrounding land use. Quantitative comparisons of alternate routes are derived from digital maps, aerial photographs, and other data sets, and supplemented by field inspections. The purpose of these comparisons is to identify the types of impacts that may occur along each possible corridor and to find the route with the lowest overall impact. Where undesirable impacts cannot be avoided, recommendations may include compensating for the damage and/or maintaining certain conditions in the corridor after construction.

PPRP's role in the CPCN process is to balance compliance with Maryland's environmental regulations and natural resource management objectives with the public's need for additional power facilities. Environmental laws affecting Waterways Construction, Water Quality and Water Pollution Control, and Erosion and Sediment Control require the use of Best Management Practices (BMPs) to eliminate or minimize disturbance in, and discharges to, Maryland waters. These BMPs are uniformly included as conditions to a CPCN. However, a CPCN can also recommend conditions to avoid, minimize or mitigate specific impacts on natural resources. Under these circumstances, conditions placed on a CPCN to mitigate impacts to wetlands, forests, and sensitive species and their associated habitats may often be more stringent than requirements under the individual statutes.

5.3.1 Impacts to Forests and Maryland's Green Infrastructure

Generation Facilities

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 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 contain more forest interior habitat and often support unique niches for rare, threatened or endangered 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 aboveground plant tissue and belowground roots as a forest grows, and is added to soils as dropped leaves and branches decay. Forests are also important commercial resources, providing construction materials and renewable fuel supplies. In view of these important ecosystem services and compelled by the significant losses of Maryland's forest resources over time, the Maryland State Legislature enacted the Forest Conservation Act (FCA) in 1991. All construction 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 condition and character is an integral component of power plant and transmission line facilities siting and development. The FCA 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. Under the FCA, tree conservation, replanting and other environmental actions must be considered before any development disturbs forest resources. The Maryland Forest Preservation Act of 2013 amended the state's forest conservation policy to specify the state's no-net-loss policy requires maintaining a statewide tree canopy cover of 40 percent. This legislation will help maintain and protect the state's forests, which is crucial to the health of local rivers, streams and the Chesapeake Bay. In addition to the no-net-loss requirements, this legislation adds a dual sustainability certification requirement for state Forests and extends tax benefits to more Marylanders who work to increase tree cover on their property.

Taken together, the Forest Conservation Act (1991), the Sustainable Forestry Act (2009), and the Forest Preservation Act (2013) all bear on actions that remove forests or develop non-forested land. Consistent with these Acts, the PSC has certain responsibilities with respect to forest conservation during the CPCN review, as specified in the Natural Resources Article, 5-1603 (f): "After December 31, 1992, the Public Service Commission 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."

Compliance with FCA mitigation standards for tree removal or for development of agricultural land meets the requirements of the PSC review. 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. New CPCNs issued for the construction of electric generating facilities require compliance with these requirements. Once a CPCN is issued, certain FCA exemptions are available to utilities for subsequent maintenance activities. Generation project developers are required to consult with their respective counties and comply with the county's requirements for any afforestation, reforestation or mitigation that may apply to the project.

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. For example, the CPCN to construct the Rock Springs generating facility in Cecil County included

Maryland's Forest Conservation Act (FCA) and Solar Generation

Maryland's agricultural land is an attractive option for siting solar generation facilities. More than 30 solar generation facilities are currently under construction or review by PPRP. Almost all of these facilities have been located on agricultural lands. The availability of large tracts of open land in rural communities, which generally does not require extensive site work (e.g., grading, or clearing), is ideal for solar generation development, particularly if located within proximity to a power substation.

Maryland's Forest Conservation Act (FCA), specifically Maryland Code, Sections 5-1602(b)(5) and 5-1603 of the Natural Resources Article, establishes standards for land development that make the identification and protection of forests and other sensitive resources an integral part of the site planning process. The conversion of agricultural land for development triggers FCA mitigation requirements, even if no trees are being removed (afforestation). Generation projects must be permitted through the CPCN licensing process and must minimize forest loss during site development. As such, PPRP recommends project-specific CPCN license conditions requiring project developers to meet the county's requirements for any afforestation, reforestation or mitigation that may apply to the project.

restoration conditions to compensate for the ecological value of mature forest lost and to compensate for some of the nitrogen deposition caused by the facility's emissions. Specifically, the removal of 20 acres of mature forest required the applicant to plant 50 acres of young trees. The reforestation, initiated in 2002 at two DNR-owned sites, included fields adjacent to streams to increase the likelihood that deposited nitrogen would be intercepted before reaching Chesapeake Bay tributaries. Subsequent site studies, however, showed that at one reforestation site, 18 acres in size, 80 percent of the planted trees died by the summer of 2013. At the other site, 32 acres in size, no individuals of many of the planted species were found, while 60 percent of the trees present were non-planted species seeded from nearby forest areas. Based on these results, PPRP plans to reevaluate the efficiency of such restoration projects.

Transmission Facilities

Transmission line right-of-way management has historically used a simplistic paradigm of clearing all vegetation, reseeding with grasses, mowing frequently and/or applying herbicides to kill shrubs and tree seedlings that invade the right-of-way. This approach allowed easy access to the transmission line but was frequently detrimental to natural habitats.

Over 40 years ago, the Working Committee on Utilities of the President's Council on Recreation and Natural Beauty prepared an extensive report on "actions required assuring utility transmission and distribution lines and utility plant sites are compatible with environmental values." Most of the recommended alternative management practices for minimizing the impact of transmission lines remain valid today. Among the suggested practices that have been recommended to transmission line owners, but have been slow in implementation, are the following:

- Right-of-way 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 right-of-way edges through forests or timber areas should undulate boundaries, not create straight "walls" that create a "tunnel" effect.

- Small trees and plants should feather the height of the right-of-way vegetation from grass and shrubbery near the center to larger trees at the edges.

Rights-of-way that are constructed through Green Infrastructure hubs and corridors fragment habitats and diminish their ability to function as integrated habitat units. 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 such as Japanese honeysuckle, Korean bush clover, Asiatic bittersweet and wicker microstegium can grow prolifically in the cleared-edge habitats of transmission line rights-of-way and can spread into the forest interior, limiting the growth of native species. Careful vegetation management in the right-of-way can minimize potential impacts. For existing transmission line rights-of-way in Green Infrastructure areas, expansions of the right-of-way into the surrounding natural territories can be particularly harmful. Siting new transmission lines within Green Infrastructure network components is strongly discouraged unless it is not possible to bypass the Green Infrastructure system and align the new transmission line with preexisting disturbed and degraded areas.

5.3.2 Impacts to Wetlands

Generation Facilities

Wetlands are important components of the environment, forming the interface between terrestrial and aquatic ecosystems. Wetland communities often comprise diverse plant species, several of which may be species of concern. Wetlands also provide numerous ecosystem services that benefit human society, including fish and wildlife habitat, flood protection, erosion control, and water quality maintenance. At the end of the 18th century, Maryland had nearly 1,650,000 acres of nontidal wetlands (24.4 percent of the land area); 220 years later, in 2009, Maryland had only about 345,000 acres of nontidal wetlands (4.8 percent of its land area), a reduction of approximately 80 percent. To address such losses, 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. For example, a ratio of 3:1 is applied to scrub/shrub and forested Wetlands of Special State Concern; a ratio of 2:1 is applied to other scrub/shrub and forested wetlands, and to herbaceous Wetlands of Special State Concern; and a ratio of 1:1 is applied for emergent wetlands. Analogous to this, the 1994 Tidal Wetlands Regulations were developed to regulate activities in tidal wetlands, and mitigation requirements are similar for state tidal wetlands. Temporary impacts and impacts to wetlands buffers do not usually have replacement mitigation requirements but may require compensatory or enhancement measures.

PPRP's CPCN analysis includes assessing potential wetland impacts and developing appropriate mitigation equal to or greater than required by the state's wetland regulations. While wetlands are present at nearly all Maryland's power facilities, impacts to these wetlands can usually be avoided. Where especially valuable wetlands are present, PPRP's process, in consultation with MDE, identifies specific CPCN conditions to ensure their protection. For example, the CPCN to construct the Competitive Power Ventures (CPV) generation facility in Charles County included the following conditions to protect the Zekiah Swamp Natural Environmental Area, a Nontidal Wetland of Special State Concern:

- Preparation of a protection plan that ensures the wetland recharge rates to Piney Branch Bog are maintained and do not exceed current conditions through the use of shallow infiltration beds and vegetated terraces; and

- Establishment of a permanent protection buffer with no vegetation clearing, earthworks or other disturbances allowed within 300 feet of Piney Branch Bog.

Generation facilities such as the Keys Energy Center (KEC) and Mattawoman projects require associated linear facilities including gas and water pipelines and transmission lead lines. Construction of gas and water linear facilities may affect streams and wetlands through vegetation removal or ground disturbance. Impacts to wetlands can be minimized through advanced construction techniques such as horizontal directional drilling (HDD). For example, in the KEC and Mattawoman cases, PPRP developed CPCN licensing conditions recommending HDD along portions of their natural gas pipeline corridors to avoid impacts to Wetlands of Special State Concern.

Transmission Facilities

Wetlands are among Maryland's most valuable natural resources. The Critical Area Act protects land within 1,000 feet of tidal waters and tidal wetlands, while nontidal wetlands — including wetlands in utility rights-of-way — fall under the Nontidal Wetlands Protection Act. Maryland's overall goal is no net loss of nontidal wetlands 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. To construct a transmission line project in a wetland, the developer must obtain a Letter of Exemption, a State Programmatic General Permit or an Individual Wetlands Permit that details project-specific conditions from MDE, the U.S. Army Corps of Engineers or both. While new routes are usually planned to avoid wetlands, rights-of-way constructed prior to the Nontidal Wetlands Protection Act were often less favorably sited, and many undesirable wetland impacts occurred. For example, the Burtonsville to Takoma Park transmission line route, which had a CPCN approved in 2014, located in Prince Georges County, Maryland traverses sensitive wetlands and streams including Little Paint Branch Creek, which has one of the state's last American Brook Lamprey populations.

Wetland impacts result when vegetation, soil or water flow is altered by a transmission line right-of-way, 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, changing both the natural drainage and the soil characteristics. Parts of the wetland that are isolated from their water source by the road or associated ditching 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 on and directly adjacent to a dry elevated roadbed and compete with the adjacent wetland plants for sunlight and water. Because of vigilant permitting oversight by MDE, U.S. Army Corps of Engineers, and DNR, and appropriate planning by the utilities, 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, avoiding direct impacts. Matting is often placed over wetland areas to minimize damage from equipment and activities when upland access is not possible, without building permanent roads.

Indirect construction and maintenance impacts to wetlands are caused primarily by soil disturbance in uplands that allows runoff to convey loosened soil into streams and associated wetland areas. Construction activities can also disrupt nearby wetland habitat, especially during critical reproductive periods for the plants and animals that comprise the wetlands ecosystem. Impacts can often be minimized during construction by the use of appropriate best management practices. After construction, impacts can be reduced by refraining from mowing or using other equipment within wetlands areas and using EPA-approved and appropriate herbicides to eliminate nonnative invasive species in or near wetland areas. 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 generation facilities primarily affect wildlife by removing habitat during construction of the project. For example, the Cove Point LNG expansion project produces liquefied natural gas for exportation; however, construction required that 97 acres of forested area be cleared for construction laydown and staging areas. The loss of habitat from this area affects forest interior dwelling species (FIDS) of birds, including the scarlet tanager, barred owl, pileated woodpecker and eastern whip-poor-will. The loss of FIDS habitat also affects properties adjacent to the cleared area. Wildlife were affected by loss of habitat, and addition of light, noise and activity during the construction period.

Wind energy projects can also have a substantial impact on wildlife during construction and operations, especially to birds and bats. Depending on the number of wind turbines, usually installed in linear arrays, 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 during assembly. The loss of habitat can lead to the eradication or displacement of species in these areas.

All of the wind power facilities developed in Maryland 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 to the north, and historically included pure stands of white pine, eastern hemlock and red spruce. At present, however, logging, coal mining and home construction have fragmented much of these forests. Where contiguous forest exists, wind power development within these forests could increase fragmentation. Fragmentation affects birds and bats as well as other terrestrial species through direct loss of forested habitat, the encroachment of species that can have direct (e.g., brown-headed cowbirds that parasitize songbird nests) or indirect (e.g., raccoons that can be disease vectors for rare mammals) detrimental effects, the potential disruption of corridors for daily movement or seasonal migration, and the failure of the resident species to adapt to the wind power facility.

PPRP and DNR’s Wildlife & Heritage Service routinely review and comment on Bird and Bat Conservation Strategies (BBCS) for wind power projects. An Avian Protection Plan or BBCS for a project is a project-specific document that 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 and bat species to the greatest extent possible, including species protected under the Migratory Bird Treaty Act, the Bald and Golden Eagle Protection Act, and the Endangered Species Act, as well as the State of Maryland Nongame and Endangered Species Conservation Act.

A BBCS must be structured around careful project planning, siting and construction, allowing power project developers to avoid impacts to birds and bats that could result from construction, operation, and decommissioning of projects. Appropriate power project design and construction measures must be implemented to avoid and minimize avian and bat impacts to the greatest extent practicable. The goal of avoidance and minimization measures for birds and bats is to eliminate aspects of a project that pose risks to these species.

Although raptor mortality rates at wind power projects in the Appalachian Mountains have been minimal to date, there has been some increase in mortality in areas of the Western United States. Conversely, bat mortality rates at some wind power projects along the Appalachian Mountains have been among the highest reported in the U.S. Birds and bats are typically treated separately in a BBCS document, therefore, with unique avoidance and minimization measures applied as appropriate. If monitoring indicates that avoidance and minimization measures are not effective, adaptive management measures have been implemented, including additional conservation measures, as needed.

In Maryland, land-based wind power facilities less than 70 MW can apply to the PSC for an exemption from obtaining a CPCN. Although this exempts developers from the coordinated PPRP environmental review, they must still comply with federal and state regulations protecting threatened and endangered species. Furthermore, an exempted project must undergo permitting review administered at the county level; and satisfy all local planning and zoning requirements.

Solar facilities are the most space-consuming types of generation plants. Approximately 5 to 7 acres of solar panels are required for each megawatt (MW) of power that is produced. Generally, larger solar projects in Maryland have been in the 100- to 300-acre range on previously cleared agricultural land, but recently an 1100-acre, 200 MW project was approved for Caroline County. Such farmed lands usually offer little existing wildlife habitat, since they have been intensively managed, limiting 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. However, these large open areas often provide forage spaces for species that live in peripheral and adjacent areas. When the farmland is lost to large solar arrays, population sizes may be reduced or the species composition may change, e.g. birds that hunt in large open spaces may be replaced by birds that favor the narrow, confined areas between solar panels.

Solar projects can also be developed and maintained in a way that provides benefits to wildlife. 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. PPRP promotes, on behalf of DNR, practices that support native Maryland pollinators and expand their habitat (see sidebar). One recent project has proposed to turn the entire area beneath the solar panels into grassland habitat suitable for ground-nesting birds.

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 honey bees, native bees, birds, bats, and butterflies, during the last few decades.

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

Source: http://www.ivmpartners.org/#!

In June 2014, President Obama issued a memorandum establishing a Pollinator Health Task Force, cochaired by USDA and EPA, to create a National Pollinator Health Strategy to promote the health of honey bees and other pollinators (including birds, bats, butterflies and insects). Migrating Monarch butterflies dropped to the lowest recorded population level in 2013-14. 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. PPRP is working with other state and DNR agencies to establish regulations that implement this certification program. Expansion of pollinator habitat is also promoted through cooperative agreements with new or existing generation projects to investigate the feasibility of providing onsite, self-sustaining habitats for honeybees, bumblebees, important insects and other pollinators. These pollinator habitats would replace frequently mowed herbaceous or crop areas (but never replace forested habitats) on a project site. The pollinator habitats consist of native herbaceous plants that are known to attract a variety of pollinator species (e.g., Bee Balm, Butterfly Milkweed, Black-eyed Susan, Joe-Pye Weed, etc.). 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 habitat can also be managed in electric transmission rights-of-way with integrated vegetation management (IVM) 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 Right-of-Way border and in ravines.

Transmission Facilities

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

A transmission line right-of-way through a forested area creates cleared areas with abrupt edges that are not desirable habitat for FIDS, and often provides a corridor for invasive species that compete with or prey upon native forest species. The effects of these changes are particularly severe near forested streams and wetlands. While there are lesser impacts in shrub-scrub and agricultural habitat areas, maintaining the right-of-way 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. Even highly mobile species may not be able to maintain a coherent population under these circumstances, because individuals that attempt to cross the cleared area may be exposed to a high risk of predation.

Forest interior habitat may support many species, including but not limited to birds, terrestrial mammals, reptiles, amphibians and plants. The forest interior habitat is uniquely productive and protected and may form a core refuge for common forest species that also live in or near forest perimeters or noninterior areas. FIDS, however, are particularly sensitive to the size of the remnant habitat patch. Interior habitat is defined as a contiguous zone of forest that is more than 300 feet inside of the edges of the forest area and is dependent on the shape of the area as well as its total size. Long-term research by DNR indicates that interior habitat usable by some plant and animal species can exist in forest parcels as small as a couple of acres, but sufficient interior habitat to support resident breeding populations of avian FIDS generally requires several hundred acres. According to the Natural Heritage Program, the populations of many avian FIDS are declining in Maryland, often because of 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 patches smaller than 100 acres or in riparian areas.

Another potential impact of transmission lines is bird collisions and electrocutions. Bald eagle nests are occasionally found on transmission line towers (see Figure 5-36). The U.S. Fish and Wildlife Service and the Avian Power Line Interaction Committee cooperatively developed guidelines to help prevent injuries to birds that contact power lines. The state uses the voluntary guidelines, as updated in 2012, to help utilities develop Avian Protection Plans that meet the specific needs of their facilities, protect birds from electrocution and collisions, and reduce the likelihood of power outages caused by bird collisions.

Figure 5-36 Bald Eagle's Nest in a Transmission Tower

5.3.4 Impacts to Rare, Threatened, and Endangered Species

Generation Facilities

Rare, Threatened, and Endangered (RTE) species, whether Federal-listed under the Endangered Species Act or state-listed under Maryland's Threatened and Endangered Species regulations are distributed throughout the state; however, for the most part, these species are restricted to specific habitats. Generation projects proposed in Maryland must undergo RTE species review by the DNR's Wildlife & Heritage Service (WHS) to identify RTE species known to occur near the affected area. Recommendations made by the WHS during the review usually form the basis for conditions in the CPCN. Regardless of the kinds of habitat involved, state-listed threatened and endangered plants and wildlife are protected under state law. Table 5-9 lists the number of protected species by category that the CPCN process considers when evaluating potential adverse effects and developing protective recommended license conditions.

Table 5-9 Number of State-Listed Rare, Threatened, and Endangered Species by Category

Summary of State Listed Species*		
Category	**Plants**	**Animals**
Endangered	271	91
Threatened	74	19
In Need of Conservation	n/a	29
Endangered Extirpated	100	28
Total	445	167

* Summary of State Listed Species only includes species listed in COMAR 08.03.08
Source: Maryland DNR: http://dnr.maryland.gov/wildlife/Pages/plants_wildlife/rte/espaa.aspx

Although few applications for power generating facilities affect listed threatened and endangered and rare species, several individual cases have considered potential impacts to Northern Long Eared Bat, Eastern Small-footed Bat, Bald Eagle (subsequently delisted both federally and by state), tiger beetles, Carpenter Frog, timber rattlesnake and plant species such as Purple Pitcher Plant, New Jersey Rush and Winterberry. During a site visit to the proposed Dan's Mountain Solar site in Alleghany County, WHS personnel determined that four specific points along the eastern part of the site and directly bordering it likely provide habitats for two listed RTE species and one rare species in Maryland; these species include Allegheny Woodrat (*Neotoma magister*; State Endangered); Eastern Small-footed Bat (*Myotis leibii*; State Endangered); and Timber Rattlesnake (*Crotalus horridus*; not listed, but rare). In addition, Northern Long-eared Bat (*Myotis septentrionalis*) occur near the proposed Dan's Mountain Solar project site. Both the federal and Maryland Endangered Species Acts list the Northern Long-eared Bat as Threatened. These four species of concern could be affected by the development of the proposed solar facilities at this site. Although the PSC ultimately denied this project, during the proceedings PPRP drafted CPCN license conditions requiring the project developer to produce a Habitat Conservation Plan that protected these four species. Further, given that forest clearing would have been required to complete this solar project, PPRP recommended that Dan's Mountain Solar coordinate with the U.S. Fish and Wildlife Service regarding the Northern Long Eared Bat.

Wind turbines can kill birds and bats that collide with them, or as recent research has shown, cause the death of bats through barotrauma, a fatal hemorrhaging of the lungs of bats from the rapid change in air pressure near the spinning turbine blade. After two decades of study at several wind power facilities in the U.S. and abroad, there is evidence that the numbers of bird fatalities are minimal at most locations. Two to three birds are killed annually per wind turbine on average. Studies at facilities constructed on eastern Appalachian ridges in West Virginia and Pennsylvania report similar rates of bird fatality. In contrast, the numbers of bats killed at these regional facilities are among the highest ever reported, and annual estimates range into the thousands for each project.[85,86,87] It is currently believed that most of the bat fatalities occur during the late summer to fall migration period as bats move to their overwintering habitat.

Wind energy facilities in the Midwest have killed several federally Endangered Indiana bats. Western Maryland provides year-round habitat to the Indiana Bat, as well as the state-listed Endangered Eastern Small-footed Bat. Most records of these two species come from winter cave surveys when the bats are hibernating. Much less is known of their habits during the flying season as they disperse throughout the landscape; however, a recent radio-tracking study followed a single female Indiana bat from a Pennsylvania cave to Carroll County, Maryland. 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.

The discovery that White Nose Syndrome was severely affecting bat populations in caves of the northeast resulted in even greater concern about the risks to cave-hibernating bat species, including the Indiana Bat, the Northern Long Eared Bat, and the more common Little Brown Bat. This fungal disease, first noted in 2006, has spread rapidly throughout eastern North America, causing up to 90 percent bat mortality in some caves. Bats succumb to White Nose Syndrome during winter hibernation periods after becoming sick and either dying within the cave or departing prematurely and perishing outside the cave during winter. The fate of these bat species, when considering the cumulative impacts of White Nose Syndrome and the growing wind energy industry, has yet to be determined. The U.S. Fish and Wildlife Service published a 4(d) Rule for the Northern Long Eared Bat that identifies protections provided under the federal Endangered Species Act related to certain practices and has designated a White Nose Syndrome Zone within which certain actions are restricted, such as tree removal. The Northern Long Eared Bat is found in a variety of forested habitats in summer. Incidental take resulting from tree removal is prohibited if it: (1) occurs within a 0.25 mile (0.4 kilometer) radius of known Northern Long Eared Bat hibernacula; or (2) cuts or destroys known occupied maternity roost trees, or any other trees within a 150-foot (45-meter) radius from the known maternity tree during the pup season (June 1

[85] Kerns, J. and P. Kerlinger. 2004. A study of bird and bat collision fatalities at the Mountaineer Wind Energy Center, Tucker County, West Virginia: annual report for 2003. Technical report prepared by Curry and Kerlinger, LLC. for FPL Energy and Mountaineer Wind Energy Center Technical Review Committee.

[86] Kerns, J. 2004. Patterns from daily mortality searches at Backbone Mountain, West Virginia. National Wind Coordinating Committee. Onshore Wildlife Interactions with Wind Developments: Research Meeting V. November 3-4, 2004.

[87] Erickson, W. 2004. Patterns from daily mortality searches at Meyersdale, Pennsylvania. National Wind Coordinating Committee. Onshore Wildlife Interactions with Wind Developments: Research Meeting V. November 3-4, 2004.

through July 31). Within the White Nose Syndrome Zone, Allegany County is designated as a county with known White Nose Syndrome infected hibernacula.

Transmission Facilities

Most rare, threatened or endangered species are composed of small populations that occupy specific environmental niches. Avoiding anthropogenic effects in these locations is the critical step in protecting the species, since even small disturbances may place the remaining population at risk. New transmission line corridors are usually an undesirable disturbance, although the habitats created by existing transmission line rights-of-way sometimes create an ideal niche for a threatened or endangered species. For example, the state-threatened Bog Turtle is known to occur in numerous locations in northern Harford County. WHS noted potential occurrences of this species impacted by the proposed eastern portion of the new Transource line. The utility was required to conduct a Phase 1 Bog Turtle Study following protocols set forth by the USFWS. Once this survey was performed and potential habitat was located, the DNR bog turtle expert made specific recommendations regarding time of year restrictions and potential distance from bog turtle hibernacula for construction impacts. Of special importance was the avoidance of vibration disturbance in the vicinity of hibernacula, as that could disturb the turtles and lead to loss. Floral species are especially a concern for the Ringgold to Catoctin transmission rebuild in Frederick and Washington Counties. At least eight floral species were identified along this ROW, including a population of White Turtlehead, the preferred host species for the endangered Baltimore Checkerspot butterfly. In a case such as this, specific coordination must occur with WHS to protect each species. In this case, licensing conditions included not only flagging and/or fencing known RTE areas, but the presence of an onsite third party environmental monitor during construction activities to help avoid or minimize impacts to sensitive species. In some cases, PPRP has recommended a licensing condition that requires the utility assist in an invasive species control program for some period of time after construction in order to ensure that construction activities did not introduce invasive species that would further impact RTE species areas.

The Maryland DNR Wildlife and Heritage Service (WHS), Natural Heritage Program, maintains a database of all known populations of the state's designated rare, threatened and endangered 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 rare, threatened or endangered species. If 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 Cumulative Effects on Biological Resources

Generation Facilities

Potential cumulative effects of generation facilities are dependent on their location, size and the amount of habitat disturbed. The most noticeable impacts are associated with wind turbines, which can kill birds and bats through collisions. The cumulative impact of bird fatalities, at present, is not considered to be severe for any one species, as no single species appears to be disproportionately affected. In addition, operational (e.g., lighting that can attract birds) and design (e.g., guyed structures) circumstances that can contribute to higher fatalities are better understood and new wind power facilities are constructed with reduced lighting and no guy wires to minimize impacts. Birds considered most at risk are songbirds that migrate nocturnally. High fatality events for these species often coincide with nights that have a low cloud cover resulting in birds flying closer to ground level. Although the Migratory Bird Treaty Act prohibits the "take" of any birds, the U.S. Fish and Wildlife Service, in practice, only requires that good faith efforts be employed to avoid fatalities.

The cumulative impact to bat species is of greater concern. The high level of recorded bat fatalities includes only a few species, predominantly red and hoary bats. These two species undertake long distance seasonal migrations and typically roost in trees, whereas most other species have shorter seasonal movements to and from caves in which they over-winter. While the specific population characteristics of these species are uncertain, they are relatively long-lived and produce few offspring annually, both characteristics that make them less able to sustain a high level of fatalities. Recent PPRP-funded studies of bat activity in Western Maryland have recorded high numbers of these two species during spring monitoring. Another study examined population genetics indicated red bats appear to have a larger overall population size than hoary bats and may be better able to absorb losses from wind energy facilities.

Transmission Facilities

In general, overhead transmission line corridors in Maryland range in size from approximately one hundred to three hundred feet wide, depending on the power-carrying capacity and the number of lines routed through the corridor. Due to their linear nature, transmission corridors invariably cross natural features such as streams; floodplains; forests; RTE species habitat; and historical and archeological sites. Siting new transmission lines or modifying existing lines requires careful planning and implementation to avoid impacts to these resources. Utilities have proposed several new transmission lines across Maryland in response to PJM's transmission planning and federal studies indicating that the northeastern U.S. is in critical need of increased transmission capacity and reliability. Furthermore, proposed offshore wind power facilities near the Maryland coast may require both offshore transmission and additional large capacity transmission lines on the Delmarva Peninsula. CPCN applications for interstate transmission projects like these raise many unique environmental and socioeconomic challenges, such as preserving natural habitats along the Atlantic Coast, shielding the views and vulnerable stream habitats of suburban central Maryland, protecting the sensitive bottom habitats of the Chesapeake Bay, or ensuring the security of power delivery to populations and facilities in Washington, D.C., Baltimore, Maryland, and other urban areas.

PPRP reviews the environmental impacts of proposed transmission line projects from several perspectives. The following subsections summarize the review considerations and typical impacts associated with these projects.

Impacts imposed by transmission line rights-of-way may be distributed over the landscape and affect many types of terrestrial natural resources. Small impacts to a resource, such as a forest or a watershed, at several locations can add up to a significant overall impact. At sensitive locations, such as stream and wetland crossings, small impacts to several different resources (e.g., forest, wetland and stream riparian areas) can disrupt the overall integrity of the ecosystem. These additive impacts of the right-of-way are called cumulative effects, and are a serious concern where ecosystems are near a critical threshold or are already degraded. Because the health of an ecosystem depends on functional interactions between its components, cumulative impacts can have a result much greater than a simple tally of the individual impacts.

There are several ways to assess cumulative effects. The effect of multiple stresses on an ecosystem is usually evaluated in a context that defines a standard for permissible impacts or a goal for restoration. For example, Maryland's Green Infrastructure network defines areas where natural conditions should be maintained or restored, while the Critical Area Law either restricts or requires mitigation for development in all sensitive habitats within Maryland's Chesapeake Bay and its tidal tributaries. Individual resources, on the other hand, are addressed in terms of specific impact thresholds or goals. For example, Maryland has set a "no net loss" standard for forests under the Forest Conservation Act and for freshwater wetlands under the Nontidal Wetlands Protection Act.

Forest clearing in a right-of-way provides an example of the nature of cumulative effects. One proposed project will require expanding the cleared width along roughly 30 miles of an existing right-of-way in southern Maryland. Although the width of additional clearing is only 100 feet and may not have large local consequences, over the length of the line, it totals to hundreds of acres of forest loss. The permanent removal of this much forest would be a significant regional environmental cost of the transmission line right-of-way.

Another transmission line right-of-way in southern Maryland, which was recently evaluated in response to a CPCN application to upgrade the capacity of the line, illustrates the multiplicity of impacts that must be considered. The right-of-way crosses more than 20 streams, at least 14 acres of Chesapeake Bay Critical Area, requires at least 20 poles in or near wetlands, fragments forest-interior-dwelling species habitat along its entire length, and affects a total of 179 acres of Green Infrastructure hubs or corridors. These statistics alone speak to the large and measurable cumulative effects that transmission line rights-of-way can have on some of Maryland's most critical natural resources.

5.3.6 Vegetation Management

In existing transmission line rights-of-way, past maintenance activities will have shifted the vegetation toward low-profile species, such as grasses, ferns, herbaceous plants or forbs, shrubs, and tree saplings. Figure 5-37 shows an example of typical transmission line vegetation management practices in Maryland. Many of the species present in the right-of-way may be nonnative species that were planted after the initial clearing to prevent soil erosion, or weedy and invasive species that have taken advantage of disturbed habitat in the corridor. In a few places where clearing to maintain the right-of-way has not been frequent, taller vegetation may be present, but generally the right-of-way 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 100-300 feet of the right-of-way boundaries) can also be degraded to some degree when the vegetative community within the right-of-way has been significantly disturbed or altered by construction and maintenance, such as in forested areas.

Figure 5-37 An Example of Typical Transmission Line Vegetation Management in Frederick County, Maryland

Trees in or near transmission line rights-of-way 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 percent of the total outages throughout Maryland.[88] There are fewer tree fall events that cause outages of larger transmission lines; however, DNR has joined with the Maryland Electric Reliability Tree Trimming (MERTT) Council, which typically focuses on 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 location, type of tree, and other details. DNR is assembling the data from utilities throughout the state into a common database and analyzing the data to provide the PSC with accurate information on the causes of such outages. The results will be used by MERTT Council members and DNR to evaluate current data collected following the implementation of new vegetation management standards, known as RM 43. These standards dictate how close tree branches can grow to

[88] PSC Staff, Engineering Division Review of 2014 Annual Performance Reports on Electric Service Reliability, Case No. 9353, August 17, 2015.

power lines, typically within a 4-year vegetation management cycle. They also allow utility companies to identify and remove hazardous trees near power lines.

NERC Regulations

Improperly maintained vegetation in a transmission line right-of-way can disrupt the integrity of the system and cause power outages. The North American Electric Reliability Corporation (NERC), operating under the oversight of Federal Energy Regulatory Commission (FERC), develops and enforces reliability standards for transmission lines. The NERC Reliability Standard FAC-003-3 (Transmission Vegetation Management), approved by FERC in 2013, codifies current best practices and requirements for reliability and is being 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 right-of-way. 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 (ANSI A300). The TVMP must also include a schedule for annual right-of-way inspections.

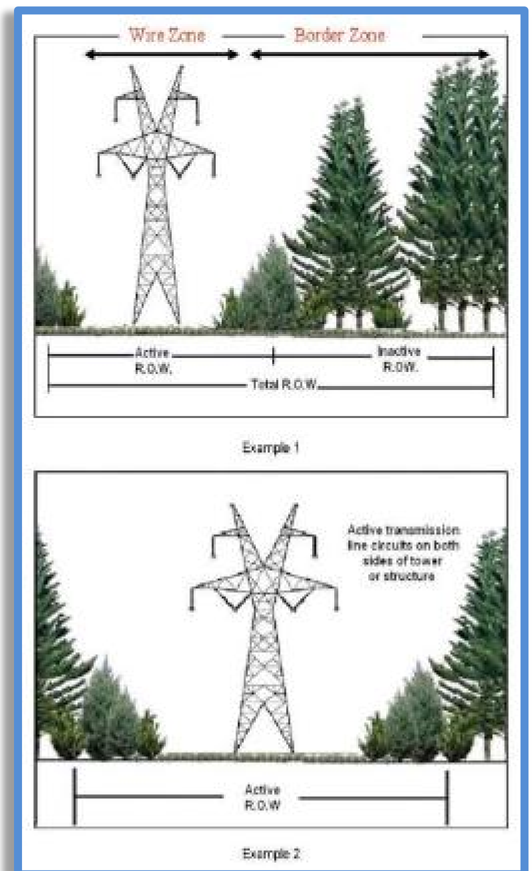
Current Practices

Transmission companies are required to maintain rights-of-way in a condition that assures 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 right-of-way, 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, and other advanced techniques such as the Integrated Vegetation Management approach recommended by the International Society of Arboriculture, can be implemented providing the required clearances are maintained. In general, most Maryland utilities use uniform, system-wide practices that may be more aggressive than NERC requirements. After forested land is cleared to create a transmission line right-of-way, several methods to maintain a low stature vegetative community within the right-of-way are generally used, including mechanical clearing, 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. Right-of-way corridors converted and maintained as open grassland habitat within forested habitats may not have much value for grassland breeding birds, and invasive and exotic species can be easily established in these areas. Clearing the entire right-of-way 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 right-of-way in a natural state to the maximum extent possible is the best alternative for protecting wildlife in sensitive areas. Creating curved or wavy right-of-way boundaries and piling brush from the cleared right-of-way so that it provides wildlife habitat would help mitigate impacts from right-of-way clearings in forested areas. Figure 5-38 illustrates feathered, or soft edges in a transmission ROW, which provide a transition from forest to open grassland or meadow habitat. Establishing a transition on both sides of the corridor that bisects a forested area with a medium height "border zone" along the edges, and a lower vegetated "wire zone" in the center of the corridor, referred to as the "U effect," also reduces the effects of fragmentation on wildlife. A transition zone of scrub-shrub habitat of at least 20 feet in height within the right-of-way is recommended for rights-of-way through forests, since long linear meadows do not have much value for grassland birds and these open areas tend to facilitate the establishment of exotic species.

