MARYLAND
DEPARTMENT OF
NATURAL RESOURCES

PPRP – CEIR – 16
DNR Publication No. 12-1242012-546

PPRP

Maryland Power Plants and the Environment

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

MARYLAND POWER PLANT RESEARCH PROGRAM

January 2012

Martin O'Malley, Governor ♦ Anthony G. Brown, Lt. Governor

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

John R. Griffin, Secretary
Maryland Department of Natural Resources

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The Power Plant Research Program (PPRP) was established in 1971 to ensure that Maryland could meet its demands for electric power in a timely manner and at a reasonable cost, while protecting the State's valuable natural resources.

PPRP coordinates the State's comprehensive review of new power plants and associated facilities as part of the state and federal licensing process. The Program also conducts a range of research and monitoring projects on existing and proposed power plants. PPRP publishes the Electricity in Maryland Fact Book, which provides information on power generation and use in Maryland. A bibliography listing the general and site-specific reports that PPRP has produced since the early 1970s is also available.

If you want more information, or to request a copy of the Fact Book, bibliography, or other reports, contact PPRP at (410) 260-8660 (toll-free number in Maryland, 1-877-620-8DNR, x8660). You can also visit our Web site at: www.dnr.state.md.us/bay/pprp. References are available upon request for all technical topics discussed in this report.

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Chapter 1 – Introduction

Day after day I asked myself what is electricity and found no answer. Eighty years have gone by since and I still ask the same question, unable to answer it.

– Nikola Tesla

Letter to Miss Pola Fotitch, 'A Story of Youth Told by Age' (1939)

1.1 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 impact 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 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 licensing conditions.

PPRP is directed by the Maryland Power Plant Research Act (§3-304 of the Natural Resources Article of the Annotated Code of Maryland) 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.

This sixteenth edition of CEIR (CEIR-16) is subdivided into chapters as follows: Chapter 2 reviews power generation, transmission, and usage in Maryland. Chapter 3 discusses the planning, oversight, and regulatory framework for power generation and transmission facilities. Chapter 4 identifies the issues and effects of power generation and transmission on Maryland's air, water, land, and socioeconomic resources. Lastly, Chapter 5 provides information on evolving policy and technical issues, such as Maryland's involvement in the Regional Greenhouse Gas Initiative (RGGI), carbon dioxide (CO_2) reduction strategies, renewable energy, and unconventional natural gas resources.

1.1.1 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, which was in the 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 Units 1 and 2 were a source of concern mainly due to their once-through cooling system that withdraws 3.5 billion gallons of water per day from the Chesapeake Bay and then discharges it back into the Bay with an approximate increase in temperature of 12°F. This and other issues prompted the creation of PPRP to ensure a comprehensive, objective evaluation based on sound science to resolve environmental and economic issues before decisions were made regarding whether or not and where to build additional power generating facilities.

Today, PPRP continues this role by coordinating the comprehensive review of proposals for the construction or modification of power generation and transmission facilities and by developing technically based licensing recommendations. 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, both for new installations or modifications to existing structures.

1.1.2 Power Plant and Transmission Line Licensing

The Maryland Public Service Commission (PSC) is the regulating entity for 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 electric company that is planning to construct or modify a generating facility or a transmission line must receive a Certificate of Public Convenience and Necessity (CPCN) from the PSC prior to the start of construction.[1] 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). Applications for a CPCN are reviewed before a Public Utility Law Judge, formerly known as a Hearing Examiner, 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 interveners such as PPRP (acting on behalf of DNR and six other State agencies). Other groups, such as federal agencies and private environmental organizations, as well as individuals, also have a right to participate as interveners in these hearings. The broad authority of the PSC allows for the comprehensive review of all pertinent issues and was designed in 1971 to be a "one-stop shop" for 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, including the cumulative effects of interrelations between various impacts. This is a unique process within the State's regulatory framework. The CPCN mechanism recognizes the fact that electricity is

[1] There are certain exceptions where a CPCN is not required, such as for land-based wind power projects no greater than 70 MW; electric generators no greater than 70 MW that consume at least 80 percent of the electricity generated on-site; and generators with capacity no greater than 25 MW that consume at least 10 percent of the electricity generated on-site (see PUC Article §7-207.1).

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 intervener status 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, the Environment, Agriculture, Business and Economic Development, Planning, and Transportation, and the Maryland Energy Administration. PPRP then develops a set of consolidated, unique, and scientifically supported recommended licensing conditions for the CPCN and submits them to the PSC on behalf of the State agencies. In many instances, these 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 adjudicatory hearings.

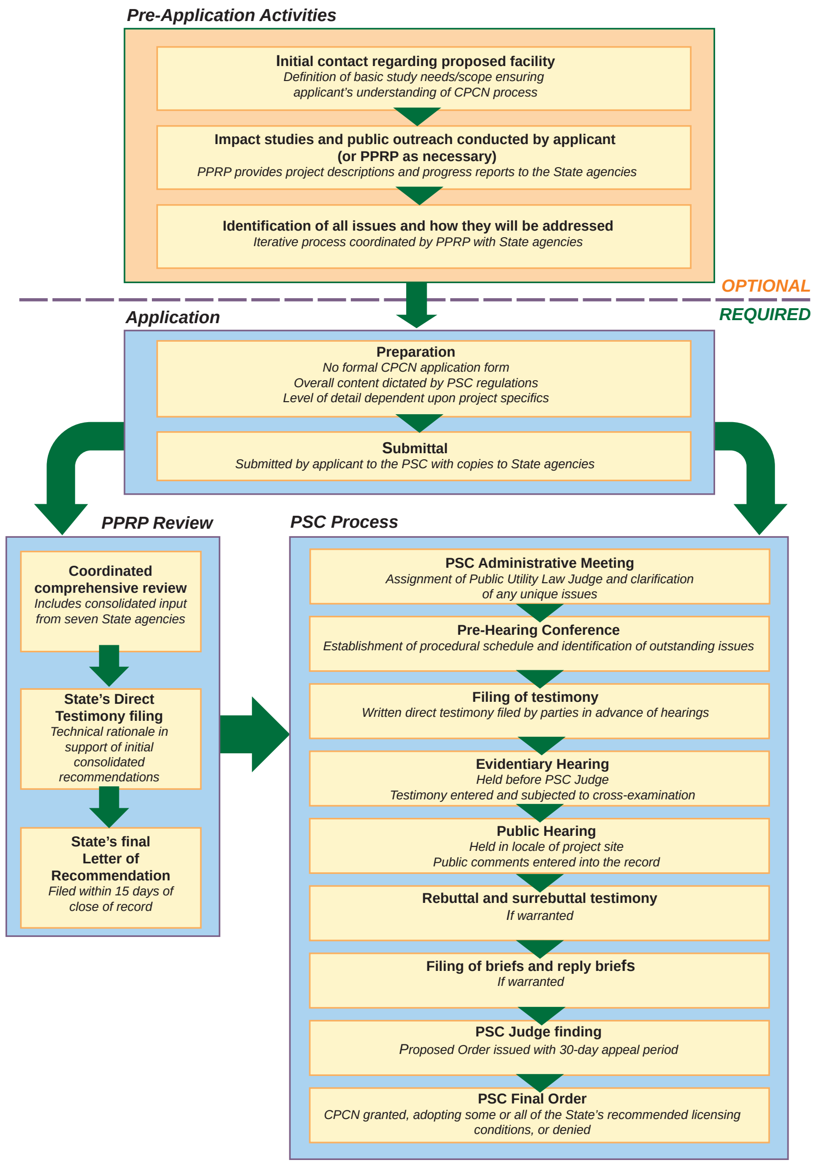
In the case of multiple facilities proposed in close proximity to each other or to existing plants or for transmission lines that span multiple regions and resource areas, PPRP includes cumulative impacts within the consolidated review process. In such a case, impacts to air, water, terrestrial, socioeconomic, and other resources are evaluated and compared to any identified thresholds of acceptability. Additionally, the cumulative analysis identifies any licensing conditions needed 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.

Pre-application. While there are no required pre-CPCN application procedures, PPRP encourages prospective generation or transmission applicants to meet with Program staff to identify potential issues of concern and to determine whether and how all relevant concerns will be addressed. This process ensures the applicant is aware of the PSC regulations and procedures. By the time the applicant files for a CPCN, there usually has been a significant amount of dialogue and, often, the applicant has established that it is likely the proposed facility can obtain a CPCN, pending the development of recommended conditions. Through a diligent and thorough pre-application process, a prospective developer can limit the risk of submitting an unsuccessful CPCN application, or make changes during the preliminary design to minimize certain 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, in coordination with other State agencies, evaluates the potential impacts of the proposed project on Maryland's resources, including water (surface and ground water), air, land, ecology, and socioeconomics, including visual and noise-related impacts. In the case of transmission line projects, the need for the project is evaluated and a review of alternatives is conducted as part of the review process. In the case of generation there is no need or justification requirement. As a market-based state, Maryland has no

Figure 1-1 The CPCN Licensing Process



integrated resource planning process and approval of power plant CPCNs is based on environmental and socioeconomic impacts.

PSC Process and PPRP Review. The PSC typically assigns a Public Utility Law Judge to the licensing case at a preliminary administrative meeting. The Judge then schedules a pre-hearing conference to establish an overall procedural schedule, including dates for evidentiary and public hearings. The adjudicatory process commences with a discovery phase, and proceeds to the filing of direct testimony from the applicant summarizing the impact analyses that have been completed and providing the basis for the applicant's request for a CPCN. During the PSC evidentiary hearing, all the parties to the proceeding 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 licensing conditions along with justifying analyses, 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 Judge also presides over public hearings to accept comments on a project from the general public.

The Judge takes into consideration the briefs filed by the applicant, the State, and any other parties, recommended license conditions, and public testimony, 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.

1.2 CEIR-16 Highlights

This CEIR provides a comprehensive overview of issues related to power plants and transmission lines in Maryland. Some of these topics have been under investigation for decades, with the scientific understanding continuing to progress. Other areas have gained prominence more recently in response to new advances in technology and economic or policy changes. Highlighted below are a few of the issues that are discussed in more detail within this report.

Investments in New Transmission Infrastructure. After being relatively dormant for many years, transmission line licensing activity has increased dramatically since 2009. Although electrical load growth has slowed in recent years, due to the global economic recession and an increased focus on energy conservation, demand response programs, and customer-sited distributed generation, transmission companies are continuing to seek permits for major new projects. Transmission line projects can involve potential ecological impacts associated with the loss of sensitive habitats and the crossing of streams, wetlands, and even the Chesapeake Bay, as well as potential impacts to cultural resources and energy costs. [More information on pages 41 and 148]

Changing Regulatory Landscape. The U.S. EPA has proposed a suite of new regulations that will affect electricity generators in the state. These regulations include new, more stringent air quality standards, reporting requirements, and permitting reviews as part of the Greenhouse Gas (GHG) Tailoring Rule, the GHG New Source Performance Standard, the Cross-state Air Pollution Rule (CSAPR), and the new Boiler Maximum Achievable Control Technology (MACT) proposal. [More information on pages 70 and 89]

Furthermore, changes to cooling water intake design requirements are associated with EPA's implementation of Section 316(b) under the Clean Water Act and new coal combustion by-product (CCB) use and disposal requirements are part of the Coal Combustion Residuals Rule. [More information on pages 102 and 140]

In addition to EPA's proposals affecting generation, changes are underway at the federal level that will affect how transmission lines are planned and permitted. [More information on page 59]

Sustainable Energy Resources. The use of renewable resources, such as biomass, solar, wind, and hydroelectric energy, continues to expand in Maryland. The associated generating technologies have generally fewer environmental impacts, particularly from an air quality perspective, than conventional power plants that burn fossil fuels and can diversify Maryland's fuel mix. Each has its own set of potential drawbacks, including land requirements, cumulative environmental impacts, and cost. Therefore, as with any new generating facility, project proposals must be carefully evaluated. The contribution of renewable energy sources to Maryland's overall electricity generation mix is currently quite small; however, legislation is in place that requires electricity suppliers in Maryland to obtain an increasing percentage of their power from renewable sources. [More information on pages 19 and 169]

Key Technical Issues Addressed by PPRP 1971 - 2011

1971

Power Plant Siting Act was passed by the Maryland legislature in 1971 to address potential effects on the Chesapeake Bay from the Calvert Cliffs Nuclear Power Plant. PPRP was created to ensure a comprehensive, objective evaluation, based on sound science, to resolve environmental and economic issues associated with building additional power generating facilities.

1975

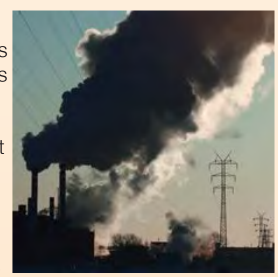
Aquatic impacts of power plants were identified due to entraining fish eggs, larvae, and/or prey organisms into their cooling systems, impinging adult and juvenile fish and crabs on intake screens, and discharging heat and chemicals into receiving waters. PPRP began testing intake designs that discourage fish congregation and determined in 1988 that impingement and entrainment could be reduced to acceptable levels, not adversely affecting aquatic biota in Maryland's surface water bodies. PPRP later evaluated methods such as barrier nets and wedge-wire screens that have become widely used for reducing impingement and entrainment levels at power plants.

1975

PPRP established its radioecology laboratory and initiated radiological assessment of Calvert Cliffs Nuclear Power Plant. In the aftermath of the Three Mile Island accident in 1979, the U.S. Nuclear Regulatory Commission requested PPRP's assistance in evaluating impacts to human health and the environment from radioactivity released during the event and its cleanup. The ongoing monitoring program expanded to cover Peach Bottom Atomic Power Station in Pennsylvania, just upstream from Conowingo on the Susquehanna River, in 1981. Over the past 30 years, the radioecology program has developed a valuable long-term database of radionuclide fate and transport throughout the Bay ecosystem.

1978

Clean Air Act Amendments of 1977 included provisions for the Prevention of Significant Deterioration (PSD) and non-attainment areas. PPRP recommended forming a policy board, establishing an offset bank exchange, and creating a multi-state planning council to share information and resolve disputes between states. On an ongoing basis, continuing with the Clean Air Act Amendments of 1990 and Maryland's Healthy Air Act of 2006, PPRP has analyzed compliance alternatives for the state's power plants and helped provide State agencies and lawmakers with technical background to support policy decisions.



1970s

1982

Coal-fired power plant operations create large quantities of solid combustion products, primarily fly ash, which need to be managed. While reuse is desired, some quantity of waste must be landfilled. PPRP conducted the first survey of CCB management methods across the state, a landmark first step in developing a thorough technical basis for evaluating, minimizing, and mitigating potential adverse impacts.

1984

Sulfur and nitrogen emissions generated by power plants were identified as a large contributor to the formation of acid rain in the Northeast and Maryland. PPRP funded significant research to determine the extent of the problem and to identify remedial actions.

1985

Aquatic impacts such as denied access of anadromous fish to upstream spawning areas were observed at main stem Susquehanna hydroelectric dams. As the State lead, PPRP worked with Pennsylvania agencies, federal agencies, and private intervenors to address both fish passage and water quality in the federal relicensing of Conowingo and other dams on the Susquehanna. The first fish passage facility on the Susquehanna began operating in 1985. Over the subsequent 15 years, an additional stretch of more than 400 miles of the river is now open to migratory fish as a result of these settlement agreements.

1992

As an outcome of PPRP's evaluation of aquatic impacts from large-volume water withdrawals at all of Maryland's power plants, BGE and PEPCO were required to conduct additional studies on long-term impacts at the Calvert Cliffs, Chalk Point, Dickerson, and Wagner power plants. In addition, PEPCO established a fish hatchery operation on the Patuxent River estuary. From 1992 to 1997, the hatchery produced 3.5 million juvenile striped bass and 750,000 shad to mitigate losses caused by the power plant's intake of cooling water. PEPCO also provided the State with $100,000 per year for five years to fund environmental education and support projects to remove passage obstructions for anadromous fish.

Source: Richard Clark, Exelon

1993

The effects of electromagnetic fields (EMFs) associated with generating, transmitting, distributing, and using electric power were evaluated and studies revealed conflicting results. PPRP reviewed all EMF studies and provided annual summary reports to the PSC on significant findings. Utilities constructing transmission lines have agreed to protocols for EMF measurements as well as utilization of conductor configurations resulting in the lowest EMF field strengths.

1980s and 1990s

1995

PPRP and MDE Bureau of Mines initiated an extensive program to address the problems of acid mine drainage as well as disposal of coal combustion by-products. The Winding Ridge project demonstrated the feasibility of using 100 percent waste products — fly ash plus by-product from sulfur dioxide removal — to seal an abandoned underground mine and minimize acidic discharges to surface water ecosystems.

1996

PPRP joined the Maryland Geological Survey and the U.S. Geological Survey in operating ground water monitoring programs to track water levels in affected aquifers over time, in response to increasing public awareness of ground water withdrawal by Maryland power plants from several coastal aquifers.

1997

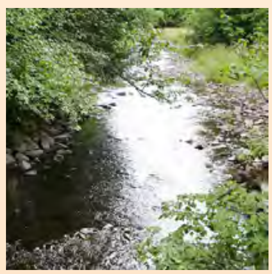
As part of the CPCN licensing process, Panda Energy agreed to use treated effluent from the Mattawoman Wastewater Treatment Facility as a source of 1.5 million gallons per day of cooling water at its combined cycle plant in Brandywine. This approach, the first use of treated effluent for power plant cooling water in the state, conserves groundwater sources in Southern Maryland, and has helped generate operational data for other Maryland power plant proposals.

1999

In response to water quality concerns in Maryland streams, apparently linked to agricultural runoff and the overuse of poultry litter as fertilizer, PPRP evaluated the suitability of using poultry litter as fuel. Three alternative technologies were identified that could accommodate the use of litter as a fuel: direct combustion, fluidized bed combustion, and gasification.

2000

The Maryland legislature introduced electricity competition. PPRP studied the potential environmental and economic impacts of restructuring and, over the next few years, observed that low utility rate freezes were limiting the development of a competitive retail market in Maryland.



2001

Through the CPCN licensing review process, Old Dominion Electric Cooperative agreed to support stream buffer restoration efforts, mitigating the effects of nitrogen deposition from the proposed Rock Springs power plant.

1990s and 2000s

2006

Maryland passed the Healthy Air Act, a comprehensive regulatory program to reduce emissions and improve air quality in the state and the region. During 2006-07, PPRP completed expedited licensing reviews of substantial emission control projects at Maryland's coal-fired plants.

2010

Maryland's first wind turbines came online - the Criterion and Roth Rock projects, both located along the western Maryland ridgeline known as Backbone Mountain. PPRP took an active role in reviewing plans for both these facilities, especially the potential for adverse impacts to bird and bat populations in the vicinity of these two sites.

2008 and ongoing

Increasing concerns about the long-term reliability of the electricity supply in the state and surrounding region have led to several proposals for transmission line projects. These include two major interstate transmission lines that would traverse parts of Maryland and numerous new or upgraded transmission lines located within the state. PPRP has been actively involved in evaluating potential environmental and socioeconomic impacts of these proposed linear facilities.

2010

Governor Martin O'Malley directed PPRP to prepare a comprehensive report evaluating approaches to meet Maryland's long-term electricity needs. PPRP conducted a thorough assessment under an array of alternative future economic, legislative, and market conditions, considering such variables as natural gas prices and climate change impacts (among many others). A final report was submitted to the Governor, the PSC, and the General Assembly in December 2011.

2009

Maryland's Public Service Commission granted a CPCN to UniStar for the construction of Calvert Cliffs Unit 3, a 1,600-MW nuclear power plant at the existing Calvert Cliffs site. PPRP coordinated the State's review of all relevant environmental and socioeconomic issues, and assisted the U.S. Nuclear Regulatory Commission in its ongoing evaluation as well. If UniStar ultimately receives federal approval and succeeds in commissioning Unit 3, it will likely be the first new nuclear facility constructed in the U.S. in 30 years.

2011

PPRP coordinated the State's review of Maryland Solar's proposed 20-MW project in Hagerstown. The PSC granted a CPCN for this project, the first utility-scale solar electrical generating facility in the state. The project is located on approximately 250 acres of State-owned land at the Maryland Correctional Institution. Maryland's aggressive goal of supplying 2 percent of the state's electricity from solar resources by 2022 has spurred increased interest in utility-scale solar energy.