Figure 5-38 Transmission Line Vegetation Management using Feathering Technique



Source: Examples adapted from NERC Standard FAC-003-2 Technical Reference, September 2009

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 rights-of-way, PPRP has, through its membership in the Maryland Electric Reliability Tree Trimming 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 rights-of-way in limited areas. The introduction of desirable species into the right-of-way through "right tree/right place" plantings or wildlife habitat enhancement projects is often possible. Where implemented, such programs have created better, more stable habitats for wildlife, and have saved thousands of dollars in annual maintenance costs.

Some research indicates that planting "connecting corridors" in the right-of-way 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-right-of-way connections, particularly in areas where the right-of-way fragments habitat used by forest interior dwelling species or crosses riparian areas and wetlands. PPRP continues to research the benefits of innovative best management practices for power line rights-of-way vegetation management.

PPRP reviews the Transmission Vegetation Management Programs of all applicants for CPCNs for new or modified transmission lines for compliance with the required standards and best management practices. As necessary, PPRP recommends licensing conditions for implementing such practices and for developing detailed vegetation management plans for sensitive locations along the ROW. PPRP maintains a database of these conditions, locations and plans, and periodically inspects ROWs for compliance.

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 discussed below.

Loss of Prime Farmland

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). These soils are of the highest quality and can economically produce sustained high yields of crops when treated and managed according to acceptable farming methods.[89] Farmland is prime where 50 percent or more of the soils in a map unit composition is prime. Farmland is of statewide importance where less than 50 percent of the components in the map unit is prime, but a combination of lands of prime or statewide importance is 50 percent or more of the map unit composition. Excluding federal land, urban land and water areas, about 23 percent of Maryland's soils are prime.[90] Counties with the highest amount of prime farmland are found either in the upper part of the Eastern Shore, including Kent, Caroline, Queen Anne's and Talbot counties or along the Pennsylvania border such as Washington, Carroll and Cecil counties. Counties with the least amount of prime soils tend to be in Southern or Western Maryland and include Garrett, Allegany, Calvert and Charles counties.

Maryland places few restrictions on the siting of solar PV facilities on agricultural land. The state's primary policy instrument for conserving prime farmland is the Maryland Agricultural Land Preservation Foundation (MALPF), a unit within the Maryland Department of Agriculture (MDA). Created by the General Assembly in 1977, MALPF purchases agricultural preservation easements that forever restrict development on prime farmland and woodland. Through FY 2018, MALPF had purchased easements on a cumulative total of 2,302 properties, permanently preserving about 312,800 acres.[91] MALPF's policy on solar facilities is codified in COMAR 15.15.14, which explains the Foundation's criteria to approve an authorized renewable energy source (ARES) for commercial profit on a farm subject to an agricultural land preservation easement.[92] The Foundation may only accept applications to approve an ARES on a farm subject to an agricultural land preservation easement before June 30, 2018. The Foundation may not approve an ARES on a farm subject to an agricultural land

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[89] USDA 1993. Soil survey manual. Soil Conservation Service. U.S. Department of Agriculture Handbook 18. Soil Survey Division Staff. 1993.

[90] https://www.nrcs.usda.gov/wps/portal/nrcs/detail/md/technical/dma/nri/?cid=nrcs144p2_025681

[91] Annual Report Fiscal Year 2018. The Maryland Agricultural Land Preservation Foundation. Accessed from https://mda.maryland.gov/malpf/Documents/!MALPF%20FY%202018%20Annual%20Report%20FINAL.pdf on August 8, 2019.

[92] COMAR §15.15.14.01

preservation easement after June 30, 2019. No other regulations at the state level address development on prime farmland, although HB 863 (Right to Solar Farm), introduced in 2017 and subsequently withdrawn after an unfavorable report from the House Environmental and Transportation Committee and opposition from MDA and the Maryland Association of Counties, was intended to loosen restrictions on agricultural land by exempting solar facilities from specified development restrictions under an agricultural preservation easement and authorizing the Maryland Environmental Trust to lease properties for the generation of electricity under specified circumstances.

Farmland Critical Mass

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.[93] This issue is not specific to SEGS. Between 2007 and 2012, for example, 14,700 acres of agricultural land, 19,100 acres of forest land and 2,700 acres of other rural land in Maryland were converted to developed land.[94] Even greater rates of conversion prior to 2000 prompted public concern about the loss of farmland. However, the concern is not what the land is converted to, but whether the rate of farmland conversion to other uses will increase after agricultural acreage drops below a critical level. This argument was advanced by Kent Conservation and Preservation Alliance in opposition to the Mills Branch Solar application to construct a 60 MW solar facility in Kent County. As stated in testimony "Kent County intentionally zoned approximately 72 percent of the farmed land for agricultural use to create a 'critical mass' of protected land [to insure] the viability of a progressive and profitable agricultural industry."[95] Although the critical mass argument was disputed in testimony, the application was subsequently denied.[96]

Post-Solar Restoration of Farmland

In Maryland and elsewhere, once the operating life of a solar facility ends (typically 30 years), the facility must be decommissioned and 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 belowground piles and buried underground cables, to be cut and abandoned in place. For example, Maryland Solar's decommissioning plan would remove below ground portions of supports in their entirety or otherwise at least two feet below ground surface and left in place. Underground collection lines would be cut off two feet below the ground surface and left in place. Great Bay's decommissioning plan would cut belowground piles 3 feet below grade, and any underground cables buried at least 30 inches would be cut at the ends and remain in place. Particularly for agricultural land, the abandonment of below ground structures is a concern. A recurring

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93 Critical Mass of Agricultural Land Report. Prepared for the Maryland Center for Agro-Ecology Inc., Queenstown, Maryland. January 2003.

94 https://www.farmlandinfo.org/statistics/Maryland

95 Direct Testimony of Francis J. Hickman on behalf of Keep Kent Scenic, Inc. PSC Case No. 9411.

96 PSC Order No. 88021.

problem in agriculture is soil compaction.[97] Intensity of operations and the use of larger equipment used in modern agricultural practice have made soil compaction more common. It has been shown, for example, that the effect of equipment weight can penetrate down to 24 inches when soils are moist.[98] The problem can be exacerbated during solar facility installation when excavation and construction equipment is deployed. Deep tilling, where soils are ripped at least one foot below the surface, is the primary method for relieving compaction. Although most implements can penetrate to a depth of about 20 inches, tilling depths of two to three feet can be achieved with heavy tracked machinery.[99] Even no-till "rippers" perform tillage to depths of 12 to 18 inches while maintaining a smooth soil surface.[100] PPRP requires the removal of all belowground structures and cabling to ensure safe agricultural operations after a site has been restored.

Energy Sprawl and Suburban Sprawl

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. The years between 1970 and 2000 saw an explosion of residential development in Maryland outside of town and city boundaries. From 1982 to 1997, the amount of developed land in Maryland increased by 35 percent, while the state's population grew by only 19 percent.[101] The resulting sprawl was one of the main drivers in the state's introduction of its Smart Growth and Neighborhood Conservation land use reforms in 1997. Loopholes still exist, particularly in agricultural zoning.[102]

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. Even with a buffer, elevated views from multi-story structures may be dominated by a broad expanse of solar panels. Public comments are usually prefaced by statements to the effect that a family located in a rural area in part for the views. There is some irony in this argument. From recent cases (Biggs Ford, LeGore Bridge, Casper) most opponents are homeowners living in single-family homes on lots of 5 acres or less, most built within the last 20 years. Building on subdivided farmland, these homes have, themselves, altered the landscape, making it far less "agricultural-looking" than in the past.

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[97] Wolkowski and Lowery, 2008. "Soil compaction: causes, concerns, and cures." A3367. Cooperative Extension Publishing, University of Wisconsin-Extension. Madison, WI.

[98] McKenzie, 2010. Agricultural Soil Compaction: Causes and Management. Agdex 510-1. Agri-Facts, Government of Alberta. October, 2010.

[99] Dane County, 2007. Dane County Erosion Control and Stormwater Management Manual. Appendix 1: Deep Tilling. Dane County land and Water Resources Department. Second Edition. January 2007.

[100] Virginia Cooperative Extension, 2009. Deep Tillage Prior to no-Till Corn: Research and Recommendations. Virginia Cooperative Extension. Publication 424-053, 2009.

[101] Sprawl in Maryland: A Conversation with the Experts. E. Ridlington, B. Heavner and D. Algoso. MaryPIRG Foundation. Summer 2004.

[102] QACA 2009. RE: Queen Anne's County Zoning. Letter to Joseph Tassone, Maryland Department of Planning from Richard S. Altman, Queen Anne's Conservation Association. May 25, 2009.

The Casper Solar Center is a case in point. As proposed, the project would have been located in an unincorporated part of Queen Anne's County near the Town of Church Hill. The northern part of the project was within Church Hill's Planning Area boundary, but outside of the Town's Growth Area boundary. The project parcel was in an area of farmland cultivated in commercial crops and pasture, with many nearby parcels also containing stables, oval tracks and other elements associated with equine breeding and training.

Residential development extends south from Church Hill and is slowly overtaking the area's rural character. This is partly a consequence of Queen Anne's lax zoning regulations governing the Agricultural and Countryside district. Two subdivisions, Condor Manor and Eagle Manor, are just north of the project site, while another, Patchwork Knoll, is west of the southern project parcel. Also adjacent to the southern parcel, Starfield Farms was granted final subdivision approval by the County's Planning Commission in 2007, but had not been developed when the application was considered.

PPRP's analysis of property data[103] found 96 parcels within one-quarter mile of the project, 85 of which are residential, 51 built after 1999.[104] These are mostly two-story homes on lots of one acre or more. A nearly 260-foot communications tower constructed in 2001 overlooks the project site and surrounding area. The result is a complex visual landscape of built residential clusters, sometimes referred to by locals as "cornfield villages", overlaying a setting that portrays less of a cohesive agricultural region than before. This contrasts significantly from the region's historical setting, described in 2000 as "a complexly interrelated rural historic landscape with agricultural and architectural resources which communicate the economic and social changes that occurred in Queen Anne's County from circa 1800 to circa 1950."[105,106]

This is a recurring issue in the permitting of SEGS in Maryland. Residential encroachment into rural lands has constrained the siting of solar facilities due to fears by homeowners that views will be degraded and/or property values will fall. These attitudes, however, are based on the expectation that nearby agricultural properties which contribute to the rural landscape will never change. The reality is that views from any property are not static nor should they be expected to remain so unless nearby properties are protected by a conservation or other preservation easement, or purchased by neighboring

[103] MdProperty View, Queen Anne's County, 2015. Maryland Department of Planning.

[104] Since 2013, more homes have been built or are under construction.

[105] Maryland Historical Trust NR-Eligibility Review Form. Fincastle-Prickett Rural Historic District. Inventory Number: QA-522. Prepared by KCI Technologies, Inc. February 2001.

[106] Since the National Register eligibility review was undertaken, as of January 2018, 10 homes had been built within the boundaries of the district, and 11 more within a quarter mile.

land owners with the intent to preserve its current use. Unencumbered properties are fair game for change – within constraints dictated by local zoning laws or other regulation.[107]

Another consideration is the landowner who has sold or leased a property to solar developers. These landowners have rights, too, and it is in their interest to maximize a parcel's return on investment. Furthermore, the agricultural economy is changing from a sole proprietorship to corporate ownership model, where the emphasis is on near-term profit maximization and diversification to buffer commodity price swings. A traditional farm's wealth is almost completely tied up in the land, which in the past was passed on to succeeding generations. But given a declining interest in family farming from one generation to another, plus rising costs and smaller profits,[108] this wealth is being extracted to pay for retirement or other expenses. Utility-scale solar offers an attractive end game for farmers owning lands suitable for development.

Agricultural Operations Near Solar Facilities

Can SEGS have a negative effect on nearby agricultural operations? 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. However, there was concern in the Casper Solar Center case that glare from the project could potentially impact nearby equine operations. Reportedly, horses were being spooked by glare from the nearby Church Hill Solar facility, and equine facilities near the project site were concerned the proposed facility would add to the problem.

In general, a horse's natural reaction to something it doesn't understand is to spook. This is because the horse is a prey animal that must be on constant lookout for predators before they get within striking range. When scared, most horses will try to flee, and a spook is the beginning of the flee reaction.[109,110] Another factor is the horse's vision. Horses see most things with one eye. This is why they may spook at something that they have already walked past because, on the return, they are seeing it with their other eye. Furthermore, a horse has a very large eyeball that magnifies everything much larger than we

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[107] With respect to the Casper Solar Center, the list of permitted and conditional uses in the AG zone is quite extensive. In addition to agriculture, permitted uses include: commercial and noncommercial forestry, effluent disposal, institutional residential, kennels, large-lot agricultural subdivision, major and minor single-family cluster subdivision, migrant labor camp, minor extraction and dredge disposal uses, etc. Conditional uses include: campgrounds, commercial apartments, major extraction and dredge disposal, institutional residential, organic fertilizer storage and transfer operations, private airports, public heliports and airports, shooting clubs and, of course, solar arrays. Many of these uses have far less stringent setback and buffering requirements than utility-scale solar arrays. Furthermore, zoning bylaws provide no recourse in the AG district against the effects of any normal farming operations conducted in accordance with standard and acceptable best management practices. Normal agricultural effects include, but are not limited to, noise, odor, vibration, fumes, dust, spray drift or glare.

[108] Minutes – March 4, 2015. Dorchester County Planning Commission. Retrieved from http://docogonet.com/index.php?page=planning_commission on June 19, 2015.

[109] https://www.thespruce.com/horses-that-spook-or-shy-1886399

[110] https://www.thespruce.com/what-makes-a-bombproof-horse-1886593

perceive it. This enables the horse to see distant objects in clearer detail than humans.[111] Spooking can be caused by any number of things. Anything that moves suddenly or makes an unexpected noise can trigger a horse's survival instinct. Examples include blowing paper, barking dogs, rustling leaves, nearby livestock, and puddles.

The physiology of the horse's eye may contribute to spooking from glint or glare. The horse has the ability to see in levels of low light and an increased sensitivity to light reflected from the ground due to the structure of the eye. Because of this, the horse adapts less quickly to changes in light levels and is more easily blinded by exposure to sudden bright light.[112] With respect to sounds, a horse's range of hearing is wider than a human's and sounds are audible at lower decibels.[113]

Little has been published on the effect of solar facilities on equestrians using byways, bridleways and roads or on equestrian businesses. The British Horse Society makes unsubstantiated reference to instances of glare and glint causing problems that were not foreseen or reported pre-construction and the possibility of other problems not yet evident. In addition, there are reports in British newspapers where farmers have stated concerns regarding the possible effect of glint and glare from nearby solar facilities on alpacas, claiming research has shown that if animals are unable to escape glare from solar panels it could cause them to suffer high levels of nervousness and other problems.[114]

British Horse Society advice appears to be based on evidence gathered from fixed-tilt solar arrays. Fixed-tilt panels can reflect sunlight to just above ground level just after dawn and before dusk, while single-axis panels like those proposed for the Casper project do not. The Church Hill Solar project uses fixed-tilt arrays, and landscape buffering around the perimeter is practically nonexistent, which possibly accounts for reported glare.

PPRP identified three equine training facilities near the Casper project site, but only one that could potentially be affected by glare. Windswept Farm is wedged between the northern and southern project parcels, although equine operations would be potentially affected by glare only from the southern parcel. Its training oval, however, would be nearly 900 feet from the nearest solar panel. Because the Casper Solar Project would use a tracking system, PPRP concluded glare would not affect equine operations in this case.

[111] The Equine Eye, (n.d.). Previously retrieved from: https://cvhs.okstate.edu/sites/default/files/docs/pdf/Equine%20Eye.pdf

[112] Murphy, J. et al 2009. What Horses and Humans See: A Comparative Review. International Journal of Zoology. Vol. 2009. Article ID 721798.

[113] Advice on Solar Farms. The British Horse Society. 2017.

[114] Scrivener, D. British Horse Society flint and glare guidance, and other animal reports. https://www.pagerpower.com/news/solar-glint-glare-british-horse-society/

Cultural and Heritage Resources

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. The Maryland Historical Trust (MHT) is the primary state agency charged with preserving and interpreting Maryland's cultural resources. Other agencies involved include Maryland Department of Transportation (MDOT) State Highway Administration (SHA) through its Scenic Byways Program, DNR (Scenic Rivers, Rural Legacy), county historical and preservation organizations, private land trusts and citizen groups. As Maryland's State Historic Preservation Office (SHPO), MHT may also coordinate its reviews with the U.S. Army Corps of Engineers, National Park Service, Federal Communications Commission, Federal Energy Regulatory Commission, state-recognized Native American tribes and others.[115]

Although most impacts from construction of solar facilities are temporary, ground disturbance or structure demolition can permanently erase the historic or prehistoric record from a culturally significant site. Thus, MHT requires sites determined to have a high archeological potential to undergo archeological surveys within a project's limit of disturbance, or to be avoided if possible. If avoidance is not feasible, additional mitigation measures must be undertaken by developers before construction can begin. As noted earlier, most solar facilities constructed or proposed in Maryland are sited on agricultural land, many of which have been disturbed through years of tilling and where the archeological potential is low. As a result, few archeological protection measures have been required following initial surveys of properties carried out by qualified cultural resources consultants.

Once operational, SEGS have relatively benign effects on cultural resources compared to other generation technologies, with the primary effect being visual. Visual impacts may include views of structures within the project's limit of disturbance, or from reflections off array surfaces, the latter usually identified as glare. This can be important since solar projects, particularly those developed on agricultural properties, can alter a landscape's setting, and criteria for evaluation of an historic property include a property's "integrity of location, design, setting, materials, workmanship, feeling and association."[116] Conversion of a farm from an agricultural setting to a utility-scale solar project can diminish the integrity of an historic property's setting, association and feeling, which is considered an adverse effect upon a property eligible for listing in the NRHP.

Such is the case with the Baker Farm located on the proposed Biggs Ford Solar site. The property was determined eligible for listing in the National Register (NR) for its association with the agricultural development of Frederick County. As proposed, solar panels would surround NR-eligible structures and occupy all available land on the parcel except where farm buildings are located, which would remain.

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[115] Participants in the Section 106 Process. Maryland Historical Trust. Accessed July 20, 2019 from https://mht.maryland.gov/documents/PDF/projectreview/Section-106.pdf.

[116] 36 CFR §60.4

Not only would the project diminish the integrity of the property's setting, but MHT concluded structures might be demolished by neglect if left vacant. MHT therefore determined the installation of the solar array would constitute an adverse effect on historic properties. Consultation between PPRP, MHT, the applicant and other identified consulting parties will be necessary to develop alternatives or modifications to the project to avoid, minimize or mitigate the adverse effects.

Because of their potential to adversely affect the integrity of a property's setting, PPRP must consider the effects of solar projects on state and other programs where scenic resources are an important element. Scenic quality is an important amenity for residents, but is equally so for the tourism industry, particularly for attracting recreational and heritage visitors to a region. Research has shown that degradation of views can affect tourist perceptions of scenic vistas and visitation levels.[117] Scenic quality can therefore affect the economic well-being of a region.

Scenic quality is recognized in many of Maryland's programmatic designations. The Maryland Environmental Trust (MET), for example, accepts offers of conservation easements to protect natural, historic and scenic resources in the state. Maryland's Rural Legacy Program provides "the focus and funding necessary to protect large, contiguous tracts of land rich in natural and cultural resources from sprawl development." Among its goals are "to establish greenbelts of forests and farms around rural communities in order to preserve their cultural heritage and sense of place" through the establishment of Rural Legacy Area (RLAs). The Maryland Heritage Areas Program preserves the state's historical, cultural, archeological, and natural resources for sustainable economic development through heritage tourism by designating Certified Heritage Areas (CHAs), defined by a distinct focus or theme that makes a place or region, including its natural landscapes, different from other areas of the state. MDOT SHA's Scenic Byways Program administers federal highway funds for encouraging the responsible management and preservation of the state's most scenic, cultural and historic roads and surrounding resources. State and local government units promote scenery in various recreational initiatives, such as bicycle, hiking and water trails.

At the federal level, scenic quality is also recognized in the management plans for units of the National Park Service located in Maryland, such as the Appalachian Trail and the Chesapeake and Ohio National Historical Park, the National Register of Historic Places, historic landscape and national historic landmark designations, the National Heritage Area program, and the Federal Highway Administration's National Scenic Byway Program, among others.

Impact on Conservation Easements

Generally, land placed in easement is protected from direct effects (i.e., pre-emption or conversion) by the terms of the Deed of Conservation Easement or similar document. The aesthetics of an easement property may be less protected from indirect effects, however. Furthermore, although easements, transferable development rights and fee estates protect specific land parcels within RLAs, RLA designation, in itself, affords no land use protection.

[117] The Value of the View: Valuing Scenic Quality using choice and Contingent Valuation Models. Leah Greden Mathews, Susan Kask and Steven Stewart. Presented to the American Agricultural Economics Association Annual Meeting. Denver, CO. August, 2004.

The degree to which these programmatic designations protect cultural and heritage resources varies. MDOT SHA funds the development of community-based corridor management plans (CMP) to make scenic byways eligible for additional grants as well as a National Scenic Byway designation, and publishes guidelines for maintaining scenic quality along byways.[118] Although the Maryland's Scenic Byways program does not have regulatory authority over land development within scenic byway corridors, SHA coordinates with other state agencies, including DNR, and local governments to achieve its programmatic goals. The Maryland Department of Planning's Scenic Byways Resource Protection Application[119] is an example of this. A GIS mapping tool that inventories and analyzes both protected and vulnerable byways, it helps local and state agencies decide which byways are in most need of immediate conservation action, allowing them to prioritize and protect their historic and natural resources.

Consistent with the state's vision for making walking and biking an integral part of Maryland's transportation system,[120] MDOT SHA has designated bike routes on many state highways to create a Bike Spine Network. By Maryland law, bicycles are vehicles.[121] Traffic laws require a vehicle overtaking another vehicle, including a bicycle, to proceed with due regard for the other vehicle on the approach, overtaking and clearance of the overtaken vehicle, and to yield to an overtaken bicycle before making any turns.[122] MDOT SHA does not otherwise regulate development of any kind along designated bike routes.

Although heritage areas do not impose regulatory controls on land use, impacts on scenic resources associated with the Stories of the Chesapeake Heritage Area contributed to PSC's denial of the Mills Branch Solar project in Kent County. When carrying out activities in a CHA, a state agency must (1) consult, cooperate, and, to the maximum extent feasible, coordinate their activities with the entity responsible for the management of each CHA; (2) ensure that the activities are consistent with the CHA's management plan; and (3) ensure that activities will not have an adverse effect on the resources of the Heritage Area unless there is no prudent and feasible alternative. In this case there was concern that by changing the character of the historic and cultural landscape and interjecting a modern intrusion of considerable scale and alteration in the landscape's visual character, the project would impose an adverse effect on the Chesterville/Morgan Creek landscape district and on the Stories of the Chesapeake Heritage Area as a whole. It was further argued that impairment to the viewshed could harm the county's tourist industry due to the change it would make to the natural setting currently in place. Damage to the viewshed to a nearby Scenic Byway was also cited in the Utility Law Judge's decision.

In most cases, consultation results in mitigation to address adverse effects of solar projects sited on agricultural land. As was done for Mills Branch, PPRP consults numerous stakeholders in its environmental reviews of solar projects to understand concerns and propose remedies. For example,

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[118] Context Sensitive Solutions for Work on Maryland Byways. Maryland Department of Transportation, State Highway Administration. February, 2008.

[119] http://mdpgis.mdp.state.md.us/BywayResourceTool/Map.html

[120] Maryland Twenty-Year Bicycle & Pedestrian Master Plan. Maryland Department of Transportation. January 2014.

[121] COMAR §11-176.

[122] http://www.mva.maryland.gov/safety/mhso/program-bicycle-safety.htm

extensive coordination with the Heart of the Civil War Heritage Area as part of the review of the Citizens UB Solar project, led to a recommended license condition requiring additional mitigation beyond buffering to enhance the entrance to the Town of Union Bridge. Conditions were added to the state's review of the Cherrywood Solar Project in Caroline County to satisfy the concerns of MDOT SHA regarding views from the Harriet Tubman Underground Railroad (HTUR) Byway, a National Scenic Byway. Recent environmental reviews of Citizens UB Solar and Kieffer Funk Solar have included conditions to protect the safety of cyclists on state-designated bike routes following consultation with MDOT SHA.

Mitigating Solar Impacts on Agricultural Land

With the state's 50 percent RPS Tier 1 solar carve-out increasing to 14.5 percent of instate solar generation in 2028, 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 U.S. These mitigation strategies do not necessary remove utility-scale solar in its entirety from agricultural land, but attempt to reduce the impact through land-sparing, dual use and buffering.

Land-Sparing Alternatives

Land-sparing alternatives refer to the use of nonproductive rather than agricultural land on which to site solar facilities. Although not all alternatives apply to Maryland, research has shown the energy potential of these land-sparing alternatives is quite high nationwide. For example, a study of the land-sparing potential of solar PV energy development sited on four nonconventional land cover types in the Great Central Valley of California – built environment, salt-affected land, contaminated land and water reservoirs (floatovoltaics) – estimated these areas comprise a capacity-based energy potential of nearly 13 times California's 2025 projected energy demand.[123] NREL researchers estimate that floating solar photovoltaics on the more than 24,000 built reservoirs in the U.S. could generate about 10 percent of the nation's annual energy production.[124]

Land-sparing alternatives to agricultural lands for siting renewable energy projects in Maryland has primarily focused on brownfields.[125] The U.S. EPA's Re-Powering America's Land Program has identified 279 sites in Maryland -totaling 103,000 acres – that contain contaminated lands, former mines

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[123] "Land-sparing opportunities for solar energy development in agricultural landscapes: a case study of the Great Central Valley, CA, United States." Madison K. Hoffacker, Michael F. Allen and Rebecca R. Hernandez. Environmental Science & Technology, 2017, 51, 14472-14482.

[124] DOE/National Renewable Energy Laboratory. "Great potential for floating solar photovoltaics systems: Technology already in widespread use overseas, especially in Japan." ScienceDaily. ScienceDaily, 8 January 2019. www.sciencedaily.com/releases/2019/01/190108125422.htm

[125] While not a brownfield, Spectrum Solar recently filed an application with the PSC to construct a 5.6 MW solar PV facility on an idle, partly-developed property containing asphalt parking lots and an unstabilized excavation site in Prince George's County.

and landfills that could potentially host renewable energy projects.[126] However, EPA's list ignores development considerations such as slope, and risk associated with constructing and operating facilities on federally regulated (i.e. RCRA and Superfund) sites. After removing sites with these constraints, up to 30,000 acres[127] of Maryland's brownfields and closed landfills could be developed if other siting criteria are satisfied, particularly since MDE has a Voluntary Compliance Program for brownfields that could potentially mitigate liability concerns.[128]

In order to provide easily accessible information to assist in smart siting decisions, MEA and PPRP sponsor SmartDG+, an online screening tool for distributed generation and renewable energy projects between 1 and 10 MW. SmartDG+ focuses on infrastructure proximity, land suitability, and other factors that could help developers and officials identify promising areas from the RE-Powering America's Land Program.

Dual-Use Solar Development

Dual-use development installs solar PV on farm fields without taking the fields out of production. It is sometimes called low impact solar development. In other parts of the world, agriculture and solar facilities coexist reasonably well. Throughout Europe and the United Kingdom (UK), small livestock (sheep, chickens) are grazed on utility-scale, ground-mounted solar facilities. In North Carolina, solar energy companies have started leasing flocks from farmers to control ground cover,[129] while sunflowers for oil production are grown under panels in Wisconsin.[130] Other productive options, such as beekeeping could complement PPRP's promotion of pollinator habitats at CPCN-licensed solar facilities.

Not all agricultural applications are suitable for colocating with solar panels. For livestock, horses can be picky about what they eat, cows are large and require a lot of space, and goats tend to chew on wires and climb on panels, which are traditionally mounted close to the ground.[131] In addition, most utility-scale solar facilities do not have an onsite water supply which can increase production costs for farmers. For crops, traditional panel placement and spacing can inhibit vegetation growth. However, innovative installation and structure design, including no-disturbance structure installation, panel spacing to minimize shading, and raised solar panels, are being tested in Massachusetts to address many of these

[126] https://www.epa.gov/re-powering/re-powering-mapper

[127] The EPA's Re-Powering America's Land Program identified 181 brownfield sites in Maryland, which is approximately 24,000 acres, and 25 closed landfill sites in Maryland, equivalent to 6,000 acres.

[128] Maryland's brownfields and closed landfills represent a capacity potential of 3,750 MW, assuming 8 acres per megawatt.

[129] https://cals.ncsu.edu/news/got-sheep-want-a-solar-farm/

[130] Overview of opportunities for co-location of agriculture and solar PV. Jordan Macknick. National Renewable Energy Laboratory. Clean Energy Economy Conference. Utica, NY. June 14, 2016.

[131] https://www.nrel.gov/state-local-tribal/blog/posts/solar-sheep-and-voltaic-veggies-uniting-solar-power-and-agriculture.html

constraints, which may someday enable the use under panels for a wide range of grazing animals or for vegetable and field crops.[132]

Setbacks and Buffering

By far, the most common mitigation for SEGS in Maryland is setbacks and buffering, and in agricultural areas mitigation can be quite robust where projects abut residential properties, scenic resources or cultural landscapes. For SEGS, a setback is the minimum distance from a property line, right-of-way or other feature to a solar component such as a panel or inverter within a project's limit of disturbance. A buffer is a vegetated strip or other landscaped feature such as a berm that is designed to mitigate views or other externalities of the project, such as noise. Typically, a solar project's perimeter road, security fence and buffer are within its setback.

For counties that address SEGS in their zoning bylaws, setback and buffer requirements are usually included in special exception conditions or in general setback and buffer requirements for zoning districts where SEGS are a permitted use, although the specifications vary throughout Maryland. For example, for utility-scale solar facilities, Queen Anne's County requires setbacks of 75 feet from any lot line, 100 feet from any road and/or right-of-way, and 150 feet from any residential use or zoning district, plus a vegetated 50-foot buffer around the perimeter of the site.[133] Design standards for SEGS in Washington County require SEGS to adhere to setback, height and coverage requirements of the district in which they are located.[134] §5A.6 of the county's Zoning Ordinance, for example, requires nonresidential lots in the Agriculture - Rural zone to have a minimum setback of at least 50 feet for "Other Principal Permitted or Conditional Uses." Landscaping requirements, including plant material specifications, maintenance and other conditions are applied to any development requiring site plan review,[135] although buffer widths are not specified.

Where SEGS are not addressed or are inadequate for addressing project impacts, PPRP includes additional project-specific setback and buffer requirements in license conditions. PPRP also adds buffer maintenance and surety requirements when not addressed by counties. While most buffering conditions require landscaping to be installed before the project becomes operational and to be effective in blocking views of and glare from the project after 3 to 5 years, PPRP has in some cases required developers to install temporary, opaque buffers prior to construction, primarily to mitigate glare impacts upon surrounding public roads.

For example, for Jones Farm Lane Solar, PPRP's concern about glare trespassing onto two roads bypassing the project site was related to motor vehicle safety. The National Highway Traffic Safety Administration, in a study on the risks of glare to oncoming vehicles, found nighttime glare from

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[132] Agriculture and Solar Energy Dual Land Use. Stephen J. Herbert, Phaedra Ghazi, Kate Gervias, Emily Cole and Sara Weise. Stockbridge School of Agriculture, University of Massachusetts Amherst. Accessed July 22, 2019 from https://ag.umass.edu/sites/ag.umass.edu/files/research-reports/Agriculture%20and%20Solar%20Energy%20Dual%20Land%20Use.pdf.

[133] §18:1-95.S Queen Anne's County Code

[134] §4.26 Washington County Zoning Ordinance

[135] §22.11.1 Washington County Zoning Ordinance

headlights was associated with decreasing visibility distance, increasing reaction times and increasing recovery times, with the risk increasing on two-lane highways.[136] Daytime glare has been found to increase situational identification time from 0.8 sec to 2.7 seconds,[137] while analysis of data from signalized intersections of Tucson, Arizona show some evidence that sun glare affects intersection crash occurrence.[138] Even though Queen Anne's County landscaping requirements are robust, they require a landscape buffer to provide an opaque visual barrier once the vegetation reaches maturity or within five years. As such, offsite glare would not be fully mitigated during the early years of project. While PPRP concluded the project's site plan satisfied the county's proposed setback and landscaping requirements, it added a license condition requiring the developer to mitigate glare impacts on nearby public roads prior to construction until the proposed landscape buffer matures enough to completely block the sun's reflections.

The effectiveness of landscaped buffers around solar projects in Maryland has been mixed so far. Setback and buffers requirements were not even included in the recommended license conditions for the Maryland Solar I project, one of the first utility-scale solar facilities licensed in the state. In the absence of county landscaping requirements, license conditions in subsequent cases generally specified a 25-foot or less buffer within a 50-foot setback, but without plant maintenance and surety guarantees. This was coupled with a condition to allow neighboring property owners to obtain relief from visual impairment or unwanted reflections through arbitration, which was assumed would be rectified by additional targeted landscaping.

PPRP's experience with the Great Bay Solar (GBS) project in Somerset County is a good example of how visual mitigation conditions for SEGS have changed over time. PPRP's recommended license conditions associated with buffering, as proposed in late 2015, are shown below.

- GBS shall set back its facilities, defined as facilities within perimeter fencing, at least 50 feet from any adjacent property line or public road. Where the Project abuts a primarily residential property, or a public or private road, GBS shall design a landscape buffer within the setback and outside the fence line that will effectively screen, to a minimum of eight (8) feet above ground level, views of the solar facility. The landscape screening requirements may be waived by the Somerset County Department of Technical and Community Services where GBS can demonstrate that conditions on adjacent land are present, such as forest, woodland, wetlands, open fields or cropland such that the landscaped buffer serves no purpose. The plan must be submitted to the Public Service Commission, PPRP and the Somerset County Department of Technical and Community Services for review and approval prior to construction.

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[136] Nighttime Glare and Driving Performance. Report to Congress. National Highway Traffic Safety Administration. February 2007.

[137] Duration of afterimage disability after viewing simulated sun reflections." R.L. Saur and S.M. Dobrash. Applied Optics, 8(9): September 1969;1799-801.

[138] "Sun glare and road safety: An empirical investigation of intersection crashes." S. Mitra. Safety Science, Volume 70, December 2014, Pages 246-254.

- GBS shall develop a process to document and address admissible complaints related to potential solar reflections. An admissible complaint shall be one formally submitted to GBS within one year of an array within a Project parcel being energized. If it is determined that the complaint is justified, GBS shall prepare a screening plan to mitigate impacts from reflective glare upon the affected property.

Note that PPRP's buffering condition resulted from the fact that SEGS were not recognized in the Somerset County's zoning ordinance and thus there were no local standards to regulate their development. PPRP further concluded that Somerset County's general buffering requirements for new industrial installations were insufficient for mitigating visual impacts upon nearby residences. Following public comment that the 50-foot setback was insufficient to protect residential properties and the local viewshed in general, the PSC order approving the project increased the setback from 50 to 75 feet from all roads and highways, and required the views of local residences be fully buffered by planting appropriate trees and shrubs.[139]

Because GBS requested the PSC to extend and amend CPCN construction deadlines, effectively dividing the project into two phases, PPRP was able to revisit the project's visual mitigation requirements and strengthen them considerably in 2019, as follows.

- GBS shall set back its facilities, defined as facilities within perimeter fencing, *at least 75 feet from any public roads and 50 feet from adjacent non-participating properties*. Where the Project abuts a primarily residential property, or a public or private road, GBS shall design a landscape buffer within the setback and outside the fence line that will effectively screen *for the life of the project*, to a minimum of eight (8) feet above ground level *year-round and within five years of project completion*, views of the solar facility. *The amount and extent of the required screening will be determined by the Somerset County Department of Technical and Community Services as part of the site plan review process*. The landscape buffer design must be submitted to the PSC, PPRP and the Somerset County Department of Technical and Community Services for review and approval prior to construction. *Due to seasonal planting restrictions, no more than twenty percent of the site shall be installed with solar panels until the vegetative buffer is installed*.

- GBS shall develop a process to document and address admissible complaints related *to visual impacts associated with Project structures, such as panel arrays and inverters within the Project's perimeter fence*, and solar reflections (glare). An admissible complaint shall be one formally submitted to GBS within *two (2) years* of an array within a Project parcel being energized. *GBS shall provide to the PSC, PPRP, and the Somerset County Department of Technical and Community Services, both a copy of the complaint and its response to the complaint. GBS's response to any written complaint shall clearly inform the aggrieved party that if not satisfied with GBS's response, the aggrieved party may seek relief by filing a complaint with the PSC. If the PSC determines that the complaint is justified*, GBS shall prepare and implement a screening plan to mitigate impacts from reflective glare upon the affected property. *The screening plan shall be in conformance with all applicable state and local laws and regulations*.

[139] Order No. 87321, Case No. 9380

The revised conditions will apply to the entire project, where applicable, meaning inadequate buffering around Phase I of the project will be replaced or supplemented. Somerset County is currently in the process of revising its zoning ordinance, which will include standards for solar projects.

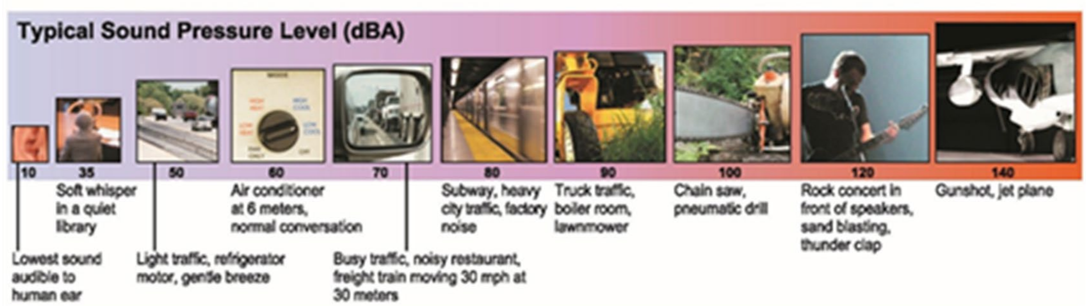
Regardless of the robustness of landscaping, there are limitations to buffering as mitigation for visual impacts from SEGS, particularly in agricultural areas where solar PV facilities present a stark visual contrast. Although the angularity of arrays can be compared to other agricultural structures, such as greenhouses or poultry barns, the spatial scale of these facilities sets them apart, covering tens or hundreds of acres instead of just a few. Without screening, solar arrays are unmistakably industrial to the eye, and may emit additional visual (glare) and audible externalities onto nearby properties. Landscape screening does offer visual relief, but does not restore prior views of the landscape, nor is the effect particularly natural, sometimes creating a visual contrast to viewers due to their linearity and uniformity of design. Visual impacts are reduced by landscaping, but not eliminated.

Evaluating Noise Impacts

Noise consists of vibrations in the air that gradually decrease, or attenuate, the farther they travel. For people who live or work near a power plant, the noise impacts, along with visual and traffic impacts, can be the most significant type of effect caused by the facility.

Noise, measured in decibels (dB), is made up of many components of different frequency (pitch) and loudness. Three decibels are approximately the smallest change in sound intensity that can be detected by the human ear. The sensitivity of the human ear varies according to the frequency of sound; consequently, a weighted noise scale is typically used when discussing noise impacts on nearby communities. This A-weighted decibel (dBA) scale weights the various components of noise based on the response of the human ear. The ear perceives middle frequencies better than low or high frequencies; therefore, noise composed predominantly of the middle frequencies is assigned a higher loudness value on the dBA scale.

Ranges of Typical Sound Levels for Common Sounds



The State of Maryland has adopted noise pollution standards, found in COMAR 26.02.03, which are derived from federal noise guidelines. The State regulations establish maximum allowable noise levels by zoning designation and time period (day vs. night). Compliance with noise standards is enforced at the county level, and some counties and municipalities in Maryland have more specific noise ordinances, including Montgomery County, Charles County and Baltimore City.

As sound waves radiate outward from a noise source, they lose intensity; thus, the sound decreases with distance. Ensuring adequate buffer distances is an effective method of controlling noise impacts. Structures such as berms and walls may also be constructed to provide noise control, and have been used in transportation applications for many years. Vegetative buffers may be used in conjunction with such structures for additional noise abatement.

PPRP evaluates potential noise impacts as part of the CPCN licensing review for proposed power plants. All generating technologies have some type of noise emissions associated with them. With the increasing number of renewable energy projects in the state, PPRP has studied noise impacts from wind and solar projects over the past few years.

- Solar power inverters emit a noticeable "electrical hum," but this is only audible at very short distances. PPRP has encouraged developers to position inverters at the interior of solar arrays, which allows noise to attenuate before reaching the property boundary.
- Wind turbines generate noise in two primary ways – from the motion of the turbine blades and from mechanical equipment inside the turbine nacelle. Low frequency noise should also be considered when evaluating the effects of wind turbines. PPRP has used modeling software, as well as literature research into recent scientific studies, to assess noise levels and potential impacts from proposed wind turbines. To mitigate both audible and low frequency noise, windpower facility design should incorporate adequate buffer distances between wind turbines and residences.

Solar Decommissioning in Maryland

Decommissioning has been a central concern of PPRP in its reviews of utility-scale solar facilities from the beginning, and is a standard condition in PPRP's environmental reviews of solar PV applications. Maryland, like most other states, does not have statewide policy regarding decommissioning, although local governments may adopt an ordinance which includes decommissioning rules.[140] However, not all county zoning bylaws recognize SEGS and therefore have not addressed the issue.

Items most often addressed in decommissioning plans, however, include:[141]

- Defined conditions upon which decommissioning will be initiated (i.e., end of land lease, no operation for 12 months, prior written notice to facility owner, etc.).
- Removal of all nonutility owned equipment, conduit, structures, fencing, roads and foundations.
- Restoration of property to condition prior to solar development.
- The timeframe for completion of decommissioning activities.
- Description of any agreement (e.g., lease) with landowner regarding decommissioning.
- The party responsible for decommissioning.
- Plans for updating the decommissioning plan.
- Anticipated present value cost of decommissioning, including an explanation of how the cost was calculated.
- A surety to cover the cost of decommissioning.

As noted earlier, key issues associated with the decommissioning of solar facilities on agricultural land are the abandonment of belowground structures and soil compaction. But the disposal of project components and their salvage value in surety or bonding calculations are also important.

Most structural and electrical components that comprise a solar array can be easily recycled. However solar panels, which can account for nearly two-thirds of equipment costs in a utility-scale solar project, are made from several materials including silicon solar cells, metal framing, glass, wires and plexiglass. While the metal, glass and wiring can be recycled, silicon cells contain heavy metals, such as cadmium and lead, and need to be disposed in specialized facilities to prevent their disposal in landfills and where scarce elements like gallium and indium can be recovered.[142]

Compared to Europe, solar panel recycling is not widely available in the U.S. Some panel manufacturers like SunPower and First Solar are beginning to recognize the issue and are instituting recycling

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[140] https://www.solarpowerworldonline.com/2019/03/how-to-decommission-a-solar-array-and-why-its-important-to-plan-ahead/

[141] New York Solar Guidebook for Local Governments. New York State Energy Research and Development Authority. Accessed from https://www.nyserda.ny.gov/All%20Programs/Programs/Clean%20Energy%20Siting/Solar%20Guidebook on July 24, 2019.

[142] https://news.energysage.com/recycling-solar-panels/

programs of their own. In addition, SEIA, the manufacturer trade group, has formed a PV recycling group and launched a PV recycling program.[143]

An alternative to recycling is repurposing, where panels that have reached their warrantied lifespan or whose efficiencies are degraded, are resold and/or reused as replacement panels or reapplied to less power-intensive projects. Some are resold through online marketplaces while others are reused by charitable organizations to provide energy independence to indigenous or disadvantaged communities at home and abroad.[144,145]

In the context of decommissioning plans, salvage values are based on present-day values of prices associated with these future markets, and therefore are highly uncertain. Operating solar facilities in Maryland are near the beginning of their lifecycle, where decommissioning is in the distant horizon. The U.S. is projected to generate about 13,000 tons of solar panel waste in 2020 and 7.5 million tons in 2050.[146] These volumes are likely to put downward pressure on prices in recycling and repurposing markets, and could lead to wide variations when estimating decommissioning costs. If so, sureties or other financial instruments executed to guarantee solar projects are decommissioned to specification could be undervalued. Removing salvage values from decommissioning costs is not necessarily the solution as developers consider it a financial barrier and disincentive for investing in a project,[147] nor are surcharges on the output or production capacity of solar photovoltaic facilities likely to address the issue.[148] A common methodology for estimating decommissioning costs and calculating salvage values is needed to ensure financial guaranties are adequate for restoring solar sites after a project's useful life.

Property Value Impacts

To date, the impact of utility scale solar photovoltaic systems on nearby property values has been the subject of little research. This may be partly because utility scale photovoltaic land requirements favor rural locations where adjacency issues are not as prevalent, or because repeat sales data, which might capture such effects, are simply not available. Still public perceptions that solar facilities adversely affect property values remain.

Limited evidence from real estate appraisal methods has mostly supported the contention that solar facility development does not influence property values. Expert opinion from a past siting case in Massachusetts, for example, concluded that utility scale photovoltaic energy systems that are not visible

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[143] http://pvsolarreport.com/seia-plan-recycling-solar-panels/

[144] https://www.solarpowerworldonline.com/2019/01/old-solar-panels-get-second-life-in-repurposing-and-recycling-markets/

[145] The latter carries the risk of developing countries becoming future dumping grounds for solar panels, as they have for consumer recyclables.

[146] https://www.greenmatch.co.uk/blog/2017/10/the-opportunities-of-solar-panel-recycling

[147] https://www.solunesco.com/2018/09/10/decommissioning-of-solar-sites-a-key-consideration-of-the-project/

[148] A bill introduced in the 2018 regular session of the Maryland House to establish a surcharge on certain solar electric generating facilities to fund the Maryland Solar Electric Generating Facility Decommissioning and Restoration Fund was withdrawn after an unfavorable report by the Economic Matters Committee.

from surrounding properties would have no impact on their market values.[149] A paired comparison of market values of residential and agricultural properties near solar facilities in North Carolina came to a similar conclusion.[150]

In another solar case filed with the Maryland PSC[151], a real estate appraisal study was commissioned by the project developer to investigate the potential impact of the project on neighboring property values using paired sales analysis of properties within and outside a half-mile radius of selected operational solar facilities in Maryland.[152] Although the methodology and limited sample size do not allow one to draw a statistical inference from the data, the study nevertheless adds support to other appraisal findings.

With a minimal vertical profile and buffering around the perimeter of the site, SEGS are largely out of sight from nearby properties. Solar facilities do not emit significant traffic, noise, air or water pollutants, or generate any hazardous waste that could potentially affect public health. In other words, SEGS have a relatively benign local presence and little influence on property values.

Transmission Lines

Effect on Agricultural Land Values from Transource Project

Proximity to high voltage transmission lines has been associated with changes in property values due to visual intrusion and perceived risk. Most evidence, however, has been based on impacts upon residential properties in urban and suburban settings. There have been relatively few studies that address the impact to rural land used for agricultural or recreational purposes.[153,154]

Most studies that have, however, show little to no effect on sales price from transmission lines, beyond the loss associated with ROW acreage. A regression analysis on sales of farm land in Saskatchewan between 1965 and 1970, for example, found that the relationship of land value to the number of power line structures was not statistically significant and that the lines did not negatively affect property

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[149] Commissioner's Agenda Information Sheet. Item: Request for Special Use Permit – Sarah Solar, LLC, Parts 2 and 3. Franklin County, NC. June 16, 2014.

[150] Letter from Richard C. Kirkland, Jr., Kirkland Appraisals, LLC to Mr. Louis Iannone, Strata Solar, July 24, 2014. Previously retrieved from: http://www.chathamnc.org/RezoningSubdivisionCases/2014/9-15-14_BOC/Strata%20Solar%20No%204%20US%2064%20W/CUP%20Application/Appraisal%20Consult%20on%20Pit%2064%20Solar.pdf. Accessed December 24, 2015.

[151] PSC Case #9429. In the matter of the application of LeGore Bridge Solar Center LLC for a CPCN to construct a 20.0MW solar photovoltaic generating facility in Frederick County, Maryland.

[152] An External Obsolescence Study Related to Proposed Solar Farms in Frederick County, Maryland. Prepared by Treffer Appraisal Group for Coronal Development Services. January 18, 2016.

[153] "Electric Transmission Lines: Is There an Impact on Rural Land Values?" Thomas Jackson. *Right of Way*. November/December 2010

[154] Transmission Lines and Property Values: Briefing Paper. Thomas Priestley. Prepared for Clean Line Energy Partners LLC. CH2MHill. Houston Texas. April 2015

value.[155] In another study, a hedonic price model of sales data from several hundred rural land transactions in Wisconsin found a small difference (<2.5 percent) in sales prices of online and offline properties, but the difference was not statistically significant. An analysis of transactions involving agricultural properties in Montana found that on production agricultural lands (cropland and range lands), there was no evidence supporting a transmission line effect on sales price.

Some exceptions do exist in the literature.[156] A sales comparison study of farmland in Minnesota found price effects ranging from zero to 20 percent where transmission lines were highly intrusive on farm operations, although the latter finding was from a single appraiser study.[157] Another study of transactions involving agricultural land in rural Alberta found a decrease in property values on parcels with irrigation potential hosting multiple transmission lines. In general, however, the findings of the most recent research suggest that a transmission line crossing an agricultural parcel has either no effect or an effect in the range of several percentage points that is not statistically significant.

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. And although the Maryland Public Service Commission has the regulatory authority to approve electric generating stations above 2 MW, the PSC takes into consideration a county's ordinances, if applicable, and concerns when reviewing an application for a CPCN.

Ordinances related to renewable energy can be found within a county's zoning documents. The level of detail and extent of ordinances vary based upon county, with some counties adopting ordinances specific to certain renewable energy technologies, such as wind or solar. In 2017 and 2018, some counties issued moratoriums on the siting of renewable energy projects while they reevaluated or established ordinances related to renewable energy. As of 2019, all county moratoriums had expired. Some of the ordinances currently in effect include:

- Limit on the number of acres which can be utilized by commercial solar systems;
- Maximum capacity per renewable energy project;
- Height restrictions on wind turbines;
- Limitations on which zoning areas renewable energy projects may be sited within; and
- Bans on certain renewable energy projects.

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[155] "The effect of power line structures and easements on farm land values." D.J.A. Brown. *Right of Way*. December/January 1975-1976.

[156] Transmission Lines and Property Value Impacts: A Review of Published Research on Property Value Impacts from High Voltage Transmission Lines. Julia Haggerty. Produced for Mountain States Transmission Intertie (MSTI) Review Project by Headwaters Economics. July 2012.

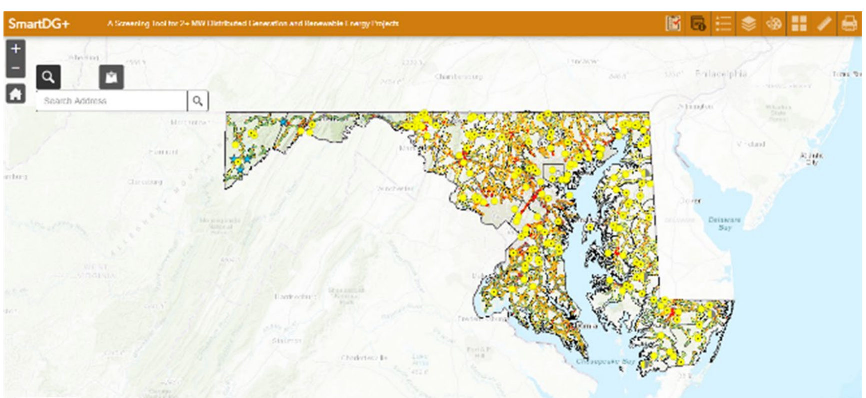
[157] The Effects of Overhead Transmission Lines on Property Values. Report to Edison Electric Institute Siting & Environmental Planning Task Force. C.A. Kroll and T. Priestly. 1992.

To ensure that a renewable energy project does not negatively impact existing operations, such as radar, a county may include a zoning provision requiring approval from multiple county agencies and/or an entity besides the county. For example, St. Mary's County requires wind and solar developers to receive permission from the Department of Navy for projects they wish to site within a certain area around the Naval Air Station Patuxent River to prevent interference with their radar. A comprehensive list of county ordinances is provided as part of the SmartDG+ tool, located on the PPRP website. The SmartDG+ tool and accompanying resources are designed to guide developers as they begin the process; however, developers should contact county planning/zoning offices when planning their project to ensure that a site meets county ordinance requirements.

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 layer 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
    - DOD no-go zones
    - County zoning
- Installed wind and solar projects



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

5.4.2 Historic and Scenic Resources in Electric Generation and 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.

Reconductoring has typically required new structures, but in many cases, lattice structures have been replaced by monopoles which, while taller, have a lower visual profile, and require less real estate on the ground. As a result, PPRP has generally concluded the visual landscape will be mostly unchanged by these projects and therefore will have few direct effects on nearby land uses, even on parcels under agricultural production.

The Independence Energy Connection (IEC) project proposed by Transource Maryland LLC, however, presented this issue in a different context as it would require a new "greenfield" corridor through agricultural lands in Harford County, and a new corridor roughly parallel to an existing transmission line right-of-way (ROW) through mostly agricultural land in Washington County. Based on the project's design and location, PPRP concluded the transmission lines would add visually conspicuous, linear features to landscapes within small areas of Harford and Washington counties, with structures adding a major source of vertical contrast.

For transmission line structures, the size, vertical visual character and geometry all contribute to their contrast against the landscape. But a range of factors can influence the perceived visual impact of the physical infrastructure. These factors include screening elements such as landforms, vegetation, and structures, earth curvature and atmospheric refraction, viewer perceptions, lighting, atmospheric conditions, viewing geometry, the visual backdrop of the viewed object (e.g., sky, ground, or vegetation); and the distance between the viewer and the viewed object.[158]

Both landscape setting and distance moderate the visual impact of transmission lines on viewers. In general, more visually complex landscapes, such as lands with greater vegetative and topographical complexity, reduce the prominence of transmission structures.[159] For an evidence based study of Ireland's transmission grid,[160] landscapes were characterized by specific landscape character types, where the lowest visual effects were found within urban, lowland lake-land, river valley farmland, lowland plain and upland forested landscapes, and the majority of the sites with lowest visual effects

[158] Electric Transmission Visibility and Visual Contrast threshold Distances in Western Landscapes. Robert G. Sullivan et al. Conference: National Association of Environmental Professionals 2014 Annual Conference, Saint Petersburg, Florida. April 2014

[159] Visual Simulation and Assessment of Electricity Transmission Towers. I. Bishop and R.B. Hull. Landscape Australia, March 1985.

[160] EirGrid Evidence Based Environmental Studies. Study 10: Landscape & Visual – Main Report. June 2016.

were found to be lowland agricultural landscape types. The highest visual effects were found within high drumlin and low drumlin esker landscapes, a finding consistent with an analysis of visual contrast threshold distances in landscapes in the western U.S., where skylined structures were visible to the unaided eye at greatest distances. The magnitude of potential visual impacts from transmission lines is strongly related to distance from the viewer, with scenic impact declining with increasing distance to structures (although also increasing with structure size).[161] Visual contrast threshold distance is the distance at which an object becomes visible or attracts visual attention and is used to determine the area of potential effect in visual impact assessments.

Scenic values associated with landscape settings can be difficult to define, particularly when scenic resources are not systematically or consistently identified. Maryland, for example, has not conducted a statewide scenic landscape inventory, although comprehensive scenic resource assessments have been conducted for some regions of the state.[162] As a result, general planning decisions for transmission line siting, in addition to other growth policy decisions, are tempered by the lack of a scenic landscape data layer based on uniform visual resource assessment guidelines. Therefore, PPRP visual impact assessments are largely discretionary, based on incomplete scenic resource data and multiple standards among scenic preservation interests for classifying visual resources.

Impacts on Heritage and Recreational Tourism

Many federal, state and local land preservation and heritage overlays of Maryland contain scenic elements. For example, the Maryland Heritage Areas Program focusses on the preservation of the state's historical, cultural, archeological, and natural resources for sustainable economic development through heritage tourism. The program designates Heritage Areas, defined by a distinct theme that makes a place or region different from other areas of Maryland. The Maryland Heritage Areas Authority (MHAA) certifies and governs Heritage Areas. A management plan sets forth the strategies, projects, programs, actions and partnerships that will be involved in achieving each Heritage Area's goals. Once certified, a Heritage Area management entity becomes eligible for state-matching grants for operating assistance and marketing activities. Local jurisdictions and nonprofit organizations in a Heritage Area may also qualify for state matching grants for planning, design, interpretation, and programming. There are 13 Certified Heritage Areas (CHAs) in Maryland. Maryland Heritage Area law requires state agencies to carry out certain actions when considering a project located in a Certified Heritage Area (CHA). Specifically, when a state agency is carrying out activities in a CHA, it must consult, cooperate, and, to the maximum extent feasible, coordinate its activities with the entity responsible for the management of each CHA; ensure that the activities are consistent with the CHA's management plan; and ensure that activities will not have an adverse effect on the resources of the Heritage Area unless there is no prudent and feasible alternative. Other designation programs include Maryland's Rural Legacy Program (RLP) and MDOT SHA's Scenic Byways Program which were described earlier.

At the federal level, scenic quality is recognized in the management plans for units of the National Park Service located in Maryland, such as the Appalachian Trail and the Chesapeake and Ohio National

[161] Sullivan et al, op. cit.

[162] Maryland's Eastern Shore: Stories of the Chesapeake Heritage Area: Cultural Landscape and Scenic Resource Assessment. John Milner Associates. Chestertown, Maryland. 2004.

Historical Park, the National Register of Historic Places, through its designation of historic landscapes and national historic landmarks, the National Heritage Area program, and the Federal Highway Administration's National Scenic Byway Program, among others. Local governments promote scenery in various recreational initiatives, such as bicycle, hiking and water trails.

While these federal, state and local land preservation and heritage overlays contain scenic elements, landscapes are not uniform within them. Many views have low scenic value or are compromised by contrasting elements, such as commercial establishments, cell and transmission towers and rural subdivisions. Because of this, land preservation and heritage overlays are poor proxies for characterizing scenic quality.

Furthermore, the relationship between scenic quality and heritage and recreational tourism is unclear. As noted earlier, degradation of views has been found to affect tourist perceptions of scenic vistas and visitation levels.[163] However, it has also been shown that perceptions drawn from views within a landscape or of objects within a landscape can vary depending on whether the landscape is an economic resource, tourism or recreational asset, family home or other identity.[164] The visual impact of a wind turbine on a tourist may be quite different from that on a nearby resident, for example. Even when landscapes are highly disturbed, they often retain a pastoral quality to urban or suburban visitors to rural areas.[165] Perceptions may also change over time. Evidence from a Finnish study, for example, suggests residents living in close proximity can adapt to transmission lines being part of the landscape.[166] Similar findings have been suggested in property value studies.[167] Still, findings of the majority of studies seeking to relate perception and aesthetics are far from certain given their lack of scientific rigor.[168] As a result, PPRP's estimation of impacts of transmission lines on heritage and recreational resources are largely based on visibility and distance from these resources.

For example, in PPRP's environmental review of the IEC-West project, three corridor segments were found to be within the Heart of the Civil War CHA, and the project was also within the programmatic boundary of the Journey Through Hallowed Ground National Heritage Area (JTHG NHA). No Maryland scenic byway intersected the transmission corridor, but the ROW was estimated to be within 1.7 miles of the Appalachian National Scenic Trail (AT) at its nearest point. Views to the west along most of the AT in Maryland are limited, but views of the Cumberland Valley from two overlooks, High

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[163] Greden et al, op. cit.

[164] EirGrid Evidence Based Environmental Studies. Op. cit.

[165] Transmission Lines in Wildland Landscapes: Gauging Visual Impact Among Casual Observers. Andrea M. Slusser. Thesis. University of Washington.

[166] Local residents' perceptions of energy landscape: the case of transmission lines. Soini et al. Land Use Policy 28, pp. 294-305.

[167] Power Lines, Visual Encumbrance and House Values: A Microspatial Approach to Impact Measurement. Des Rosiers. Journal of Real Estate Research, Vol 23, No. 3.

[168] Aesthetics and Public Perception of Transmission Structures: A Brief History of the Research. Tikalsky & Willyard. Right of May. March/April 2007.

Rock and Pen Mar, are regarded as among the most notable east of the Rocky Mountains. PPRP also identified an MDOT SHA-designated bicycle route crossing the IEC-West ROW.

However, in consultation with reviewing state agencies, PPRP concluded adverse effects on scenic and heritage resources, to the extent they occur, were expected to be confined largely to the transmission line ROWs and be primarily associated with construction. Therefore, even though the IEC-West corridor passes through the Heart of the Civil War Heritage Area, key heritage resources would not be adversely affected by the project, nor was the project expected to have an adverse effect upon the Journey Through Hallowed Ground National Heritage Area. A visibility assessment conducted by PPRP did find that although the elevated overlooks of the Cumberland Valley from the AT are more than 2.5 miles from IEC-West centerline, structures might still be visible when atmospheric conditions permit. However, structure detection from these locations would be limited due to the complexity of a Cumberland Valley landscape that includes other transmission facilities, roads and other built forms. As a result, PPRP concluded the IEC-West transmission line would not have an adverse effect on the many trail systems, driving and bicycle tours, and other cultural and recreational attractions in the area.

5.4.3 Renewable Technology Supply Chains

Energy Employment

In 2018, the electric power generation sector employed 13,254 workers in Maryland, which is approximately 1.2 percent of total state employment.[169] The majority of the jobs were construction related (42 percent), followed next by the utility industry (27 percent). As noted in Figure 5-39, approximately 7,500 of Maryland's electric power generation jobs focused on renewable energy (solar, wind, and hydropower), with 81 percent attributed by the solar industry (including full time and part time). Based on a forecast by the Energy Futures Initiative and the National Association of State Energy Officials, Maryland's electric power generation sector is expected to grow by approximately 4.8 percent in 2019.[170] In addition to the electric power generation industry, there were approximately 800 jobs under the transmission, distribution and storage sector related to energy storage in Maryland in 2018 (this number is not reflected in Figure 5-39).

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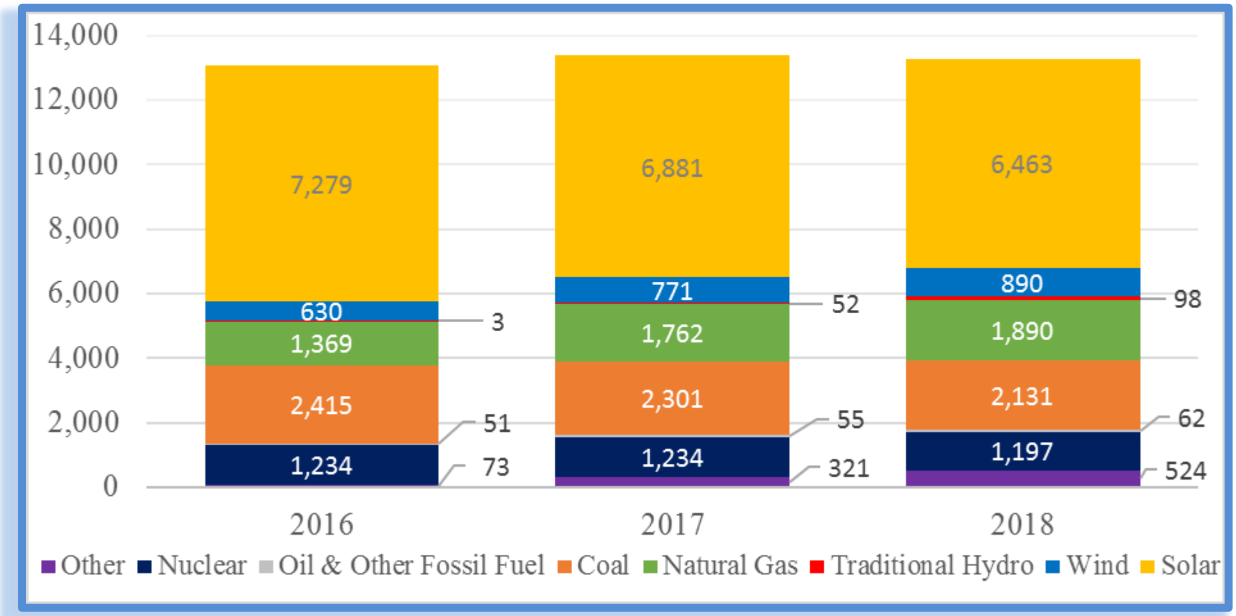
[169] "2019 U.S. Energy and Employment Report: Energy Employment by State," Energy Futures Initiative and National Association of State Energy Officials. https://www.usenergyjobs.org/s/USEER-Energy-Employment-by-State.pdf., February 2019.

[170] Ibid.

Figure 5-39 Electric Power Generation Sector Employment in Maryland by Fuel Type (2018)



Note: "Other" includes other biofuels and all other fuels, including employers cannot assign employment to a single technology/fuel type.

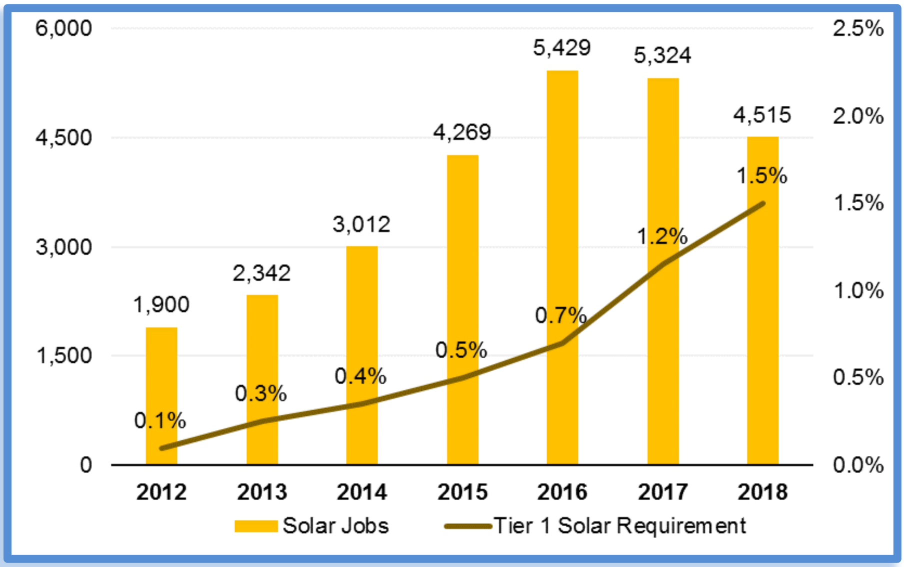
Source: "2019 U.S. Energy and Employment Report: Energy Employment by State," Energy Futures Initiative and National Association of State Energy Officials. https://www.usenergyjobs.org/s/USEER-Energy-Employment-by-State.pdf., *February 2019.*

The instate solar carve-out requirement of the RPS is partially responsible for existing solar jobs in Maryland; however, despite increases in the carve-out, Maryland has experienced a decline in solar jobs over the past few years. As show in Figure 5-40, full-time solar related employment in Maryland peaked in 2016 with 5,429 jobs, but has since declined despite the instate solar carve-out increasing from 0.7 percent in 2016 to 1.5 percent in 2018.[171] One explanation for this shift, as put forth by industry participants, is that the initial RPS requirement levels, coupled with federal and other state incentives, created significant demand that the industry met and exceeded.[172] A resultant glut in solar generation resulted in early compliance with the solar carve-out of the Maryland RPS and put downward pressure on solar renewable energy credit (SREC) prices, making it less economic for continued development of new solar projects.