MARYLAND DEPARTMENT OF NATURAL RESOURCES

2000s and Beyond

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Chapter 2 – Power Generation, Transmission, and Use

Electricity is often called wonderful, beautiful; but it is so only in common with the other forces of nature. The beauty of electricity or of any other force is not that the power is mysterious, and unexpected, touching every sense at unawares in turn, but that it is under law, and that the taught intellect can even govern it largely.

– Michael Faraday

Notes for a Friday Discourse at the Royal Institution (1858)

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 end usage.

2.1 Electricity Generation in Maryland

Currently in Maryland, 40 power plants with generation capacities greater than 2 megawatts (MW)[2] are interconnected to the regional transmission grid. The individual power plant sites are listed in Table 2-1 and locations are shown in Figure 2-1. In aggregate, Maryland power plants represent over 13,500 MW of operational capacity. The largest portion of Maryland's generating capacity comes from fossil fuel (see Figure 2-2), with the remainder attributed to nuclear and renewables.

2.1.1 Fossil Fuels

Fossil fuel-fired power plants comprise approximately 80 percent of Maryland's total installed capacity. The primary fuel used for electricity production in Maryland is coal.

Coal

In 2010, Maryland consumed over 9.7 million short tons of coal for electricity generation, which was an increase of nearly 31 percent compared to 2009. Also in 2010, only one — Warrior Run — of the eight coal-fired power plants in Maryland primarily used coal mined within the state. A portion of the coal burned at the R. Paul Smith plant (approximately 16 percent in 2010) was also sourced from mines within the state. Most Maryland power plants cannot efficiently burn coal mined in the state because they were designed for coal with higher volatility characteristics. Based on 2010 data, 77 percent of the coal burned in Maryland plants was mined in the Appalachia region of the U.S. Table 2-2 lists the amount of coal purchased at each power plant in 2010 and its location of origin.

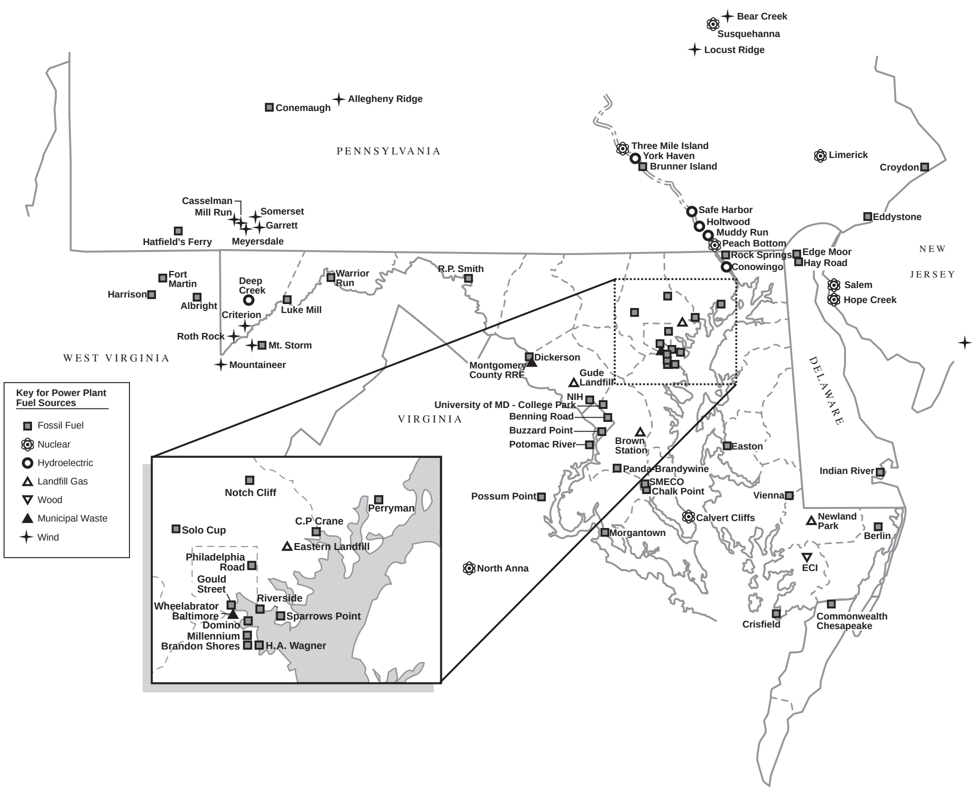
[2] 2 MW is equal to 2 million watts, enough power to meet the simultaneous peak demand of about 500 homes.

Table 2-1 Operational Generating Capacity in Maryland (>2 MW)

Owner	Plant Name	Fuel Type	Nameplate Capacity (MW)
INDEPENDENT POWER PRODUCERS			
AES Enterprise	Warrior Run	Coal	229
Allegheny Energy Supply	R. Paul Smith	Coal	110
Brookfield Renewable Power, Inc.	Deep Creek	Hydroelectric	20
Calpine Corporation	Crisfield	Oil	10
Constellation Generation Group[a]	Brandon Shores Calvert Cliffs[b] C.P. Crane Criterion Wind Park Gould Street Notch Cliff Perryman Philadelphia Road Riverside H.A. Wagner	Coal Nuclear Coal Wind Natural Gas Natural Gas Oil/Natural Gas Oil Oil/Natural Gas Coal/Oil/Natural Gas	1,370 1,829 416 70 104 144 404 83 244 1,059
Eastern Landfill Gas	Eastern Landfill	Landfill Gas	3
Exelon Generation Company	Conowingo	Hydroelectric	572
INGENCO	Newland Park Landfill	Landfill Gas	3
GenOn Energy	Chalk Point Dickerson Morgantown	Coal/Oil/Natural Gas Coal/Oil/Natural Gas Coal/Oil	2,563 930 1,548
Montgomery Country	Resource Recovery Facility (RRF)	Waste	68
Northeast Maryland Waste Disposal Authority	Gude & Oaks Landfills	Landfill Gas	3
NRG Energy	Vienna	Oil	183
Panda Energy	Brandywine	Natural Gas	289
Pepco Energy Services	National Institutes of Health	Natural Gas	23
Prince George's County	Brown Station Road	Landfill Gas	6
Gestamp Wind	Roth Rock Wind Facility	Wind	50
Suez Energy North America	Millennium Hawkins Point University of Maryland – College Park	Oil/Natural Gas Oil/Natural Gas	11 27
Wheelabrator Technologies	Wheelabrator Incinerator (formerly BRESCO)	Waste	65
PUBLICLY OWNED ELECTRIC COMPANIES			
Berlin	Berlin	Oil	9
Easton Utilities	Easton	Oil/Biodiesel	69
Old Dominion Electric Cooperative	Rock Springs	Natural Gas	770
Southern Maryland Electric Cooperative (SMECO)	Chalk Point Turbine	Natural Gas	84
SELF-GENERATORS			
American Sugar Refining Co.	Domino Sugar	Oil/Natural Gas	18
Maryland Department of Public Safety and Corrections	Eastern Correctional Institution (ECI) Cogeneration Facility	Wood	4
OAO Severstal	Sparrows Point	Natural Gas/Blast Furnace Gas	120
New Page	Luke Mill	Coal	65
Solo Cup	Solo Cup – Owings Mills	Natural Gas	11
Total			13,586

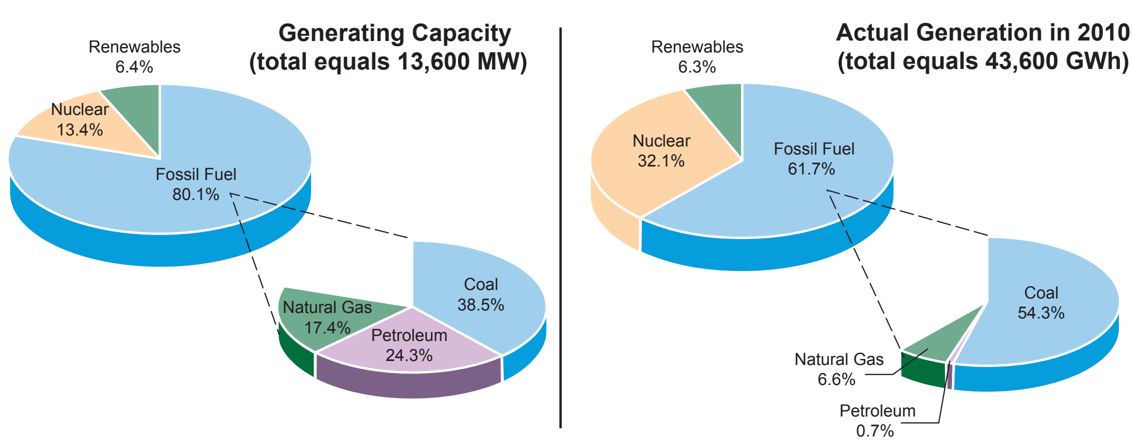
[a] Constellation Energy Group has made application to the Maryland Public Service Commission, seeking to merge with Exelon Corporation.
[b] Through a joint venture with Électricité de France (EDF) called Constellation Nuclear Energy Group, Constellation owns 50 percent of the Calvert Cliffs nuclear facility.

Figure 2-1 Power Plant Locations In and Around Maryland



In March 2011, Constellation Energy completed a conversion project at its C.P. Crane power plant allowing it to burn up to 100 percent sub-bituminous coal. Going forward, compliance with the Maryland Healthy Air Act (HAA) regulations will likely include the increased use of sub-bituminous coal, largely from the Powder River Basin in Wyoming and Montana, which typically has a lower sulfur content than bituminous coal. In addition, sub-bituminous coals generally have higher

Figure 2-2 Power Plant Capacity and Generation in Maryland by Fuel Category



Source: U.S. Energy Information Administration, 2011.

moisture and volatile matter contents and a lower heating value, most often expressed in million British Thermal Units (MMBtu) per pound, than bituminous coal. According to 2010 data from the U.S. Energy Information Agency (EIA), bituminous coals sold for an average of $60.88/short ton in the U.S. compared to $14.11/short ton for sub-bituminous coals.

Table 2-2 Tons of Coal Purchased at Maryland Power Plants in 2010

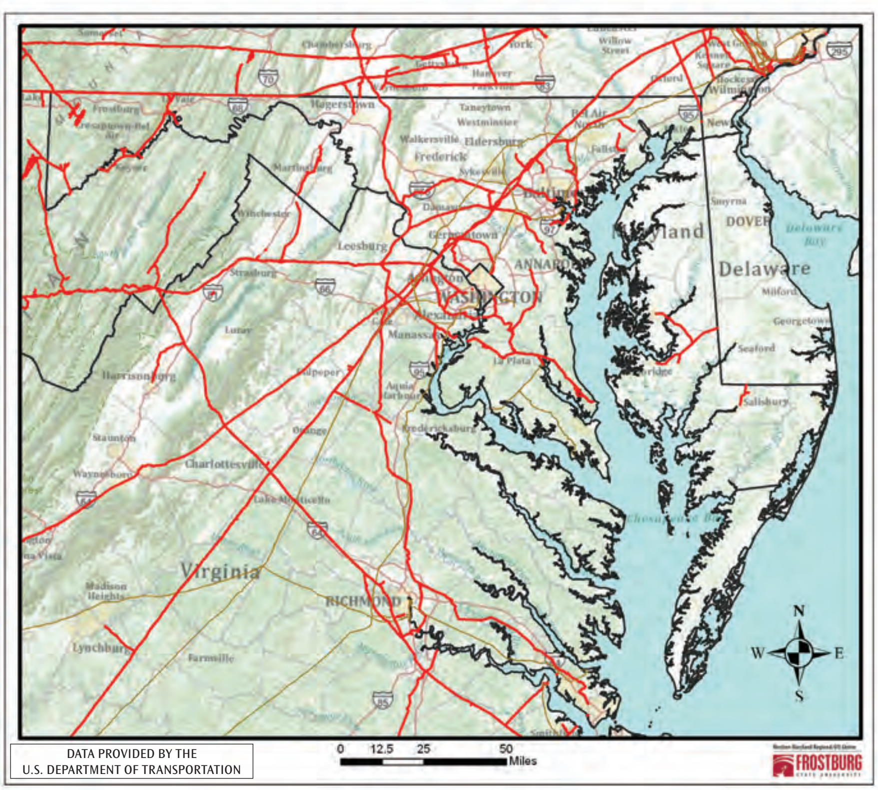
Origin of Coal	Brandon Shores	H.A. Wagner	C.P. Crane	Dickerson[a]	Chalk Point[a]	Morgantown	Warrior Run	R. Paul Smith	Total By Source	% By Source
Appalachia	2,430,409	691,851	98,524	536,696	727,822	2,279,833	669,869	130,344	7,565,348	77.4%
Powder River Basin	---	---	394,094	---	---	---	---	---	394,094	4.0%
South America	306,538	19,781	---	536,696	727,822	220,686	---	---	1,811,523	18.5%
Total Coal by Plant	2,736,947	711,632	492,618	1,073,392	1,455,643	2,632,198	669,869	130,344	9,770,964	100.0%

[a] Utility company provided total coal burned, but did not provide a breakdown by source; therefore, it was assumed that equivalent amounts of coal were received from each source.

Natural Gas

In 2010, approximately 15.7 billion cubic feet of natural gas was used for electricity generation in Maryland, representing 9.1 percent of total state-wide consumption for all uses. Currently, Maryland receives bulk natural gas from several pipelines that traverse the state (see Figure 2-3). 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 our region (which includes Maryland, New Jersey, Pennsylvania, Virginia, and West Virginia). Other potentially suitable storage sites may also exist in Western Maryland.

Figure 2-3 Interstate Natural Gas Pipelines in Maryland



Source: Western Maryland Regional GIS Center.

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 economic to recover until the development of horizontal drilling and hydraulic fracturing techniques in the 1990s. (See Chapter 5 for more information on shale gas.) Over the last five years, natural gas producers began adopting these techniques, resulting in a 19.5 percent increase in U.S. natural gas production from 2005 to 2010. Domestic natural gas consumption over the same period increased only 9 percent, resulting in decreased imports of natural gas via pipeline from Canada and decreased liquefied natural gas (LNG) imports, primarily from Trinidad and Tobago.

U.S. natural gas wellhead prices were in the range of $2.00 per thousand cubic feet throughout the 1990s, then started a steady increase, doubling to $4.00 by 2001 and reaching a high of $10.82 in mid-2008. Natural gas prices have been decreasing since June 2008 to an average of $4.16 in 2010 due to increased shale gas production and the economic slowdown. The LNG price is linked to that of crude oil, which has increased as domestic natural gas prices have declined. Export LNG prices climbed from $5.79 per thousand cubic feet in 2005 to $9.53 per thousand cubic feet in 2010.

Import volumes at the Cove Point LNG facility in Lusby, Maryland declined 67 percent between 2005 and 2009. Cove Point is one of nine LNG import facilities operating in the U.S. Plans for new or expanded LNG facilities in the U.S. have either been cancelled or modified for operation as LNG export facilities in response to high LNG export prices.

In September 2011, Dominion, which owns the Cove Point facility, filed the first phase of a two-phase export authorization request with DOE. Dominion is seeking permission to operate Cove Point as a bi-directional facility whereby they can also liquefy natural gas and then export the LNG. The increased natural gas production from the shale formations has producers looking for ways to get the natural gas to international markets. According to the application, Dominion is proposing to export up to 1 billion cubic feet per day over a 25-year period, starting in 2016. In addition to DOE authorization, Dominion will also need to seek environmental and regulatory approvals from the Federal Energy Regulatory Commission (FERC), as well as applicable State and local approvals.

In January 2009, FERC approved the proposed AES Sparrows Point LNG Terminal and Mid-Atlantic Express Pipeline project. The project would include an estimated 17 million cubic feet of LNG storage at the terminal, and the ability to vaporize and inject approximately 1.5 billion cubic feet per day of natural gas into the Northeastern U.S. pipeline system. In April 2009, the Maryland Department of the Environment (MDE) denied the project's water quality certification (pursuant to § 401(a)(1) of the Clean Water Act), due to insufficient information about the project's affect on wetlands, waterways, and water quality. This decision was also upheld in the U.S. Court of Appeals, Fourth Circuit in December 2009, thereby preventing construction from beginning. In February 2011, AES Sparrows Point provided to the State correspondence, which described potentially redefining the project to focus only on the Mid-Atlantic

Express pipeline and possibly a gas-fired power plant. No formal application has yet been submitted.

Petroleum

A small amount of electricity — approximately 1 percent of the state's total — is generated by combusting distillate or residual fuel oil. According to the U.S. EIA, fuel oil consumption for electric power in Maryland totaled 26.5 million gallons in 2009, or about 3 percent of state-wide consumption for all uses. 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. GenOn Energy, formerly Mirant Corporation, also obtains fuel oil for its Chalk Point and Morgantown power plants through its Piney Point terminal in St. Mary's County.

2.1.2 Nuclear

Maryland is home to one nuclear power facility, Constellation Energy Nuclear Group'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 approximately 13 percent of the state's total electricity generation capacity and accounted for about one-third of the state's total generation in 2010. UniStar Nuclear, owned by Électricité de France (EDF), a large, European-based energy company, has received a Certificate of Public Convenience and Necessity (CPCN) from the Maryland Public Service Commission (PSC) and has applied for a license from NRC to add a third unit at the Calvert Cliffs site (see Section 2.4.1).

2.1.3 Distributed Generation

Distributed generation (DG) is defined as generating resources located close to or on the same site as the facility using the power. This includes both facilities that are not grid-connected, and those that are grid-connected to allow the sale of electricity in excess of on-site requirements. On-site generators with capacity less than 373 kilowatts (kW) are not required to apply to the PSC for a CPCN. In addition, certain generators 373 kW through 70 MW in capacity are eligible to seek a CPCN exemption:

- *Facilities with a capacity of less than 70 MW, consuming at least 80 percent of the electrical output on-site; and*
- *Facilities less than 25 MW in capacity, consuming at least 10 percent of the electrical output on-site.*

The Maryland PSC requires those seeking a CPCN exemption to identify their facility as one of four specific types:

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

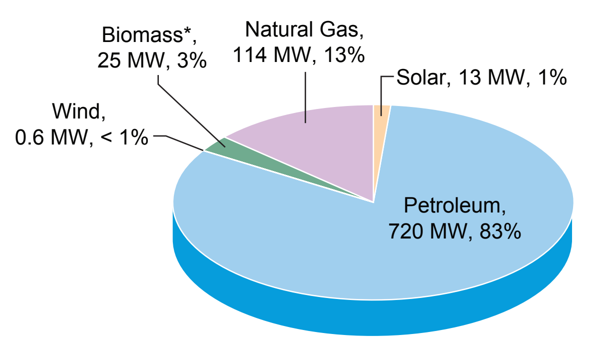
It is difficult to accurately estimate the total amount of DG in Maryland, as systems smaller than 373 kW are not required to obtain a CPCN exemption. The vast majority of solar DG systems fall into this category.

As of the end of 2010, about 1,100 MW of generation capacity had been granted CPCN exemptions in Maryland. This figure, however, included only 2.3 MW of solar capacity. According to the PSC report on net metering (see Chapter 5 for a detailed discussion on net metering), by the end of 2009 almost 13 MW of solar DG had been installed in Maryland under net metering arrangements. Additionally, wind facilities up to 70 MW can apply for CPCN exemptions and the 1,100 MW of CPCN-exempted projects included three utility-scale (non-DG) wind facilities totaling 190 MW of capacity. According to the net metering report, as of the end of 2009, approximately 600 kW of small DG wind capacity was installed in Maryland.

According to the Maryland PSC, approximately 82 percent of the CPCN exemptions granted to non-solar and non-wind generators through the end of 2009 were for Type I units; therefore, the vast majority of non-solar and non-wind DG installations in Maryland are not grid-connected. Instead, DG units are used to provide emergency back-up 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 DGs (see Figure 2-4) is mostly fossil-fueled consistent with their use as back-up generators. An increasing, but still small, share of this capacity is solar, which is predominantly grid-tied for purposes of net-metering and generating renewable energy credits for sale or trade.