[171] Full time solar related employment is defined as a worker who spends more than 50 percent of its hours working on solar projects.

[172] MDV-SEIA, https://ccanactionfund.org/media/MD-Solar-Jobs-Losses-Press-Release.pdf

Figure 5-40 Maryland Full-Time Solar Employment Compared to the Instate Solar Carve-Out and Generation (2012-2018)



Solar PV

The National Renewable Energy Laboratory (NREL) estimates that about 60-70 percent of utility-scale PV installation costs are for hardware (i.e., module, inverter, structural balance-of-system (BOS), and electrical BOS), with the remaining costs evenly split between construction and services. For distributed systems, less of the project cost goes to manufactured components and more to services. Operation and maintenance (O&M) costs, which include warrantied and non-warrantied parts replacement, monitoring and property maintenance, are weighted toward services, which are usually fulfilled locally. O&M costs vary by technology, system size, location and other factors.

Solar PV systems are constructed of highly recognizable components like solar cells, modules, racking and inverters, but also hardware such as monitoring equipment, cabling, connectors, nuts and bolts and other manufactured products that knit the system together. Major components, such as modules and inverters, are largely imported. In comparison, there is a greater domestic presence of manufacturers of structural and electrical BOS. In the year ended October 31, 2018, approximately 90 percent of modules were imported.[173] According to Solar Power World, there are 25 domestic solar panel manufacturing facilities,[174] although most of these manufacturers import key components from other countries for assembly in the U.S. or are vertically integrated companies that provide end-to-end services (i.e., design

[173] Solar Foundation 2019. National Solar Jobs Census 2018. The Solar Foundation. Available at SolarJobsCensus.org.

[174] Solar Power World 2019. "U.S. Solar Panel Manufacturers." https://www.solarpowerworldonline.com/u-s-solar-panel-manufacturers/. Accessed February 2019.

through installation).[175] Nine companies manufacture some or all of their solar panels in the U.S. (see Table 5-10).

Table 5-10 U.S.-Based Companies Involved in Manufacturing Solar PV Panels

COMPANY	MANUFACTURING LOCATION	HEADQUARTERS/ PARENT	NOTES
Heliene	Mountain Iron, MN	Canada	
Mission Solar	San Antonio, TX	Texas	
Seraphim	Jackson, MS	China	
Silfab Solar	Bellingham, WA	Canada	
Solaria	Fremont, CA	California	
SolarTech Universal	Riviera Beach, FL	Florida	
SolarWorld Americas	Hillsboro, OR	Germany	In bankruptcy proceedings
SunSpark	Riverside, CA	China	
Tesla/Panasonic	Buffalo, NY	California/Japan	Joint venture

Source: https://news.energysage.com/u-s-solar-panel-manufacturers-list-american-made-solar-panels/

Inverters, which convert direct current (DC) output from a solar panel into utility frequency alternating current (AC), are an integral component of every solar PV system. Eight companies manufacture inverters domestically, ranging from stand-alone to grid-tie models,[176] but only three of the leading utility-scale inverter manufacturers are located in the U.S.[177,178] According to the *National Solar Jobs Census 2017*, U.S. inverter production declined after two major facilities closed at the end of 2016.[179] Some of these jobs may return under certain conditions. In particular, U.S. Section 301 tariffs on Chinese goods could shift inverter manufacturing from China to India, Mexico and the U.S.[180]

Other solar components are generally categorized as structural BOS and electrical BOS. Structural BOS includes racking, mounting, and tracking systems plus any other materials needed to support the modules. ENF Solar, a consultancy, lists more than 100 solar-mounting manufacturers in the U.S.[181]

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[175] https://news.energysage.com/u-s-solar-panel-manufacturers-list-american-made-solar-panels/.

[176] https://www.solarpowerworldonline.com/global-inverter-manufacturing-locations/.

[177] http://wiki-solar.org/company/inverters/index.html

[178] ABB acquired GE's inverter business in mid-2018.

[179] Solar Foundation 2018. National Solar Jobs Census 2017. The Solar Foundation. Available at SolarJobsCensus.org

[180] Solar Foundation 2019. National Solar Jobs Census 2018.

[181] https://www.enfsolar.com/directory/component/mounting_system?country=187

Nine companies manufacture solar-tracking systems.[182] At least two companies selling structural BOS components are located in Maryland.[183] Electrical BOS comprises equipment that transports DC energy from solar panels through the conversion system that produces AC power. Components include conductors, conduits, combiner boxes, disconnects, and monitoring systems. ENF Solar lists 33 solar charge controller manufacturers and 36 solar monitoring system manufacturers in the U.S.

Opportunities for manufacturing growth in Maryland from continuing solar PV deployment is probably limited to the structural and electrical BOS supply chains. This is because the solar installers tend to be vertically integrated, that is, they own or control manufacturing, sales and installation which limits opportunities for other companies to enter the market.

Onshore Wind

More than two-thirds of capital expenditures for a land-based wind power plant project are for turbines, with another 10 percent for electrical infrastructure.[184] Assembly and installation accounts for only three percent of construction costs, while site access and staging, foundation and engineering management account for another 7 to 8 percent. About 54 percent of O&M expenditures are for maintenance and 8 percent for land lease payments.[185] Replacement parts constitute about two-thirds of maintenance expenditures.[186]

As the cumulative capacity of U.S. wind projects has grown over the last decade, foreign and domestic turbine equipment manufacturers have localized and expanded operations in the U.S. There were more than 145 wind turbine and component manufacturing and assembly facilities in 2015[187] and currently more than 500 wind-related manufacturing facilities in the U.S., although only three in Maryland.[188] Most manufacturers have chosen to locate in markets with substantial wind power capacity or near already established large-scale original equipment manufacturers. There are more than 60 wind-related

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[182] http://www.greenworldinvestor.com/2011/07/06/solar-tracker-manufacturers-usachinaindia-list-and-market-review-of-sale-price-and-cost/. Updated September 2016.

[183] https://www.seia.org/national-solar-database

[184] 2016 Cost of Wind Energy Review. National Renewable Energy Laboratory. Technical Report NREL/TP-6A20-70363. December 2017.

[185] 2016 Cost of Wind Energy Review. National Renewable Energy Laboratory. Technical Report NREL/TP-6A20-70363. December 2017

[186] Economic Development Impact of 1,000 MW of Wind Energy in Texas. Technical Report NREL/TP-6A20-50400. August 2011.

[187] 2015 Wind Technologies Market Report. Energy Efficiency and Renewable Energy. U.S. Department of Energy. August 2016.

[188] https://www.awea.org/Awea/media/Resources/StateFactSheets/Maryland.pdf

factories in Ohio, followed by Texas (40), Illinois (35), North Carolina (27), and Michigan, Pennsylvania, and Wisconsin (26 each).[189]

The trend in onshore wind turbines has been toward greater capacities, larger rotor diameters and higher hub heights. Wind turbines installed in the U.S. in 2018 had an average nameplate capacity of 2.4 MW, 116-meter rotor diameter and 88-meter hub height.[190] In addition, through 2018, 23 wind projects had been partially repowered with significantly larger rotors and power ratings.[191]

The domestic supply chain faces competitive pressures from foreign manufacturers and uncertain future demand as the federal Production Tax Credit is phased out. No new wind-related manufacturing facilities opened in 2018, although two are expected to commence operations in 2019. There continues to be increased industry concentration among top original equipment manufacturers (OEMs) and centralization of manufacturing operations to gain economies of scale. As a result, employment growth is expected to moderate from previous years. Despite its domestic presence, the U.S. wind industry remains reliant on imports, particularly on turbines and components.[192]

Maryland's share of the U.S. onshore wind supply chain is small. There were less than 500 direct wind industry jobs in the state in 2018 and no new onshore projects in the pipeline.[193] Instate wind industry supply chain growth is likely to be highly dependent on offshore wind development in Maryland's Wind Energy Area (WEA).

Offshore Wind

NREL estimates between 40-50 percent of offshore wind construction cost is for manufactured goods.[194] An additional one-third is for assembly and installation, with the remaining portion covering services and water transportation. More than half of O&M expenditures are for corrective maintenance parts and other machinery, with the balance for maintenance construction and miscellaneous services.

Although the majority of onshore wind turbine components (as a fraction of total equipment-related turbine costs) installed in the U.S. are domestically sourced, offshore wind installations require many

189 https://www.awea.org/Awea/media/Resources/Publications%20and%20Reports/Market%20Reports/AWEAEconomicDevelopmentImpactsofWindEnergy.pdf

190 Increasing Wind Turbine Tower Heights: Opportunities and Challenges. National Renewable Energy Laboratory. Technical Report NREL/TP-5000-73629. May 2019.

191 2018 Wind Technologies Market Report. Office of Energy Efficiency and Renewable Energy. U.S. Department of Energy. August 2019.

192 2018 Wind Technologies Market Report. Ibid.

193 https://www.awea.org/Awea/media/Resources/StateFactSheets/Maryland.pdf

194 2016 Cost of Wind Energy Review. National Renewable Energy Laboratory. Technical Report NREL/TP-6A20-70363. December 2017.

specialized components that are not currently produced in the United States.[195] Even where facilities serving the U.S. onshore wind market may be capable of manufacturing offshore wind components, logistical concerns primarily related to the long-distance transport of large components may limit their ability to supply the offshore market. As a result, an offshore wind supply chain has not yet developed in the U.S.

Because of this, most near-term manufacturing opportunities for offshore wind are limited to upstream materials and subcomponents that can be easily transported. Upstream products include scaffolding, coatings, ladders, fastenings, hydraulics, concrete, and electrical components. Table 5-11 identifies some businesses in the Mid-Atlantic region that have the potential to support the offshore wind supply chain.[196,197]

Table 5-11 Number of Existing Companies and Firms Identified in the Mid-Atlantic Region with the Potential to Supply OSW Components

INDUSTRY	MD	DE	NJ	VA	PA
Electronics	**1**	0	3	2	15
Manufacturing & assembly	**17**	0	1	6	17
Installation, construction, materials	**13**	2	1	5	28
Maintenance, logistics, transportation	**16**	0	4	34	6
Services	**6**	2	6	34	4
TOTAL	**53**	**4**	**15**	**81**	**70**

Source: NREL 2015.[198]

Both existing OREC applications (US Wind and Skipjack)[199] to the Maryland PSC allocate significant percentages of construction costs to Maryland, and specifically target investment in a Maryland steel fabrication facility. Apart from these projects, however, there is considerable uncertainty about which industries in Maryland will benefit from offshore wind development. Both US Wind and Skipjack are attempting to develop relationships with instate businesses that traditionally have not participated in energy development projects and markets.[200]

[195] U.S. Offshore Wind Manufacturing and Supply Chain Development. Prepared for U.S. Department of Energy. Navigant Consulting Inc. February 22, 2013, 19.

[196] https://issues.nawindpower.com/article/maryland-prepares-offshore-wind-push

[197] Offshore Winds Jobs and Economic Development Impacts in the United States: National Renewable Energy Laboratory. Technical Report NREL/TP-5000-61315. February 2015.

[198] Offshore Wind Jobs and Economic Development Impacts in the United States: Four Regional Scenarios. National Renewable Energy Laboratory. Technical Report NREL/TP-5000-61315. February 2015, 13.

[199] Maryland PSC Case No. 9341.

[200] https://www.bizjournals.com/baltimore/news/2019/01/23/maryland-offshore-wind-developers-look-to-partner.html

Some studies predict future opportunities for suppliers will be greatest in industries responsible for providing foundations and substructures, towers, blade materials, power converters, and transformers.[201,202] NREL has taken this outlook further by estimating the share of critical offshore wind component manufacturing that could take place in the Mid-Atlantic region. These estimates are broken down into three investment scenarios (see Table 5-12).

Table 5-12 Regional Investment Paths for the Dynamic Components for Offshore Wind in the Mid-Atlantic

	LOW INVESTMENT		MEDIUM INVESTMENT		HIGH INVESTMENT	
YEAR:	2020	2030	2020	2030	2020	2030
Deployed capacity (MW)	366	3,196	1,912	7,832	4,100	16,280
Turbine	32%	68%	35%	95%	65%	100%
Blades & towers	13%	71%	25%	95%	30%	95%
Substructures & foundation	11%	30%	20%	50%	30%	85%

Source: NREL 2015.

However, while there exists domestic infrastructure for the manufacture of some offshore wind components (e.g., offshore oil and gas industry suppliers), a more complete domestic supply chain is unlikely until sufficient demand exists to justify the investment in new, dedicated facilities. This is particularly the case because the offshore wind market faces rapidly changing technologies and continued regulatory uncertainty. Deployment has lagged to date and, as a result, installed offshore wind capacity projections have been consistently pushed into the future and, with it, the development of a domestic offshore wind supply chain. Demand along the Atlantic coast may not be sufficient to attract a wind turbine generator manufacturing facility until the mid-2020s or later.[203,204]

Onshore Hubs for Offshore Wind

Even though offshore wind has been slow to develop in the U.S., declining costs and state RPS policies have the potential to leverage development of offshore wind resources and industries.[205] If offshore

[201] U.S. Offshore Wind Manufacturing and Supply Chain Development. Prepared for U.S. Department of Energy. Navigant Consulting Inc. February 22, 2013.

[202] 2018 Massachusetts Offshore Wind Workforce Assessment. Massachusetts Clean Energy Center, 46.

[203] U.S. Offshore Wind Manufacturing and Supply Chain Development. Prepared for U.S. Department of Energy. Navigant Consulting Inc. February 22, 2013.

[204] U.S. Job Creation in Offshore Wind. BVG Associates Ltd. NYSERDA Report 17-22. October 2017.

[205] "Offshore Wind Ready to Take Off in the United States." S&P Global Market Intelligence. July 20, 2018. Accessed from https://www.spglobal.com/marketintelligence/en/news-insights/research/offshore-wind-ready-to-take-off-in-the-united-states on February 27, 2019.

wind is developed to projected capacities, multiple U.S. ports will need to be improved to support staging and manufacturing operations.[206]

Known as onshore hubs for offshore wind, these facilities can generate significant economic impacts, potentially leveraging existing manufacturing competencies in a region and adding new ones. The Port of Bremerhaven on the North Sea is an example of a successful onshore wind hub. The harbor has attracted more than $325 million of investment to create a major onshore wind energy cluster.[207] Three turbine manufacturers, a blade manufacturer and a foundation manufacturer are located in the harbor area, and the region hosts over 300 suppliers, service providers and research institutions. An estimated 1,500 local jobs around Bremerhaven are directly attributable to offshore wind energy. With projected annual installation and repowering approaching 200 wind turbines in the North Sea, a 500-acre expansion of Bremerhaven's harbor was initiated in 2011 to accommodate Germany's offshore wind strategy.

Several Atlantic coastal states, including Virginia, South Carolina, Massachusetts and others have identified potential onshore hubs for offshore wind, although only the Rhode Island ports at Block Island, Galilee, Quonset Point and ProvPort (Providence) have actually been used as construction and staging hubs, in this case for a 30 MW, 5-turbine offshore wind farm off the coast of Block Island. However, with plans by wind developer Ørsted to locate a factory for steel foundations in Paulsboro, New Jersey for its 1.1 GW Ocean Wind project, onshore hubs may soon become a reality along the Atlantic Coast.[208]

In return for Round 1 ORECs, both US Wind and Skipjack are required to invest in a Maryland steel fabrication facility, use a port facility in the greater Baltimore region for marshalling project components, use Ocean City as the O&M port and invest in upgrades to the Tradepoint Atlantic shipyard. As such, Tradepoint Atlantic has positioned itself to potentially become a hub for offshore wind on the East Coast, with space for offshore wind laydown, manufacturing and vessel loading.[209]

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[206] Assessment of Ports for Offshore Wind Development in the United States. Prepared for U.S. Department of Energy by GL Garrad Hassan. March 21, 2014.

[207] Offshore Terminal Bremerhaven: Information for Infrastructure Investors. BIS Economic Development Company Ltd., Bremerhaven, Germany. January, 2011.

[208] https://www.greentechmedia.com/articles/read/orsted-and-germanys-eew-plan-offshore-wind-factory-in-new-jersey?utm_medium=email&utm_source=Daily&utm_campaign=GTMDaily#gs.om3f12

[209] Offshore Wind Factsheet. Tradepoint Atlantic. Accessed at https://tradepointatlantic.com/downloads/.

5.5 Radiological Issues

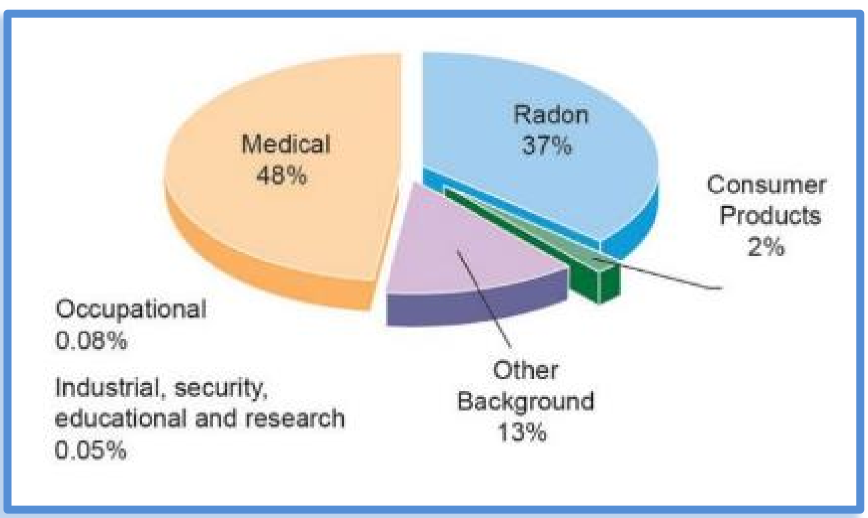
5.5.1 Pathways to Exposure

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 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. The NRC regulates releases from nuclear power plants according to the principle that the exposure of the environment and humans to radiation be kept "as low as reasonably achievable."

Pathways of exposure to radioactive material in the environment are similar to those for other pollutants. An aqueous (water) pathway dose can be received internally or externally by ingesting contaminated water and seafood, or by exposure to contaminated sediments and water. An atmospheric pathway dose can result from exposure to or inhalation of radioactive gas or airborne particles, or ingestion of radionuclides deposited on or assimilated by terrestrial vegetation and animals.

Nuclear power plants are minor contributors to radiation exposure in the United States. As Figure 5-41 illustrates, natural radiation sources (radon and other background sources) account for nearly 50 percent of the average radiation dose to humans. Of the remaining radiation dose to humans that arises from manmade sources, less than 0.05 percent is attributed to commercial nuclear power production.

Figure 5-41 Annual Estimated Effective Dose Equivalent (mrem) to the General Population from Natural and Manmade Sources



Source: National Council on Radiation Protection and Measurements, Ionizing Radiation Exposure of the Population of the United States, NCRP Report No. 160, 2009

As noted above, nuclear power plants such as Calvert Cliffs and Peach Bottom routinely release small quantities of gaseous, particulate, and liquid radioactive material into the atmosphere and adjacent waterways used for cooling water (e.g., Chesapeake Bay). The level of radioactivity in the effluent at any given time depends on many factors, including plant operating conditions and conditions of the nuclear fuel.

Most of the releases to the environment from Calvert Cliffs and Peach Bottom consist of tritium to waterways and radioactive noble gases into the atmosphere, neither of which have environmental significance since they are easily dispersed or are chemically inert. Aqueous discharges, however, may contain varying concentrations of radionuclides (e.g., iodine and metals such as iron, cobalt, cesium, chromium, zinc and manganese) that can be accumulated by biota or become trapped in bottom sediments. Over time, these radionuclides may potentially contribute to a radiation dose to humans by transport through the food chain.[210] Environmentally significant radionuclide releases have declined over the past two decades due to improvements in coolant water filtration technology.

5.5.2 Nuclear Power Plants and Maryland

Figure 5-42 shows the locations of nuclear power plants in and near Maryland. Calvert Cliffs Nuclear Power Plant, in Calvert County, is the only nuclear power plant in the State of Maryland. The next closest plant, Peach Bottom Atomic Power Station, is on the Susquehanna River just north of the Pennsylvania/Maryland border. Both facilities release very low levels of radionuclides into Maryland's environment.

Figure 5-42 Nuclear Power Plants in and Around Maryland

[210] 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.

Calvert Cliffs Nuclear Power Plant

Exelon Generation Company, a subsidiary of Exelon Corporation, operates the Calvert Cliffs Nuclear Power Plant (CCNPP) on the western shoreline of the Chesapeake Bay. Each of the two units are pressurized water reactors with a total generating capacity of approximately 1,829 MW. The units began service in May 1975 and April 1977.

Peach Bottom Atomic Power Station

Exelon also operates Peach Bottom Atomic Power Station (PBAPS). PBAPS began operations in 1974 and is located on Conowingo Reservoir, 2.7 miles north of the Pennsylvania/Maryland border. The plant's two operating units are boiling water reactors, each with a combined generating capacity of approximately 2,280 MW.

Besides these plants, there are nine additional nuclear generating sites within 100 miles of Maryland (see Table 5-13).

Table 5-13 Out-of-State Nuclear Power Plants Near Maryland

Plant	Owner/Operator	Location	Generating Capacity (MWe)
Salem Nuclear Generating Station	PSEG Nuclear, LLC	Hancocks Bridge, NJ	2,365
Hope Creek Generating Station	PSEG Nuclear, LLC	Hancocks Bridge, NJ	1,178
Oyster Creek Nuclear Generating Station	Exelon Generation Co., LLC	Forked River, NJ	625
Three Mile Island Nuclear Station	Exelon Generation Co., LLC	Middletown, PA	837
Susquehanna Steam Electric Station	PPL Susquehanna, LLC	Salem Township, PA	2,600
Beaver Valley Power Station	FirstEnergy Nuclear Operating Co.	Shippingport, PA	1,800
Limerick Generating Station	Exelon Generation Co., LLC	Limerick, PA	2,317
North Anna Power Station	Virginia Electric & Power Co.	Louisa, VA	1,892
Surry Power Station	Virginia Electric & Power Co.	Surry, VA	1,676

5.5.3 Monitoring Programs and Results

Because of the potential direct impact of nuclear power generation (specifically routine releases of radioactivity) on Maryland's natural resources, PPRP conducts monitoring near Calvert Cliffs and Peach Bottom to assess the radiological effects on the environment attributable to each of the power plants (Table 5-14). PPRP has monitored radionuclide levels in the environment surrounding Calvert Cliffs since 1975 and surrounding Peach Bottom since 1979 and publishes its environmental assessments biennially.

Table 5-14 Nuclear Power Plant Environmental Monitoring Elements

Matrix	No. Stations	Locations	Analytes	Collection Frequency
1. Air Filter	8	Calvert County, Baltimore, Cecil County, Harford County, Eastern Shore	α, β, ^{7}Be, ^{137}Cs	continuous (exchanged weekly)
2. Charcoal Filter	8	Calvert County, Baltimore, Cecil County, Harford County, Eastern Shore	^{131}I	continuous (exchanged weekly)
3. Potable Water	7 1 1 1	Calvert County Baltimore City Patuxent River Potomac River	α, β, ^{3}H	quarterly monthly quarterly quarterly
4. Raw Water	1 1	Patuxent River Potomac River	α, β, ^{3}H	monthly monthly
5. Precipitation	1	Baltimore City	α, β, ^{3}H, ^{7}Be	weekly
6. Raw Milk	1	Cecil County	^{89}Sr, ^{90}Sr, ^{131}I, ^{140}Ba, ^{137}Cs, ^{40}K	quarterly
7. Processed Milk	1	Baltimore City	^{89}Sr, ^{90}Sr, ^{131}I, ^{140}Ba, ^{137}Cs, ^{40}K	quarterly
8. Sediment	28	Chesapeake Bay (near CCNPP)	γ	quarterly
9. Tray Oysters	2	Chesapeake Bay	γ	quarterly
10. Sediment	19	Chesapeake Bay & Susquehanna River (near PBAPS)	γ	semiannually
11. Finfish	1	Susquehanna River	γ	semiannually
12. Submerged Aquatic Vegetation (SAV)	3	Chesapeake Bay & Susquehanna River	γ	semiannually

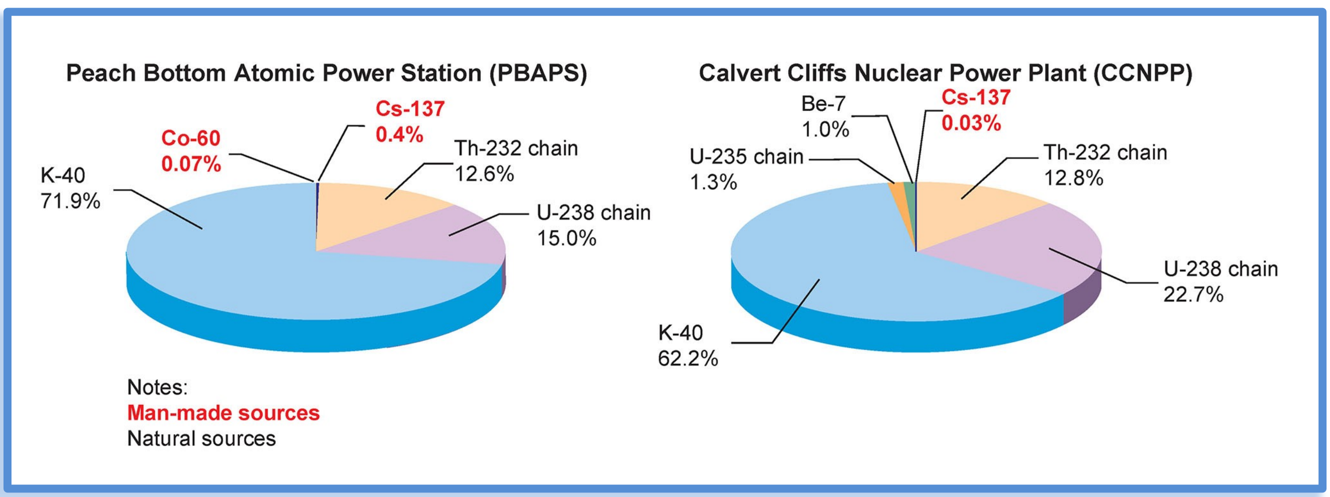
Monitoring by PPRP is conducted to satisfy NRC requirements to verify that any releases from normal plant operations result in potential doses to humans that are below regulatory limits. The monitoring also meets Maryland requirements to research the environmental effects of electric power generation and to maintain state oversight of environmental monitoring.

The most recently compiled results (for the years 2016 to 2017) from weekly air and annual vegetation monitoring conducted by Constellation Energy Nuclear Group (previous owner of Calvert Cliffs), Exelon Generation Company, and independently by PPRP indicate that releases of radioactivity to the atmosphere from the Calvert Cliffs plant were not detectable in air, precipitation, or vegetation.

Estuarine (e.g., Chesapeake Bay) and riverine (e.g., Susquehanna River) sediments are also useful indicators of environmental radionuclide concentrations because they serve as natural sinks for both stable and radioactive metals. PPRP collects sediment samples periodically from a network of transects in both study areas in the vicinity of Calvert Cliffs and Peach Bottom. No plant-related radionuclides, specifically ^{60}Co, were detected in Bay sediments near Calvert Cliffs during the 2016-2017 reporting period (see Figure 5-43).

At Peach Bottom, plant-related ^{60}Co was detected on 10 occasions (detection frequency of 13.2 percent) in sediments collected from Conowingo Reservoir and Susquehanna River, but not within the upper Chesapeake Bay. As shown in Figure 5-43, the quantity of ^{60}Co in sediment samples, when detected, was proportionally far below the levels contributed by residual radioactive fallout and natural sources. The detection frequency of ^{60}Co in sediment samples from Peach Bottom during the 2016-2017 reporting period was slightly lower than the average for historical samples (16.3 percent since 1996).

Figure 5-43 Proportion of Natural vs. Manmade Radionuclides in Sediment Samples near CCNPP (2017) and PBAPS (2016)



Bay oysters are ideal indicators of environmental radionuclide concentrations because they do not move and readily ingest and concentrate metals. Oysters have been historically commercially harvested near Calvert Cliffs, and have the greatest potential for contributing to a human radiation dose through seafood consumption. The oysters are collected at scheduled time intervals and analyzed for radionuclide content in their tissues. Radiosilver (^{110m}Ag) has historically been the principal plant-related radionuclide accumulated by test oysters and oysters on natural beds. Since the fourth quarter of 2001, concentrations of ^{110m}Ag in oysters have fallen below analytical detection limits. The lack of detectible ^{110m}Ag reflects a downward trend in ^{110m}Ag releases, as well as other environmentally significant radionuclide releases, from Calvert Cliffs.

Finfish are the primary pathway for Peach Bottom-related radionuclide releases to contribute to a human radiation dose because the reservoir contains a recreational fishery. Finfish are collected semiannually by PPRP from the Conowingo Reservoir area near Peach Bottom. During 2016-2017, finfish samples contained no radionuclides attributable to PBAPS.

As part of its assessment program, PPRP estimates doses of radiation to individuals consuming seafood. The doses are calculated based on maximum or worst-case estimates of the amount of plant-related radioactive material potentially available in the seafood. Results indicate that radiation doses attributable to operations at Calvert Cliffs are well below federally mandated limits (see Table 5-15). As shown in Figure 5-41, the annual total body dose that originates from industrial releases of radionuclides, and subsequent consumption of seafood and drinking water, is small relative to other modes of dose accumulation.

Table 5-15 Comparison of Radiation Doses to Humans and Applicable Regulatory Limits

Exposure Route	Maximum Dose Estimate (2016)	Maximum Dose Estimate (2017)	EPA Regulatory Limit (40CFR190 Subpart B)	NRC Regulatory Limit (10CFR50 Appendix I)
Ingestion (mrem)				
Oyster ingestion, whole body dose (from CCNPP)	<0.007 (child)[a]		25	3
Oyster ingestion, other organ dose (from CCNPP)	<0.05 (adult GI tract)[a]		25	10
Finfish ingestion, whole body dose (from PBAPS)	0.0041 (adult)[a]		25	3
Finfish ingestion, other organ dose (from PBAPS)	0.0066 (teen liver)[a]		25	10
Inhalation (mrem)				
Whole body dose (gaseous, from CCNPP)	0.00032 (child)[b]	0.00026 (child)[b]	25	3
Other organ dose (gaseous, from CCNPP)	0.00034 (child skin)[b]	0.00026 (child GI tract)[b]	25	10

Exposure Route	Maximum Dose Estimate (2016)	Maximum Dose Estimate (2017)	EPA Regulatory Limit (40CFR190 Subpart B)	NRC Regulatory Limit (10CFR50 Appendix I)
Whole body dose (gaseous, from PBAPS)	0.245 (any age class)[b]	0.214 (any age class)[b]	25	3
Other organ dose (gaseous, from PBAPS)	0.319 (any age class skin)[b]	0.279 (any age class skin)[b]	25	10

[a] Source: PPRP biennial reports

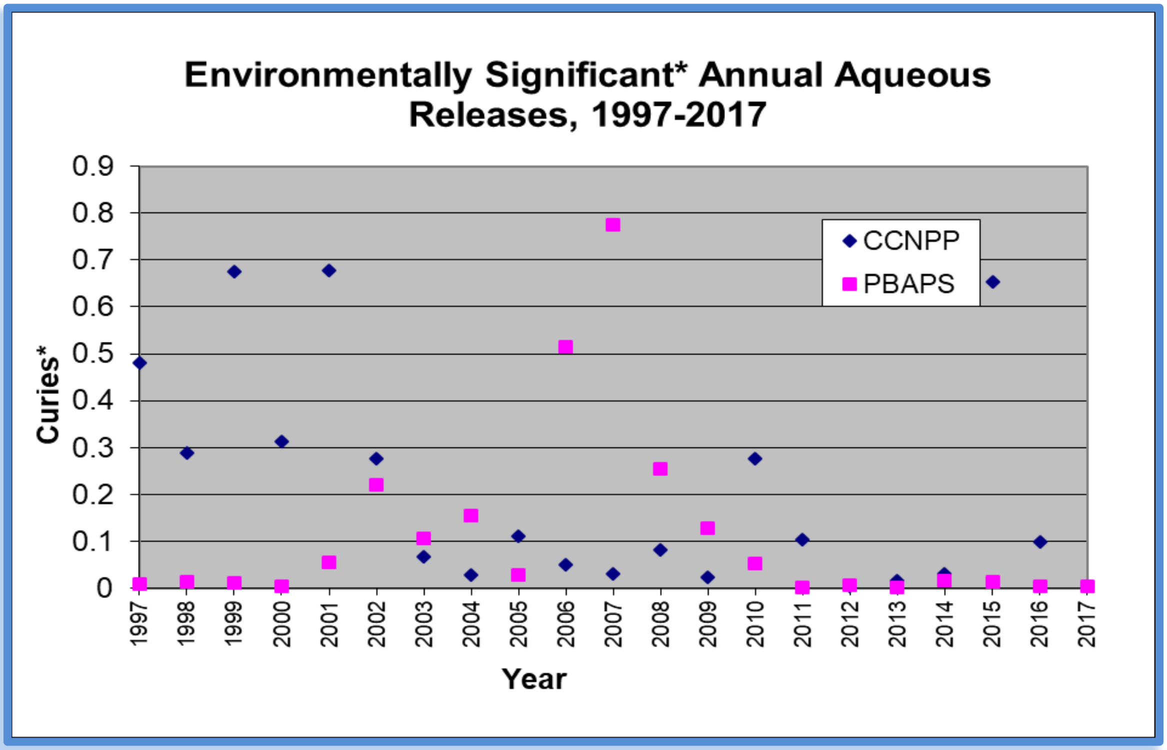
[b] Source: Annual Radiological Environmental Operating Reports for 2016 and 2017, Exelon Generation

Results of analyses of environmental samples collected in the vicinity of Calvert Cliffs and Peach Bottom can be found in the periodic environmental reports described above. A comparison of radionuclide concentrations in environmental samples collected in 2016 to 2017 with historical levels shows the following:

- Plant-related radionuclides were not detected in seafood (i.e., oysters and finfish) during 2016 to 2017;
- Plant-related radionuclides were infrequently detected in sediments during 2016 to 2017;
- 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 Calvert Cliffs and Peach Bottom, when detected, is very small compared with background radioactivity in the environment from natural sources and weapons test fallout; and
- Radiation doses to humans due to atmospheric and aqueous releases are well within regulatory limits (see Table 5-15).

In summary, environmental, biological and human health effects from releases of radioactivity from Calvert Cliffs and Peach Bottom were not significant.

Figure 5-44 Environmentally Significant Annual Aqueous Releases, 1997-2017*



* Environmentally significant refers to radionuclides that are known to be assimilated by biological organisms and are discharged in detectable amounts. Aqueous releases of noble gases, tritium, and very short-lived radionuclides are not included because they do not bioaccumulate or they decay rapidly to stable forms.

5.5.4 Emergency Response

Maryland state agencies (such as DNR, MDE and the Maryland Emergency Management Agency), local counties and Exelon conduct emergency response exercises annually, and an indepth, federally evaluated, ingestion pathway emergency response exercise approximately every six to eight years. The multi-agency exercises demonstrate and provide practice for Maryland's onsite and offsite response measures using a simulated accident at Calvert Cliffs. The exercises encompass the implementation of protective actions for all phases (e.g., plume, ingestion pathway, reentry) of the simulated accident, depending on simulated conditions at Calvert Cliffs and simulated impacts to the surrounding environment. The protective actions affect farm operations, drinking water supplies, and may include evacuation or sheltering in place for nearby populations. The exercises include taking simulated environmental samples in the area surrounding Calvert Cliffs and delivering them to a certified analytical laboratory. The offsite portion of the exercise is evaluated by representatives from the Federal Emergency Management Agency.

5.5.5 Radioactive Waste

In addition to the production of atmospheric and liquid effluent releases as a byproduct of normal power generation operations, both Calvert Cliffs and Peach Bottom generate radioactive waste products which require disposal.

Low-Level Radioactive Waste

Low-level radioactive waste (LLRW) consists of materials such as contaminated gowns, toweling, glassware, resin, equipment, oil and reactor control rods that are used in the normal daily operation and maintenance of the power plant. Much of the waste is safety and testing equipment that have become contaminated through normal use. Resin is used to remove radioactivity from wastewater through an ion-exchange process. Depending on the waste type and radioactivity level, the waste is dried, compressed and sealed into high-integrity containers, steel boxes or 55-gallon drums. These containers may, in turn, be sealed into shipping casks or containers. LLRW from Calvert Cliffs, similar to LLRW from other industries, is transported by truck to a licensed radioactive waste processing firm.

“Waste Confidence” and the “Continued Storage of Spent Nuclear Fuel Rule” for U.S. Nuclear Power Plants

Nuclear “waste confidence” is a general regulatory term indicating that used (spent) nuclear fuel can be stored safely and with minimal environmental impacts at nuclear plant sites for some extended period of time (e.g., 60 years) after a plant’s operating license expires.

In 2010, the NRC updated its *Waste Confidence Decision,* reiterating that used nuclear fuel generated at commercial nuclear power plants could continue to be stored using dry storage technology (i.e., ISFSIs).

In 2012, the District of Columbia Circuit Court of Appeals vacated the *Waste Confidence Decision*, concluding that the NRC’s analysis supporting two waste confidence findings (repository availability and long-term interim onsite storage) was insufficient under the National Environmental Policy Act.

In response to the Court’s decision, the NRC issued the *Continued Storage of Spent Nuclear Fuel Rule* in 2014. This rule revised the previously vacated *Waste Confidence Decision* and changed the name of the rule in response to public comment to more accurately reflect its nature and content.

Specifically, this rule adopted the findings of an NRC-prepared Generic Environmental Impact Statement, which concluded that used nuclear fuel can be stored for an indefinite period. In addition, the NRC found that a “no repository scenario” is highly unlikely and contrary to current law. The rule is currently under appeal in the District of Columbia Circuit Court.

High-Level Radioactive Waste (Irradiated Fuel)

Used (spent) nuclear fuel from both Calvert Cliffs and Peach Bottom are presently stored at each site within spent fuel pools for the recently discharged fuel or, in the case of older fuel generated in earlier years of plant operation, at dry storage independent facilities located within each plant’s protected area. Independent Spent Fuel Storage Installations (ISFSIs) design and construction must conform to strict NRC specifications (10CFR72) that protect against unauthorized entry, earthquakes and other natural phenomena such as floods and hurricanes. Onsite storage facilities, such as the ISFSI, are currently the only long-term storage facilities for irradiated fuel available [see sidebar].

Exelon’s dry cask storage facility at Peach Bottom is estimated to have used 93 percent of its currently installed storage pad space. Peach Bottom’s ISFSI license will expire in 2040. The Calvert Cliffs ISFSI is estimated to have used 93 percent of its currently installed storage capacity. The Calvert Cliffs ISFSI license will expire in 2052. Future modules will be built as needed to continue to store spent nuclear fuel generated at each of the power plants.

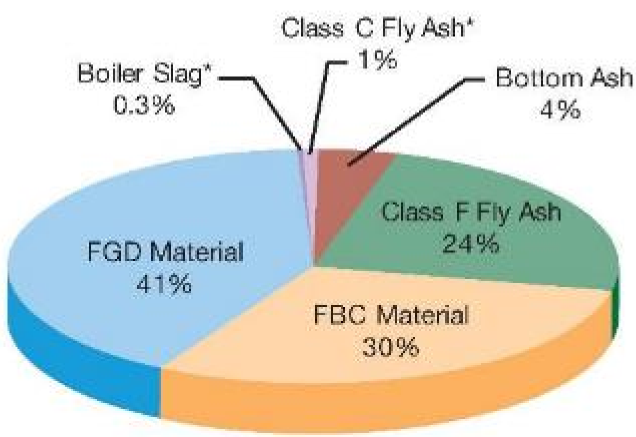
5.6 Power Plant Combustion Byproducts

The combustion of coal to produce electricity yields solid coal combustion byproducts (CCBs), also known as coal combustion residuals (CCRs). These materials are often disposed of in landfills, but there are also a variety of beneficial uses for CCBs that reduce disposal and the demand for virgin raw materials. This section of the report focuses on the generation of CCBs at coal-fired power plants in Maryland as well as beneficial use and disposal practices. The ultimate goal is that all CCBs generated in Maryland will be used in environmentally beneficial or benign ways.

5.6.1 CCB Generation and Characteristics

In 2018, coal-fired power plants in Maryland generated approximately 1 million tons of CCBs, as reported to the Maryland Department of the Environment (MDE). The term CCBs includes several solid materials with different physical and chemical characteristics. The types and percentages of CCBs generated in Maryland are shown in Figure 5-45.

Figure 5-45 CCBs Produced in Maryland in 2018



* Boiler Slag and Class C Fly Ash were produced only at the C.P. Crane Power Plant, which ceased burning coal and began conversion to natural gas fuel in 2018.

The chemical characteristics of CCBs depend upon the nature of the coal burned, the combustion process used and any emission control processes used. Most power plants in Maryland burn bituminous coal from the eastern United States and produce Class F fly ash and bottom ash. Fly ash is composed of very fine, and generally spherical, glassy particles that are fine enough to be transported from the furnace along with emission gases and are captured in electrostatic precipitators or baghouses. Bottom ash is composed of coarser, angular and porous particles that are heavier and thus fall to the bottom of the furnace, where they are collected. Boiler slag is a specialized form of bottom ash that is collected in a glassy form. The only Maryland power plant to generate boiler slag, the C.P. Crane power plant, ceased to burn coal in 2018 and began switching to natural gas as a fuel source; further generation of boiler slag within the state is not anticipated in the near future.

Class F fly ash and bottom ash are primarily composed of silicon, aluminum and iron oxides, making them excellent pozzolan material (meaning that they contribute to cementitious reactions when combined with water and free lime). They may also contain trace metals such as titanium, nickel, manganese, cobalt, arsenic and mercury. For this reason, electric utilities are required to include all applicable constituents of their CCBs when reporting chemical releases to EPA's Toxics Release Inventory (TRI) program, which maintains a database listing the quantities of toxic chemicals released to the environment annually by various industries. When fly ash is used as pozzolan to produce solid material, its potential to leach trace elements is greatly reduced.

Fly ash and bottom ash composition may be affected by emission control technologies, like low NO_x burners. These burners reduce the emission of smog-producing nitrogen oxides from power plant emissions, but they also tend to result in CCBs with higher levels of unburned carbon (also known as loss-on-ignition or LOI). Excess unburned carbon reduces the quality of concrete and cannot be used by the ready-mix concrete industry. Maryland power plants have overcome this problem by adopting CCB beneficiation technologies. There are two fly ash beneficiation plants in Maryland, the STAR plant and the STET plant (formerly known as the STI plant). These two plants use different technologies to reduce the level of unburned carbon in fly ash, making it highly desirable for the ready-mix concrete industry.

Alkaline CCBs like fluidized bed combustion (FBC) material and Class C fly ash contain high levels of calcium and have high pH values. The AES Warrior Run power plant near Cumberland uses FBC technology in which coal and finely ground limestone are fed into the combustion chamber and mixed by forcing in air. The heat in the combustion chamber causes the limestone to decompose to an oxide that captures SO_2 released from the burning of the coal. FBC units can remove more than 95 percent of the sulfur produced from burning coal and the resulting FBC material byproducts contain both calcium sulfate (gypsum) and calcium oxide (free lime). The free lime content of these materials makes them self-cementing with the addition of water. Class C Fly ash results when hi-calcium coal (generally mined in the midwestern United States) is burned. Only the C.P. Crane power plant used this type of coal in 2018. However, it also ceased to burn coal during the year as it began conversion to natural gas fuel; thus, further production of Class C fly ash in Maryland is not anticipated in the near future.

The third major category of CCBs produced in Maryland is flue gas desulfurization (FGD) material. Like FBC processes, FGD uses limestone as a sorbent to control sulfur emissions. Unlike FBC processes, the sorbent is introduced, not with the coal, but into the exhaust system, producing a completely separate stream of residuals with a distinctive composition. FGD materials consist almost entirely of calcium sulfate, and are often referred to as synthetic gypsum. FGD scrubbers were installed at the Brandon Shores, Dickerson, Chalk Point and Morgantown power plants in 2010.

If not managed in accordance with sound engineering principles, landfilled CCBs have the potential to adversely impact Maryland's terrestrial and aquatic resources. In 2019, the Environmental Integrity Project published a report describing previously documented impacts to ground water from CCB sites across the United States. Four of the sites mentioned in the report are located in Maryland: the Brandywine Ash Management Facility, the Fort Armistead Road Landfill, the Westland Ash Management Facility and the BBSS site.

5.6.2 Regulation of CCBs

The use and final disposition of CCBs is dependent on the creation and development of state and federal regulations that establish the requirements for their beneficial use and disposal. Figure 5-46 presents a timeline that shows milestones in the CCB industry and corresponding regulatory developments; Figure 5-47 presents a more detailed regulatory timeline, broken down by state vs. federal actions.

Figure 5-46 Industry and Regulatory Activities Affecting CCBs

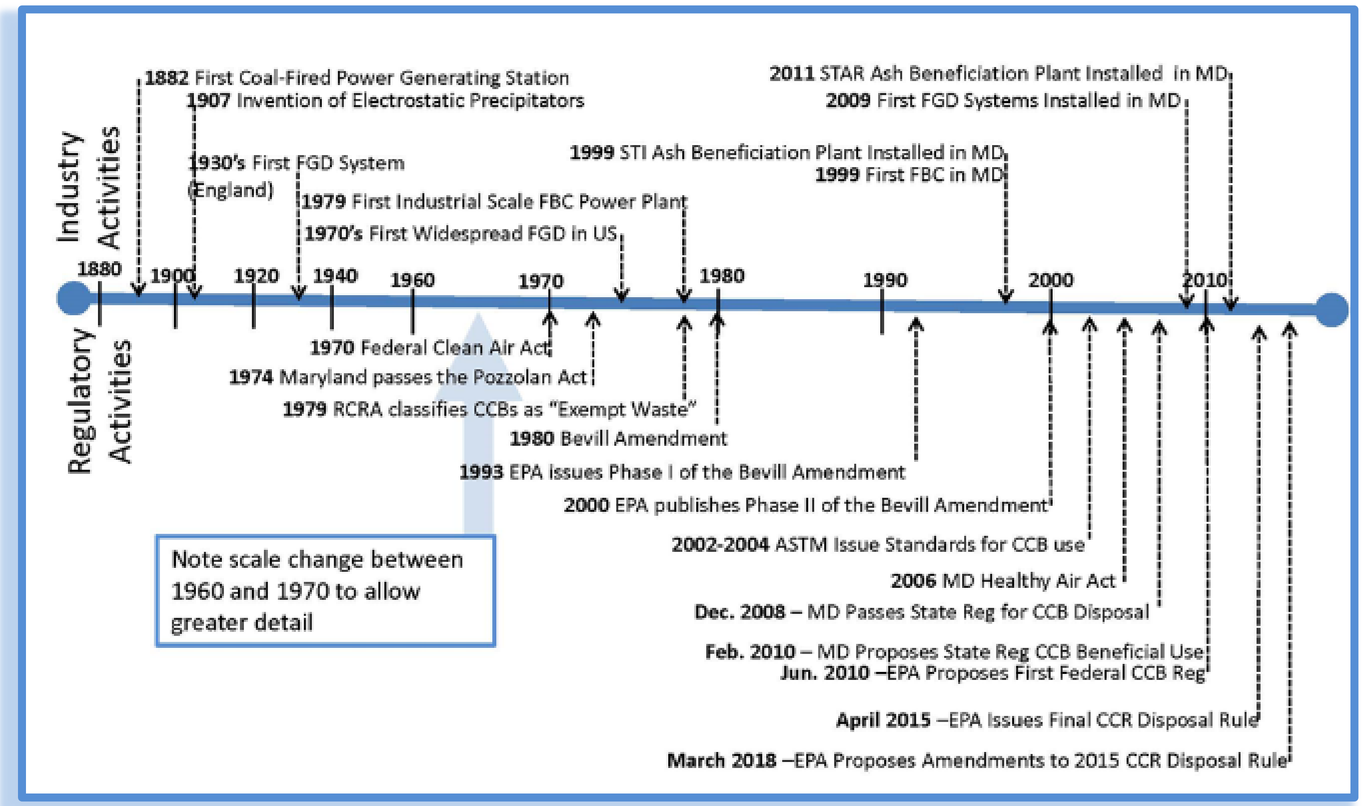
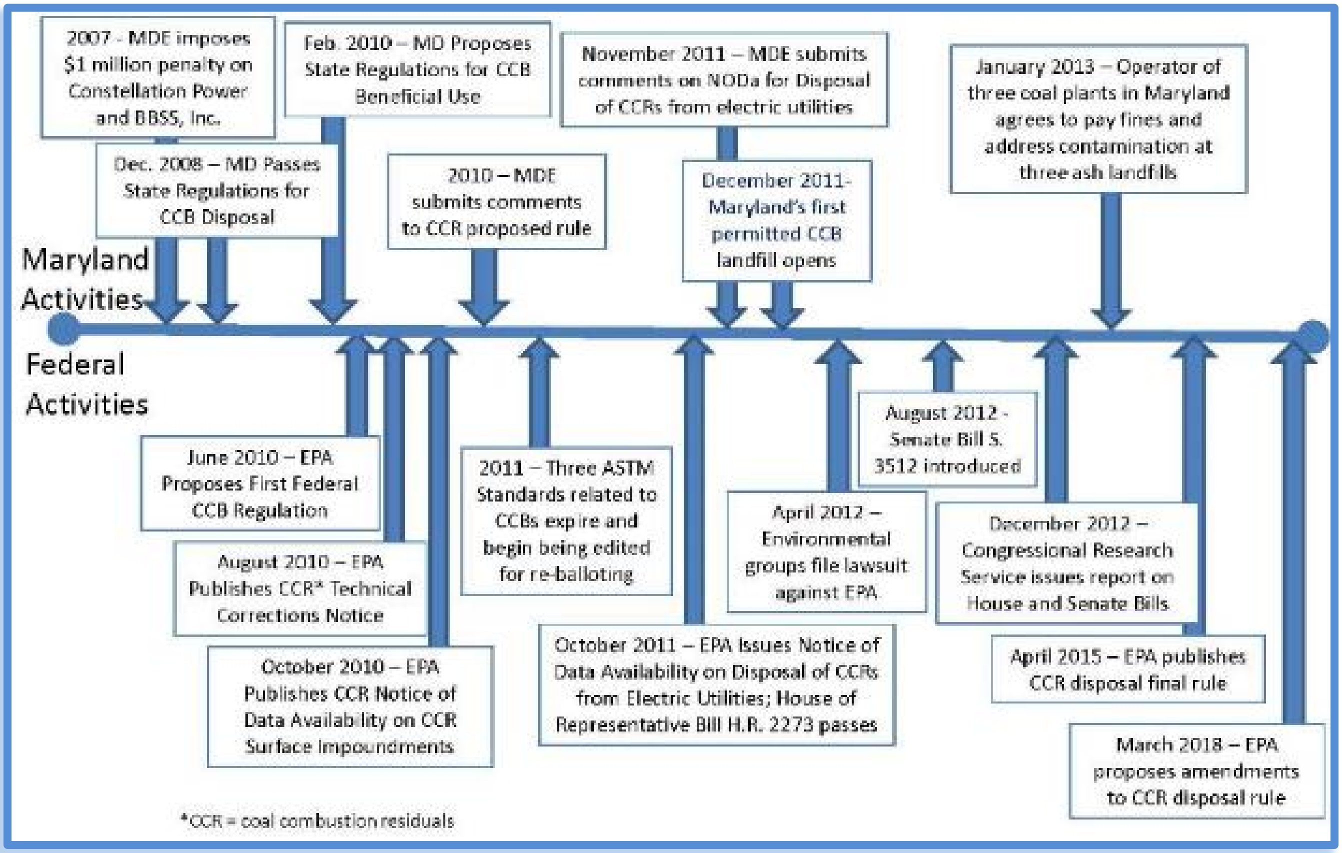


Figure 5-47 CCB Regulations in US and Maryland



Maryland Regulations

Historically, use and disposal of CCBs at the state level in Maryland was governed by the Pozzolan Act of 1974. In 2008, Maryland established more specific regulations for the disposal of CCBs and their use in mine reclamation. This regulation requires permitting of new CCB disposal facilities under the same regulations as industrial solid waste facilities. The regulation further extends the industrial solid waste landfill requirements to reclamation of noncoal mines. CCBs used for coal mine reclamation are required to be alkaline in nature. A second regulation was proposed and drafted in 2010 that would have governed the beneficial use and transportation of CCBs. Work on this second regulation was suspended following EPA's 2010 announcement that it would begin developing a new federal rule to govern CCB use and disposal.

Federal Regulations

Between 1980 and 2010, CCBs were excluded from the federal definition of “waste materials” by the Bevill Amendment to the Resource Conservation and Recovery Act (RCRA). EPA proposed the first federal regulations of CCB disposal in June 2010, and published the final rule in April 2015 after an extended period of comment and receipt of additional data. The final rule classifies CCBs (referred to as coal combustion residuals (CCRs) within the rule) as a nonhazardous waste, subject to RCRA Subtitle D requirements for disposal. These requirements are primarily enforced at the state level. The federal rule also established monitoring requirements for CCB landfills. The rule affirmed the use of CCBs in encapsulated applications (such as cement, concrete and wallboard), but placed restrictions on the use of CCBs in unencapsulated land applications. The use of CCBs to reclaim sand and gravel pits was specifically deemed a “disposal” activity and thus subject to landfill requirements for construction and monitoring. The federal rule took effect in October 2015. In 2018 a series of amendments to the 2015 federal regulation were proposed. During the same time period, several court cases were argued, decided, and appealed that may have implications for further amendments to or enforcement of the 2015 federal rule. As of the writing of this report, the full impacts of the federal rule amendments and court cases have yet to be determined.

5.6.3 Disposition and Beneficial Use

Beneficial Use

When properly engineered and correctly applied, manufacturing, civil engineering, mine restoration, and agricultural applications can utilize CCBs. The beneficial use of CCBs as raw materials in applications that are environmentally sound, technically safe and commercially competitive leads to a reduction in disposal. Various uses of CCBs can also reduce GHG emissions. When fly ash is used to replace a portion of the portland cement in concrete, the emission of CO_2 that is associated with production of the portland cement (when $CaCO_3$ is converted to CaO) is avoided. A continued increase in the beneficial use of Maryland CCBs will further lead to:

- Conservation and protection of the natural resources of the state;
- Reductions in the cost of producing electricity and cost for consumers;
- Substantial savings for end-users of CCBs; and
- Decreased need for landfill space.

Table 5-16 CCBs Produced in Maryland and 2018 Use Types

CCB Type	Source in Md	Quantity Produced in 2018 (tons)	% Used	Use Types
Class F Fly Ash	Brandon Shores, H.A. Wagner, Morgantown, Dickerson, Chalk Point	257,541	77%	Cement, Concrete
Bottom Ash	Brandon Shores, H.A. Wagner, Morgantown, Dickerson, Chalk Point	40,358	0%	--
FBC Fly Ash/Bottom Ash	Warrior Run	317,547	100%	Coal Mine Reclamation (as backfill and to offset acid production in mine pavement)
FGD Material	Brandon Shores, Morgantown, Dickerson, Chalk Point	439,016	95%	Wallboard, cement

Notes: Class C Fly ash and boiler slag are not included in this list as only small amounts of these CCBs were produced in 2018 and they are not expected to be produced again in the near future. The small quantitiy of Class C Fly ash and boiler slag that were produced in 2018 were disposed in accordance with Maryland's state CCB disposal regulatioons and the Federal CCR Rule.

Beneficial use of CCBs in Maryland historically included large-scale fill applications as in highway embankments and mine reclamation. Over time the use of CCBs in encapsulated forms, such as cement, concrete, and wallboard has become more prevalent; as indicated in Table 5-16, in 2018 all beneficial use of Class F Fly ash and FGD material was concrete, cement and wallboard manufacture. Industry practice, technology, costs of natural materials, regulations and guidelines, public perception, and demands for sustainability in the commercial marketplace drive these changes.

The other beneficial use that was active in 2018 was coal mine reclamation. About 300,000 tons of alkaline FBC material was 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 mine pavement. This is the only unencapsulated use of CCBs currently active in Maryland.

Figure 5-48 shows the locations of Maryland's six active coal-fired power plants. In addition, the R. Paul Smith power plant (which closed in 2012) and the C. P. Crane power plant (which began converting from coal as a fuel source to natural gas in 2018) are also shown. The figure also highlights some of the beneficial use sites and disposal sites across the state that have been active over the last 20 years. Figure 5-49 highlights the quantity of CCBs generated versus CCBs disposed by Maryland's coal-fired power plants in 2018.

Figure 5-48 Locations of CCB Generation, Use, and Disposal in Maryland

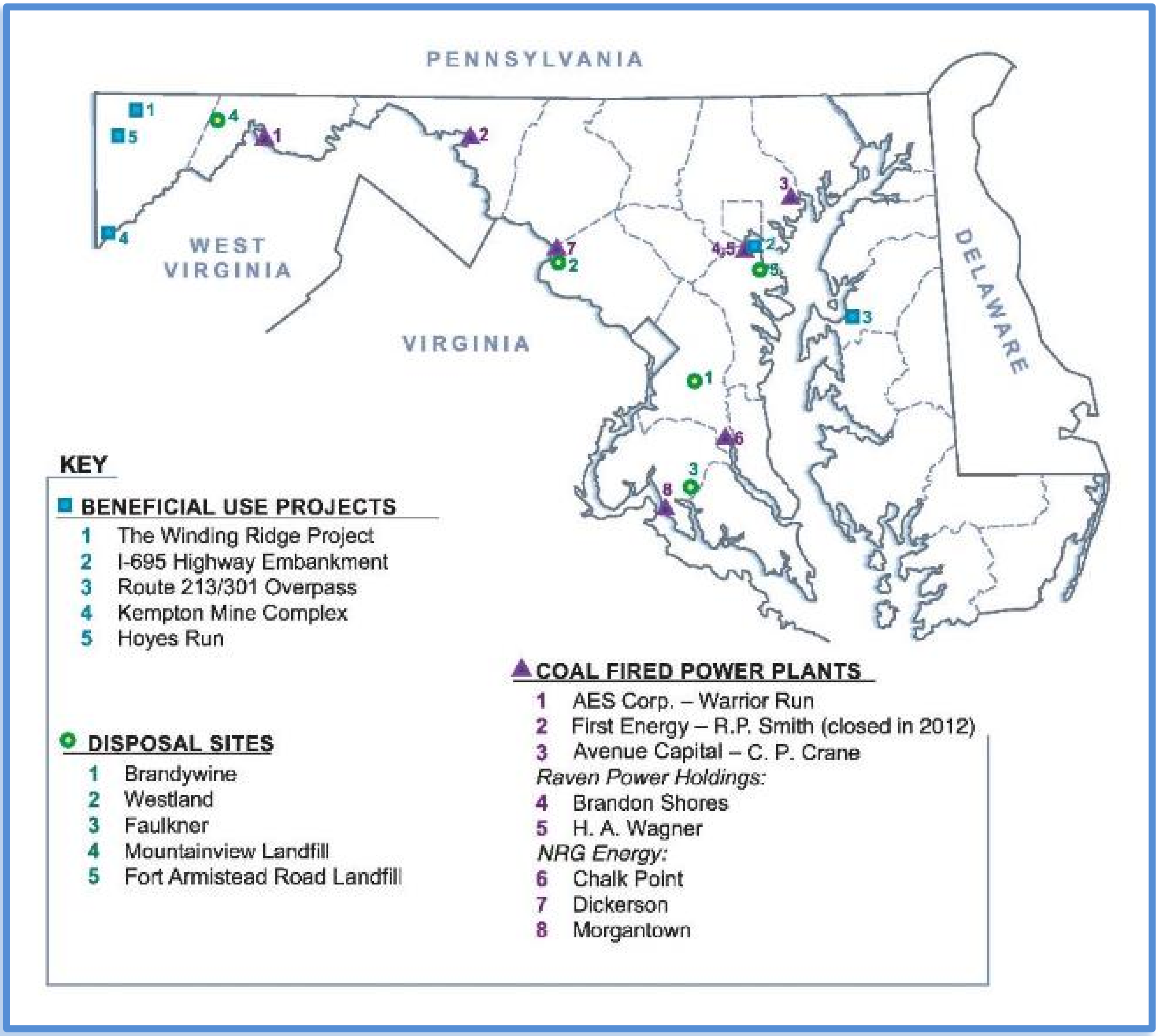
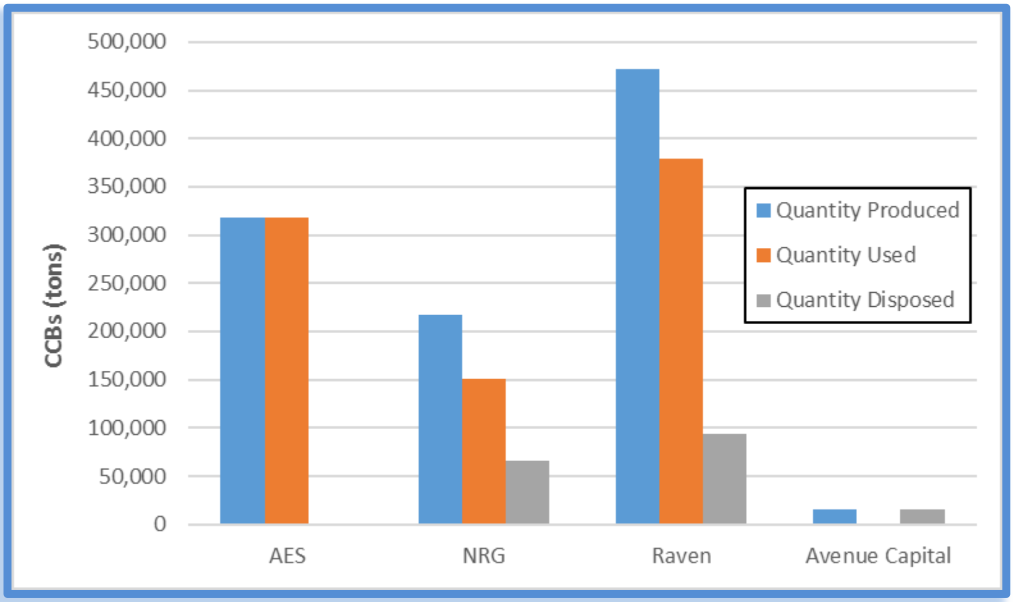


Figure 5-49 CCB Generation and Disposal (2018 Data)



Fly ash, bottom ash and FGD material have different primary beneficial uses because each type of CCB has distinct physical and chemical properties suited to specific applications. In Maryland, the sale of fly ash to the cement, grout, and ready-mix concrete industries accounted for all of the beneficial use of Class F fly ash in 2018. The relatively uniform spherical shape and particle distribution of fly ash improves properties of flowable fill and the fluidity of these cementitious materials. The manufacture of cement, concrete and grout are also potential beneficial uses for bottom ash, although these uses did not occur in 2018. Nationwide, bottom ash is also used as road base/sub base, structural fill and snow and ice control. Since the first FGD scrubbers were installed in Maryland in 2010, the majority of FGD material generated in Maryland has been sold to wallboard manufacturers as a replacement for natural gypsum. This use accounted for over 75 percent of the total FGD material produced in Maryland in 2018. Cement production accounted for a smaller portion of the beneficially used FGD material. The small percentage of FGD material that was disposed is primarily comprised of "off-spec gypsum" that could not be sold because it did not meet the standards required by industry for wallboard manufacturing.

Disposal

The first permitted and lined CCB landfill in Maryland (the Fort Armistead Road Landfill) began operation in 2011. This landfill is fully compliant with current state and federal CCB disposal regulations. However, prior to 2008, there were no regulations in Maryland governing the disposal of CCBs (see Section 5.6.2). CCBs were disposed 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 Maryland CCBs are currently going into beneficial uses and current disposal practices are more protective of ground water, these legacy ash disposal sites continue to have the potential to leach constituents into ground water. 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 CCB Marketing Activities

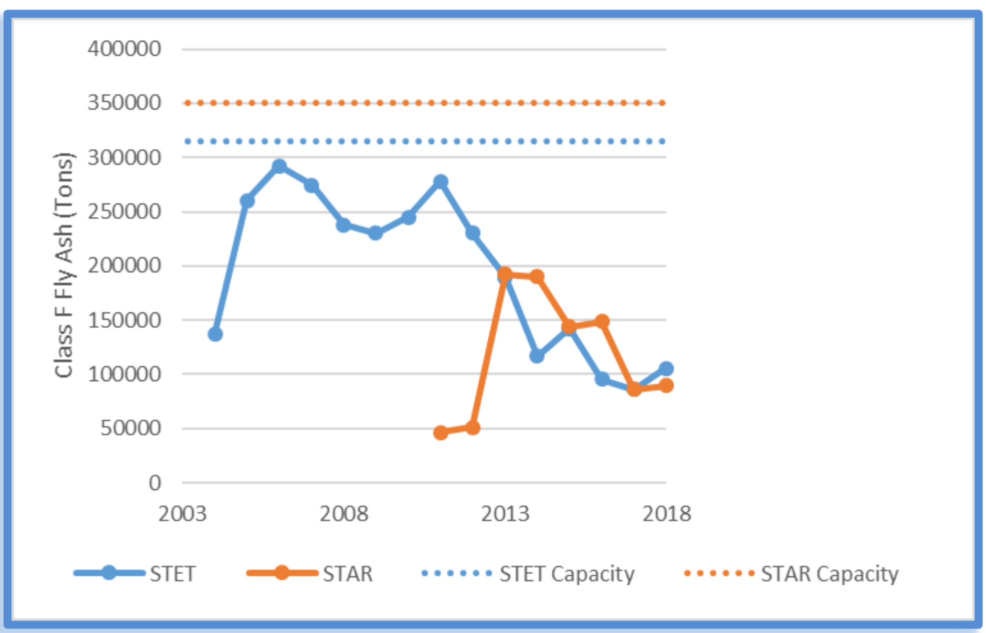
Demand

Class F fly ash provides a number of benefits to cement and concrete producers. Its pozzolonic properties improve the strength of concrete and grout while the fine-grained spheres that comprise this material improve concrete workability. As previously noted, the use of Class F fly ash to replace a portion of portland cement in concrete reduces GHG emissions associated with the production process.

Gypsum is fundamental to the production of wallboard and also has some utility in cement production. Use of FGD material by both of these industries reduces their reliance on mined gypsum. This not only conserves natural mineral resources, but may also allow avoidance of transportation costs if wallboard or cement manufacturers are located closer to coal-fired power plants than to gypsum mines.

The success of marketing freshly produced CCBs to cement manufacturers, the ready-mix concrete industry, and wallboard manufacturers has produced a demand for these materials within each industry. As older coal-fired power plants are retired or replaced by gas-fired generating units, these companies are willing to consider, and pay for, previously disposed CCB materials. Beneficiation facilities like STET and STAR were designed to handle a certain volume of fly ash from their associated power plants. As these power plants are beginning to burn less coal each year, they are generating less fly ash, the beneficiation plants have unused capacity available to accept more CCBs, if they were to become available (see Figure 5-50).