Generally, the amount of DG should grow along with general load growth as new large facilities with essential back-up needs install generators. The solar energy requirement in the Maryland Renewable Portfolio Standard (RPS) will also continue to add distributed solar generation to the Maryland grid.

Figure 2-4 Distributed Generation Fuel Type (as of October 2010)



*Biomass includes digester and landfill gas units

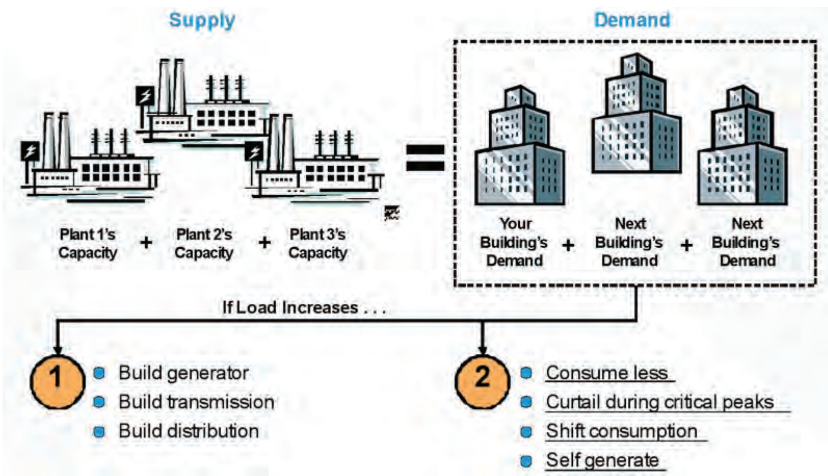
Source: Maryland PSC.

2.1.4 Demand Response

Demand response (DR) is a rapidly growing element of the State's resource mix. Demand response in the PJM Interconnection, LLC (PJM) is utilized as a supply resource in the same way generators are. PJM runs several DR programs that compensate customers for reducing their load. PJM members that act as demand response providers are called curtailment service providers (CSP). 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).

What is Demand Response?

Grid operators must meet peak demand reliably with all available resources. Enabling the demand side of the equation optimizes resources.



Demand response resources with adequate response times (i.e., within 10 minutes) can also bid into the PJM's synchronized (spinning) reserve market, allowing PJM to utilize demand-side resources to respond to unexpected generator outages or other system contingencies.

From 2007 to 2011, participation of demand response resources in PJM programs grew by an annual average of about 50 percent. As of July 2011, the following demand response resources were available:

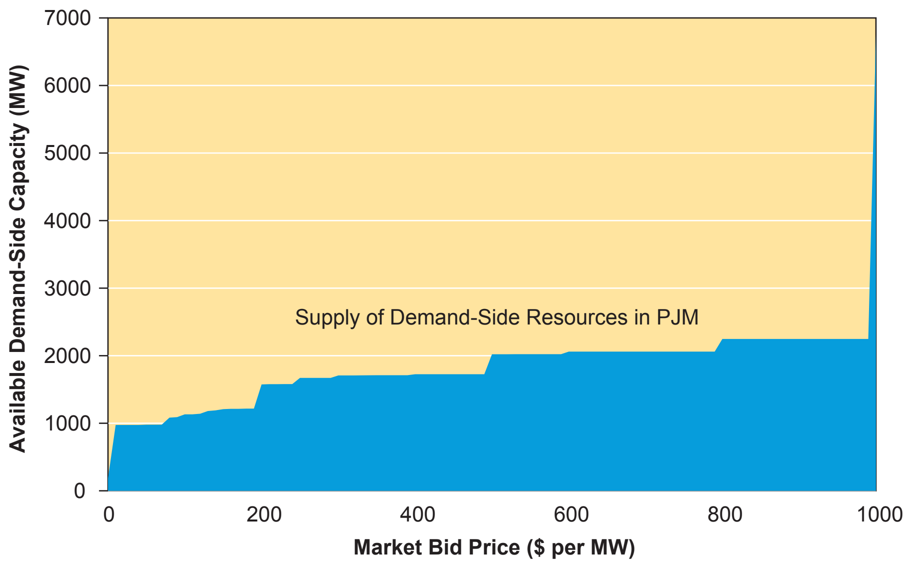
- *1,782 MW of economic (price-dependent) demand response; and*
- *11,822 MW of demand response and Interruptible Load which can only be curtailed under emergency conditions as defined by PJM.*

As the present statistics indicate, the vast majority of PJM curtailment resources are emergency-only (11,822 MW emergency versus 1,782 MW economic). However, available PJM bid data indicates that over half of emergency demand response capacity is willing to engage in economic curtailments when wholesale prices are more than $200 per MWh in the spot market. Figure 2-5 presents a snapshot of demand-side management bids from an unspecified day in June 2010, demonstrating the price levels at which various CSPs and DR providers are willing to engage in curtailments.

PJM is seeking FERC approval to create a new market product—"Price Responsive Demand" (PRD). PRD would apply 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 5.6.1 for a description of AMI).

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. As smart grid technologies mature, much of these PRD reductions would be automatically controlled as residential systems respond to price signals automatically based on the independent preferences and rules set by thousands of homeowners and businesses. More information on demand response and smart grid technologies are included in Section 5.1.3 and Section 5.6, respectively.

Figure 2-5 Curtailment Price Levels



Source: PJM DR database, http://www.pjm.com/pub/extdataposting/demand-response-bid data/201006XX_dsr_bid.csv

2.1.5 *Renewable Resources*

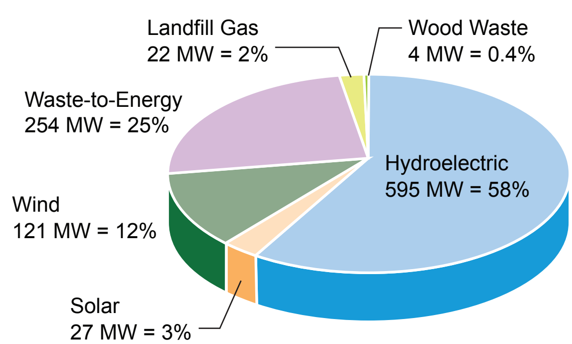
Presently, there are four main types of renewable energy resources in use in Maryland: wind, biomass, solar, and hydropower. Approximately 1,000 MW of generation capacity in Maryland comes from these resources, with hydroelectric accounting for the largest share (see Figure 2-6).

Wind Power

In Maryland, the best wind resources are located in the western-most counties and off of the Atlantic Coast on the Outer Continental Shelf. To date, no offshore wind facilities have been constructed in the United States; however, about 40 gigawatts (GW) of utility-scale wind capacity is in operation using land-based resources in the United States.

The conversion of wind power to electricity is typically accomplished by constructing an array of wind turbines in a suitable location. Utility-scale wind projects range in size from just a few turbines to hundreds of turbines, depending on the location and scope of the project, among other things. Wind turbines range in size from 20-watt micro-turbines (used for small-scale residential or

Figure 2-6 Installed Renewable Energy Capacity in Maryland as of September 2011



Note: Figure does not include black liquor, a biomass-based by-product of the pulp and paper industry that is co-fired with coal at the New Page facility in Luke, Maryland. Capacity values may not add up to 100 percent due to independent rounding.

Wind Turbine Wake Effect

It is well known that when wind turbines are deployed in large arrays, overall efficiency decreases due to the complex interactions between the wind and the turbines. With large arrays of wind turbines, where many turbines are clustered together, turbulence generated by the massive blades can degrade the performance of other windmills by as much as 10 to 30 percent. There is a growing body of research aimed at optimizing the distance between turbines to provide the highest efficiency. Interestingly, research has shown that the smooth ocean surface does not attenuate the wakes as much as rougher land surfaces, causing these efficiency losses to be greater at offshore wind facilities unless accounted for in turbine spacing and location.

institutional applications) to new 10-MW prototypes, with manufacturers now researching the possibility of 20-MW turbines for offshore facilities. Utility-scale wind turbines typically have a rated capacity between 1.5 and 3 MW.

The U.S. Department of Energy's (DOE) National Renewable Energy Laboratory (NREL) estimates that the United States may have an onshore wind resource capacity in excess of 10,000 GW.[3] Maryland is estimated to have an onshore wind resource capacity of approximately 1.5 GW.[4] Figure 2-7 illustrates the prospective onshore wind resource areas in Maryland.

As of early 2011, two wind plants, representing a total of 120 MW, were operational in Maryland. 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 plant 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.*

Such facilities will still be subject to any federal, State, and local approvals needed to address (among other things) erosion and sediment control, Federal Aviation Administration lighting requirements, and threatened and endangered species impacts.

In Garrett and Washington Counties, two regions with high levels of interest from wind developers, there are no zoning regulations regarding the development of commercial-scale wind turbines. Garrett County has minimal zoning rules, while Washington County only regulates the development of small wind energy systems (defined as 50 kW or less).

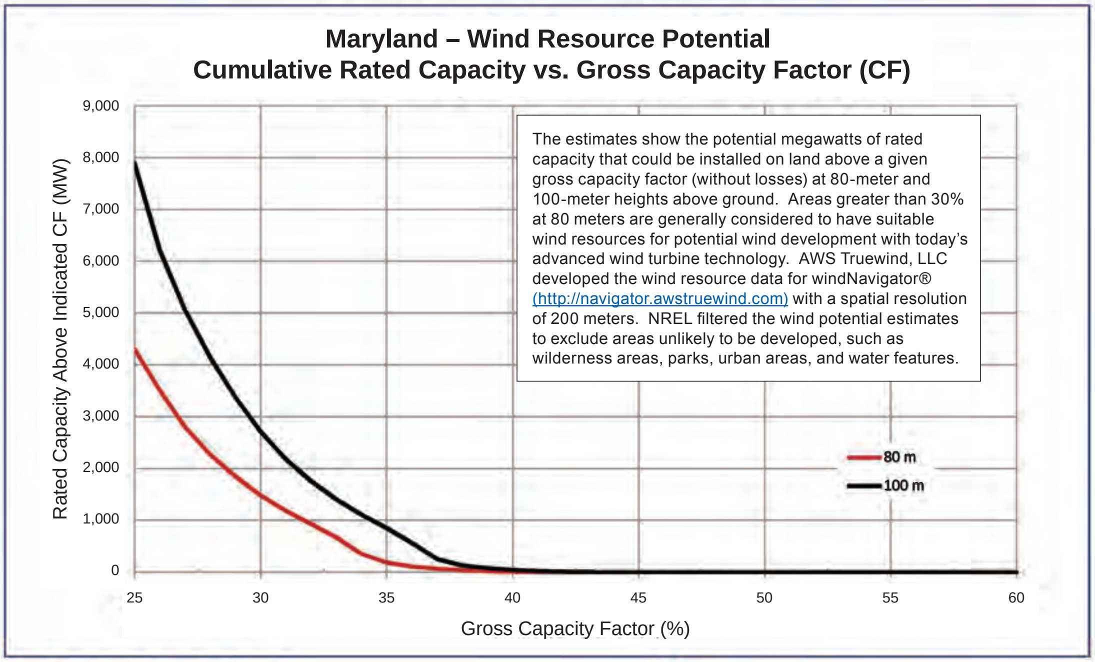
In May 2009, Allegany County implemented zoning regulations that place restrictions on the development of commercial-scale wind turbines. The rules specify setback requirements (according to turbine height) and minimum separation distances between wind turbines and any structures not owned by the developer. Note that if a commercial wind-powered generating facility is granted a CPCN by the PSC, the project may be constructed without regard to local zoning rule, regulation, law, or ordinances.

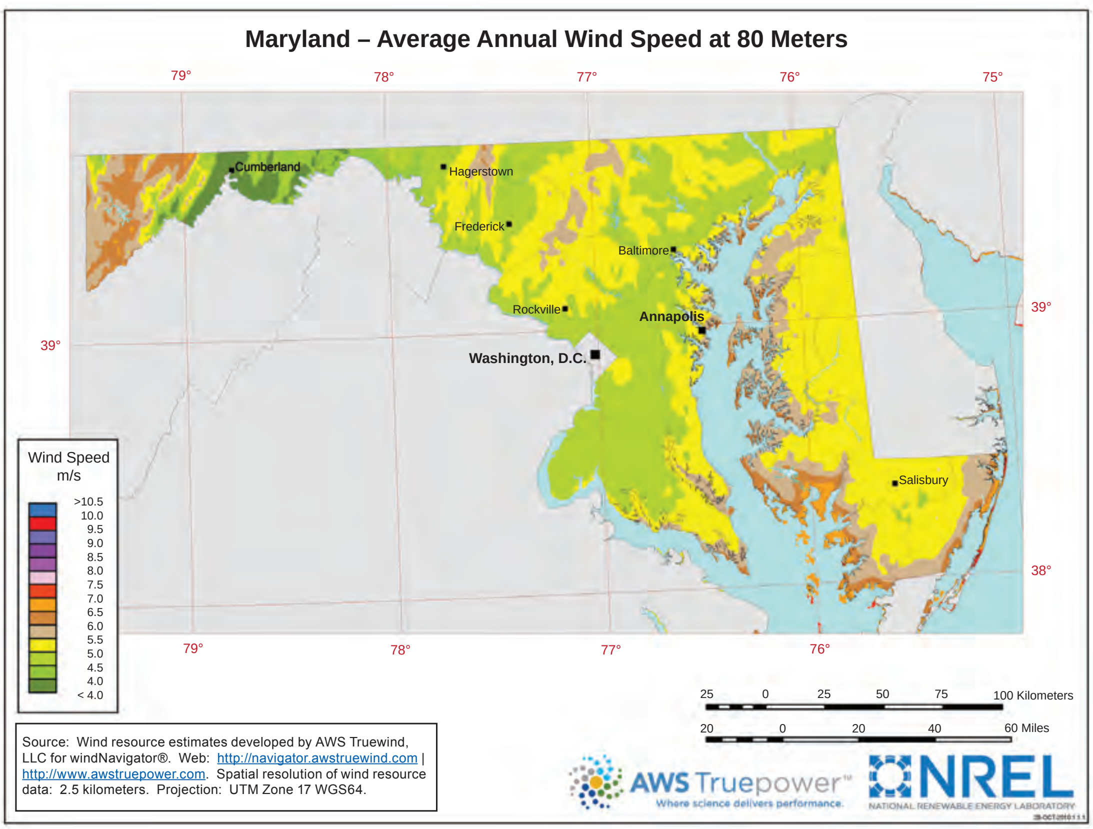
Onshore Wind Projects in Maryland

Table 2-3 shows the operating and proposed wind facilities in Maryland. The two operational wind power facilities — Criterion and Roth Rock — are located on the Backbone Mountain ridge line in western Maryland.

[3] National Renewable Energy Laboratory, Wind Powering America: 80-Meter Wind Maps and Wind Resource Potential (February 2010). http://www.windpoweringamerica.gov/wind_maps.asp.
[4] Ibid. This estimate is based on the amount of available windy land area in Maryland, assuming a height of 80 meters and 5 MW/km^2 of installed nameplate capacity.

Figure 2-7 Maryland Wind Resources





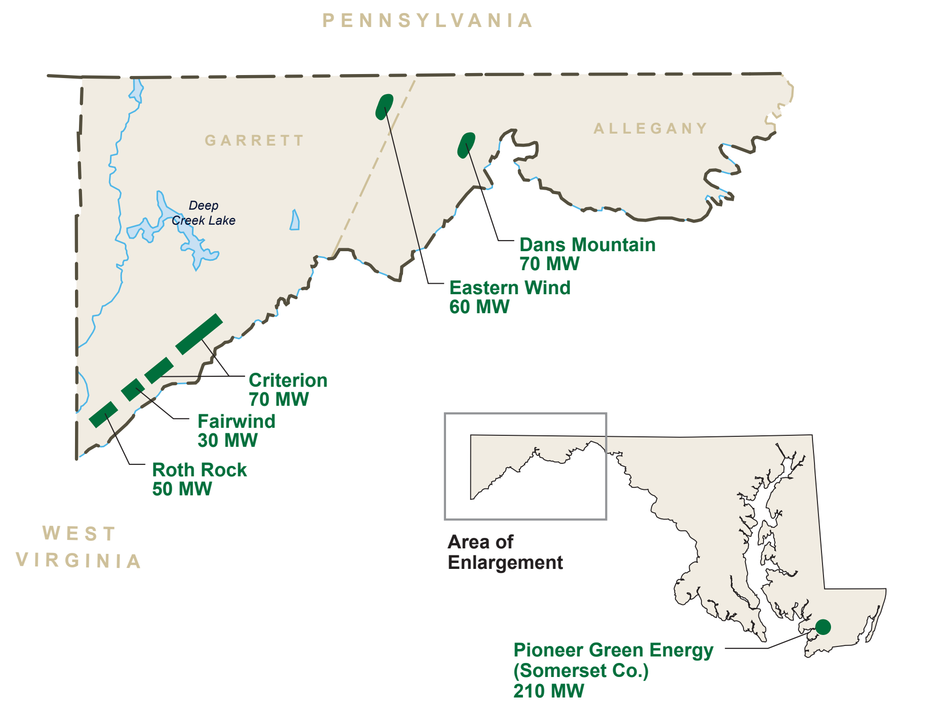
Their combined power capacity of 120 MW is estimated to represent less than 10 percent of Maryland's onshore wind resource potential. Four other projects, representing about 370 MW, are currently in the planning and development stages.

Table 2-3 Status of Onshore Wind Projects in Maryland

Project – Developer/Owner	Size (MW)	Location	Nearest Town	Status
Criterion – Constellation Energy	70	Backbone Mountain, Garrett County	Oakland	Operational
Roth Rock – Gestamp Wind	50	Backbone Mountain, Garrett County	Oakland	Operational
Eastern Wind – Synergics	60	Four-Mile Ridge, Garrett County	Frostburg	Proposed
Dans Mountain – US Wind Force	69.6	Dans Mountain, Allegany County	LaVale	CPCN exemption granted; delayed
Fairwind – Clipper Windpower	30	Backbone Mountain, Garrett County	Oakland	Proposed
Pioneer Green Energy	210	Somerset County	Princess Anne	Proposed

Originally developed by Clipper Windpower, the 70-MW Criterion Wind Project was acquired by Constellation Energy in April 2010. 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 late December 2010. Constellation Energy signed a 20-year power purchase agreement (PPA) with the Old Dominion Electric Cooperative for both energy and renewable energy credits (RECs) produced by the wind facility. The Criterion Wind Facility is expected to generate about 175,000 MWh on an annual basis.

Figure 2-8 Approximate Locations of Wind Energy Projects in Maryland



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, consists of

20 Nordex 2.5-MW turbines, and stretches approximately three and a half miles along a ridge near the West Virginia border. Synergics entered into a 20-year PPA with Delmarva Power and Light for both energy and RECs produced at the facility. The Roth Rock Wind Facility is expected to generate about 130,000 MWh per year.

In 2009, Synergics informed the PSC of its intent to file an application for a CPCN exemption for a 60-MW wind project in Garrett County. Known as the Eastern Wind Project, it would run roughly seven miles along Four Mile Ridge and Elbow Mountain, and would consist of about 25 turbines. To date, Synergics has not yet filed for a CPCN exemption.