Figure 5-50 CCB Beneficiation Processing vs. Capacity

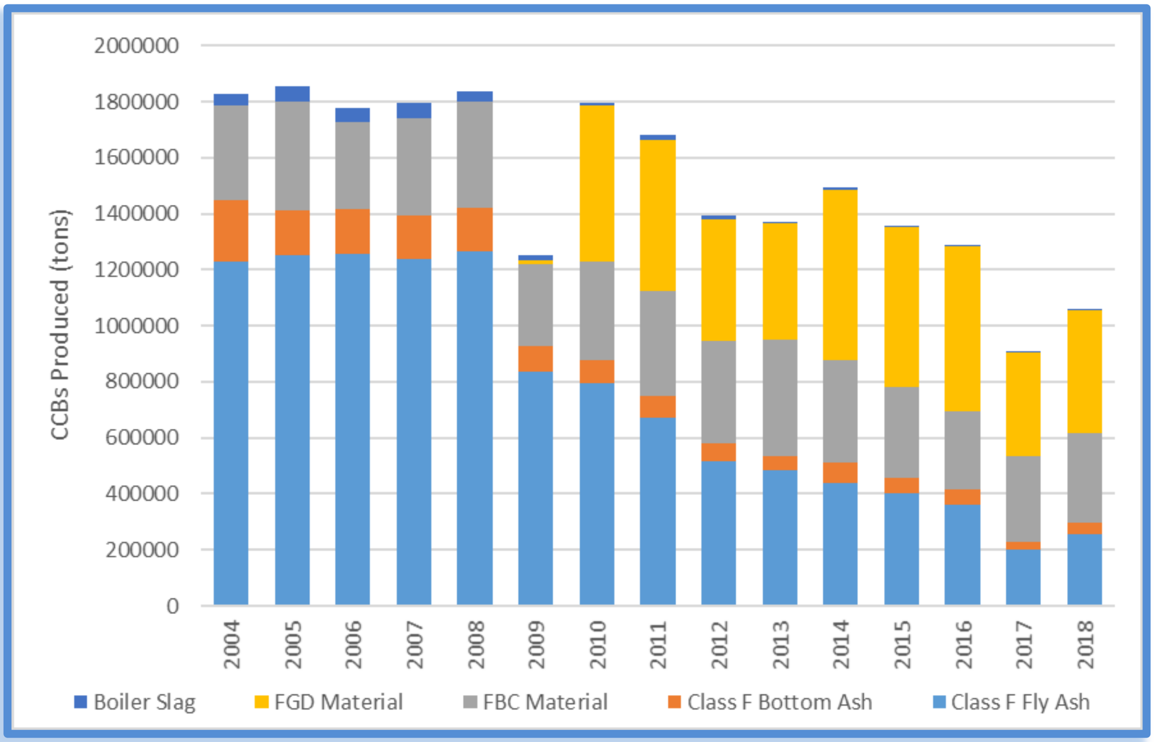


Supply

Annual CCB Production

The total tonnage of CCBs generated in Maryland has decreased in recent years from an average of 2.5 million tons in 2004 to just over one million tons in 2018. Not only has the total tonnage decreased, but the proportion of that tonnage that is comprised of Class F fly ash has also decreased over time (Figure 5-51). The closure or conversion of older coal-fired power plants (such as R. Paul Smith and C.P. Crane) has driven this change in part. As the generation of CCBs decreases, users have begun to consider using CCBs that have been recovered from former fill and disposal sites.

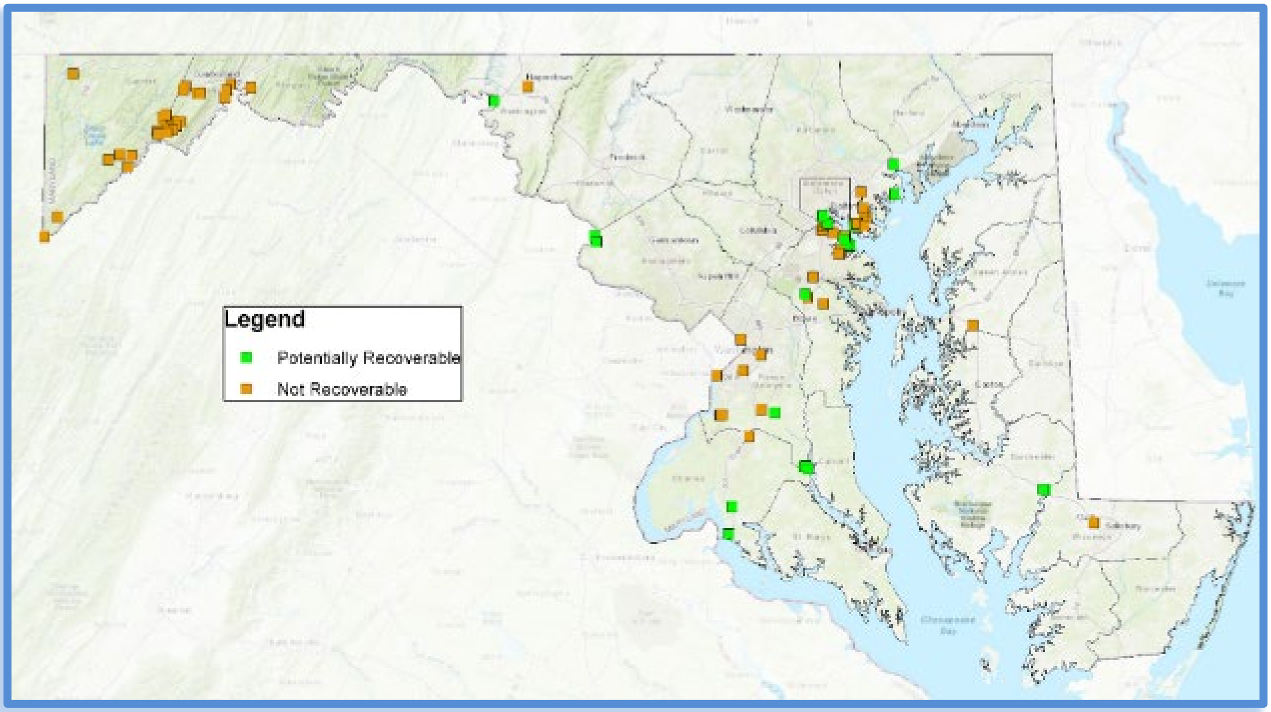
Figure 5-51 Quantity and Type of CCBs Produced in Maryland



Legacy Ash Sites

In addition to the active CCB disposal sites currently operating in Maryland, there are a number of historic fill and disposal sites across the state (Figure 5-52). In recent years, PPRP has been engaged in cataloging the locations of these sites as well as researching known information about them (i.e. period used, types of materials disposed, and disposal practices, where available). It is estimated that 20-25 million tons of material is 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 impact surface waters and ground waters, and supplies a raw material that these industries are willing to purchase.

Figure 5-52 Legacy CCB Sites in Maryland



There are a variety of challenges to overcome for recovery and beneficial use of previously disposed CCBs to become commonplace. Not all of the disposal areas may be accessible for CCB recovery. Some have been redeveloped with buildings, roads or other infrastructure; making the CCBs essentially inaccessible as long as they are covered. A second challenge is the quality of material disposed. CCBs that were codisposed with household garbage, industrial materials or construction and demolition debris are unusable without significant sorting efforts, which is cost prohibitive for recovery and reuse at this time.

In many cases, even if only CCBs were disposed, fly ash and bottom ash were combined and thus recovery would include a mixture of both, which may prove to be problematic for some users. In other cases, historic burning practices at the power plants could mean that the CCBs contain constituents that make them inappropriate uses, in particular some NOx and sulfate emission control practices can impact the chemical characteristics of CCBs. Finally, legacy CCBs generally contain more moisture than fresh CCBs and some users may require preprocessing of the materials before they can be used. Drying is the most common practice and a variety of companies are developing equipment to assist with this process. Other preprocessing needs may include crushing or grain size separation.

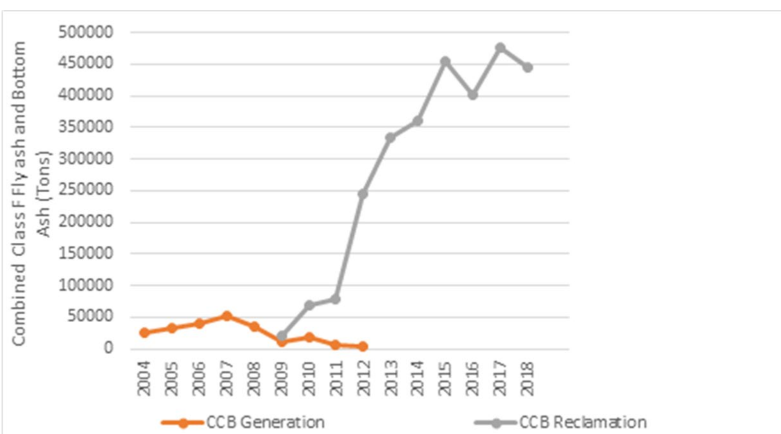
The subject of legacy CCB sites has been of significant interest in multiple states as of late. As state and federal deadlines for closure of older CCB disposal sites approach, Virginia and North Carolina have made rulings requiring that CCBs be removed from unlined fill areas and either beneficially used or placed into lined landfills compliant with state and federal regulations. Virginia's ruling includes a requirement to recycle at least 25 percent of the removed CCBs. Virginia is further allowing CCB generators to recover a portion of the CCB excavation and removal costs via rate increases to customers. Similar allowances have also been discussed in North Carolina. Both rulings are expected to result in an increase in the marketing of these states' legacy CCBs to Maryland industries, and could result in greater interest in recovery of CCBs from historic disposal sites in Maryland.

Recovery of CCBs from Former R. Paul Smith Ash Disposal Site

The R. Paul Smith power plant, in Williamsport, Maryland generated up to 50,000 tons of Class F fly ash and bottom ash before its shutdown in late 2010. The CCBs were conveyed by sluice across the Potomac River to settling ponds in West Virginia. After settling, the CCBs were transferred to an adjacent dry landfill. Beginning in 2009, in coordination with local cement manufacturers in West Virginia and Maryland, the landfill operators began to excavate CCBs from the landfill for sale to cement producers (Figure 1). Between 2009 and 2018 the annual rate of CCB recovery exceeded the annual rate of CCB production when the plant had been in full operation (Figure 2). At the end of 2018, more than 2.8 million tons of CCBs had been recovered from the landfill and beneficially used in cement production. It is anticipated that the landfill on the West Virginia side of the Potomac River will be entirely mined out by 2020. At that point the former landfill area will be covered with topsoil and re-vegetated. Additional material is present on the Maryland Side of the river that awaits a deconstruction plan to allow recovery.

Figure 1 2019 Photo of CCB Recovery at Former R. Paul Smith Landfill

Figure 2 CCB Production vs Recovery at Former R. Paul Smith Landfill



As mining of the R. Paul Smith landfill nears an end, cement manufacturers who have used this material have expressed interest in locating similar stockpiles of material for reuse. Several other CCB fill sites are known to exist in Maryland and efforts are currently underway to determine whether any of these sites may be accessible for CCB recovery and contain material of appropriate quality for use in cement production.

5.6.5 PPRP Demonstration Projects

With 80 percent of the state's annual production of CCBs currently being beneficially used, Maryland is well above the national utilization rate of 64 percent, as reported by the American Coal Ash Association for 2017. PPRP has supported research and demonstration projects for more than 35 years regarding beneficial use of CCBs, particularly those applications that could use massive quantities of CCBs in encapsulated form. A wide variety of bench-scale research projects and field-scale demonstration projects have been completed with significant focus being placed on uses of CCBs in underground mine reclamation and restoration of disturbed lands.

Underground Mine Reclamation

A long history of coal mining in Western Maryland has left a legacy of environmental challenges including acid mine drainage (AMD) as well as land subsidence as aging mine tunnels weaken and collapse. Through demonstration projects such as the Winding Ridge Project and the Kempton Man Shaft project, PPRP demonstrated the feasibility of injecting grouts made from 100 percent CCBs into underground mines to reduce acid-producing reactions and to help restore natural ground water flow patterns.

Desktop research projects have characterized the broad extent of opportunities for such uses on a larger scale. PPRP sponsored a review of the Works Progress Administration (WPA) Maryland Mine Sealing Program of the 1930s that sought to mitigate AMD by sealing mine openings. The program was largely judged to be unsuccessful in mitigating AMD; however, the extent of the Mine Sealing Program and reasons for its failure to impact acid mine drainage were investigated as guidance for large-scale use of CCB grouts in mine applications. In addition, PPRP supported efforts of the Maryland Department of the Environment Abandoned Mine Lands Division (MDE AMLD) to address a mine blow out at the McDonald Mine that overwhelmed the doser treating its effluent (Figure 5-53).

Figure 5-53 McDonald Mine Seep


Photo courtesy of WMGISC

Photo on left shows the post-blowout mine discharge at the McDonald Mine. Photo on the right shows treatment system components added to help treat additional post-blowout discharge. (Cylindrical shape in background is the doser that was already present at the site.)

PPRP and MDE AMLD collaborated on investigations of how to bring the increased flow under control, manage the large volume of sediment being generated and provide more effective treatment in the limited space available between the mine discharge and Georges Creek. Opportunities for CCB use in the form of grout and concrete were included in these investigations. PPRP further supported a benchtop weathering study of CCBs to demonstrate their stability in the presence of acidic waters typical of AMD.

Restoration of Disturbed Lands

Beyond historic mining practices, other factors may disrupt natural landscapes and flow patterns. Karst geology and the sinkholes associated with it can cause land subsidence and can severely damage buildings and infrastructure. Quarry activities can create artificial sinks for ground water that alter the natural direction of ground water flow and can exacerbate the development of solution channels that may already be present. CCB grouts have been shown to have sufficiently high strength and low permeability to help mitigate these problems when properly engineered and injected.

The Hoyes Run Project provided an excellent example of this use (Figure 5-54). Hoyes Run is a highly valued trout stream adjacent to the Key Stone Quarry in Garrett County, Maryland. During periods of low flow, its entire flow was lost to solution channels developed in a loss zone near the quarry. Initial attempts to seal the channels using a conventional chemical grout were unsuccessful because these grouts expanded with such pressure that partings in the streambed increased causing even greater stream loss. A grout of fly ash and fine particle FBC material was developed to effectively fill the solution channels and seal the streambed without causing any problems so long as the channel entrances could be identified and isolated for grout injection. The grout proved to be highly effective at sealing the small openings and channels in the limestone bedrock. However, during a period of high rainfall and high flow rate in the stream, clay layers overlying the limestone bedrock were washed out and new areas of stream loss developed. Thus, the project demonstrated the strength of the CCB grout seals, but also called attention to the need for thorough study and understanding of site-specific geology in planning restoration projects.

Figure 5-54 Hoyes Run Project

Photos During and Shortly After 2007 CCB-Grout Injection at Hoyes Run. Stream flow was restored within hours of grout injection.

Appendix A - Permits and Approvals for Power Plants and Transmission Lines in Maryland

Under Maryland regulations, a person, developer, or electric company that is planning to construct or modify a generating facility or a transmission line greater than 69 kilovolts (kV) in Maryland must receive a Certificate of Public Convenience and Necessity (CPCN) from the Maryland Public Service Commission (PSC) prior to the start of construction. The approved CPCN constitutes permission to construct the facility and incorporates several, but not all, required construction and operation permits. The CPCN process was designed in 1971 to be a "one-stop shop" for power plant licensing and the broad authority of the PSC allows for the comprehensive review of all pertinent issues.

In the case of new or modified power plants, most of the air quality permits and approvals that are required for construction are incorporated into the CPCN, for example:

- Air quality Permits to Construct for power plants that are minor sources of air emissions, and
- Prevention of Significant Deterioration (PSD) and Nonattainment Area New Source Review (NA-NSR) permits for major new or modified power plant sources in Maryland.

As with all major source air permits issued by the state, the U.S. Environmental Protection Agency (EPA) Region III is provided the opportunity to review and comment on the draft recommended license conditions during the CPCN process. Agencies that EPA authorizes to issue Part 70 Title V operating permits may also issue Clean Air Act Title IV Acid Rain and Cross-State Air Pollution Rule (CSAPR) permits. In Maryland, the Maryland Department of the Environment (MDE) is the entity authorized to issue Part 70 Title V, Acid Rain and CSAPR permits.

The CPCN also encompasses the water appropriation permitting process for a new power plant. Obtaining a CPCN grants a facility developer the right to withdraw ground water and surface water for use at the facility, subject to relevant permit conditions that are incorporated into the CPCN (such as flow monitoring and reporting).

The table below lists the permits and approvals that may be required for a new power plant or transmission line or modifications to existing facilities in Maryland. The shaded rows indicate those permits that are included within the CPCN. While there are several permits that are issued separately, PPRP evaluates the entire suite of environmental and socioeconomic impacts during the consolidated licensing review process (described in Chapter 1 of this report).

List of Permits and Approvals Typically Required for Construction and Operation of Power Plants in Maryland

Subject	Description	Regulatory Entity Issuing Permit in Maryland	Comments
Certificate of Public Convenience and Necessity (CPCN)	Incorporates several state and federal permits and approvals — those incorporated into CPCN are highlighted	Maryland Public Service Commission (PSC)	
AIR QUALITY			
Air Quality Permit to Construct[1]	Applies to any minor new, modified, or reconstructed sources of air pollution	PSC/Maryland Department of the Environment (MDE)	Constitutes a "minor New Source Review (NSR) construction permit"
Nonattainment Area New Source Review (NA-NSR)[1]	Required for new or modified major sources that emit VOCs or nitrogen oxides (NO_x); requirements and limitations are location-specific	PSC/MDE	Constitutes a "major NA-NSR" permit; requires Lowest Achievable Emission Rate (LAER), offsets, and alternatives analyses
Prevention of Significant Deterioration (PSD)[1]	Required for major new or modified sources in attainment areas	PSC/MDE	Constitutes a "major PSD" permit; requires air quality monitoring, Best Achievable Control Technology (BACT), ambient impact analyses (modeling), impact on surrounding Class I areas
Title V Operating Permit (federal) and Maryland Permit to Operate	Facility-wide permit to operate	MDE	
Title IV - Acid Rain Permit	Covers "affected" power plant generating units for minor sulfur dioxide (SO_2) emissions	MDE	Requires continuous emission monitoring, recording, and reporting; acquisition of SO_2 allowances
Clean Air Act (CAA) Section 112(r)	Risk management plan for storage of ammonia and other toxic substances, as listed	EPA	May apply to facilities that use ammonia in SCR systems to control NO_x

Subject	Description	Regulatory Entity Issuing Permit in Maryland	Comments
Cross-State Air Pollution Rule (CSAPR)	The rule uses a cap and trade system to reduce SO_2 by 73 percent and NO_x by 54 percent from 2005 levels.	MDE	Applies to 28 eastern states and the District of Columbia
WATER QUALITY AND USE			
Waterway Construction	State-federal review and permitting for waterway impacts	MDE/ U.S. Army Corps of Engineers (USACE)	Waterway impact determination necessary
Maryland Coastal Zone Management Program	Balances development and protection in the coastal zone, which includes the Chesapeake Bay, coastal bays, and Atlantic Ocean, as well as the towns, cities, and counties that contain/help govern the coastline.	MDE/ National Oceanic and Atmospheric Administration (NOAA)	State and federally coordinated program
Chesapeake Bay and Atlantic Coastal Bays Critical Areas	Protects Maryland's Critical Areas, which include all land within 1,000 feet of Maryland's tidal waters and tidal wetlands as well as the waters of the Chesapeake Bay, the Atlantic Coastal Bays, their tidal tributaries, and the lands underneath these tidal areas.	DNR/County/ Municipality	Generally, enforced at the local or county level, but if a state Action is involved, such as granting a CPCN, the full Critical Area Commission must review the project.
Scenic and Wild Rivers	Designates and protects the water quality and cultural and "natural values" of Maryland's wild and scenic rivers, including the impacts to the River mainstem and all tributaries thereof.	DNR	Maryland's Scenic and Wild River Act can be found in the Maryland Code, Section 8-401 et seq. of the Natural Resources Article
Erosion/Sediment Control Plan Approval	Plan to prevent erosion and stormwater pollution during construction	County	Required before construction disturbing 5,000+ square feet of area
Storm Water Management Plan	Plan to prevent storm water pollution associated with industrial activities.	County	Required prior to discharging storm water associated with industrial activity
Surface Water Discharge/	Combined state and federal permit for industrial wastewater and possibly storm	MDE	Individual NPDES permits may include discharge of storm water

Subject	Description	Regulatory Entity Issuing Permit in Maryland	Comments
National Pollutant Discharge Elimination System (NPDES) Permit	water discharge to state water must meet applicable federal effluent guidelines, satisfy state water quality standards and comply with CAA Section 316(b) regulations regarding surface withdrawals.		associated with industrial activities, or the facility must apply for a general permit for these activities. The permit application is due 180 days before discharge commences.
General Storm Water Permit (Industrial Activity)	For discharges associated with industrial activity	MDE/County Conservation District	MDE determines whether a facility can operate under a general storm water permit.
Wellhead Protection Program	Groundwater protection	MDE/County/ Municipality	Applies to public water supply wells and wells in groundwater management areas
Water and Sewerage Conveyance and Construction Permit	Required before installing, extending, or modifying community water supply and/or sewerage systems including treatment plants, pumping stations, and major water mains and sanitary sewers	POTW or County/ Municipality	Required to ensure that infrastructure projects throughout the state are designed on sound engineering principles and comply with state design guidelines to protect water quality and public health.
Dam and Reservoir Safety Permit	If applicable, for any lake or pond used for nonprocess water	MDE/USACE	640 acre drainage area, 20 foot or greater embankment, high hazard class, natural trout water
Maryland Water Quality Certification	Section 401 of the Clean Water Act provides states with the power to either deny or impose restrictions on construction that might affect water quality. Generally, this has been applied to construction or operation of hydroelectric projects under jurisdiction of the Federal Energy Regulatory Commission	MDE	Wetland impact determination necessary
Surface Water Withdrawal Permit/Water Appropriation & Use Permit[1]	Water appropriation and use is tracked by a Water Resources Administration Permit	PSC/MDE	The appropriation of either surface or groundwater is incorporated into the CPCN. Trigger: withdrawal exceeding 10,000 gallons per day.

Subject	Description	Regulatory Entity Issuing Permit in Maryland	Comments
Public Water Supply Line Connection	A variety of Clean Water Act permits, State Historic Preservation Officer (SHPO) clearance, National Resource Conservation Program (NRCS) consultation, floodplain permitting, and road boring permits	County/ Municipality	
Tidal Wetland Permit	State-federal review and permitting for tidal wetland impacts	The Board of Public Works (BPW)/ PSC/MDE Water Management Administration (WMA)/USACE	Wetland impact determination necessary. BPW has the ultimate authority for issuing tidal wetlands permits and licenses.
Nontidal Wetlands Permit	State-federal review and permitting for nontidal wetland impacts	MDE WMA/ USACE	Wetland impact determination necessary
Groundwater Withdrawal[1]	Requires submittal of an application to the WMA for any withdrawal of groundwater for use in a project (sanitary water, process water, cooling, etc.)	PSC/MDE WMA	An impact assessment must be conducted
Consumptive Use Review and Approval Process	Required for new consumptive water uses in the Susquehanna River basin	Susquehanna River Basin Commission	Requires approval by Commission for any new consumptive water uses or if consumptive use exceeds an average of 20,000 gallons per day for any consecutive 30-day period

Subject	Description	Regulatory Entity Issuing Permit in Maryland	Comments
OTHER APPROVALS AND NOTIFICATIONS			
Facility Response Plan	Prevents on-shore oil facilities from polluting navigable waters	EPA	All owners/operators of non-transportation related onshore facilities with greater than 1,000 gallons of oil onsite and the potential to discharge oil into navigable waters must prepare and submit plan
Sanitary Sewer Permit / Industrial User's Permit	For plant sanitary or process waste disposal to municipal facilities, a Wastewater Treatment Plant (WWTP) Permit must be obtained from the Publicly Owned Treatment Works (POTW)	Municipal Authorities	
Health Department Permit	If septic tanks are used for sanitary waste, a Health Department Permit must be obtained	County	
Spill Prevention Control and Countermeasure (SPCC) / Storage tank regulations	Plan to prevent and manage accidental spills of petroleum products stored on site	MDE	Typical threshold quantities of petroleum products: 1,320 total above ground gallons (for tanks 55 gallons or greater), and 4,200 gallons underground
Oil Operations Permit	State permit required for the operation of oil storage tanks	MDE	Required for storage of 10,000 gallons of oil in aboveground tanks, transportation of oil, or operation of oil transfer facilities and facilities that have a total above ground capacity of 1,000 gallons of used oil
Local building permits during construction	Requirements under local ordinances to be filed as necessary with County	County / Municipality	Includes building permit and site plan approvals as applicable

Subject	Description	Regulatory Entity Issuing Permit in Maryland	Comments
Forest Conservation Act	Requirements to prepare Forest Stand Delineations and Forest Conservation Plans, and mitigation for impacts related to energy development.	DNR Forest Service (delegated to Counties)	Mitigation may be required for disturbance, whether or not trees are removed.
Phase II Cultural Resources Investigation	Research potential significant impacts to cultural resources on site	MHT	Coordinate with Maryland State Historic Preservation Officer if necessary
National Historic Preservation Act / Maryland Historical Trust Act	Protection of cultural/historic artifacts found during development	MHT	Coordinate with Maryland State Historic Preservation Officer if necessary
Threatened and Endangered Species Clearance	State-implemented program under the Endangered Species Act; includes field investigations and data research	DNR Wildlife and Heritage Service (WHS)	WHS Natural Heritage and Biodiversity Conservation Programs; coordinate with US Fish & Wildlife Service and NOAA
Oversize Equipment Delivery Permit	For delivery of oversize and/or super loads of construction equipment from rail to site	Maryland Department of Transportation (MDOT)	Threshold (only 1 needs to be exceeded to trigger permit) 102 inches wide, 13 ft. 6 inches high, 70 ft. overall length, 150,000 lb. weight
New Roadway Access Permit	To cover new road to plant	MDOT	Letter of request, location sketch, overall site plan, scaled drawings, grading and drainage plan, entrance plan and method of restoring disturbed land
Solid Waste Disposal Permit for Construction and Demolition Debris	For removal and disposal of solid waste during construction	MDE/County/ Municipality	If waste is taken off site, it must be taken to a properly permitted facility
Utility Occupancy of State Highway Administration (SHA)-owned Land	For projects that are proposed for location on property owned by SHA.	MDOT SHA	Longitudinal occupancy of a MDOT SHA ROW by electrical transmission lines greater than 98kV prohibited.
Approval for Solid Waste Disposal	If waste, such as fly ash, is taken offsite, it must be taken to a properly permitted facility	MDE	

Subject	Description	Regulatory Entity Issuing Permit in Maryland	Comments
Notification of Regulated Waste Activity	For waste oil, universal waste, hazardous waste, disposal registration	MDE	If facility wishes to haul its own regulated waste, an additional permit may be necessary
Notice of Proposed Construction or Alteration	For projects located near an airport or landing strip	FAA, MDOT	Any construction or alteration of more than 200 feet or a height greater than a defined imaginary surface extending outward and upward from an airport or heliport.
Patuxent River Naval Air Station Wind Turbine Restrictions	The Department of Defense (DOD) must be notified if a wind turbine will be within 56 miles of the Patuxent River Naval Air Station.	PSC/DOD	This regulation arose from concerns over wind turbine interference with radar signals
National Fire and Electrical Codes	For the construction and operation of electrical generation and transmission facilities.	National Fire Protection Association (NFPA)	Minimum standards defined in NFPA 1 (Fire Code) and NFPA 70 (National Electrical Code)
National Environmental Policy Act (NEPA)	Completion of an Environmental Assessment (EA) or Environmental Impact Statement (EIS)	Federal entity, such as USACE or NPS	Triggered when project crosses federal lands, or when FERC backup authority is invoked for siting an interstate transmission line.

[1] Incorporated in CPCN.

Appendix B - Electricity Markets and Retail Competition

Introduction

Effective July 2000, the Maryland Electric Customer Choice and Competition Act of 1999 restructured the electric utility industry to allow Maryland businesses and residents to shop for power from suppliers other than their franchised electric utilities. Prior to restructuring, the local electric utility, operating as a regulated, franchised monopoly, supplied electricity to all end-use customers within its franchised service area under bundled service rates. These rates included the three principal components of electric power service: generation, transmission and distribution. Under retail competition, electricity suppliers purchase electricity on the wholesale market for resale to electricity consumers. Consumers may choose any supplier with a license to sell electricity in Maryland. The regulated utility provides electric service for consumers who do not select a supplier or are unable to receive service from a competitive supplier, and contracts with wholesale suppliers on behalf of its consumers, under the supervision and guidance of the PSC. This appendix provides a background on electricity markets and the influence of markets, technology, fuel and environmental regulations on the retail prices paid by end-use consumers.

Wholesale Markets and PJM

The majority of electricity sales and purchases that occur in the wholesale market of the PJM RTO are bilateral transactions, wherein two entities negotiate a contract for the sale and purchase of electricity according to the terms established in a contract. These bilateral contracts may be the result of a competitive solicitation or a privately negotiated power purchase agreement (PPA), the details of which are typically kept confidential. Entities seeking to buy and/or sell electricity might also look to one or more of the regional markets and trading platforms. Electricity trades can be categorized according to two main classes: physical trading and financial trading. In physical trading, the electricity supply is balanced against demand and price is established at the point where the highest offer for electricity (supply) meets the lowest bid for electricity (demand) so that the load requirements are met. Physical trades can be determined in advance of trading (e.g., participation in day-ahead markets) or after trading (e.g., imbalance markets and ancillary services[211]).

The primary purpose of financial trading is to protect against expected price volatility and to provide price discovery for purposes of evaluating future supply contracts. However, power marketers and traders can also use electricity futures contracts to obtain physical electricity at the hub. This delivery potential helps to validate the futures prices. Financial trading is conducted through a financial market or exchange such as the Intercontinental Exchange (ICE) or the New York Mercantile Exchange (NYMEX) according to the specifications determined by the commodity exchange.

The electricity supply markets in PJM's wholesale electric market consist of four separately organized units, defined in greater detail as: two markets for the sale or purchase of energy (the Day-Ahead and Real-Time Markets); and two markets designed to support the various services required to keep the

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[211] The term "ancillary services" refers to a suite of services necessary for the reliable generation and delivery of power and includes such services as reactive supply and voltage control, scheduling, and operating reserves. A more detailed discussion of ancillary services is provided later in this appendix.

electricity system functioning (the Capacity Market and the Ancillary Services Market). These markets are competitive and suppliers and buyers submit bids and offers. Except for a small number of ancillary services that are provided at cost-based rates, the prices for electricity, capacity, and ancillary services are set through the balancing of supply and demand. The four different wholesale markets are discussed in detail below.

Markets for Energy

Two separate PJM markets exist for the daily buying and selling of electricity. These are the Day-Ahead Market and the Real-Time Market. These markets operate on the basis of locational marginal prices (LMPs)—electricity prices that vary by time and geographic location. Sellers include those entities offering electricity supply such as generation companies, agents who may have contracts with generators, curtailment service providers (or demand response providers) who offer to reduce load on demand (a form of negative supply that serves to balance supply and demand as effectively as additional generation), and brokers. Buyers consist of those needing electricity, which can include brokers and companies termed "load serving entities" (LSEs). An LSE is any supplier, including regulated utilities providing standard offer service or default service, which is responsible for the sale of electricity to a retail customer. Along with electricity, LSEs must also purchase their proportionate share of the PJM system's peak capacity (to ensure reliability) and transmission services (to move the electricity from the generator to the distribution system).

Day-Ahead Market

The Day-Ahead Market is a spot market (deliveries are expected in a month or less at that day's quoted price) in which participants can purchase and sell energy for the next operating day. It provides the opportunity for buyers and sellers to request short-term energy and transmission services to meet electricity needs. Hourly LMPs are calculated by PJM for the next operating day based on generation offers and demand bids. PJM then matches bids and offers and sets the price for the Day-Ahead Market, creating a financially binding day-ahead schedule based on the known electric deliveries and corresponding hourly prices for a specific hour and location.

Each supplier in PJM submits hourly supply schedules specifying the amounts of generation at various prices it would be willing to supply. PJM arrays these bids from lowest to highest price, adjusting each price to reflect incremental system losses. Incremental losses are specific to each generation bus and reflect the impact on total system losses of an increase in generation. The price bid submitted by the last generating unit required to meet demand (the marginal unit) becomes the hourly dispatch rate. PJM then computes hourly LMPs by adjusting dispatch rates to include the effect of congestion. Congestion is also location-specific and reflects the manner in which PJM must resolve transmission constraints to serve load at various locations on the grid. If the transmission interface with PJM West is constrained, for example, PJM may have to order the dispatch of generating units elsewhere in PJM, out of economic merit order, in order to supply load in the east.

Real-Time Energy Market

The Real-Time Market acts as the balancing market between what was scheduled through the Day-Ahead Market and bilateral transactions, and what is required to meet real-time energy needs. This is a spot market in which LMPs for each zone are calculated at five-minute intervals based on actual electricity grid operating conditions. Transactions are settled hourly. LSEs pay the real-time LMP for any demand that exceeds their day-ahead scheduled quantities. In cases where an LSE uses less energy than it purchased in the day-ahead market, the LSE can sell that excess energy back into the real-time market and receive revenues for it. Generators are paid real-time LMPs for any generation that exceeds their day-ahead scheduled quantities since it gets sold at the real-time price into the market. Generators also must pay the real-time LMP for generation deviations below their scheduled quantities since the electricity they had promised to supply must now be supplied by other generators who need to be compensated. PJM tracks the supply and demand of each market participant and assigns costs and revenues accordingly, on an hourly basis.

Capacity Market

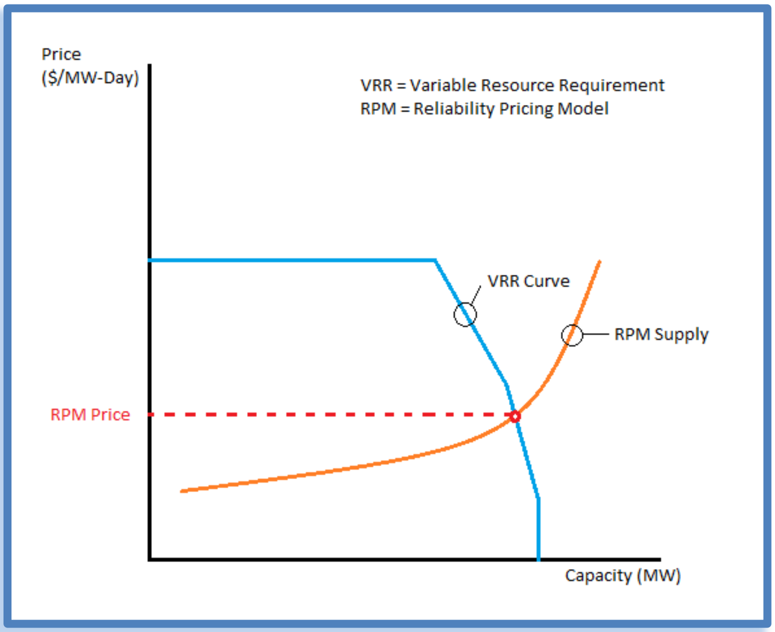
Capacity refers to the amount of electricity generation available at any given time. The capacity market is a forward market in which LSEs purchase supply-side and demand-side capacity resources. Each LSE is required to have available its share of the PJM system peak plus a planning reserve margin of an additional (approximate) 15 percent of peak load. This means that the system as a whole must always have more generation capacity available than what is expected to be required to meet peak loads so that extra electricity generation can be brought into use if needed, e.g., in the event of an unplanned outage of one or more large generating plants or extreme weather conditions.