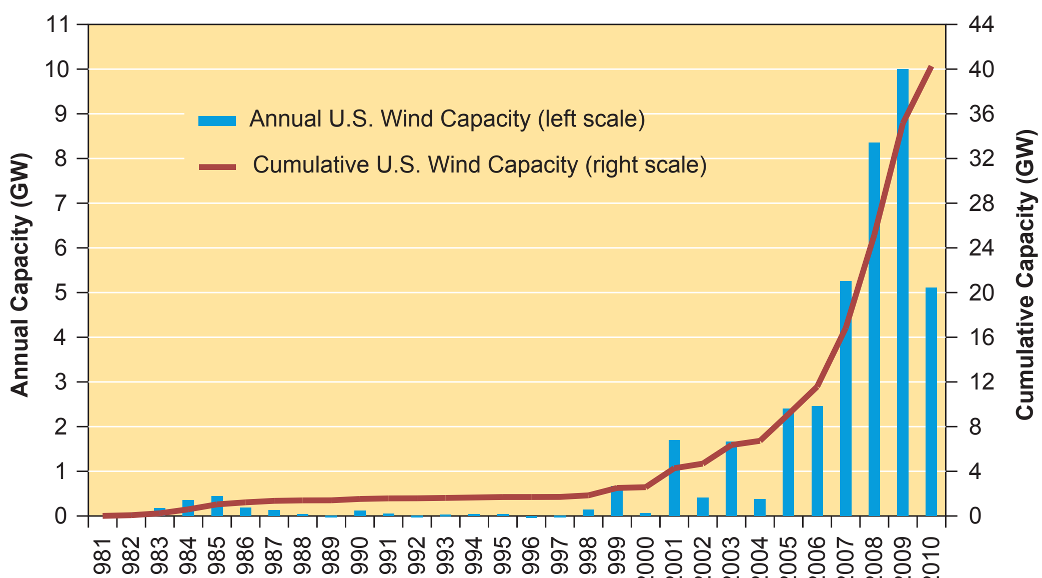
Dans Mountain is a 70-MW wind project in Allegany County that has been proposed by US Wind Force. The PSC granted US Wind Force a CPCN exemption for the Dans Mountain project in March 2009. US Wind Force delayed the project after Allegany County enacted revised zoning regulations in May 2009.

Clipper Windpower has proposed the 30-MW Fairwind Project, which would be located adjacent to the Criterion Wind Project. Pioneer Green

Growth of Wind Energy in the United States

The U.S. wind energy industry has experienced significant growth over the last decade. By the end of 2010, over 40,000 MW of wind energy capacity was online in the United States (compared to less than 3,000 MW by the end of 2000). The U.S. wind power industry grew by 15 percent in 2010, with approximately 5,116 MW of new wind energy installations. Moreover, land-based wind energy facilities have accounted for about 35 percent of all new generating capacity since 2007. As offshore wind facilities begin to come online, wind power will likely make up an even larger share of new capacity in the country.

Historically, wind energy has been supported by public policies such as the Production Tax Credit and RPS; however, the cost of wind energy is nearing cost-competitiveness with traditional energy sources. The EIA projects that, in 2016, the cost of producing electricity from a new wind facility in the windiest parts of America's midsection (e.g., in the Dakotas and Colorado) will be about equal to that from a new gas-fired power plant. Furthermore, as wind energy has no fuel cost, it is not subject to the price volatility associated with fossil fuels, making long term contract rates for wind energy more appealing. As such, we can expect the wind industry to continue to grow and become a significant contributor to the U.S. energy portfolio.



Source: Lawrence Berkeley National Laboratory, *2010 Wind Technologies Market Report* (June 2011).

Energy has proposed a wind power facility in Somerset County — the first proposed for the Eastern Shore of Maryland — which could have a capacity as large as 210 MW. Neither company has yet filed for either a CPCN or CPCN exemption.

Offshore Wind Resource Potential

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.[5] NREL estimates that Maryland alone has an unrestricted offshore wind power capacity in excess of 25 GW.[6] A report prepared by the University of Delaware suggests that after accounting for possible conflict areas, Maryland's wind resource potential is likely closer to 13 GW.[7] Currently, proposed offshore wind projects in all of the United States total about 5 GW. For more information about offshore wind plans in Maryland and along the Eastern seaboard, see Section 5.4.1.

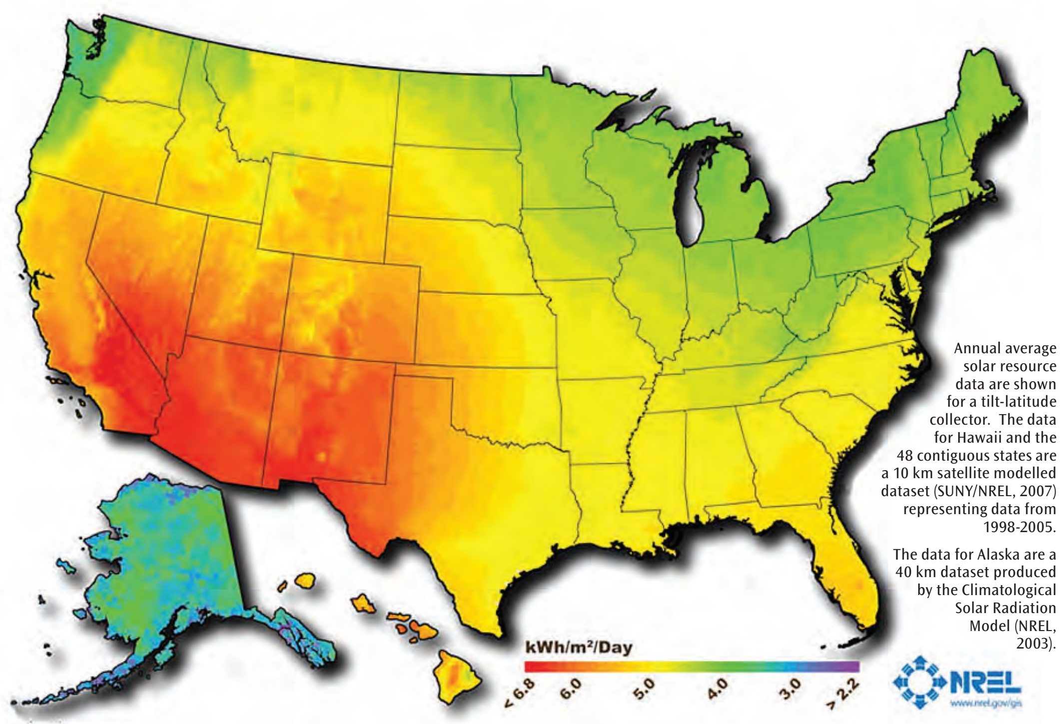
Solar

Maryland, by virtue of its more northern location, is only an average solar resource with moderate solar energy intensities as is illustrated in Figures 2-9a and 2-9b. 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 20 percent renewable energy by 2022, with two percent coming from solar energy sources. Utilities must self-generate or purchase solar generation energy credits or face penalties of up to $400 per MWh (declining through time), providing a financial incentive to homeowners, businesses, and independent developers to install solar renewable energy systems.

PJM tracks solar Renewable Energy Certificates (RECs) that are eligible for use in complying with the Maryland RPS. As of September 2011, 1,628 in-state solar projects representing 27 MW of solar power were registered with the PJM Generation Attribute Tracking System (GATS)[8] and producing RPS-eligible RECs. While most of the facilities are smaller than 10 kW, several larger systems have recently come on-line and several more large projects are in development. In October 2011, Maryland Solar, LLC, an Easton-based energy company, was granted a CPCN for a 20-MW solar photovoltaic facility. The project is planned to be built on State land surrounding the Maryland Correctional Institution outside of Hagerstown. Maryland Solar expects the facility to be producing energy by the end of 2012. Table 2-4 lists the GATS-registered solar facilities by system size.

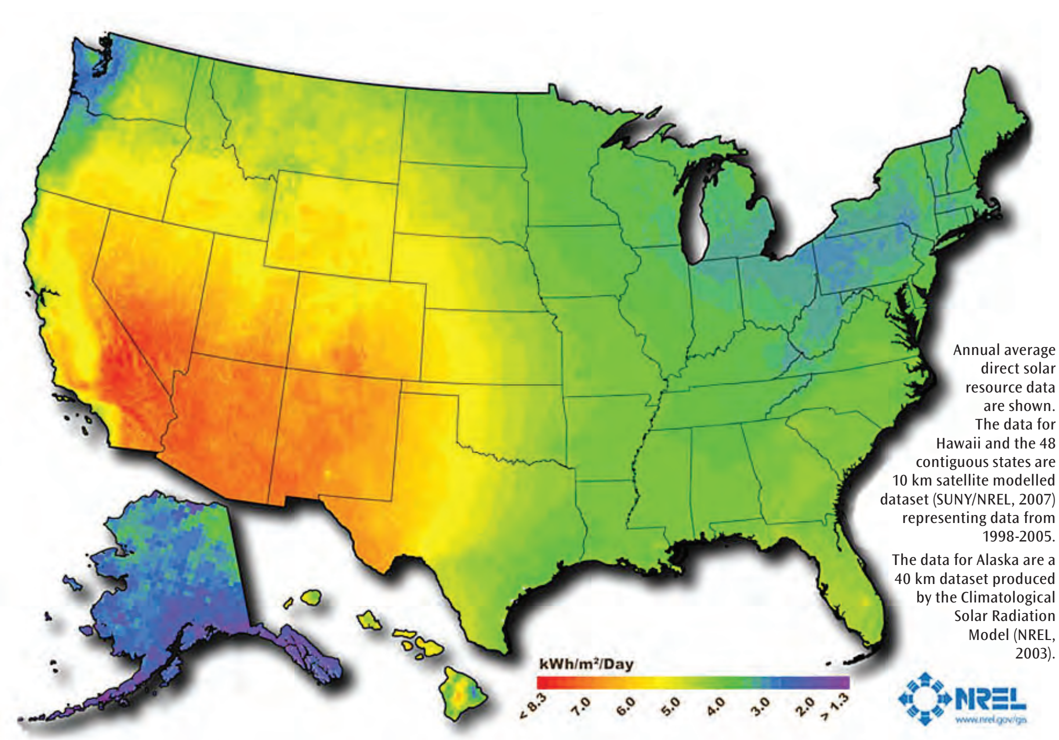
[5] U.S. Department of Energy, National Renewable Energy Laboratory. Large-Scale Offshore Wind Power in the United States (September 2010). http://www.nrel.gov/wind/pdfs/40745.pdf. No exclusions (e.g., shipping lanes and environmentally sensitive areas) were applied to these offshore wind resource estimates.
[6] Ibid. This estimate is assuming average wind speeds of 8.5 to 9 m/s, at a distance of 12 to 50 nautical miles from the shoreline, with no exclusions for shipping lanes or environmentally sensitive areas.
[7] Firestone, Jeremy, et al. Maryland's Offshore Wind Power Potential (February 2010) http://offshorewind.net/Other_Pages/Links%20Library/MarylandsOffshorewindPowerPotential-feb2010.pdf.
[8] 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.

Figure 2-9a Quality of Photovoltaic (PV) Resource



Author: Billy Roberts, October 20, 2008 This map was produced by the National Renewable Energy Laboratory for the U.S. Department of Energy.

Figure 2-9b Quality of Concentrated Solar Power (CSP) Resource



Author: Billy Roberts, October 20, 2008 This map was produced by the National Renewable Energy Laboratory for the U.S. Department of Energy.

Table 2-4 Maryland's Solar Facilities Listed in PJM GATS (as of September 2011)

System Size (kW)	Number of Projects	Total Capacity (MW)
0 to ≤ 3	284	0.6
> 3 to 6	736	3.3
> 6 to 10	406	3.1
> 10 to 50	146	2.2
> 50 to 100	13	0.9
> 100	43	17.2
Total	**1,628**	**27.3**

Source: PJM GATS

According to the GATS data, Maryland's solar RPS resources generated approximately 8,100 MWh of renewable electricity in 2010, representing approximately 0.02 percent of total in-state electricity generation. To meet the 2022 RPS goal, Maryland's RPS solar generation must grow by about 41 percent per year.

Similar to Maryland, New Jersey also provides strong policy support for solar technologies. New Jersey's 20 percent RPS requirement initially featured a 2.12 percent solar PV set-aside that has since been changed to a generation target at 5,316 GWh. At the end of 2010, New Jersey had 260 MW of installed solar capacity.[9]

The costs of solar PV installations have declined steadily through time, but during 2005 to 2009, costs remained stagnant despite widespread deployment in areas with high solar incentives such as California, New Jersey, Germany, and Spain (see Figure 2-10). Costs remained flat for a variety of reasons including supply/demand imbalances and materials price escalation among others. In 2010, solar PV system prices regained their downward trend with the national weighted-average system prices falling by 20.5 percent, from about $6.45/watt (W) to about $5.13/W. This was partly due to a shift toward larger utility-scale systems.[10]

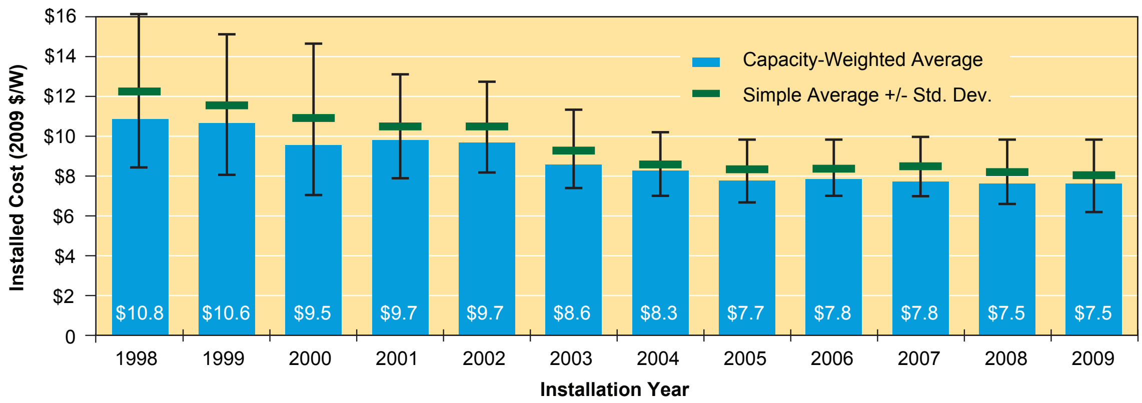
Certain incentive policies, like the Maryland and New Jersey renewable portfolio standards, have assumptions of declining PV prices built into the enforcement mechanisms. In the case of the RPS policies, the alternative compliance payment (ACP), which places a ceiling on solar REC costs, generally moves 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.

Solar Energy Facility at Mount St. Mary's University

Mount St. Mary's University and Constellation Energy have partnered to build one of the largest solar facilities on any private college campus in the United States. As part of the State of Maryland's Generating Clean Horizons initiative, Constellation Energy is developing a 17-MW direct current (DC) solar PV installation on land leased from Mount St. Mary's University in Emmitsburg, Maryland. In the agreement with Constellation, the University will lease 100 of its 1,400 acres on the east campus to house Maryland's first large-scale PV facility creating more than 22,000,000 kWh of emission-free, clean electricity.

[9] New Jersey Board of Public Utility, Clean Energy Program Report: http://www.njcleanenergy.com/renewable-energy/project-activity-reports/project-activity-reports
[10] Solar Energy Industry Association: http://www.seia.org/galleries/pdf/SMI-YIR-2010-ES.pdf

Figure 2-10 The Cost of Solar PV

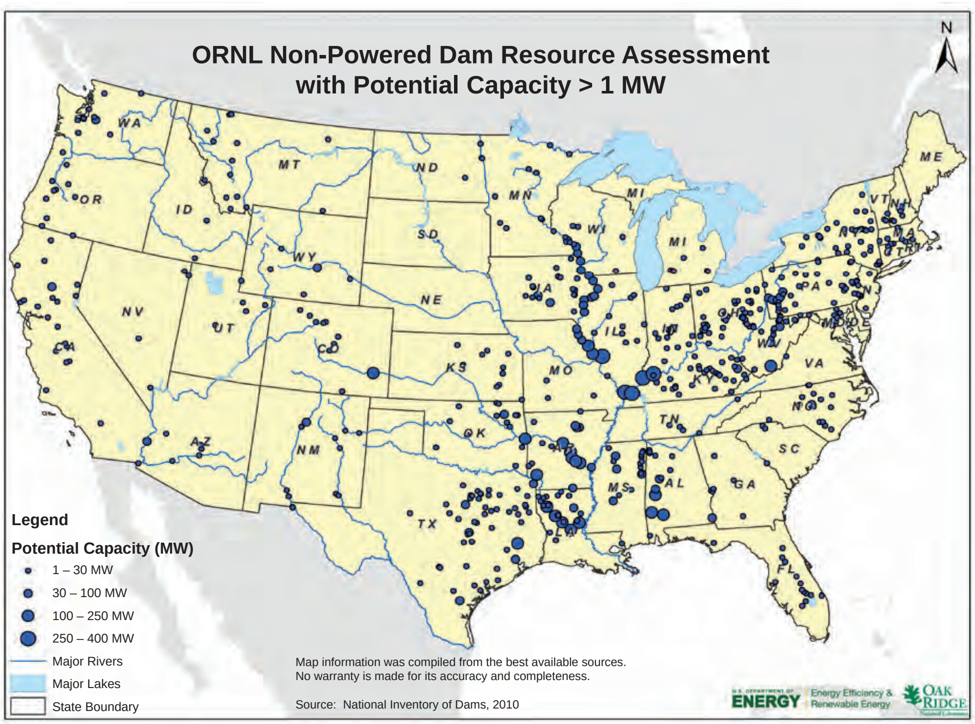


Source: Barbose, Galen, Naim Darghouth, and Ryan Wiser, "Tracking the Sun III: The Installed Costs of Photovoltaics in the U.S. from 1998-2009". Lawrence Berkeley National Laboratory, December, 2010.

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. Hydrokinetic energy refers to energy harnessed directly from moving water and includes run-of-river hydro, wave, tidal energy projects, and conduit hydro.

Hydroelectric Potential at Existing Dams in the United States



A report by the Department of Energy's Oak Ridge National Laboratory (ORNL) found that adding powerhouses to 54,000 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.

Source: National Hydropower Association. http://hydro.org/wp-content/uploads/2011/04/ORNL-Hydro-Factsheet-final.pdf

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. Pumped storage hydro uses off-peak energy to pump water up to an elevated reservoir, which is then later released to create electricity during peak hours.

Maryland has two large-scale (greater than 10 MW capacity) hydroelectric dam projects and five additional small-scale facilities. Maryland's hydroelectric plants are listed in Table 2-5 with locations shown in Figure 2-11. Chapter 4 includes further discussion about hydroelectricity and its potential impacts.

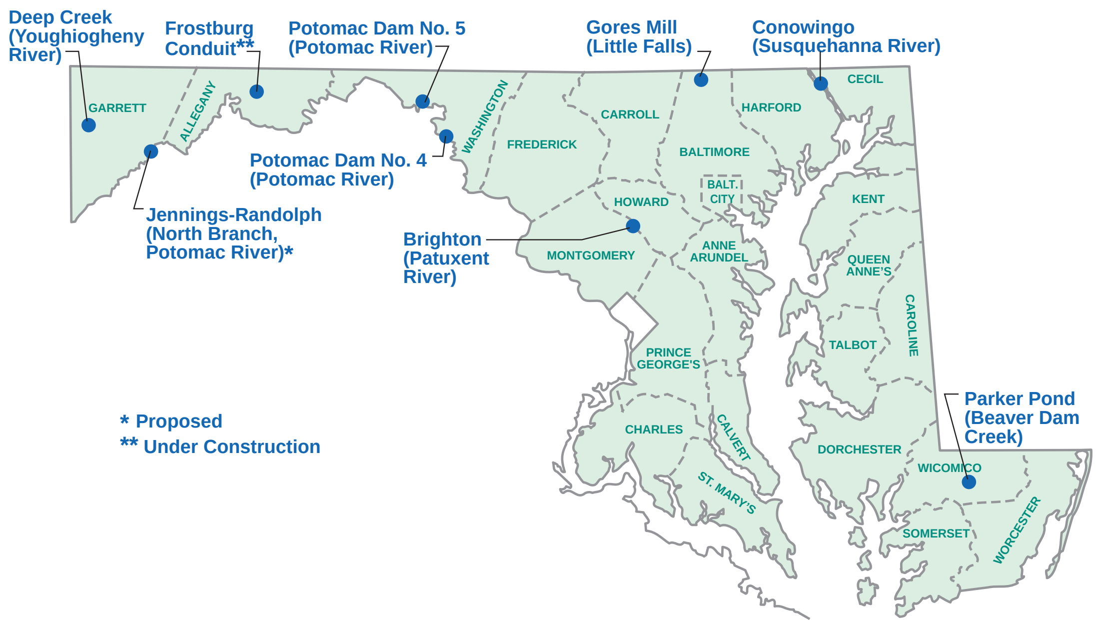
Table 2-5 Hydroelectric Projects in Maryland

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	Susquehanna Power Co. and PECO Energy Power Co.	Major License	1980	2014	1928
Deep Creek	20[a] MW	Deep Creek/ Oakland, Garrett County	-	Brookfield Power	None[b]	-	-	1928
Jennings-Randolph (proposed)	13 MW	North Branch Potomac River/ Bloomington, Garrett County	12715	Fairlawn Hydroelectric at USACE dam	Major License (Application Submitted)	-	-	(Proposed for 2014)
SMALL-SCALE PROJECTS								
Potomac Dam 4	1,900 kW	Potomac River/ Shepherdstown, WV	2516	Allegheny Energy Supply	Major License	2004	2033	1909
Potomac Dam 5	1,210 kW	Potomac River/ Clear Spring, Washington County	2517	Allegheny Energy Supply	Major License	2004	2033	1919
Gores Mill	10 kW	Little Falls/ Baltimore County	-	C. Lintz	None	-	-	1950s
Parker Pond	40 kW	Beaver Dam Creek/ Wicomico County	-	W.H. Hinman	None	-	-	1950s
Brighton	400 kW	Patuxent River/ Clarksville, Montgomery County	3633	KC Brighton LLC	Minor License	1984	2024	1986
Frostburg	75 KW	NA/Allegany County	14059	City of Frostburg	Conduit Exemption	2011		(Under Construction)

[a] Nameplate capacity listed in EIA-860 database.
[b] Deep Creek Hydroelectric Project is administered under a Maryland water appropriations permit from MDE, which expires January 1, 2018.

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

Figure 2-11 Location of Hydroelectric Facilities in Maryland



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 that may provide localized electricity in the future.

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. The City of Frostburg applied for and received an exemption from FERC licensing to construct the 75 kW Frostburg Low Head Project, a small conduit hydropower project to be located on Frostburg's municipal raw water line in Allegany County, with an average annual generation of 240 MWh.

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 (MSW). 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 by about 75 percent.

Maryland Senate Bill 690, Renewable Energy Portfolio – Waste-to-Energy and Refuse-Derived Fuel, passed during the 2011 legislative session. The new law alters the RPS to designate WTE as a Tier 1 renewable resource rather than Tier 2 renewable resource. The bill also adds refuse-derived fuel as a Tier 1 renewable resource. Refuse-derived fuel, not previously a Tier 2 renewable resource, is created from municipal solid waste by finely shredding the material before combustion. See Section 5.1.1 for information on the Maryland RPS Tier 1 and Tier 2 requirements.

There are about 90 WTE facilities currently operating nationwide, including three major facilities in Maryland that are certified under Maryland's RPS. As displayed in Table 2-6, there are also a few WTE plants in the planning and development stages in Maryland.

WTE facilities are heavily regulated due to various environmental impacts. As an energy source, WTE is similar to coal and oil electricity generators in terms of carbon dioxide, sulfur dioxide, and nitric oxides emissions. However, WTE facilities have the potential to be significant contributors to the environmental deposition of mercury, dioxin, furan, and other toxic metals and organic compounds without adequate pollution controls.

Montgomery County Resource Recovery Facility

The Montgomery County Resource Recovery Facility began commercial operation in August 1995. The facility processes an average of 1,500 tons of solid waste daily, generating around 55 MW of renewable energy. All waste is first delivered to the Shady Grove Transfer Station in Derwood, compacted into intermodal steel waste containers and then loaded onto railcars by crane. Each day a train makes the 22 mile trip to the facility in Dickerson, where the containers are off-loaded and trucked from the on-site railyard to the facility's enclosed refuse building. The waste is combusted at furnace temperatures exceeding 1,800 degrees Fahrenheit, reducing it to an inert ash residue that is approximately 10 percent of its original volume. The ash residue is loaded into sealed containers and shipped by rail to a landfill located in Brunswick, Virginia. This unique rail system allows Montgomery County to virtually eliminate truck traffic associated with the facility on the rural roads leading to the site.

Source: Northeast Maryland Waste Disposal Authority. http://www.nmwda.org/about/mcrrf.asp.

Table 2-6 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
Pennwood Power Station (Sparrows Point, Maryland)	Operational	120	Severstal
Harford Waste-to-Energy Facility (Joppa, Maryland)	Operational	1.2	Energy Recovery Operations
Fairfield Renewable Energy Power Plant (Baltimore, Maryland)	Permitted	120	Energy Answers International
Frederick/Carroll County Renewable Waste-to-Energy Facility (Frederick, Maryland)	Proposed	55	Northeast Maryland Waste Disposal Authority
Harford/Baltimore County Renewable Waste-to-Energy Facility (Joppa, Maryland)	Proposed	TBD	Northeast Maryland Waste Disposal Authority

Note: The Harford Waste-to-Energy Facility generates steam from the processing of the waste and sells it to the Edgewood Area of the U.S. Army's Aberdeen Proving Ground. Since it does not sell electricity into the PJM grid, it is not considered an eligible RPS resource.

Poultry Litter-to-Energy

Poultry litter power plants have been under consideration in Maryland, stemming partly from concerns over the environmental impact from poultry waste runoff entering the Chesapeake Bay watershed. In 2008, the Maryland RPS was amended to move Poultry Litter-to-Energy (PLE) from a Tier 2 eligible resource to a Tier 1 eligible resource. Poultry litter-fueled power generation can come in a variety of forms, such as anaerobic digestion, direct combustion, fluidized bed combustion, or gasification.

The Maryland Environmental Service and the Maryland Department of Public Safety and Correctional Services are studying the feasibility of developing a thermophilic anaerobic digester for the Eastern Correctional Institute (ECI) co-generation facility. By using poultry litter as a fuel, the project would reduce the impact of poultry litter runoff on the Chesapeake Bay watershed while providing heat and power to the ECI facility. In addition, Fibrowatt, LLC is currently considering Maryland's Eastern Shore as a potential location for a future plant, which uses conventional combustion technology with poultry litter as a fuel source.

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

Methane Gas Use at Washington Wastewater Facility

The Blue Plains Wastewater Treatment Plant (WWTP) in Washington, D.C., broke ground in May 2011 on a $1.4 billion project aimed to process wastewater into methane. This methane will then be used to generate electricity, reducing the amount of power needed to be purchased from local fossil fuel-fired utilities. Thermal hydrolysis and anaerobic digesters will be used to "pressure-cook" the biosolids to produce the methane gas, a process that is the first of its kind in North America. The process also will reduce the amount of solid waste exiting the WWTP by one half, which is estimated to save the plant $20 million each year in energy and trucking costs. The project is also expected to reduce the amount of GHG emissions from the plant by up to 40 percent.

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 2-7 lists the LFG-to-energy projects that are currently operating in Maryland. Not listed in the table is the Millersville LFG project, which collects LFG and sells it directly to Fort Meade to fuel operations at the base.

Table 2-7 Landfill Gas Projects in Maryland

Landfill Name and Location	Estimated Total Waste in Place (2006 tons)	Project Status	LFG Energy Project Start Date	LFG Energy Project Type	MW Capacity	Project Developer
Brown Station Road (Prince George's County)	8,900,000	Operational Operational Operational	1987 1987 2003	Reciprocating Engine Boiler Reciprocating Engine	2.6 Steam 3.5	PG County
Sandy Hill (Prince George's County)	5,126,000	Operational	2003	Boiler	Steam	Horizon LFG
Eastern/White Marsh (Baltimore County)	5,215,000	Operational	2006	Reciprocating Engine	2.5	Pepco Energy Services
Newland Park (Wicomico County)	2,765,000	Operational	2007	Reciprocating Engine	2.6	INGENCO
Central Landfill (Worcester County)	1,700,000	Operational	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	Operational	2009	Reciprocating Engine	2.4	SCS Engineers
Quarantine Road (Baltimore County)	10,000,000	Operational	2009	Cogeneration	1.5	Ameresco Federal Solutions
Reichs Ford Landfill (Frederick County)	3,940,000	Operational	2010	Reciprocating Engine	2.0	Energenic-US

Notes: The Brown Station, Gude, and Sandy Hill landfills are closed and are no longer accepting waste. 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.
Source: U.S. EPA Landfill Methane Outreach Program database.

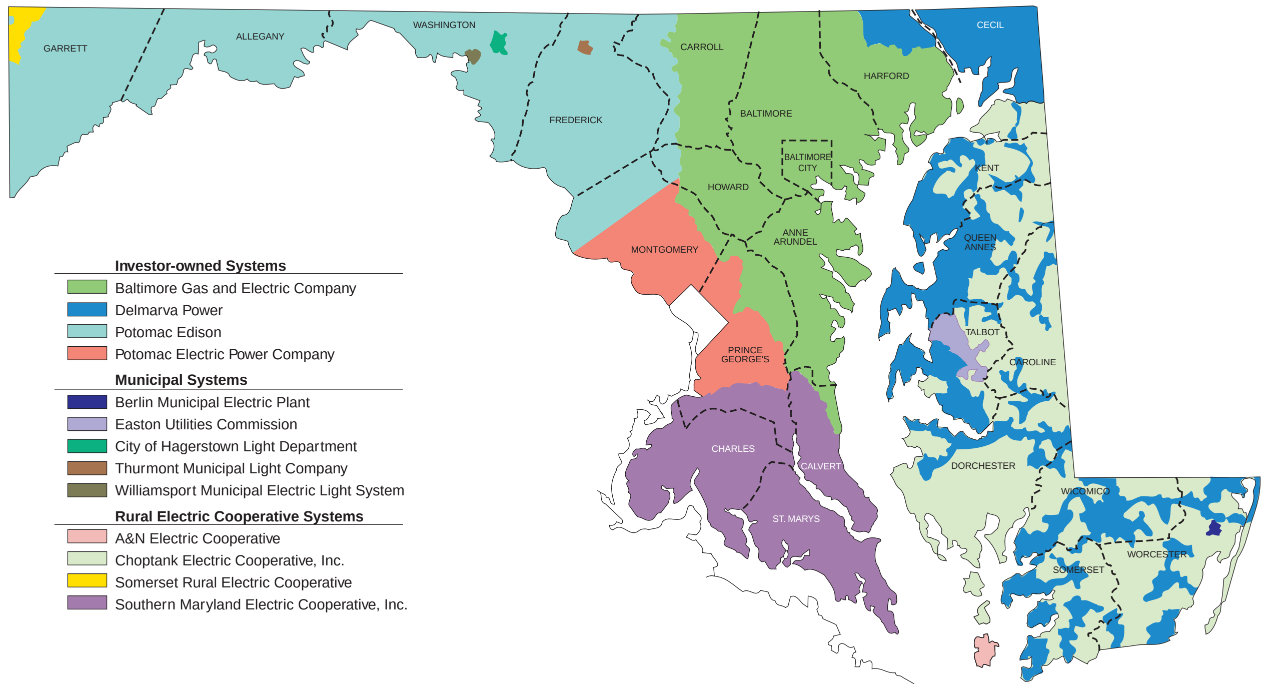
2.2 Electricity Distribution

There are 13 utilities distributing electricity to customers in Maryland (see Table 2-8). 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 Potomac Electric Power Company (Pepco). They are owned by three holding companies — FirstEnergy (formerly Allegheny Energy); Constellation Energy; and Pepco Holdings, which owns both Delmarva 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 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 2-12.

Table 2-8 Maryland Electric Distribution Companies

Company	Approximate Number of Maryland Customers
INVESTOR OWNED	
Potomac Edison	255,400
Baltimore Gas & Electric	1,239,300
Delmarva Power & Light	205,800
Potomac Electric Power Company	536,700
Subtotal	2,237,200
MUNICIPAL SYSTEMS	
Berlin Municipal Electric Plant	2,400
Easton Utilities Commission	10,500
City of Hagerstown, Light Department	17,400
Thurmont Municipal Light Company	2,900
Williamsport Municipal Electric Light System	1,000
Subtotal	34,200
COOPERATIVE SYSTEMS	
A&N Electric Cooperative	330
Choptank Electric Cooperative, Inc.	52,100
Somerset Rural Electric Cooperative	790
Southern Maryland Electric Cooperative, Inc.	148,000
Subtotal	201,220
Total Customers	2,472,620

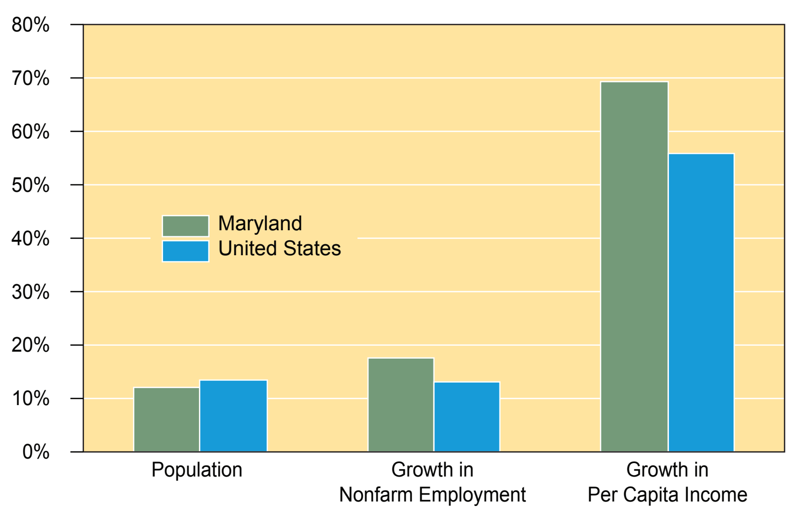
Figure 2-12 Electricity Distribution Service Areas



2.3 Maryland Electricity Consumption

Maryland end-use customers consumed about 65 million MWh of electricity during 2010. Between 1997 and 2010, the annual average growth rate in electricity consumption in Maryland was lower than that in the U.S. as a whole — 1.16 percent in Maryland versus 1.37 percent in the U.S. Figure 2-13 compares some of the key factors contributing to growth in electricity demand in Maryland and the U.S. from 1997 through 2010. Maryland's population growth slowed significantly between 2001 and 2007, but accelerated between 2007 and 2010, as depicted in Figure 2-14. Despite the varying growth rates, per capita income and non-farm employment has grown more rapidly than the national average over the last 14 years. In general, as more people live and work in Maryland, and as incomes grow, they collectively use more electricity. The shares of electricity consumption in Maryland used by residential and nonresidential sectors

Figure 2-13 Comparison of U.S. and Maryland Growth Factors Affecting Electricity Consumption (1997 – 2010)



Source: Bureau of Economic Analysis, Regional Economic Accounts, 2011.

(i.e., the sum of commercial, industrial, and street lighting) are similar to the United States as a whole (see Figure 2-15).

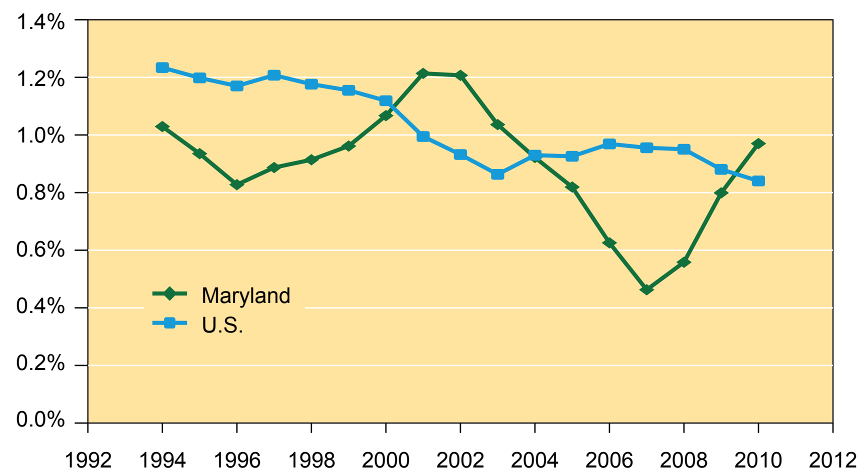
2.3.1 Maryland Electricity Consumption Forecast

Figure 2-16 illustrates the most recent forecast for future electricity consumption in Maryland, as projected by the utilities serving loads in the state. The slower growth in forecasted electric energy consumption compared to historical growth is largely attributable to projected increases in the real price of electricity, slower growth in population and employment, the effects of the economic recession, 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, the stock of electricity-consuming equipment and appliances is adjusted over time by replacement with equipment and appliances that are more energy-efficient.

The relatively slow growth in electricity consumption is projected to persist through the PJM 15-year forecast period (2011-2026). Over this period, consumption is expected to grow at an average annual rate of approximately 1.1 percent.

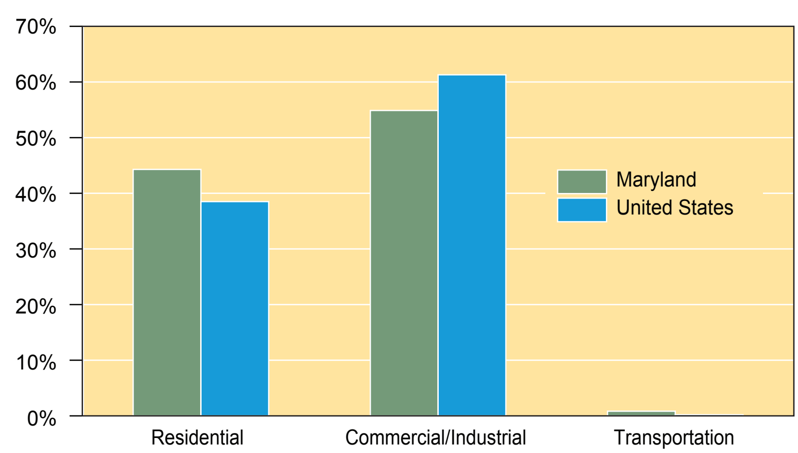
Future electricity prices (and hence consumption of electricity) are significantly affected by natural gas prices. Between 1996 and 2006, natural gas prices almost tripled. Electricity generated from natural gas combustion currently accounts for only a small percentage of electric energy produced in Maryland (approximately 10 percent), but natural gas-fired facilities are often the marginal resources within the PJM Interconnection region and as such strongly influence

Figure 2-14 Population Growth Trends in Maryland and the U.S.



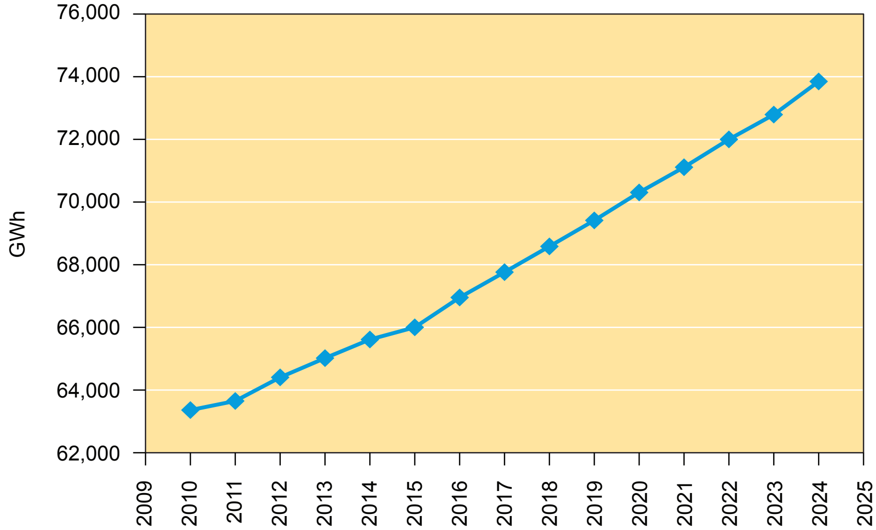
Source: Bureau of Economic Analysis, Regional Economic Accounts, 2011.