The current PJM capacity market is based on PJM's Reliability Pricing Model (RPM), implemented in 2007 as a means to provide power plant developers with price signals to influence decisions on whether (and where) to construct new power plants and to provide owners of existing generation with price signals to influence decisions on whether to retire existing plants. The RPM is an approach developed by PJM and used to provide a market price for capacity that is aligned with PJM's assessment of the cost of new entry (CONE), i.e., the level of revenue that a power plant developer would require in order to make the decision to develop peaking resources economically feasible. The approach also recognizes and accommodates higher capacity prices when PJM is capacity short and lower prices when excess capacity exists.

How the RPM Works

Fundamentally, the market clearing price is determined through the intersection of a demand curve and a supply curve.

Figure B-1 PJM Demand and Supply Curves



The Demand Curve – the downward-sloping demand curve, referred to by PJM as the Variable Resource Requirement (VRR), is developed for the PJM region and also for the locational delivery areas[212] (LDAs). This curve is plotted on a graph with dollars per MW-day on the vertical axis and MW of capacity (or percentage of reliability requirement) on the horizontal axis.

The Supply Curve – the supply curve is obtained by PJM through the capacity bids offered by the capacity owners. Eligible capacity includes existing and new capacity, demand-side resources (e.g., load response), and qualified transmission upgrades. The capacity offers from the auction are stacked (lowest cost to highest cost), resulting in an upward-sloping supply curve. The auction clearing price is determined by the intersection of the VRR and the supply curve (the auction bids).

PJM conducts a Base Residual Auction (BRA) to obtain committed capacity for LSEs that have not opted for the Firm Resource Requirement (FRR) alternative.[213] The BRA is conducted three years in advance of the year for which the capacity will be committed (e.g., the BRA for the planning year June 2013 through May 2014 was held in May 2010). The BRA process determines the market clearing quantity and price for capacity for PJM as a whole and for each LDA based on the intersection of the demand and supply curves. The capacity resources that clear the BRA receive the market-clearing price

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[212] PJM divides the PJM region into deliverability areas based on transmission connections and constraints.

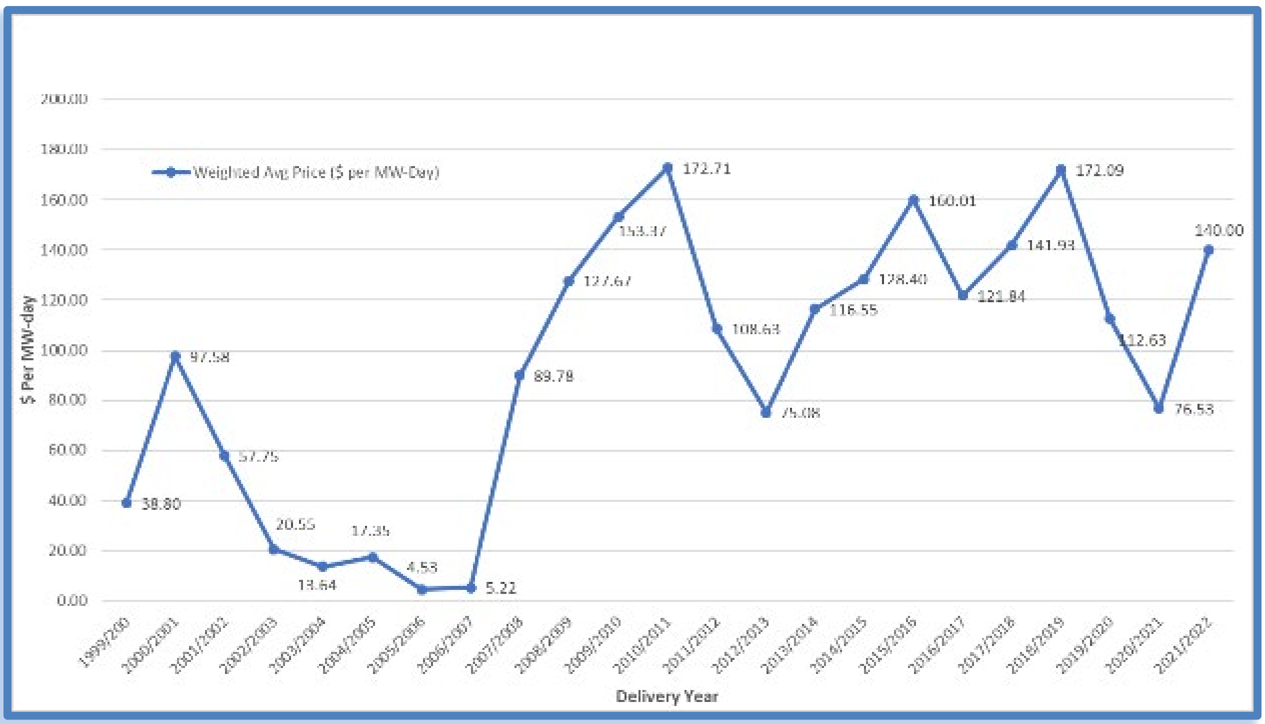
[213] Certain LSEs (utilities, electric cooperatives, or municipal utilities) may opt to commit capacity to meet peak demand plus the reserve requirement on a firm basis for a minimum five-year period subject to PJM approval.

and assume the obligation to provide capacity in the relevant planning year. In the event that a party fails to meet its capacity commitment, PJM can impose significant penalties.

PJM may conduct "incremental auctions" following the BRA. The purpose of the incremental auctions is to allow cleared resources in the BRA to adjust the capacity quantities bid (for example, for planned resources that may not become available in the quantities expected or for unanticipated additional quantities). Additionally, PJM can use the incremental auction option to secure additional capacity if the peak load forecast is increased.

The price for capacity increased significantly throughout the PJM region in the 2021/2022 delivery year auction after the capacity clearing price fell significantly for the 2019/2020 delivery year due to changes in the products offered through the BRA. The capacity price in 2021/2022 delivery year increased 83 percent over the prior delivery year due to the continued decrease in energy revenues. Figure B-2 shows historical capacity prices for PJM through the 2021/2022 delivery year.

Figure B-2 Average PJM Capacity Prices by Delivery Year, 1999/2000 - 2021/2022



Source: Monitoring Analytics, 2018 *State of the Market Report for PJM and* PJM, *2020/2021 RPM Base Residual Auction Results*.

Historically, demand response has been included in the PJM auctions as one of three resource types: limited, extended summer, and annual. Delivery year (DY), DY 2017/2018 (i.e., June 1, 2017 through May 31, 2018), was the last year in which PJM permitted the use of these three DR capacity products. These products, detailed in Table B-1, allowed DR participants to bid into the auction in a limited annual capacity.

Table B-1 PJM Demand Response Capacity Products through DY 2017/2018

Product	Limited	Extended Summer	Annual
Eligible Auctions	Through DY 2017/2018	Through DY 2017/2018	Through DY 2017/2018
Availability	June - September	May - October	Any day during DY
Potential Event Hours	12:00 PM - 8:00 PM	10:00 AM - 10:00 PM	May - October 10:00 AM - 10:00 PM November - April 6:00 AM - 9:00 PM
Maximum Duration of Event	6 Hours	10 Hours	10 Hours
Annual Maximum Number of Events	10 Times or Less	Unlimited	Unlimited

For DY 2018/2019 through DY 2019/2020, PJM only accepted one type of DR capacity product, Base Capacity. Base Capacity was the same as the Extended Summer Project that expired in the DY 2018/2019. Beginning with the auction for DY 2018/2019, PJM accepted bids for Capacity Performance, a DR capacity product that requires participants to respond year-round, with no limit on event duration or the number of events called per year. See Table B-2 for a summary of the two capacity products available beginning in DY 2018/2019. As a result of the changes, those that have bid into the auction have had to alter their bid strategies and amount of bids, ultimately impacting the clearing price of the BRA. Effective with the 2020/2021 Delivery Year, PJM will procure only a single demand response capacity product, Capacity Performance.

Table B-2 PJM Demand Response Capacity Products Beginning DY 2018/2019

Product	Base Capacity	Capacity Performance
Eligible Auctions	DY 2018/2019 & DY 2019/2020	Effective beginning DY 2018/2019
Availability	June - September	Any day during DY
Potential Event Hours	10:00 AM - 10:00 PM	May - October 10:00 AM - 10:00 PM November - April 6:00 AM - 9:00 PM
Maximum Duration of Event	10 Hours	No Limit
Annual Maximum Number of Events	Unlimited	Unlimited

Ancillary Services Market

Ancillary services are all the services necessary to support the transfer of energy from generation resources to end-users or load, while maintaining the integrity of the transmission system. Ancillary services include scheduling, system control, and dispatch; reactive supply and voltage control; regulation and frequency response; energy imbalance; and operating reserves. Costs for ancillary services are recovered from a combination of market-based and cost-based pricing cleared or set by PJM. Market-based services set prices through auctions, such as generators bidding to offer regulation and/or operating reserve energy. Cost-based services are provided by PJM and billed to participants according to a set rate based on revenue requirements.

An important element of PJM's ancillary services is regulation. Regulation service matches generation with short-term changes in load, maintaining desired frequency and voltage by increasing or decreasing the output of selected generators, load response units, or electricity storage systems as needed via automated control signals. Longer-term deviations from scheduled load are met by the operating reserves and generator responses to economic signals. PJM's regulating requirement is 525 effective MW during off-ramp hours and 800 effective MW during on-ramp hours, with the on-ramp and off-ramp periods determined seasonally and based on system conditions. The PJM regulation market accepts bids from generators and fast-responding load resources and electricity storage systems. These entities enter an offer price for each hour and, if called upon, are paid the hourly market clearing price for regulation service.

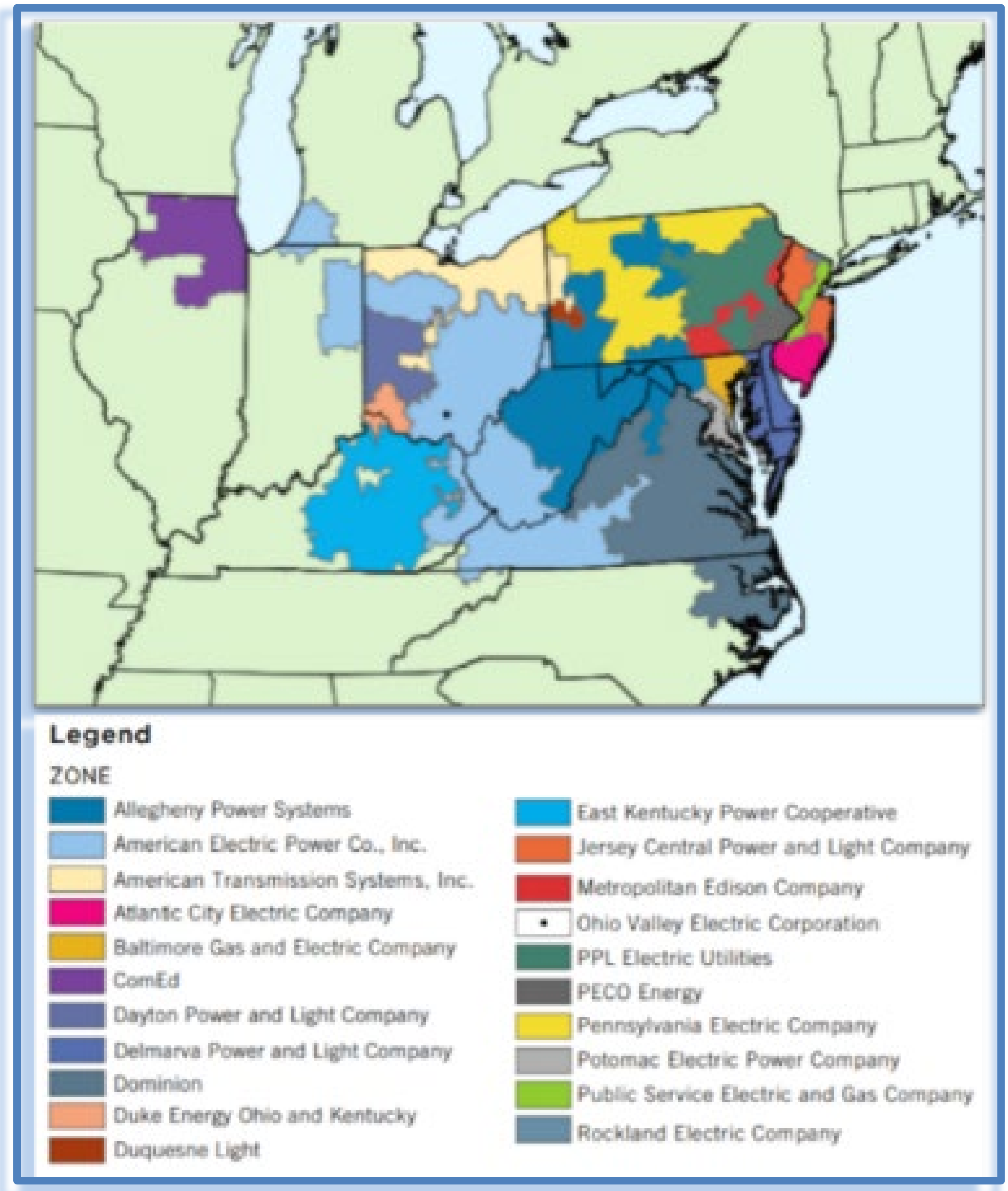
Operating reserves represent the generating capability that is standing by ready for service in the event of a disruption on the power system, such as the loss of a generator. These operating reserves, the standby generation made available to serve load in case there is an unplanned event, are not the same as the 15 percent planning reserve requirement, which is an annual capacity obligation based on PJM's independent load forecast and other system planning assumptions and scenarios. The 15 percent annual planning reserve requirement refers to the overall amount of extra capacity that must be maintained in the PJM system as a whole in order to keep the probability of a loss of load event below a specified level. In other words, the PJM system must always maintain a condition where overall generation ability exceeds peak demand by 15 percent. The operating reserves refer to the amount of generation kept in standby mode as part of daily system operations so it can be called upon in case of an emergency, such as a major generation unit tripping offline. Operating reserves can include both supply-side resources, i.e., power plants, and demand-side resources such as end-users participating in load management or load curtailment programs who can quickly reduce the amount of electricity they are using when called upon to do so. Primary reserves are those resources available within ten minutes of a request by PJM. Secondary reserves must be available within 30 minutes of a request. Synchronized or spinning reserves are typically the first primary resources called upon and are paid to be available, whether called upon to respond to an event or not. These are the reserve units that are either already running but idling in standby mode, or can be started up very quickly and synchronized with the grid, and can therefore supply energy within the 10-minute timeframe.

Market Pricing

Factors Affecting Locational Marginal Prices

The PJM region is divided into different zones (shown in Figure B-3), organized primarily according to the service territories (or aggregations of two or more service territories) of the distribution utilities. PJM tracks the demand and supply of electricity within each zone. The spot market price of electricity is based on the supply and demand for electricity for that time of day in that area. Depending upon local conditions, the price for electricity can be very different from zone to zone for the same time of the day. The disparity of prices from zone to zone is largely attributable to the ability, or inability, to transmit electricity from one zone to another. The transfer of electricity between zones is sometimes limited by the size or capacity of the transmission system. For a system not constrained by transmission grid limitations, conditions in all zones would be the same at all times and the marginal prices would be equal in all areas at any given time. However, in the wholesale electricity market, LMPs vary because of physical system limitations, congestion and loss factors. This transmission congestion can have a significant impact on the price of electricity in the wholesale markets. Generators selling electricity in a zone with transmission congestion may be able to obtain higher prices than a generator with comparable operating costs located in a zone that is not subject to transmission congestion.

Figure B-3 PJM Zones



Source: PJM

LMPs, as established at each zone, can be summarized according to time of day; peak hours are Monday through Friday (except holidays) from 7:00 a.m. to 11:00 p.m.; off-peak hours are the remaining evening, weekend, and holiday hours. Table B-3 provides the PJM average and median prices experienced over the 2018 calendar year.

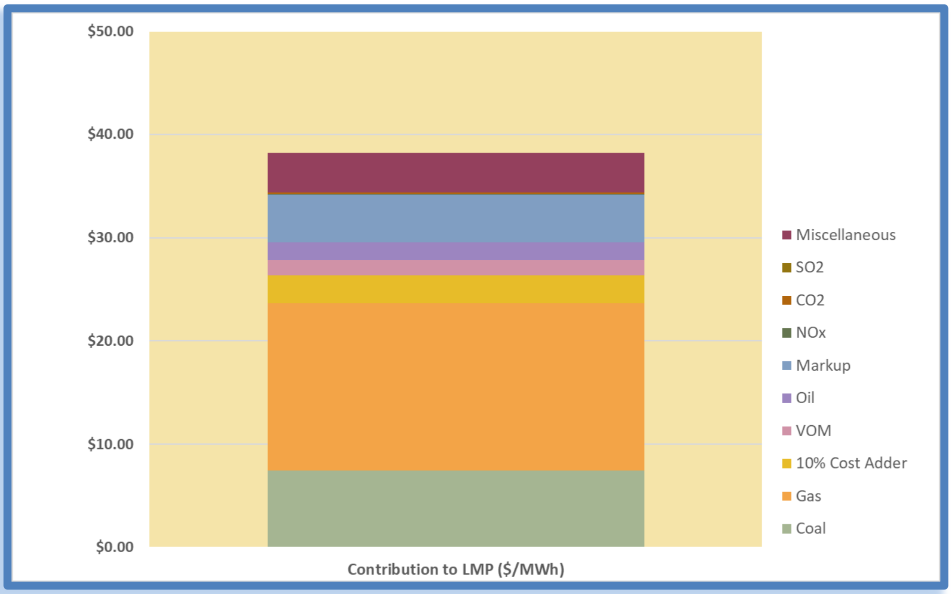
Table B-3 PJM Off-Peak and On-Peak Average LMPs for 2018

	Day-Ahead ($/MWh)		Real-Time ($/MWh)	
	Off-Peak	On-Peak	Off-Peak	On-Peak
Average	$30.70	$41.41	$31.33	$40.81
Median	$25.43	$36.66	$24.41	$32.99

Source: Monitoring Analytics, *2018 State of the Market Report for PJM*

Operating costs and other factors contribute to the bid prices offered by generators and the resulting overall annual average LMP. Fuel costs make up the largest share of generator operating costs and therefore contribute most to the bid price, and hence, LMP (see Figure B-4). The PJM Market Monitor calculates the factors contributing to annual average LMP based on the weighted average of the factors influencing the generator bid prices at specific locations. This weighted average considers both on- and off-peak prices, and which plants are operating on the margin in which conditions. In 2018, the capital and fuel supply costs of gas-fired generators made up 42.4 percent of the annual average LMP, while coal-fired generators made up 19.4 percent. This is a significant shift from two years ago, when coal-fired generators made up a majority of the LMP. Variable operating and maintenance costs (VOM) contributed 3.8 percent of the LMP and PJM's cost adder contributed 7.1 percent overall. PJM allows generators to add a 10 percent cost adder to their bids to account for the uncertainty in the process of defining costs. In addition, the cost adder provides protection against unintended understatement of variable operating costs, which could be harmful to reliable grid operation because it could create an incentive for generators to restrict their generation offer parameters. Besides fuel costs, other factors contributing to price levels include environmental costs (such as cost of controls and emission allowances), nonfuel operating costs, and profit margins. Cost for compliance with CO_2, NO_x and SO_2 emissions regulations contributed approximately 1 percent to the total LMP. All generators, however, are paid the LMP of their zone; the PJM Market Monitor estimates these cost factors for informational purposes only.

Figure B-4 Components of Load Weighted Annual Average LMP (2018)



Source: Monitoring Analytics, *2018 State of the Market Report for PJM.*

Average annual LMPs in PJM rose from the late 1990s to the late 2000s, more than doubling from 1998 to 2008 (see Table B-4). During the last decade, a large portion of the constructed new generating capacity has been natural gas-fired. Natural gas and petroleum prices tripled between 1998 and 2008. Due to the nature of the commodity markets and short-term supply contracts, these price increases were quickly reflected in electricity generation bid prices. LMPs in 2009 and 2010 were much lower than in 2008, however, due mainly to reduced electricity demand as a result of the recession. In 2011 and 2012, LMPs were once again significantly lower than in 2008, and in 2012, LMPs were the lowest since 2002. After a slight uptick in 2013 and a sharp increase in 2014, LMPs once again fell back to their 2012 levels in 2015 and continued to decline in 2016. This can be largely attributed to the low cost of natural gas. In line with the increase in natural gas prices, LMPs increased in 2017 and 2018. Although natural gas prices have increased recently, they are still well below the high natural gas prices experienced in 2008. The price of natural gas has declined since 2008 due to lack of load growth since the Great Recession, due mostly to a weak economic recovery from the recession, increased fracking, as well as increased penetration of energy efficiency and behind-the-meter renewable energy projects. Subsequently, this decline in the cost of natural gas has put downward pressure on market prices for electric power. Figure B-5 depicts fuel costs for electricity suppliers between 1999 and 2018.

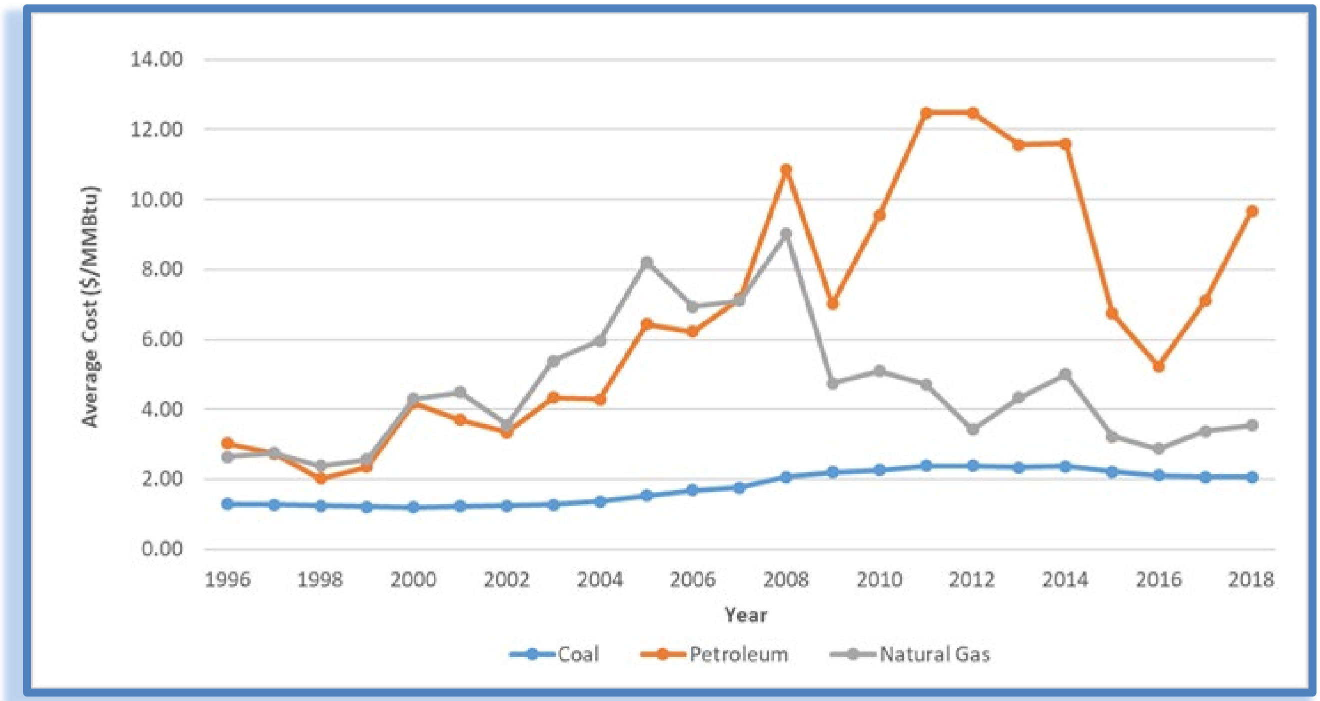
The cost of uranium fuel (not shown in Figure B-5) is only a small part of the overall operating and maintenance cost for a nuclear facility. However, the price of uranium has been declining over the last several years. In 2006, the weighted average of uranium was $18.61 per pound and increased significantly in 2011 to a record high price of $55.64 per pound. Since then, the price has steadily declined to a weighted average price of $38.81 per pound in 2018. A pound of uranium provides approximately 171 MMBtu; therefore, the cost to the electric power industry was approximately 23 cents per MMBtu in 2018. While the cost of uranium fuel does have a small impact on operating costs, it has little to no influence on the dispatching of a nuclear facility since they are a base load power source.

Table B-4 PJM Real-Time Load-Weighted Day-Ahead Average LMP, 1999-2018

Year	LMP ($/MWh)	Change from Previous Year ($/MWH)	Percent Change
1999	34.07	9.91	41.02%
2000	30.72	(3.35)	-9.83%
2001	36.65	5.93	19.30%
2002	31.6	(5.05)	-13.78%
2003	41.23	9.63	30.47%
2004	44.34	3.11	7.54%
2005	63.46	19.12	43.12%
2006	53.35	(10.11)	-15.93%
2007	61.66	8.31	15.58%
2008	71.13	9.47	15.36%
2009	39.05	(32.08)	-45.10%
2010	48.35	9.30	23.82%
2011	45.94	(2.41)	-4.98%
2012	35.23	(10.71)	-23.31%
2013	38.66	3.43	9.74%
2014	53.14	14.48	37.45%
2015	36.16	(16.98)	-31.95%
2016	29.23	(6.93)	-19.16%
2017	30.99	1.76	6.02%
2018	38.24	7.25	23.40%

Source: Monitoring Analytics, *2018 State of the Market Report for PJM*.

Figure B-5 Fuel Costs for the Electric Power Industry, 1997-2018



Source for 2008 through 2008: *Electric Power Annual 2018*, U.S. Energy Information Association, October 2019.
https://www.eia.gov/electricity/annual/html/epa_07_01.html Table 7.1
Source for 1996 through 2007: *Electric Power Annual 2017*, U.S. Energy Information Association, January 2009.
https://www.eia.gov/electricity/annual/archive/03482007.pdf Table 4.5

The dispatcher must at all times respect the physical limitations of the transmission system, including thermal limits, voltage limits, and the need for the system to maintain equilibrium. These limitations sometimes prevent the use of the next least-cost generator, instead causing the dispatch of a higher-cost generator located closer to the load in lieu of a lower-cost generator located at a greater distance from the load. LMP differentials caused by transmission system limitations between zones are referred to as congestion. The PJM system is divided into three regions — Western, Mid-Atlantic, and Southern Regions. LMP differentials between regions are mainly due to congestion between the Western Region, where abundant low-cost generation is located, and the Mid-Atlantic Region, in which the major load centers are located, which can lead to different electricity prices in the transmission zones that comprise PJM (see Table B-5).

As seen below in Table B-5, the differences in LMPs in 2018 between the Western Region and Mid-Atlantic Region increased compared to the differences in LMPs between the Western Region and Mid-Atlantic Region in 2017. This can be attributed to higher amounts of congestion in 2018 than in 2017. PJM reported an 87.8 percent increase in total congestion costs in 2018 compared to 2017. In Table B-5, the PJM zones that impact Maryland are highlighted in orange. Additional information on congestion is provided in Chapter 4 of this CEIR.

Table B-5 Real-Time Annual Load-Weighted Average LMPs for 2017 and 2018

Zone	2017 LMP	2018 LMP	Variance
Eastern PJM Zones			
AECO	$29.63	$37.10	7.47
AP	$31.32	$39.83	8.51
BGE	$34.76	$44.09	9.33
Dominion	$33.49	$43.22	9.73
DPL	$33.39	$43.82	10.43
JCPL	$30.74	$37.11	6.37
Met-Ed	$31.15	$37.10	5.95
PECO	$29.80	$36.40	6.60
PENELEC	$30.48	$37.95	7.47
Pepco	$33.70	$42.65	8.95
PPL	$29.99	$35.99	6.00
PSEG	$30.92	$36.72	5.80
RECO	$31.26	$37.43	6.17
Western PJM Zones			
AEP	$30.17	$37.84	7.67
ATSI	$31.23	$40.24	9.01
ComEd	$28.29	$30.08	1.79
Day	$31.06	$39.00	7.94
DEOK	$30.55	$39.20	8.65
DLCO	$30.63	$40.03	9.40
EKPC	$29.19	$36.24	7.05
OVEC	NA	$30.61	NA

Source: Monitoring Analytics, 2018 State of the Market Report for PJM.

Appendix C - Determinants of Electricity Demand Growth in Maryland

Introduction

This appendix provides an overview of the basic theoretical foundations upon which forecasts of electricity consumption and peak demand rest, and an analysis of the trends of the key economic and noneconomic determinants of the demand for electricity. The Maryland data presented herein were obtained from the Maryland Department of Planning, the Bureau of Economic Analysis of the U.S. Department of Commerce, and the Bureau of Labor Statistics of the U.S. Department of Labor. Economic variables include income, price of electricity, and employment; noneconomic variables include population (which is itself influenced by income and employment) and weather. Historical information is required for estimation purposes, while projected data are necessary to forecast the demand for power using the statistical relationships between these variables and electricity consumption determined during the estimation process based on the historical data.

This appendix is composed of five sections. The following section presents a brief discussion of the theoretical foundations used for modeling the demand for electricity econometrically. This section sets the stage for the rest of Appendix C, which examines economic and demographic trends for Maryland by region. For purposes of presentation, the state has been divided into six regions, as shown in Table C-1. The section covering the theoretical foundations is followed by a section discussing trends in per capita income, which, in turn, is followed by a section discussing trends in employment. Trends in population and the number of households follow the employment section. The final section of Appendix C presents a brief summary.

Table C-1 Principal Regions in Maryland

Region	Counties	Predominant Electric Distribution Utility
Baltimore	Anne Arundel Baltimore Baltimore City Carroll Frederick Harford Howard	Baltimore Gas and Electric Company
Washington Suburban	Montgomery Prince George's	Potomac Electric Power Company
Southern Maryland	Calvert Charles St. Mary's	Southern Maryland Electric Cooperative
Western Maryland	Allegany Garrett Washington	Potomac Edison Company
Upper Eastern Shore	Caroline Cecil Kent Queen Anne's Talbot	Delmarva Power and Choptank Electric
Lower Eastern Shore	Dorchester Somerset Wicomico Worcester	Delmarva Power and Choptank Electric

Theoretical Foundations for Econometrically Modeling Electricity Demand

"Econometric" forecast studies use the economic theory of demand as the organizing principle to model the demand for electricity. The total demand for any good or service, including electricity, is simply the sum of the demands of the individual consumers in the market. The portion of market demand for residential use of electricity is driven by factors to which individual residential consumers are sensitive. Similarly, for the commercial and industrial sectors of the market demand for electricity, the factors affecting demand are those to which producers are sensitive.

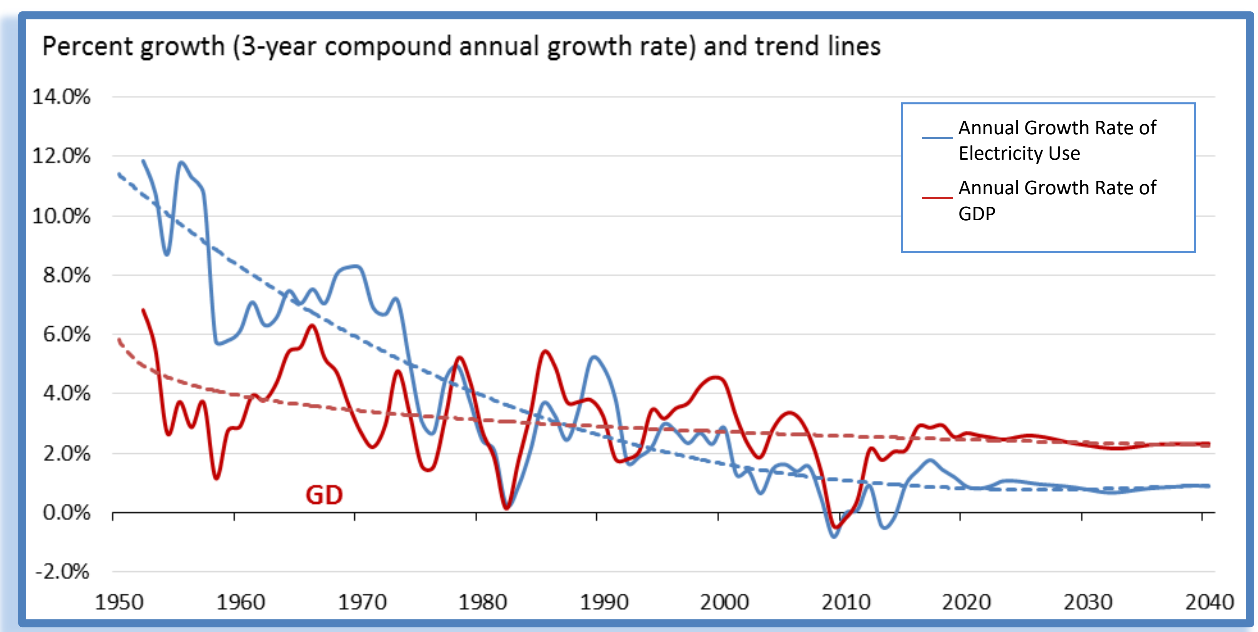
The residential demand for electricity is assumed to result from the exercise of choice by which the consumer maximizes their usage, subject to a budget constraint. Consumer demand for electricity is taken to be a function of its price, consumer income, weather, and the price of related commodities (i.e., substitutes and complements such as natural gas for home heating). It is important to note that electricity, in and of itself, conveys no benefits to the consumer. Rather, the consumer benefits from the services of the stock of appliances that require electricity. These services include space conditioning, refrigeration, cooking, clothes washing and drying, and numerous other services and functions. Consequently, the demand for electricity can be appropriately viewed as a derived demand; that is, it results from the demand for the services provided by electricity-consuming appliances.

For commercial and industrial customers, electricity is a factor of production, i.e., an input. For the profit-maximizing producer, demand for a commodity (including electricity) is driven by its price, the price of related inputs and the level of output. Producer demand for electricity is also driven by other factors, including weather.

Both the residential and nonresidential demand for electric power are discussed above in terms of the individual consumer or producer. The market demand for electric power, for example, in Maryland or within regions in Maryland, is also dependent on the number of consumers (households) and the level of goods and services produced in the region. Because no satisfactory time series of output data is available at a suitably disaggregated level, we use employment as a proxy for output. Commercial and industrial electric sales are projected per employee, which is then multiplied by the number of forecasted employees to project total commercial and industrial demand for electricity.

The growth in electricity use has historically been linked to the level of economic growth. The rate of growth of electricity use nationwide exceeded the rate of increase in gross domestic product (GDP) in the 1950's by 5 percent. As shown in Figure C-1, the differential between the growth in real GDP and the growth in electric use has declined steadily from 1950 until the 1990's when growth in electric use fell below GDP growth. Similar to the recession in the early 1980's, the differential between GDP growth and growth in electric use during the Great Recession of the late 2000's is minimal.

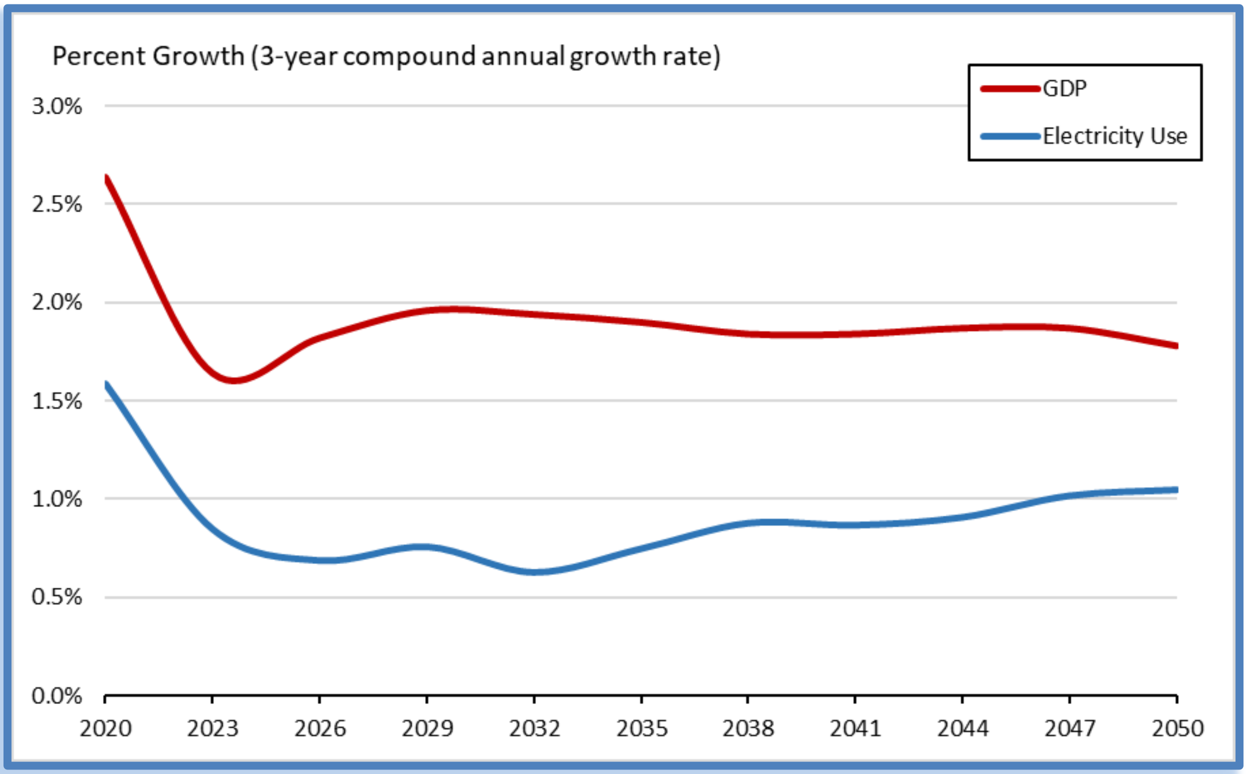
Figure C-1 U.S. Electricity Use and Economic Growth, 1950-2040



Source: U.S. Bureau of Economic Analysis; U.S. Energy Information Agency's Annual Energy Outlook for 2014 and 2015.

The U.S. Energy Information Administration (EIA) reports in its 2019 Annual Energy Outlook (AEO) that average electric use is projected to grow around 0.91 percent per year from 2019 through 2050, compared to average real GDP growth of 1.9 percent over the same period (Illustrated in Figure C-2). Over the next three decades, the EIA projects that electricity use will continue to grow; however, the rate of growth will slow over time. The EIA does not expect the growth in electricity use to equal or exceed real GDP growth for any sustained period of time due to efficiency standards for lighting and other appliances continued downward pressure on the growth in electricity consumption.

Figure C-2 Projected U.S. Electricity Use and Economic Growth, 2020-2050



Source: U.S. Energy Information Agency's Annual Energy Outlook for 2019.

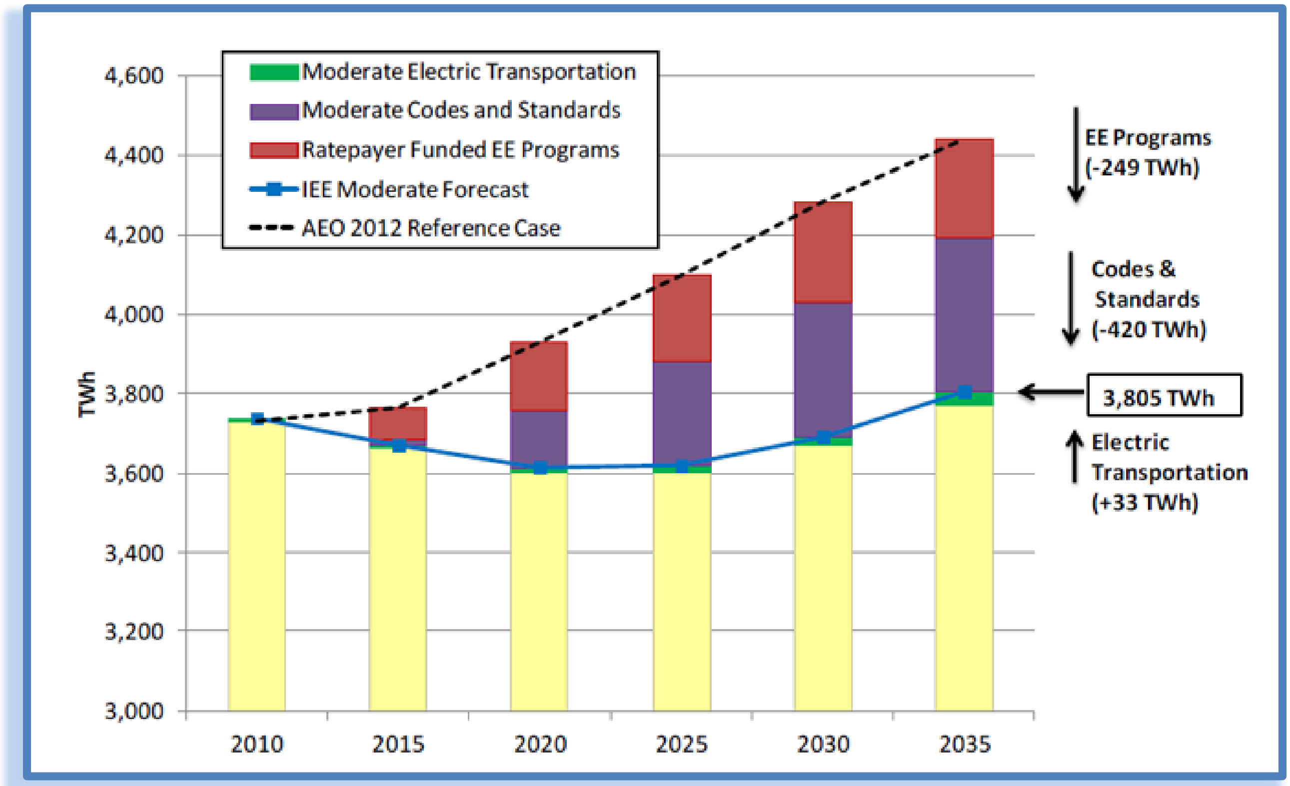
According to the Edison Foundation's Innovation Electricity Efficiency Institute (IEE), the major factors that are expected to affect growth in electricity use through mid-century are:

- Energy efficiency (EE) programs sponsored by electric utilities, and
- Government codes, standards and policies that impact appliance, equipment and building energy use.

The IEE projects that improvements in building energy codes, adoption of appliance/equipment energy standards and expansion of ratepayer-funded energy efficiency programs could result in declining electricity use through 2020 after which time economic growth and the potential growth in use of electric vehicles could result in modest electric growth through 2035. This effect is illustrated in Figure

C-3, with the IEE energy use forecast, shown in blue, being far below the 2012 Annual Energy Outlook forecast.

Figure C-3 Projected U.S. Electric Energy Use, 2010-2035



Source: Innovation Electricity Efficiency, an Institute of The Edison Foundation. "Factors Affecting Electricity Consumption in the U.S. (2010 – 2035).

Per Capita Income Trends

Income is an important determinant of the residential demand for electricity, and changes in income will affect the quantity of electricity purchased. Changes in income affect electric power consumption in two ways. First, a change in income will induce a change in the intensity of use of the existing stock of electricity-consuming appliances; for example, consumers will reevaluate the intensity of use of a more constrained budget if there is a decline in income. This can be manifested in higher air-conditioning settings or use of lower-wattage lamps for electricity requirements. Second, an income change will induce changes in the stock of electricity-consuming appliances as it impacts consumers purchasing energy efficient devices. As income changes, therefore, the demand for electricity will rise or fall. Previous PPRP forecast studies have demonstrated a positive and, typically, statistically significant relationship between income and the residential demand for electricity.

Real (i.e., inflation adjusted) per capita income can be used as an explanatory variable for residential per-customer electricity consumption. Real per capita income figures are reported in Table C-2 for the Maryland regions defined in Table C-1. Table C-2 summarizes historical and projected data as well as average annual growth rates for the period 2000 through 2025. As shown by the historical data, the rate of income growth has remained constant or has slowed for all regions in Maryland. For the state as a whole, growth in real per capita income declined to 0.73 percent per year between 2005 and 2010, compared to an average annual growth rate of 2.23 percent between 2000 and 2005. All regions of the state, with the exception of Southern Maryland (owing to its proximity to Washington, D.C. and federal government employment opportunities, which drive up wages and the in-migration of relatively high-income households), saw considerable decreases in the rate at which income grew during the 2005-2010 time period relative to 2000-2005. The Upper Eastern Shore region saw a decline in inflation-adjusted income between 2005 and 2010. This slowing was a product of the severe economic downturn and associated job losses affecting numerous Marylanders who lost their incomes, and economic conditions placed downward pressure on wages as the competition for available jobs became more intense.

From 2010 to 2015, the rate of real per capita income growth increased relative to the 2005-2010 period. A forecast by the Maryland Department of Planning for 2015-2020 shows that as the nation (and Maryland) emerges from the recession and the economy once again begins to grow, income will follow the economy's upward trajectory. Income growth is projected to once again slow (but is not negative) between 2015 and 2020 as the economy returns to steady-state rates of growth lower than those expected during the rebound period that follows the recession.

Table C-2 Historical and Projected Per Capita Income for Maryland, 2000-2025

	Per Capita Income (2009 $)						Average Annual Growth Rates				
Region	2000	2005	2010	2015	2020	2025	'00-'05	'05-'10	'10-'15	'15-'20	20-'25
Maryland	$42,501	$47,467	$49,221	$52,000	$56,854	$60,112	2.23%	0.73%	1.10%	1.80%	1.12%
Baltimore	$41,240	$46,709	$48,850	$52,498	$57,965	$61,589	2.52%	0.90%	1.45%	2.00%	1.22%
Washington Suburban	$48,357	$53,167	$54,395	$56,155	$60,675	$63,808	1.91%	0.46%	0.64%	1.56%	1.01%
Southern Maryland	$37,765	$41,536	$44,827	$46,626	$51,162	$54,298	1.92%	1.54%	0.79%	1.87%	1.20%
Western Maryland	$28,638	$32,391	$34,428	$36,452	$40,332	$42,947	2.49%	1.23%	1.15%	2.04%	1.26%
Upper Eastern Shore	$37,822	$42,076	$42,110	$46,155	$50,940	$54,017	2.15%	0.02%	1.85%	1.99%	1.18%
Lower Eastern Shore	$30,646	$34,698	$35,873	$37,824	$41,320	$43,592	2.51%	0.67%	1.06%	1.78%	1.08%

Source: Prepared by the Maryland Department of Planning, Planning Data Services, January 2015. Historical data, 1970-2010, from the U.S. Bureau of Economic Analysis.

Employment Trends

Nonresidential demand from commercial and industrial electricity consumers is largely driven by their economic output (e.g., customers served, quantities manufactured, etc.). Higher output implies some additional use of electricity. Output data at the county level are not available on a consistent basis, hence, a proxy for output needs to be used. Nonfarm employment has typically been relied upon for this purpose. By virtue of the necessity to have adequate numbers of employees to achieve a desired level of output, it is a sound alternative and it is not subject to data consistency problems. Employment data at the regional level are reported in Table C-3.

Table C-3 Historical and Projected Employment for Maryland, 2000-2025

	Total Jobs (thousands)						Average Annual Growth Rates				
Region	2000	2005	2010	2015	2020	2025	'00-'05	'05-'10	'10-'15	'15-'20	20-'25
Maryland	3,065	3,316	3,345	3,552	3,752	3,881	1.54%	0.22%	1.21%	1.10%	0.68%
Baltimore	1,514	1,609	1,627	1,754	1,846	1,900	1.21%	0.22%	1.56%	1.06%	0.58%
Washington Suburban	1,088	1,186	1,197	1,252	1,324	1,372	1.68%	0.18%	0.92%	1.15%	0.72%
Southern Maryland	124	148	156	162	174	184	3.43%	1.06%	0.84%	1.43%	1.18%
Western Maryland	130	138	136	143	149	156	1.08%	-0.27%	0.98%	0.88%	0.89%
Upper Eastern Shore	99	115	115	123	133	140	2.90%	0.07%	1.40%	1.53%	1.05%
Lower Eastern Shore	110	120	114	118	126	130	1.70%	-0.90%	0.62%	1.29%	0.64%

Source: Historical data from the U.S. Bureau of Economic Analysis, Tables CA25 and CA25N.
Projections from 2015 to 2040 prepared by the Maryland Department of Planning, Planning Data Services, January 2015.

As shown in Table C-3, while every region of the state has seen consistently positive employment growth over the past two decades, the Lower Eastern Shore and Western Maryland were the hardest hit by the recession. Growth between 2010 and 2020 is projected to be most rapid in the Southern Maryland and Upper Eastern Shore regions and slowest in Western Maryland and the Lower Eastern Shore. The City of Baltimore emerged from a recent trend of employment growth lower than the state average (2000-2005) to have a rate of employment slightly higher than the state as a whole from 2010-2015. Overall employment trends for the state tend to track those in the Baltimore and Washington, D.C. suburban regions as these areas contain the largest number of jobs. Both the Baltimore and Washington, D.C. suburban regions, and subsequently the State of Maryland in aggregate, are projected to see similar growth rates through 2025.

The economic downturn in the late 2000's continued to greatly affect employment, as well as energy consumption, and considerably slowed the employment growth rates between 2005 and 2010. Maryland's unemployment rate rose from 3.5 percent in 2007 to 7.65 percent in 2010. However, Maryland has still fared better than the United States as a whole. The nationwide unemployment rate in 2010 was 9.6 percent. As with real per capita income, the anticipated growth rebound out of the recession has considerably increased the forecast of job creation through 2025 relative to growth between 2005 and 2010. Now well out of the recession, the unemployment rate for the nation and Maryland was down to 3.9 percent in 2018.

Population Trends

Population is an important causal variable because population trends determine (in large part) the number of residential customers. Both the number of households and household size play a role in influencing electricity demand. The number of households affects the number of residential customers purchasing electricity, and changes in average household size can affect usage per customer. Larger numbers of customers mean higher demand, and smaller household sizes (for a given total population) will typically result in higher demand. While smaller households use less electricity in absolute terms, the relationship between size and usage does not scale linearly, as household electricity uses (such as heating and lighting) decline at rates lower than the decline in number of household members. Population growth and the rate of household formation are closely related, and both affect the residential use of electricity. However, household size has seen a slow but steady decline (in Maryland and the United States as a whole) as cultural and societal norms change over time. Deferred marriage and the decision to limit or forgo child-rearing have steadily lowered the size of the average household. Accordingly, increases in population lead to increases in the number of households (and hence residential customers), although these rates of change need not coincide due to changes in the size of households. Population and household data are reported in Tables C-4 and C-5.

Population data at regional and state levels are reported in Table C-4. The table summarizes historical and projected data, as well as average annual rates of growth for the period 2000-2025. The population growth rates have been positive since 2000 for every region of Maryland except the western region which was projected to decrease slightly between 2010 and 2015. Between 2000 and 2010, population growth in Maryland was on average 0.87 percent per year. The state's population is projected to experience a slow growth through 2020 before experiencing a slight uptick by 2025. While following these trends generally, Southern Maryland and the Upper Eastern Shore have seen much more rapid population growth than that in the rest of the state. The rates of growth in population are uneven across the state. Historically, the largest growth rates were reported for Southern Maryland and the smallest rates for Western Maryland. Baltimore's growth rates are expected to be the lowest during the 2015-2025 period.

Table C-4 Historical and Projected Population for Maryland, 2000-2025

	Total Population (thousands)					Annualized Growth Rates			
Region	2000	2010	2015	2020	2025	'00-'10	'10-'15	'15-'20	20-'25
Maryland	5,296	5,774	5,988	6,142	6,337	0.87%	0.73%	0.51%	0.63%
Baltimore	2,512	2,663	2,738	2,800	2,852	0.58%	0.56%	0.45%	0.37%
Washington Suburban	1,870	2,069	2,187	2,229	2,314	1.01%	1.12%	0.38%	0.75%
Southern Maryland	281	340	358	382	405	1.93%	1.04%	1.27%	1.18%
Western Maryland	237	252	252	261	272	0.65%	-0.03%	0.70%	0.83%
Upper Eastern Shore	209	240	241	249	262	1.38%	0.10%	0.65%	1.04%
Lower Eastern Shore	187	209	211	220	231	1.15%	0.19%	0.84%	0.97%

Source: Projections for the Baltimore region based on Round 9 from the Baltimore Metropolitan Council of Government's Cooperative Forecasting Committee. Projections for the Washington suburban region based on Round 9.0 of the Metropolitan Washington Council of Governments Cooperative Forecasting Committee. Aggregated data prepared by the Maryland Department of Planning, August 2017.

Household data for the state are shown in Table C-5. The table shows a summary of historical and projected data, as well as average annual rates of growth for the period 2000-2025. Household growth rates differ from population growths due to population demographics and differences in household size. Because of this, household growth captures certain variables, such as the establishment of new households by young adults or the movement of childless couples into the region, which a raw population statistic fails to convey. On average, areas with high household sizes will see higher increases in electricity demand from household growth. Inspecting the rate of change in household size can convey the type of households being added. For example, Southern Maryland is expected to see the highest growth rates in both population and housing in the state. However, it will also see the most rapid decline in household size, suggesting that the households being added may be smaller, and subsequently elicit different changes in electricity demand.

Since 2000, household size in five of the six Maryland regions has been declining or flat, and the decline is forecast to continue through 2025. The Suburban Washington region experienced household size growth between 2000 and 2015, but that growth is projected to decline through 2025 along with the five other regions. For the state, average household size was level at 2.61 people during the period 2000-2015. Household size is expected to decline to 2.56 people by 2025.

Table C-5 Historical and Projected Number of Households and Average Size of Households in Maryland, 2000-2025

	Number of Households (thousands)					Annualized Growth Rates			
Region	2000	2010	2015	2020	2025	'00-'10	'10-'15	'15-'20	20-'25
Maryland	1,981	2,156	2,242	2,326	2,417	0.85%	0.78%	0.73%	0.77%
Baltimore	959	1,021	1,057	1,092	1,125	0.63%	0.69%	0.67%	0.59%
Washington Suburban	681	746	784	810	844	0.91%	1.00%	0.65%	0.82%
Southern Maryland	98	120	127	137	147	2.04%	1.24%	1.52%	1.42%
Western Maryland	91	97	97	101	106	0.69%	0.08%	0.82%	0.94%
Upper Eastern Shore	80	91	93	97	103	1.39%	0.46%	0.78%	1.08%
Lower Eastern Shore	73	82	83	87	92	1.14%	0.35%	0.95%	1.10%
	Household Size					Annualized Growth Rates			
Maryland	2.61	2.61	2.61	2.58	2.56	0.00%	0.00%	-0.23%	-0.15%
Baltimore	2.55	2.54	2.52	2.5	2.47	-0.03%	-0.13%	-0.22%	-0.22%
Washington Suburban	2.7	2.73	2.75	2.71	2.7	0.11%	0.11%	-0.29%	-0.08%
Southern Maryland	2.83	2.8	2.77	2.74	2.71	-0.09%	-0.21%	-0.24%	-0.24%
Western Maryland	2.44	2.43	2.42	2.4	2.39	-0.01%	-0.14%	-0.09%	-0.08%
Upper Eastern Shore	2.58	2.58	2.53	2.52	2.51	0.00%	-0.37%	-0.13%	-0.04%
Lower Eastern Shore	2.43	2.42	2.4	2.39	2.38	-0.03%	-0.18%	-0.06%	-0.09%

Source: Historical data from the U.S. Census. Forecasts prepared by the Maryland Department of Planning, August 2017.

Summary

This appendix provides a review of the theoretical and demographic foundations used for modeling the demand for electricity econometrically. In doing so, emphasis is placed on some of the key determinants of the demand for electric power. The determinants of demand are classified into residential and nonresidential, as well as into economic and noneconomic for purposes of exposition. Per capita income is an explanatory economic variable that influences the residential demand for electricity; population, the number of households, and average household size are noneconomic explanatory variables affecting residential electricity consumption. This appendix also shows trends in employment, which affect the nonresidential demand for electricity. Selected data on these determinants of demand are reported and trend analyses presented. The broad conclusion to emerge from these trends is that electricity demand should continue to grow in Maryland.

Glossary

The following list provides definitions of selected terms that are commonly used in the electricity generating industry.

Advanced Metering Infrastructure (AMI)
Technology deployed at end user locations in conjunction with a smart grid, allowing for a new, dynamic rate structure for electricity prices.

Anadromous
Anadromous fish are those that ascend rivers from the sea for breeding.

Aquifer
An underground layer of water-bearing permeable rock or unconsolidated materials from which groundwater can be extracted using a water well.

Attainment area
Area in the country where National Ambient Air Quality Standards are being met.

Best Available Control Technology (BACT)
Level of pollution control required for sources that trigger PSD air quality requirements (see Prevention of Significant Deterioration, PSD).

Biomass
Biological material (such as wood, agricultural, and animal wastes) that can be used as fuel for transportation, steam heat and electricity generation.

Black Liquor
Black liquor is a thick, dark liquid that is a byproduct of the process that transforms wood into pulp, which is then dried to make paper. One of the main ingredients in black liquor is lignin, which is the material in trees that binds wood fibers together and makes them rigid, and which must be removed from wood fibers to create paper.

BMPs
Best management practices.

Bottom ash
A coal combustion byproduct collected from the bottom of the furnace after combustion and composed of coarse, angular, porous or glassy particles.

British Thermal Unit (Btu)
A unit of thermal energy equivalent to 252 calories; serves as the base unit for measuring the heat content of a fuel source.

Capacity
The capability to generate electrical power. The generating capacity of a power plant is the maximum amount of power it can instantaneously supply to the grid and is measured in megawatts (MW).

Carbon capture and storage (CCS)
A range of technologies used to prevent large quantities of CO_2 from being released into the atmosphere, mainly from large point sources such as fossil fuel-fired power plants.

Certificate of Public Convenience and Necessity (CPCN)
Issued by Maryland's Public Service Commission to an electric company planning to construct or modify a generation facility or transmission line; grants permission to construct the facility subject to certain conditions.

Class F Fly Ash
As classified by the American Society for Testing and Materials (ASTM), Class F fly ash is distinguished from Class C fly ash by having less than 10 percent calcium (expressed as CaO) by weight.

Closed-cycle cooling
Type of cooling that involves recirculating water in cooling towers.

Coal combustion byproducts (CCBs)
Solid byproducts consisting of components of coal not consumed during combustion, such as fly ash and bottom ash.

Conduit hydropower
Hydropower produced by water-carrying structures (tunnels, canals, pipelines, etc.) fitted with electric generating equipment without the use of a dam or reservoir.

Congestion
Describes a situation where power cannot be moved from where it is being produced to where it is needed because the transmission system does not have sufficient capability to carry the electricity.

Conservation
A conscious choice that a person makes to change behavior solely to use less energy (or other resources).

Consumptive water use
Use of water in such a way that it does not return to its source following use, such as water that evaporates from cooling towers at power plants.

Cross-state Air Pollution Rule (CSAPR)
EPA's cap-and-trade program designed to reduce interstate transport of PM2.5 and ozone.

Curtailment Service Providers (CSP)
Grid members that act as demand response providers.

Demand
The amount of power that must be supplied to a customer (i.e., a load).

Demand response
Refers to shifting demand for electricity to nonpeak periods or reducing electricity use during periods of peak demand.

Distributed generation
Generating resources located close to or on the same site as the facility using the power.

Distribution
The process of delivering electricity received from transmission providers to local customers.

Electric company
The company that delivers electricity to a customer's home or business through its system of poles, power lines, and other equipment.

Electric cooperative
An electric company that is owned by, and operated for the benefit of, those using the system.

Electricity supplier
An entity that sells electricity to customers (and, in Maryland, is licensed to do so by PSC).

EmPOWER Maryland
A state energy initiative that began in 2008 with a goal of reducing Maryland's per capita energy consumption and peak demand by 15 percent by 2015.

Energy efficiency
Finding ways to accomplish the same amount of work using less energy.

Energy use
A measure of electrical power used over a period of time, usually expressed in kilowatt-hours or megawatt-hours.

Federal Energy Regulatory Commission (FERC)
An independent commission responsible for regulating wholesale electric power transactions and interstate transmission and sale of natural gas for resale. FERC is the federal counterpart to state utility regulatory commissions.

FIDS
Forest interior dwelling species.

Flue gas desulfurization (FGD)
Technology that introduces sorbent into the exhaust gas after combustion to remove sulfur compounds from power plant emissions, thereby reducing air pollution.

Fluidized bed combustion (FBC)
Technology that uses a heated bed of sand-like material suspended (or fluidized) within a rising column of air to burn many types and classes of fuel, including waste-type fuels. Typically has a higher efficiency and lower emissions than conventional power plant combustion technologies.

Fly ash
A coal combustion byproduct made up of finely divided residue or ash that is transported from the furnace along with emission gases. Composed of very fine, and generally spherical, glassy particles.

Flywheel
A system that uses a large rotational mass to store energy and provide regulation services to smooth output fluctuations from a local solar or wind facility.

Fuel cell
A device that converts the chemical energy from a fuel into electricity through a chemical reaction with oxygen or another oxidizing agent.

Generation
The process of producing electrical energy. Electricity generation is the amount of power supplied through time (energy) and is measured in megawatt-hours (MWh).

Generation Attribute Tracking System (GATS)

GATS is a database maintained by PJM that lists the generation attributes (e.g., time, facility, fuel type) for all MWh generated in the PJM territory and outside the PJM territory if the generator is eligible for a PJM-state's RPS and has registered as such with PJM.

Greenfield
Area of land that has not previously been developed.

Greenhouse gases (GHGs)
Gases that occur both naturally and from human activities that trap heat in the atmosphere, such as carbon dioxide and methane.

Hazardous air pollutants (HAPs)
List of pollutants identified by EPA as having the potential to cause an adverse impact to human health or the environment.

Independent Power Producer (IPP)
Private company that develops, owns, or operates an electric power plant.

Independent spent fuel storage installation (ISFSI)
Long-term storage facility for spent nuclear fuel located at a nuclear power plant site and regulated by the NRC.

Investor-owned utility
A for-profit company in the business of supplying electric power to end users.

Landfill gas (LFG)
Gas produced when organic solid wastes decompose in a landfill. LFG is a combination of methane and carbon dioxide.

Load
Kilowatt or megawatt demand placed on the electric system by consumers of power.

Locational Marginal Price (LMP)
Electricity price that varies by time and geographic location; provides the basis for the regional market for buying and selling electricity.

Maryland Healthy Air Act (HAA)
Requires substantial reductions in emissions of NO_x, SO_2 and mercury from coal-fired generating units in the state. Also requires Maryland to participate in the Regional Greenhouse Gas Initiative to reduce emissions of pollutants that contribute to climate change.

Maryland Public Service Commission (PSC)
Government agency that regulates public utilities and certain passenger transportation companies doing business in Maryland, including gas, electric, telecommunications, water, sewage disposal, passenger motor vehicle, railroad, and taxicab companies.

Maximum Achievable Control Technology (MACT)
An EPA standard designed to reduce emissions of HAPs, such as heavy metals, acid gases and organics, from coal- and oil-fired power plants.

Municipal utility
An electric company owned and operated by a municipality serving residential, commercial and/or industrial customers usually within the boundaries of the municipality.

National Ambient Air Quality Standards (NAAQS)
Ambient air quality standards developed by EPA to represent the maximum pollutant concentrations that are allowable in ambient air.

New Source Review (NSR)
A complex set of EPA regulations that govern the construction of new pollution sources and modifications or expansions of existing sources.

Nuclear Regulatory Commission (NRC)
Federal agency that regulates nuclear power plants in the United States, particularly focused on reactor safety, nuclear waste management and license renewal of existing plants.

Particulate matter (PM)
Dust, soil and liquid droplets that form during the combustion of fossil fuels or in the atmosphere by chemical transformation and condensation of liquid droplets. Defined by particle size: PM10 = particles smaller than 10 microns in diameter and PM2.5 = particles smaller than 2.5 microns.

Peak demand
The maximum demand on an electric system in a designated period of time (e.g., over a year, a month, or a season).

Peaking plants
Power plants that operate for a relatively small number of hours, usually during peak demand periods. Such plants usually have high operating costs and low capital costs.

PJM Interconnection, LLC (PJM)
A regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states, including Maryland, and the District of Columbia.

Power Plant Research Program (PPRP)
A subdivision of the Maryland Department of Natural Resources, PPRP functions to ensure that Maryland meets its electricity demands at reasonable costs while protecting the state's valuable natural resources. It provides a continuing program for evaluating electric generation issues and recommending responsible, long-term solutions.

Pozzolan
A type of material that, when added in the process of mixing cement, improves the strength of the resulting solid. Fly ash, a coal combustion byproduct, has pozzolanic properties making it suitable for beneficial use in certain cement industry applications.

Prevention of Significant Deterioration (PSD)
In attainment areas, EPA's New Source Review program is referred as PSD.

Processed refuse fuel (PRF)
Fuel derived from residential, commercial and nonhazardous industrial waste, which can be burned to produce energy.

Radionuclides
Naturally occurring or manmade atoms with an unstable nucleus that undergoes radioactive decay, emitting gamma rays or subatomic particles.

Regional Greenhouse Gas Initiative (RGGI)
The first cap-and-trade regulatory program to reduce greenhouse gas emissions in the United States. (See Section 5.1.5)

Reliability councils
Regional organizations formed by the electric utilities to coordinate utilities' generation and transmission systems and monitor the availability of electric services.

Renewable energy
Sources of energy that are continually being replaced such as energy from the sun (solar), wind, geothermal, and hydroelectric.

Renewable Portfolio Standard (RPS)
A standard adopted in Maryland requiring that a portion of electricity supply comes from renewable resources.

Retail competition
Permitting enduse customers to contract directly with suppliers for their electric or gas service, while transmission and distribution companies provide for delivery of the service.

Reserve margin
Total system generating capacity minus annual system peak demand, divided by the annual system peak demand, expressed as a percent.

Right-of-way
A defined pathway owned or legally established for the use of utilities, vehicles or pedestrians, such as for transmission lines or roadways.

Self-generator
A generating facility that consumes most or all of the electricity it produces to meet onsite power demand.

Shale gas
Natural gas trapped in deep, fine-grained rock formations; recovered using horizontal drilling and hydraulic fracturing methods.

Smart grid
A type of electrical grid system that attempts to predict and intelligently respond to the behavior of electric power users connected to it in order to supply reliable and economically viable electricity.

Soil Compaction
Soil Compaction is the physical consolidation of the soil that destroys structure, reduces porosity, limits water and air infiltration, and increases resistance to root penetration, usually resulting in reduced crop yield.

Solar photovoltaic (solar PV)
Type of renewable energy created by converting solar radiation into electricity using semiconductors.

Standard offer service (SOS)
Electricity service that is provided to customers who do not choose an electricity supplier. Maryland's SOS service is based on competitive wholesale market rates.

Time of use rates
A utility rate structure that charges higher rates during peak hours of the day in an effort to shift peak period demand to off-peak hours.

Transmission
The process of delivering electricity from generation plants to entities that serve loads.

Volt
A unit of electrical pressure; 1 kilovolt (kV) = 1,000 volts.

Waste-to-energy (WTE)
An electricity generating facility that combusts municipal solid waste in order to heat boilers and create high pressure steam.

Watt
The electrical unit of power or rate of doing work; 1 kilowatt (kW) = 1,000W; 1 megawatt (MW) = 1,000,000 watts; 1 gigawatt (GW) = 1,000,000,000 watts.

Watt-hour
An electric energy unit of measure that is equal to 1 watt of power supplied or taken steadily from an electric circuit for 1 hour; 1 kW-hour (kWh) = 1,000 watt-hours.

Wetlands
Areas of land that form the interface between terrestrial and aquatic ecosystems.

Prepared by the Maryland Department of Natural Resources
Power Plant Research Program

Tawes State Office Building, B-3
580 Taylor Avenue
Annapolis, Maryland 21401
Toll free in Maryland: 877-620-8DNR, ext. 8660
Outside Maryland: 410-260-8660
TTY users call via the Maryland Relay
dnr.maryland.gov