Figure 2-15 Electricity Consumption by Customer Class for 2010



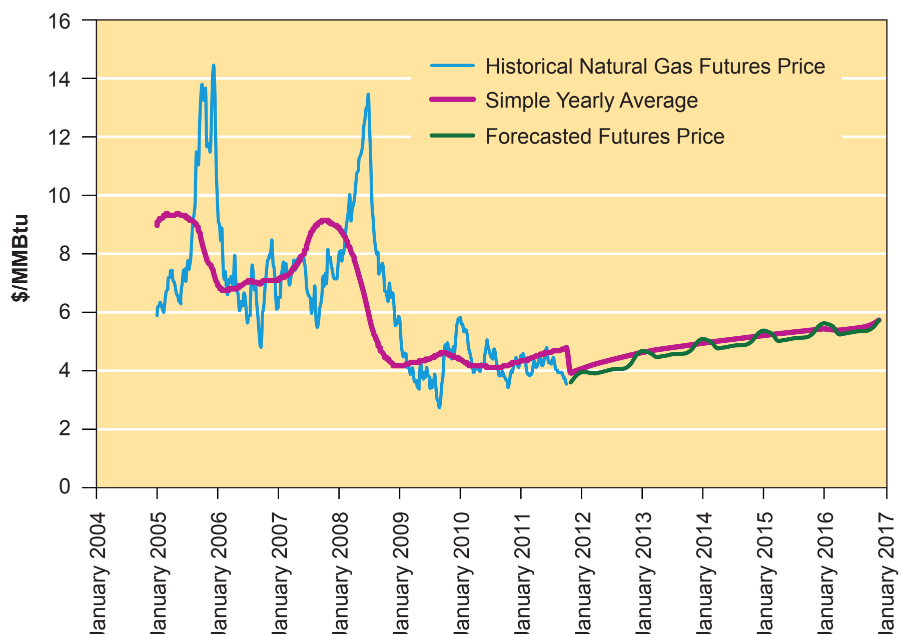
Source: U.S. Energy Information Administration, 2011.

Figure 2-16 Maryland Forecasted Consumption (GWh)



Source: Maryland PSC's Ten-Year Plan of Electric Companies in Maryland, August 2011.

Figure 2-17 Historical and Future NYMEX Henry Hub Natural Gas Prompt Month Futures Prices



Source: Historical prices obtained from the Natural Gas Futures Prices (NYMEX), U.S. EIA, and forecasted prices from The CME Group, October 2011.

market prices. In late-2008, natural gas prices started to drop. In mid-2009, natural gas prices were below $4.00 per MMBtu compared with prices of about $13.00 per MMBtu in mid-2008.[11] Natural gas prices remained relatively low in 2010, averaging between $4 and $5 due to abundant shale gas supply. Natural gas futures show the market expects natural gas prices will move to $5.00 per MMBtu by late 2014, which is lower than natural gas prices over much of the 2003 to 2008 period (see Figure 2-17). Based on these factors, we can anticipate level electricity prices through 2011, with moderate increases thereafter.

The economic recession that began in 2008 has also resulted in a downward trend on electricity consumption in Maryland. While Maryland has not been as seriously affected by the recession as many other states, Maryland has not been immune to the higher unemployment levels and lower levels of economic activity. The impacts of the economic downturn have overshadowed the price effects of the lower natural gas prices and

[11] The natural gas prices used here are from the Henry Hub, a pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX). Henry Hub is a point on the natural gas pipeline system in Erath, Louisiana that interconnects with nine interstate and four intrastate pipelines: Acadian, Columbia Gulf Transmission, Gulf South Pipeline, Bridgeline, NGPL, Sea Robin, Southern Natural Pipeline, Texas Gas Transmission, Transcontinental Pipeline, Trunkline Pipeline, Jefferson Island, and Sabine.

Long-Term Electricity Report for the State of Maryland

On July 23, 2010, Governor Martin O'Malley signed Executive Order 01.01.2010.16—Long-Term Electricity Report for the State of Maryland. The purpose of the report is to evaluate Maryland's long-term electricity needs, identify approaches to meet those needs, and to build a foundation to achieve a clean, reliable, and affordable energy future.

The report, prepared by PPRP, assesses future electric energy use requirements and peak electric demand requirements, and identifies sources and alternative resources to meet any gaps in these requirements through the end of calendar year 2030. Among other factors, the report evaluates:

- *Existing and planned electric generating capacity;*
- *Demand response;*
- *Electricity-based transportation;*
- *Existing and planned electric transmission;*
- *Conventional and renewable generating capacity additions (including small-scale distributed generation);*
- *Fuel-switching (including use of natural gas and biomass);*
- *Energy conservation and efficiency;*
- *Smart grid technologies;*
- *Energy storage technologies; and*
- *Consistency with State and federal environmental laws.*

The LTER was submitted to Governor O'Malley in December 2011 and is available to the public on PPRP's website at http://esm.versar.com/pprp.

resulting lower electricity prices. Electricity sales in 2009 were about 1 percent below 2008 levels, largely explained by the recession-induced declines in economic activity.

Another factor contributing to the slower growth in state-wide electricity consumption is the EmPOWER Maryland legislation. This law targets a 15 percent reduction in per capita electricity consumption by 2015 from 2007 levels. For more information about EmPOWER Maryland, refer to Section 5.1.2.

2.3.2 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 Maryland's geographic border match or exceed the state's consumption. Historically, Maryland's demand for electricity has exceeded the amount of energy generated within the state, necessitating imports from out of state resources. Maryland, as part of PJM, relies on the generating resources within PJM as a whole, as well as electric power that can be imported into the PJM area. Consequently, imbalances between Maryland consumption and generation should not be viewed as adversely affecting reliability or availability of electricity in Maryland. However, 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 in-state 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. Electric energy consumption in Maryland during 2010 exceeded electric energy generation in the state by about 38 percent. Table 2-9 compares electricity consumption and generation in Maryland.

The decreased levels of in-state generation between 2008 and 2010, relative to the earlier parts of the decade, can be partially attributed to the efficiency losses associated with new emissions controls that were installed to comply with the HAA (see Section 4.1.1 for information on the HAA). In addition, the recent economic recession led to a reduction in energy demand throughout the PJM region, which in turn reduced the PJM dispatch and related energy production time for many power plants.

Table 2-9 Total Maryland Electric Energy Consumption and Generation (thousands of MWh)

	Retail Sales (Consumption)	Sales + T&D Losses[a]	Generation	Net Imports	Percentage of Sales Imported
2000	60,620	65,470	51,145	14,325	22%
2005	68,365	73,834	52,662	21,172	29%
2007	65,391	70,622	50,198	20,424	29%
2008	63,326	68,392	47,361	21,031	31%
2009	62,589	67,596	43,775	23,821	35%
2010	65,489	70,728	43,613	27,115	38%

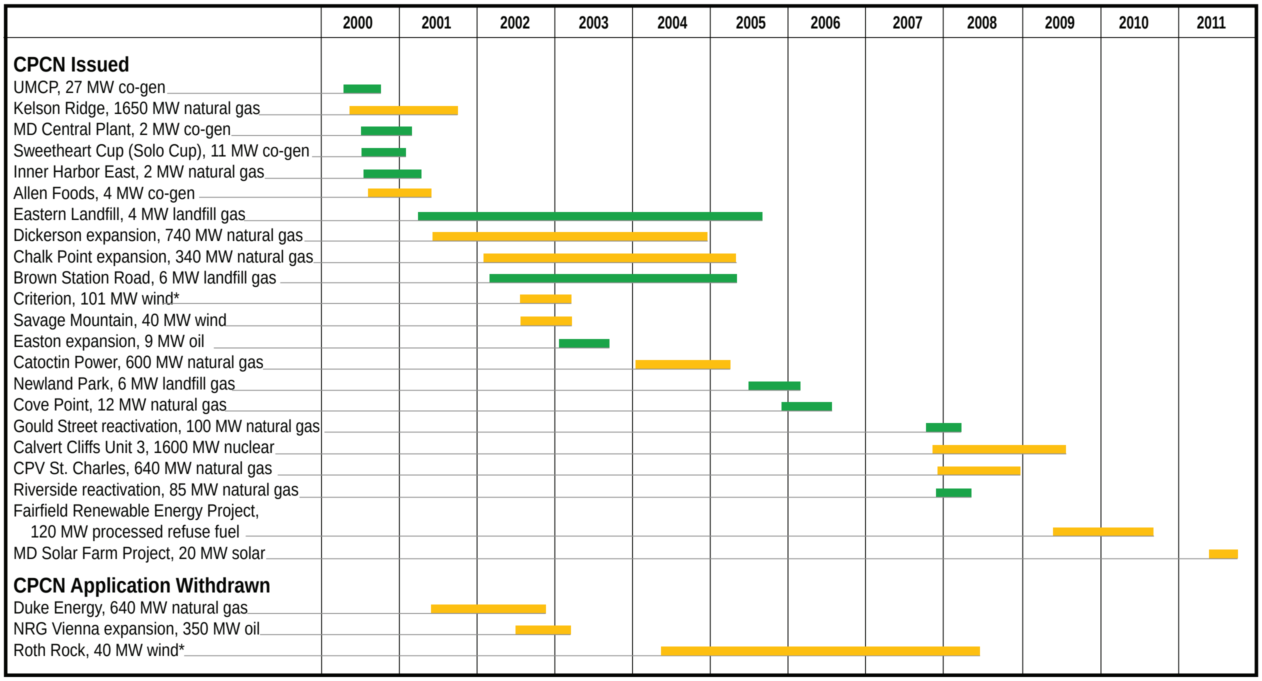
[a]Assumes transmission and distribution (T&D) losses of 8 percent.
Source: U.S. EIA.

2.4 New and Proposed Power Plant Construction

The PSC has received 25 CPCN applications for new generation since 2000, representing several thousand megawatts of potential generating capacity at existing facilities and at greenfield sites (see Figure 2-18). While the majority of these proposed plants did obtain a CPCN, only 11 are now in operation, with the remainder being delayed or abandoned because of various financial or commercial reasons. Several projects, however, are still considered viable. For example, in 2007 the Kelson Ridge site was purchased by CPV Maryland with plans to develop the site as a new generation facility. The project, a 640-MW natural gas-fired facility, received a CPCN in October 2008. In August 2011, CPV Maryland filed an application with the PSC for a CPCN amendment and construction deadline extension. This modification includes the use of newer, more efficient natural gas turbines and associated slight changes to stack and cooling tower parameters. These changes, if approved, would increase the nameplate capacity of the proposed facility to 725 MW.

The process by which new power plants were proposed and developed in Maryland has changed as a result of the move to retail competition and electrical utility restructuring. Maryland's regulated utilities are no longer responsible for building new generation. Resource planning resides with the competitive electricity market, driven by economics and price signals. High prices that result from tight supply markets are supposed to attract investors and developers; low prices that result from over-supplied markets supposedly discourage investors from entering the

Figure 2-18 CPCN Requests 2000-2011



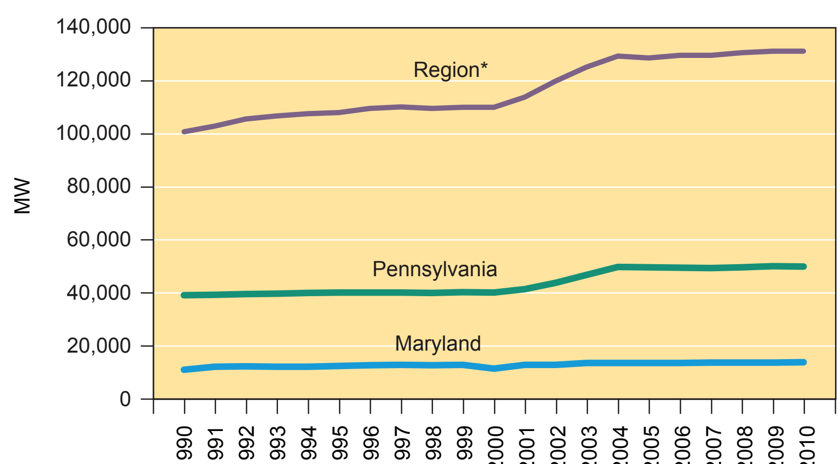
Bar length indicates the duration of the CPCN process from the time the application was filed to the time it was withdrawn or a PSC order was filed. Bar coloring indicates whether the project is now in operation:

= Project is operational
= Project is not operational

* Project was subsequently reconfigured, granted a CPCN exemption, and is now operational. See Section 2.1.5 for more information.

market; however, it requires substantial and sustained price differentials to elicit such market behaviors. 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. The PJM region experienced a boom in power plant development between 1999 and 2003. Figure 2-19 shows the amount of capacity on-line for Maryland, Pennsylvania, and the region. In the late 1990s, with the transition to a restructured market and increased reliance on independent power producers, the amount of new capacity in the region leveled off and then rose more steeply before leveling off again in 2004. In 2002,

Figure 2-19 Regional Installed Capacity (MW)



*The region includes Maryland, Pennsylvania, Washington, D.C., Virginia, West Virginia, Delaware, and New Jersey.
Source: U.S. Energy Information Administration, 2011.

wholesale power prices were unusually low, making some projects uneconomic. Projects that had started construction prior to the decrease in wholesale market prices went on-line by 2004, after which there was a slowdown in new facilities coming on-line in the region. With the majority of new facilities being developed to the west of the major load centers of Washington, Baltimore, Philadelphia, and New York, it has become increasingly difficult and expensive to transport electricity over congested transmission lines.

2.4.1 Calvert Cliffs Expansion

Construction of new nuclear power plants in the U.S. has been stagnant since the Three Mile Island accident in 1979.[12] However, the need for generating capacity in some regions, combined with improvements in nuclear plant design and increasing concern over GHGs has led to renewed interest in nuclear power as investors and power companies began considering building new nuclear facilities. Additionally, as part of the Energy Policy Act of 2005, Congress provided $3.1 billion in tax credits for new nuclear facilities, created a loan guarantee program with $18 billion allotted to nuclear power, created a compensation mechanism for undue legislative or regulatory delays, and expanded liability protection. Nonetheless, the Japanese nuclear crisis in March 2011 has revived public concerns about the safety of nuclear energy, which may further delay the development of new nuclear power.

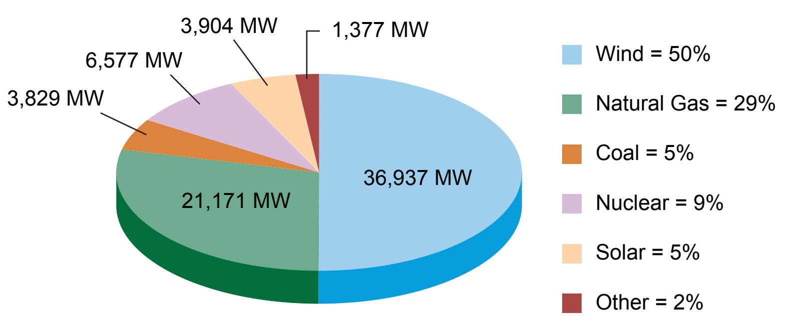
In 2007, Constellation and EDF launched the joint venture UniStar Nuclear with the intent to develop new nuclear facilities in the U.S. and Canada. Along with partners AREVA and Bechtel, UniStar pursued plans for Calvert Cliffs Unit 3, a new 1,600-MW nuclear reactor just south of the two existing units that Constellation operates at Calvert Cliffs. The new AREVA reactor would be one of the largest single unit reactors in the world, and its addition to the existing Calvert Cliffs site would nearly double the site's generating capacity.[13]

The proposal of a new nuclear facility in Maryland brings with

PJM Generator 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, based on the dates the requests are received. The list of dated interconnection requests is referred to as the generator interconnection queue. As of the end of 2010, projects totaling almost 74 GW of capacity had requested that PJM perform interconnection studies. Wind projects are the dominant resource, followed by natural gas, in the PJM generator interconnection queue. Renewable energy projects accounted for 56 percent of the capacity actively pursuing interconnection to the transmission grid in the PJM region, mainly driven by RPS requirements. Though many projects requesting interconnection studies are ultimately canceled, the queue data indicates a strong interest on the part of power producers to develop additional generating capacity in PJM.

MW of Projects in the PJM Generator Interconnection Queue



[12] Existing nuclear facilities have added almost 6,000 MW of generating capacity, equivalent to approximately six new reactors, through uprates since 1977. Source: http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/power-uprates.html.
[13] In an unrelated process, Constellation is currently seeking to renew its NRC license for storing spent nuclear fuel at the site in its independent spent fuel storage installation (ISFSI).

it siting, environmental, health, and community issues that need to be addressed as part of the licensing processes overseen both at the federal level by the NRC and the Army Corps of Engineers (USACE), and at the State level as part of the CPCN proceedings before the Maryland PSC. The PSC issued a final order granting the CPCN, subject to conditions addressing local environmental and socioeconomic issues, in June 2009.

The federal licensing of Calvert Cliffs 3 is also evaluating environmental impacts, as well as issues that the NRC has prime responsibility for, such as radiological safety and waste disposal. The State has provided comments on the federal licensing process as a participant in the case. In May 2011, the NRC and USACE completed the final environmental impact statement (EIS), concluding that there are no environmental impacts that would preclude issuing a license for the proposed third reactor.

Meanwhile, energy prices which had risen to all-time highs in 2007 and 2008 entered a steep decline following the global economic downturn and recession. Additionally, other AREVA construction projects in France and Finland have been beset by a series of delays and cost overruns, raising fears that the costs of the expansion would also creep higher. In October 2008, UniStar officials confirmed that the third unit was anticipated to cost nearly $10 billion dollars, or $4,500 to $6,000 per kW, roughly twice the cost of an equivalent coal plant.

In October 2010, Constellation announced it was pulling out of the UniStar venture and EDF was purchasing its share. A foreign company cannot "own, control, or dominate" a nuclear power plant under U.S. law, and therefore, EDF has been seeking a new U.S. partner for the venture. UniStar cannot continue with NRC licensing proceedings until a U.S. partner is found.

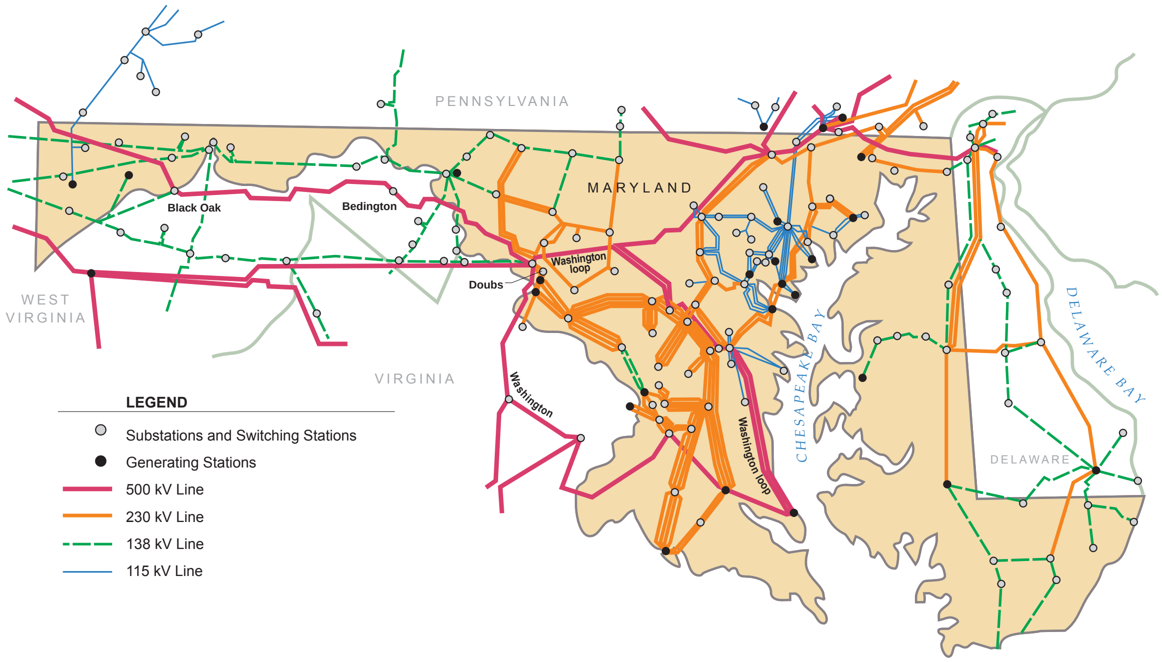
2.5 Electric Transmission

The network of high-voltage lines, transformers, and other equipment that connect power generating facilities to distribution systems are 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 2-20 shows a map of this high-voltage transmission grid in Maryland.

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 over peak time periods.

The transmission of electricity in Maryland is almost totally dependent on the PJM planning process. As a principal responsibility, PJM must ensure that there is sufficient transmission system capacity to meet

Figure 2-20 Transmission Lines in Maryland (>115-kV)



all North American Electric Reliability Corporate (NERC) standards. In addition, PJM routinely examines many other proposed transmission projects to determine if they are economically justified and would produce an overall system benefit. 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 and build the transmission requirement.

2.5.1 New and Proposed Transmission Projects

The PSC has received 10 CPCN applications for new and modified transmission line projects since 2009, representing over 250 miles of new, expanded, or rebuilt transmission lines in Maryland. These projects represent both large, multistate transmission lines proposed to support the regional transmission grid as well as smaller, in-state transmission line projects designed to improve local network stability. Transmission planning and regulatory drivers, as well as oversight, are described in Section 3.3.

Regional Transmission Line Projects

Three large, interstate projects, portions of which traverse Maryland, have been proposed within the last several years to address regional reliability issues as part of the PJM RTEP process (see Section 3.3.3). These backbone projects are proposed to enhance west-to-east power transfer, help alleviate projected reliability issues, and reduce congestion costs. These projects are the American Electric Power (AEP) Company and Potomac Edison's joint venture Potomac-Appalachian Transmission

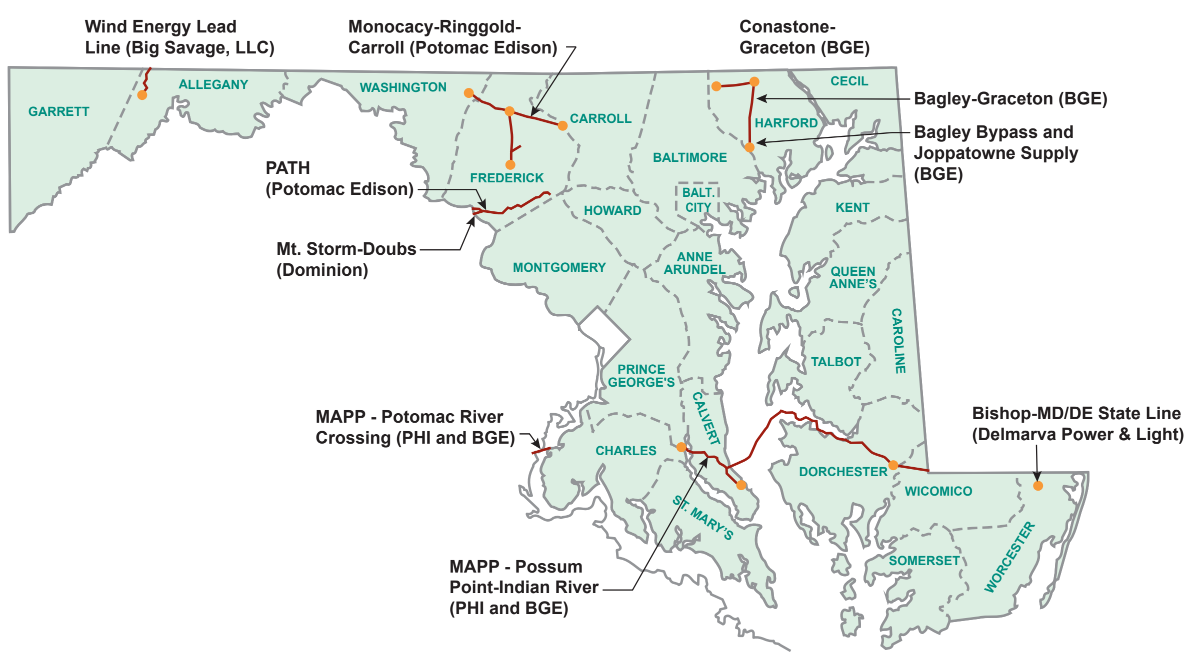
Highline (PATH) Project, the Pepco Holdings, Inc. (PHI) and Baltimore Gas & Electric (BGE) Mid-Atlantic Power Pathway (MAPP) Project, and Dominion's Mt. Storm to Doubs rebuild. The Maryland portions of these proposed projects are shown in Figure 2-21.

PATH

The proposed PATH Project is a 276-mile, single-circuit, 765-kV transmission line that extends from the Amos Substation in Putnam County, West Virginia, crosses through Virginia over the Appalachian Trail and the C&O Canal and extends through Maryland, terminating at a proposed substation located near Kemptown in Frederick County. Within the state, the project consists of 20 miles of new 200-foot right-of-way and the construction of a new 41-acre substation, located on 167 acres in Kemptown. The project would cross the scenic Monocacy and Potomac rivers, sensitive Green Infrastructure areas, and Rare, Threatened, and Endangered species habitat. Furthermore, because the project crosses federal lands, a National Park Service (NPS) and U.S. Forest Service-led NEPA EIS review process was initiated in May 2009. The potential impacts of this project on Maryland's resources are further described in Section 4.2.

In February 2011, PJM's revised load forecasts demonstrated no near-term need for the project due to the slow economic recovery coupled with new generation and demand-side resources. Accordingly, Potomac Edison withdrew its CPCN application. Most recently, in May 2011, the PATH developers requested that their NPS EIS application be held in abeyance until the end of the year to allow PJM to conduct further analyses of the project. The PATH project will likely remain suspended for the time being.

Figure 2-21 Approximate Corridors for Proposed New Transmission Lines



MAPP

The MAPP Project is a proposed 152-mile, double-circuit 500-kV alternating-current (AC, 69 miles) and 640-kV DC (83 miles) transmission line that traverses Charles, Prince George's, Calvert, Dorchester, and Wicomico counties in Maryland and Sussex County in Delaware. It consists of overhead conductors and both underground and submarine cables. The project includes new aerial crossings of the Potomac, Patuxent, and Nanticoke rivers and a 39-mile submarine crossing of the Chesapeake Bay and Choptank River. The potential impacts to Maryland's resources are discussed further in Section 4.2. In August 2011, PHI requested a temporary delay in the procedural schedule to allow PJM to conduct further analyses of the need for the project. The projected completion date has been delayed until at least 2019.

Mt. Storm to Doubs

Most recently, Dominion proposed to rebuild a 100-mile, 500-kV transmission line from Mt. Storm, West Virginia, across Virginia to the Potomac River/Maryland border and on to the Doubs substation in Maryland. A short portion of the line stretching from the Virginia/ Maryland state border to the Doubs substation is owned by FirstEnergy. The original transmission line was built in 1966, and as part of this project, will have its lattice steel structures replaced with new ones that will be built within the existing right-of-way. This rebuild, expected to be completed by mid-2015, would improve system reliability and increase the line capacity by roughly 66 percent.

In-state Transmission Line Projects

Several smaller projects have recently been proposed or approved within the state to address local reliability and load growth issues. These projects are spread out across the state and include new right-of-way acquisitions as well as project upgrades or rebuilds within existing rights-of-way. Table 2-10 summarizes the various projects for which CPCN applications have been filed and Figure 2-21 shows their proposed locations in Maryland. Most of these proposed projects occur within existing rights-of-way; however, they may still have significant impacts on Maryland's resources of concern and require a thorough environmental and socioeconomic impact evaluation. A detailed discussion of the potential impacts of these projects can be found in Section 4.2.

2.5.2 Transmission Line Design

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 AC transmission lines are the most common, alternative transmission line types, such as DC, underground, and submarine, are becoming more prevalent. These types of technologies are discussed in the following sections.

Table 2-10 In-State Transmission Line Projects 2010 – 2011

Line	Developer/ Owner	Size (kV)	Approximate Length in MD (miles)	Project Type	Affected MD Counties	PSC Case Number	Status
Monocacy-Ringgold-Carroll (MRC)	Potomac Edison	230	37	Rebuild of single circuit 138-kV to 230-kV	Washington, Frederick, and Carroll	9239	CPCN issued April 2011
Bagley Bypass	BGE	230	< 1	Rebuild of existing single circuit	Harford	9243	CPCN issued March 2011
Joppatowne Supply	BGE	115	< 1	Single-pole tap line	Harford	9244	CPCN issued February 2011
Conastone-Graceton	BGE	230	9	Upgrade single to double circuit	Harford	9246	PPRP direct testimony filed April 2011; project on hold pending revised PJM studies
Bagley-Graceton	BGE	230	14	Rebuild single to double circuit	Harford	9251	Procedural schedule suspended May 2011
Bishop-MD/DE State Line	Delmarva Power & Light	138	2	New single circuit line within existing right-of-way	Worcester	9264	CPCN issued November 2011
Wind Energy Lead Line	Big Savage, LLC	138	7 (2 underground)	New single circuit line on new right-of-way	Allegany	9268	CPCN issued September 2011

DC Transmission Lines

According to DOE, several thousand miles of high-voltage DC transmission lines are installed in the U.S., which is relatively small compared to the over 200,000 miles of total installed high-voltage transmission lines (including 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.

The proposed MAPP Project would utilize 640-kV HVDC technology for 83 miles, from a new converter station in Calvert County to the proposed converter stations in Wicomico County and Sussex County, Delaware, including a 39-mile submarine crossing of the Chesapeake Bay and Choptank River. Although ultra-HVDC systems that operate at 800-kV and can carry 5,000 MW of electricity have been installed above-ground in locations outside the U.S., there are currently no transmission cables (AC or DC) installed underground or under water that operate at 640-kV. Several recently planned projects in the U.S. and Europe, including the 300-mile Atlantic Wind Connection project stretching offshore from New Jersey to Virginia (see Section 5.4.1), would use similar technology.

Underground Transmission Cables

As described in Section 2.5.1, both the MAPP Project and the Big Savage wind energy lead line project include underground construction components. Underground transmission lines are typically implemented in locations where overhead lines are difficult to place or would create aesthetic or environmental issues.

Underground transmission cables are typically placed four to five feet below ground surface in conduits, reinforced duct banks, or are directly buried in specially prepared soil, as shown in Figure 2-22. 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.

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 a transmission cable can be more disruptive than an overhead line.

Disadvantages of underground cables include thermal impacts during operation (described further in Section 4.2), significantly higher project costs versus comparable overhead installations, and longer cable repair times due to difficulties locating and accessing the cables and re-installation. 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, via trenching or using horizontal directional drilling (HDD) for shorter lengths, 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. In September 2009, 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, which includes an approximately one-mile HDD submarine crossing of the Patuxent River near Solomon's. The construction of this project is expected to begin in 2013. The proposed MAPP Project, described in Section 2.5.1, would include a 39-mile submarine crossing of the Chesapeake Bay and Choptank River.

Submarine cables are typically manufactured and installed as one continuous line to provide the greatest reliability and can stretch up to 8 – 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 – 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, compared to the use of an overhead waterway crossing. Impacts from submarine cables are typically associated with disruption of the seabed and sedimentation during trenching and heat dissipation during operation, which are described in greater detail in Section 4.2.3.

Figure 2-22 Direct-burial Underground Transmission Line Installation

Source: ABB, 2008.

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Chapter 3 – Markets, Regulation, and Oversight

Why, sir, there is every possibility that you will soon be able to tax it!
(to PM William Gladstone, on the usefulness of electricity)

– Michael Faraday

English physicist who contributed greatly to the understanding of electromagnetism, 1791-1867

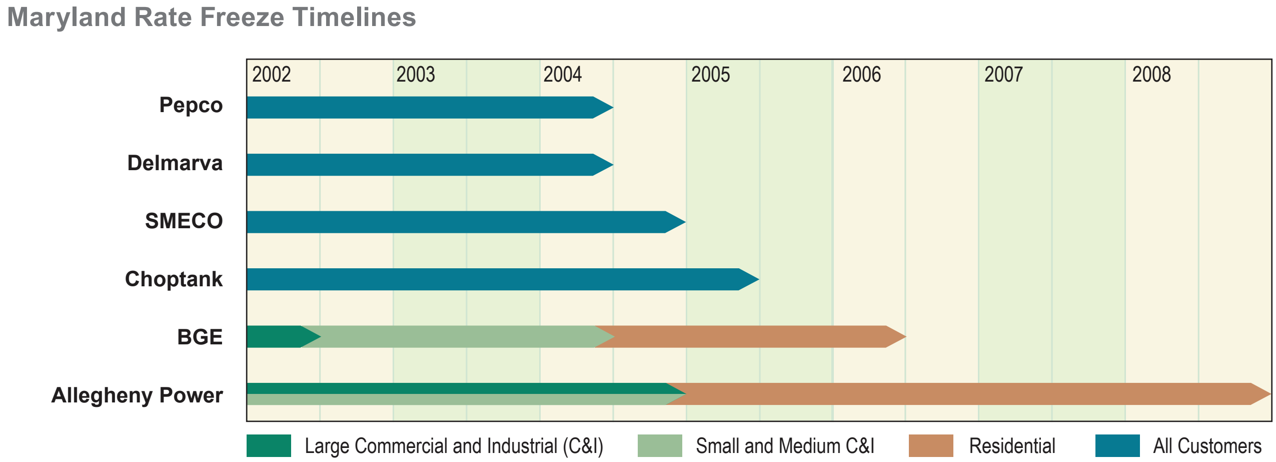
Traditionally in the U.S., the electricity system was dominated by regulated integrated utilities, each operating their local generation, transmission, and distribution systems. Following the successful deregulation of other industries, such as telecommunications and air travel, in the 1990s, states began to examine ways to restructure the electricity industry. California was the first state to begin restructuring its electricity sector, but put the initiative on hold for several years following an energy crisis in which electricity supplies were constrained and prices increased dramatically. Though the California experience caused many states to halt restructuring efforts, numerous others, typically states characterized by high electricity prices, continued with their restructuring plans. This has led to a national electricity system landscape where some states continue to operate under a traditional regulated regime and others have moved towards competitive generation at the retail level.

3.1 Retail Electricity Markets

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. The costs and prices of generation and supply of electricity are not regulated in 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 operator, PJM. Note that the State retains regulatory control over siting for new generation and high-voltage transmission development (i.e., over 69,000 volts) in Maryland through the Certificate of Public Convenience and Necessity (CPCN) process. 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 Public Service Commission (PSC). Customers are billed for each of the three separate functions, although most customers receive just one consolidated electric bill. 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 prices, providing an array of alternative supply products (for example,

Maryland Rate Freeze Timelines

Implementation of the Electric Customer Choice and Competition Act of 1999 included the capping of rates charged by investor-owned utilities for a certain period of time. The caps, which kept rates at or below the rates that competitive suppliers were able to offer, have now expired. Thus, competitive electricity suppliers are able to better compete with utility Standard Offer Service.



green power supply), and giving customers a choice in their electric power supplier. However, for many years the competitive market did not develop as hoped when the legislation was adopted.

At the beginning of 2009, only 2.8 percent of residential customers were being served by competitive suppliers. By the beginning of 2010, 5.1 percent of residential customers had signed with competitive suppliers. The number of residential customers being served by competitive suppliers more than doubled through 2010 and reached 17.3 percent in June 2011 (see Table 3-1).

Table 3-1 Percentage of Customers Served by Competitive Suppliers

Residential	Small Commercial & Industrial	Mid Commercial & Industrial	Large Commercial & Industrial
17.3%	28.1%	55.7%	91.3%

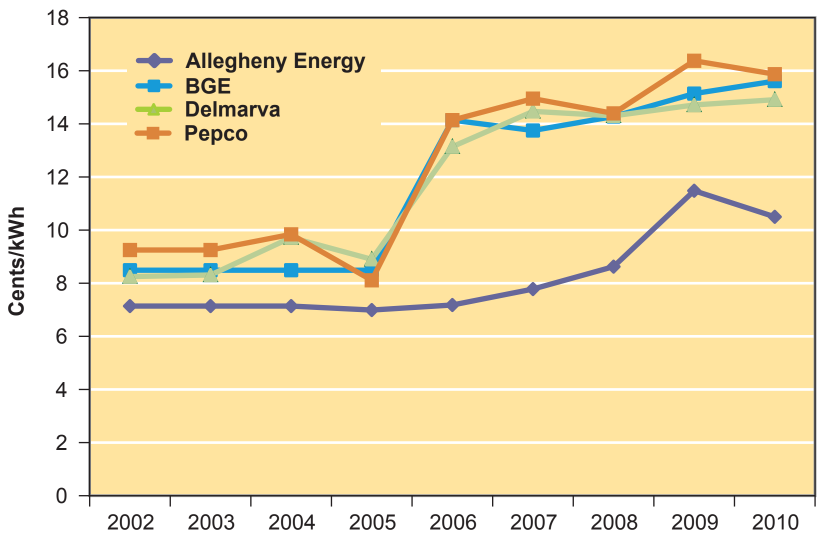
Source: Maryland PSC, Electric Choice Enrollment – June 2011.

3.1.1 Standard Offer Service

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). Under the current residential SOS procurement approach, utilities procure 25 percent of total residential SOS load every six months under two-year contracts with competitive wholesale suppliers.

Rate freezes have now expired for all residential customers, and with the price caps removed, customers now purchase electricity at a price that is set by the wholesale market. Wholesale market prices have risen significantly since 2000, and residential customers have seen substantial increases in their electric bills since the removal of the price caps. Figure 3-1 compares the residential SOS rates in effect in 2002 and for each subsequent year.

Figure 3-1 Comparison of Summer Retail Electricity Rates for Residential SOS Customers, 2002-2010 (cents/kWh)



Note: Includes generation, transmission, and distribution charges.

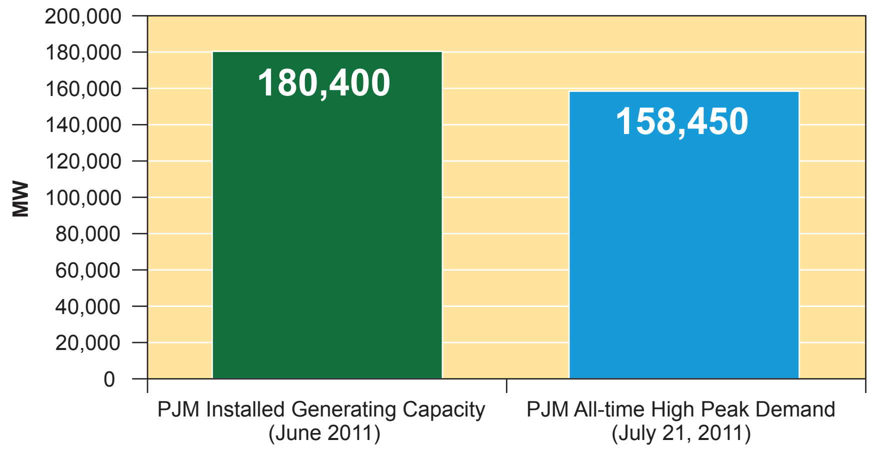
3.2 Wholesale Markets and PJM

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.

A reliable supply of energy depends upon sufficient electric generating capacity at times of high demand. Most states 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 as that capacity is needed to serve the load. Figure 3-2 shows the 2011 supply and demand in PJM.

Figure 3-2 PJM Supply and Demand for 2011



3.2.1 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 (see Appendix B for additional information). Electricity generators bid in the amount of energy they would like to sell at a particular time and price.

For energy products, the PJM operator determines the hourly dispatch of plants on the basis of price bids submitted by suppliers. Zone-wide energy prices are based upon the bids designating a price and quantity at which a generator is willing to sell electricity. PJM stacks these bids from lowest price to highest price until it is able to satisfy the quantity required to meet energy requirements in the zone. It is the price of the last resource, the marginal price, that becomes the zone-wide energy component of the hourly LMP for the next operating day. While energy prices may vary considerably by location, the average PJM region day ahead and real time LMPs for 2010 are shown in Table 3-2.

Table 3-2 PJM Off-Peak and On-Peak Hourly Locational Marginal Prices for 2010

	Day Ahead		Real Time	
	Off-Peak ($/MW)	On-Peak ($/MW)	Off-Peak ($/MW)	On-Peak ($/MW)
Average	$37.46	$52.67	$37.44	$53.25
Median	$33.73	$45.48	$31.83	$43.20

Source: Monitoring Analytics, "2010 State of the Market Report for PJM," March 10, 2011.

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. During periods of congestion to accommodate the power supply requirements, PJM must dispatch generation resources that are located at or near the load zone even if those resources are not the most economic resources available to meet load. 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. The cost of congestion refers to the incremental cost of dispatching these more expensive location-specific resources.

Congestion most often occurs during times of peak demand, when transmission lines are reaching full capacity and certain sections become constrained. LMP differentials between PJM regions (see Table 3-3) 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. PJM estimates that congestion added approximately $82.9 million in costs for BGE in 2010, $112.8 million in the Pepco zone, and $50.5 million in the Delmarva Power & Light zone.[14]

Table 3-3 Average Annual Load-weighted LMP for 2010

Maryland	$58.86	Pennsylvania	$49.49
Washington, D.C.	$57.36	West Virginia	$41.72
Delaware	$55.09	Ohio	$39.47

Source: Monitoring Analytics, "2010 State of the Market Report for PJM," March 10, 2011.

3.2.2 Power Plant Construction

Prior to electricity restructuring, Maryland, like most other states, would identify a need for generating capacity as part of the 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 movement toward electric industry restructuring, the generation function was placed in the competitive arena and the competitive market is relied upon to provide new generation sources to meet load requirements. Capacity is constructed by independent power producers (IPPs) in response to wholesale electricity market signals. The RPM capacity market was established by PJM to provide a mechanism to give incentives to power plant owners and developers to keep existing plants on-line and to construct new generating capacity in the most advantageous zones as market conditions dictated.

With electric industry restructuring, it was anticipated that market prices would provide signals to power plant developers and new power plant construction would result as market prices for electricity increased. Since the late 1990s, however, very little new generation has been constructed in the Mid-Atlantic region, and concerns have arisen regarding the reliability of power supply in Maryland and other nearby states. While several smaller projects have come on-line in recent years, and demand response has grown significantly (see Chapters 2 and 5), no new baseload generation projects have been constructed in the state.

[14] The Pepco zone includes Washington D.C. and the Delmarva zone includes Delaware.

IPPs have proposed various projects, but they have mainly been expansions of existing sites. Without the financial assurances that were previously available through utility ownership and rate base cost recovery, and the inability of IPPs to secure long-term contracts for electricity output, it has become increasingly difficult for IPPs to find new sites and obtain the financial backing needed to build new generation. Construction of proposed high-voltage transmission lines would alleviate the potential for power supply shortages in the Mid-Atlantic region for the near term, but ultimately new power plants will need to be constructed near the load centers in the Mid-Atlantic area as excess generation capacity in the western portion of PJM is absorbed.

The PSC is currently considering options to attract new generating resources to the state to ensure the reliability of electricity in Maryland. In September 2009, the PSC opened Case 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."[15] In September 2011, the PSC made a preliminary determination that new generation is needed to meet long-term, anticipated electricity demand in Maryland. Subsequently, the PSC directed the state's four investor-owned utilities to issue a Request for Proposals (RFP) that could result in as much as 1,500 MW of new natural gas-fired generation in Maryland. The PSC will hold a hearing in 2012 to consider all evidence on the record and make a final determination of the necessity of the RFP.

3.3 Transmission and Reliability

Historically, the transmission system enabled utilities to locate power plants near inexpensive sources of fuel, and transmit electricity over long distances to consumers. By interconnecting transmission systems, utilities were able to improve reliability by backing up each other's generating capacity. The power grid that began as a local structure grew into an interstate system subject to both federal and state regulation. The federal Energy Policy Act of 1992 required that any generator, independent or utility-owned, could 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 operators (RTOs), such as PJM, while maintaining ownership and maintenance responsibilities over their lines.

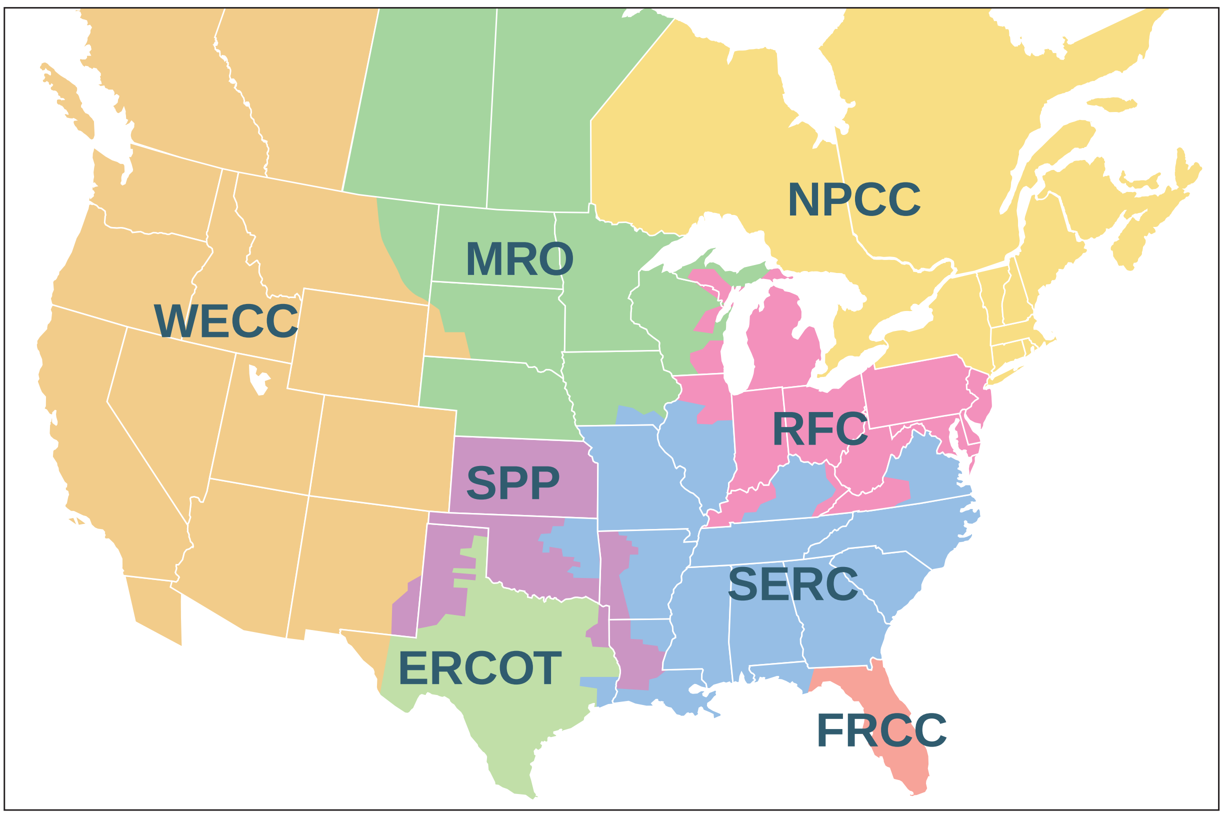
[15] PSC Order No. 82936, September 29, 2009.

3.3.1 Reliability

The North American Electric Reliability Corporation (NERC) is charged with developing guidelines and protocols for implementing standards and assessing the reliability of the bulk power system. NERC, which is governed by a 12-member independent board of trustees, develops reliability standards that are ultimately approved and made mandatory by the Federal Energy Regulatory Commission (FERC). Development of mandatory standards was part of the Energy Policy Act of 2005 prompted by the Northeast blackout of August 2003. NERC delegates enforcement authority to eight regional reliability councils, including the ReliabilityFirst Corporation that serves the PJM RTO (see Figure 3-3).

One of the reliability standards applicable to PJM is the Resource Planning Reserve Requirement. The standard requires that each LSE participating in the PJM Regional Transmission Organization have sufficient resources such that there is no loss of load from insufficient resources more than one day in ten years. In order to maintain

Figure 3-3 NERC Reliability Councils



Legend

WECC – Western Electric Coordinating Council
MRO – Midwest Reliability Organization
SPP – Southwest Power Pool
ERCOT – Electric Reliability Council of Texas
NPCC – Northwest Power Coordinating Council
RFC – ReliabilityFirst Corporation
SERC – SERC Reliability Corporation
FRCC – Florida Reliability Coordinating Council 2006.

Source: NERC, 2006 Long-Term Reliability Assessment, October 2006.

compliance under this reliability standard, PJM conducts annual resource planning exercises to ensure all LSEs have sufficient generation resources to supply their peak electricity load, plus a specified annual reserve margin of approximately 15 percent.

3.3.2 Congestion

The economic impacts of congestion are described in Section 3.2.1; however, congestion may also affect reliability when 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. When 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. While this type of congestion may result in economic consequences to the consumer, it is not due to higher electricity costs. Economic congestion that results in higher electricity costs is far more common than a loss-of-load, or blackout, caused by insufficient transmission or generation resources.

Eliminating key constraints can alleviate congestion. This may be achieved through construction of new transmission lines, building new generation within a load pocket, upgrades to limiting facilities/equipment, or demand side management. Transmission constraints, such as congestion, need to be ameliorated so that reliability violations do not emerge. Economic congestion is congestion that produces localized increases in electricity prices, but does not trigger a reliability event. This congestion may not be addressed in PJM's reliability planning since it is considered a business decision rather than a reliability problem. However, depending on the total economic impact and benefits, PJM may include corrective projects as part of its economic planning process.

3.3.3 PJM Transmission Planning

PJM conducts reliability studies in order to forecast potential problems and to plan for the expansion and upgrade of the transmission system to mitigate or alleviate problems. PJM's Regional Transmission Expansion Planning (RTEP) process incorporates a reliability assessment that models future load and energy use and highlights likely problems and the effectiveness of proposed grid improvements. PJM has authority over the transmission system and an obligation to maintain reliability. PJM can only put forward transmission solutions to reliability issues.[16] PJM cannot impose generation or demand response solutions, and includes in its studies only generation projects that have requested interconnection to the PJM grid and are at a relatively late stage of development, in the RTEP model. 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 in the modeling. Once a transmission constraint is identified, PJM authorizes construction and cost recovery

[16] PJM's RTEP process also considers market-based economically beneficial transmission enhancements, but the criteria for approving projects under this process is rigorous and to date, very few economic projects have been approved and constructed.

of transmission upgrades to address the area of concern. PJM mandated upgrades do not supercede state regulation, so projects may also require a CPCN depending on state siting and permitting regulations.

PJM is currently working on revising the RTEP process to incorporate public policy goals into the transmission planning process. Over the past several years, there has been an increasing focus on climate change policies by both federal and state governments. An important element of such policies is the greater use of renewable resources, including wind. Integrating wind resources, which are often distant from population centers, presents a unique set of challenges to planning new transmission. In addition, the RTEP planning process must address the need to strengthen the transmission system to accommodate the retirements of generating resources not able to meet environmental regulations associated with emission reduction goals.

On February 28, 2011, PJM released the 2010 RTEP report, which outlines planned system upgrades approved by the PJM Board through December 31, 2010. The PJM Board has approved more than $19 billion in transmission enhancements since the inception of PJM's RTEP process in 1997, ensuring that PJM is compliant with NERC reliability criteria.

Maryland RTEP Upgrades

The 2010 PJM RTEP lists seven potential reliability-related transmission upgrades for Maryland that cost over $5 million and two generation interconnection-related upgrades, for Calvert Cliffs and between Talbert and Oak Grove (shown in Table 3-4). If approved, the cost of these transmission upgrades would total $655 million.

Table 3-4 Maryland 2010 PJM RTEP Upgrades

Transmission Upgrade	Date	Cost $M	To Zone
Rebuild the Townsend – Church 138-kV circuit	June 2015	6.0	Delmarva
Rebuild the Glasgow – Cecil 138-kV circuit	June 2015	16.0	Delmarva
Build a second Raphael – Bagley 230-kV and rebuild the existing line	June 2015	18.0	BGE
Replace the Northeast 230/115-kV transformer #3	June 2015	10.1	BGE
Build a new 500/230-kV substation at Emory Grove and rebuild the Emory – North West 230-kV circuits	June 2015	71.0	BGE
Rebuild existing Erdman 115-kV substation to a dual-ring bus configuration and construct 115-kV double circuit underground line from Coldspring to Erdman substation	June 2015	139.6	BGE
Upgrade the terminal equipment at Doubs substation and rebuild Mt. Storm – Doubs transmission line in Maryland	June 2020	370.0	Potomac Edison
Construct transmission line at Calvert Cliffs	June 2017	10.5	Dominion
Upgrade conductors between Talbert and Oak Grove	June 2012	14.0	Pepco

Source: PJM 2010 RTEP.

Since the release of the 2010 RTEP, PJM has performed updated analyses for the system upgrades included in the report. Due to current conditions and a revised load forecast by PJM, the required in-service date for many of these projects has been delayed. The updated in-service dates for the projects listed in Table 3-4 can be found in the 2011 RTEP, which is expected to be released by PJM by spring 2012.

PJM Renewables Integration

By 2020, an estimated 34,000 MW of wind and 6,000 MW of solar energy will be needed to meet state RPS requirements in the PJM region. PJM estimates that by 2026, there will be about 135,000 GWh of renewable energy on its system, accounting for roughly 14 percent of PJM annual net energy. Wind and solar energy have a certain level of intermittency and variability in generation output. To facilitate the integration of these variable resources into its grid, PJM has implemented several measures to attend to the market, operational, and reliability issues of variable resources.

In addition to these measures, PJM also recently began undertaking a PJM Renewable Integration Study. The study will be a comprehensive renewable power integration study that will clarify what the operational, planning, and market effects are of large-scale integration of renewable power in PJM. It will also determine what mitigation and facilitation measures are available to PJM, and make recommendations regarding their implementation. The report is expected to be released in late 2012.

3.4 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.

3.4.1 Federal Energy Regulatory Commission

FERC is an independent regulatory arm of the U.S. Department of Energy (DOE). FERC authority derives from the Interstate Commerce Clause (Article I, US Constitution) and a large set of acts and regulations exercising that authority including primarily the Federal Power Act, the Natural Gas Act, 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 storage, interstate electric transmission, and import and export facilities for liquefied natural gas (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 some types of mergers and acquisitions by energy companies. FERC does not have authority over local or otherwise non-interstate reliability, rates, facilities and activities or over energy issues regulated by state energy authorities (such as the PSC) or regional energy authorities such as TVA.

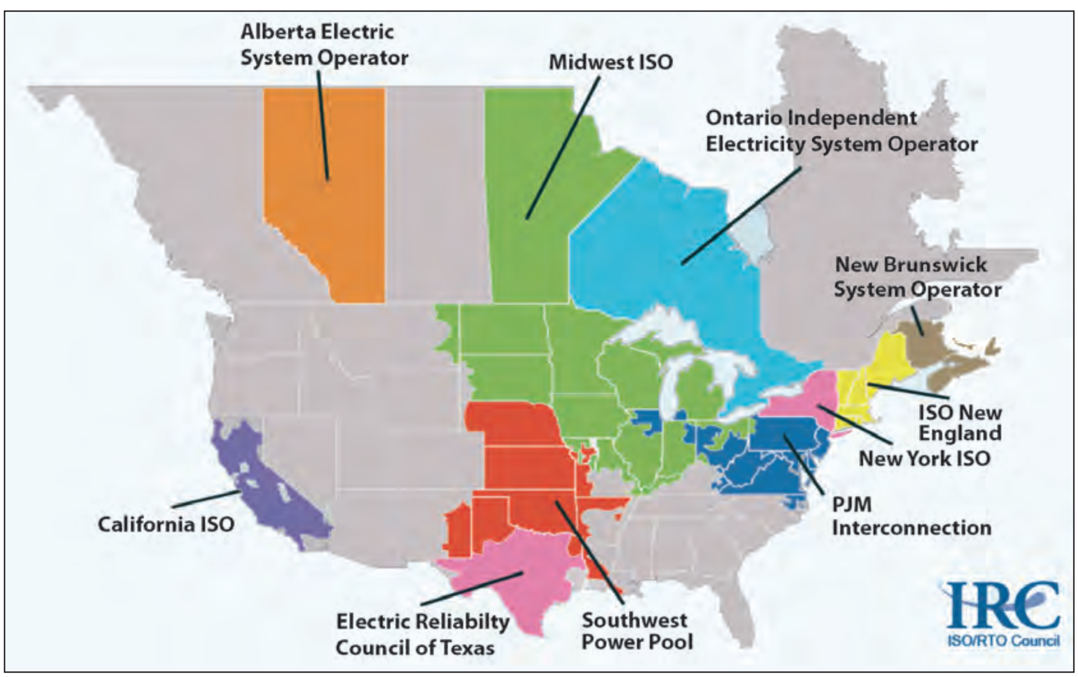
Electricity Transmission

FERC jurisdiction over wholesale transmission applies to entities that own, control, or operate interstate transmission facilities, primarily investor-owned utilities. This generally does not 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 (ERCOT) 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 ERCOT). North American RTOs are shown in Figure 3-4.

Congress, through the Energy Policy Act of 2005, directed FERC to establish rules that provide economic incentives for new transmission lines including incentive rate structures and tax incentives. The first planned transmission projects in PJM to be awarded new rate incentives from FERC were the Potomac-Appalachian Transmission Highline (PATH) and Trans-Allegheny Interstate Line (TrAIL). In August 2008, FERC approved incentive rates for another planned regional high-voltage line, the Mid-Atlantic Power Pathway (MAPP) Project. And recently in 2011, FERC approved incentive rate treatment for the planned offshore Atlantic Wind Connection transmission line, provided it is included in PJM's RTEP.

The Energy Policy Act of 2005 also directed DOE to conduct triennial congestion studies and designate National Interest Electric Transmission Corridors (NIETCs) within which FERC would have backstop authority

Figure 3-4 North American Regional Transmission Operators



over transmission projects. DOE identified the Mid-Atlantic region, from Ohio and West Virginia to northern New York, as one of two NIETCs and designated this region, including all of Maryland, as the Mid-Atlantic Area National Corridor. An NIETC designation means that additional transmission capacity in this area is so critical that FERC may overrule state utility commissions and issue permits for regional transmission projects that are deemed to be in the national interest. This authority, however, was challenged and overturned in the U.S. Court of Appeals. Additionally, the NIETC designations were invalidated by the Federal Appeals Court, which concluded that DOE failed to provide sufficient state consultation and to consider the environmental consequences of designating such corridors.

Following the court's decision, DOE considered a plan under which it would transfer its NIETC authority to FERC. The resulting proposal was strongly opposed by the states, however, and U.S. Energy Secretary Steven Chu announced in October 2011 that DOE would not be adopting the proposal. Secretary Chu also stated that DOE would work more closely with FERC in reviewing proposed electric transmission projects. The next congestion study is due to Congress in 2012, and DOE is currently conducting regional workshops to receive input and suggestions from stakeholders.

The Obama Administration has been working to expedite the construction of seven new backbone transmission projects slated to improve the reliability and security of the nation's electrical system. The proposed projects include over 3,100 miles of new transmission lines spread across 12 states. In addition to purportedly creating thousands of new jobs, these projects are intended to serve as pilot demonstrations of streamlined federal permitting and improved cooperation among federal, state, and tribal governments. One of the proposed projects, the Susquehanna to Roseland Line, is a 145-mile, 500-kV transmission line that would stretch from Pennsylvania to New Jersey.

Transmission Planning and Cost Recovery

FERC originally issued Order No. 888 in April 1996, establishing requirements for transmission planning, both at the 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 providing transparent comparable service to all customers.

In February 2007, FERC issued Order No. 890, which 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 outlined new criteria for transmission planning including:

- *Transmission planning meetings must be open to all affected parties;*
- *Transmission providers are required to disclose the basic criteria, assumptions, and data used to create transmission system plans;*
- *Transmission providers must treat all similarly-situated customers comparably;*

- *Regional Coordination – transmission providers are required to coordinate their planning with neighboring transmission providers; and*
- *Economic Planning Studies – transmission providers are required to conduct studies that identify 'significant and recurring' transmission congestion to ensure that transmission planning incorporates more than just reliability.*

In July 2011, FERC issued Order 1000 to amend some of the transmission planning and cost allocation requirements established in Order 890. FERC noted that regional transmission planning processes have improved but some deficiencies remained.

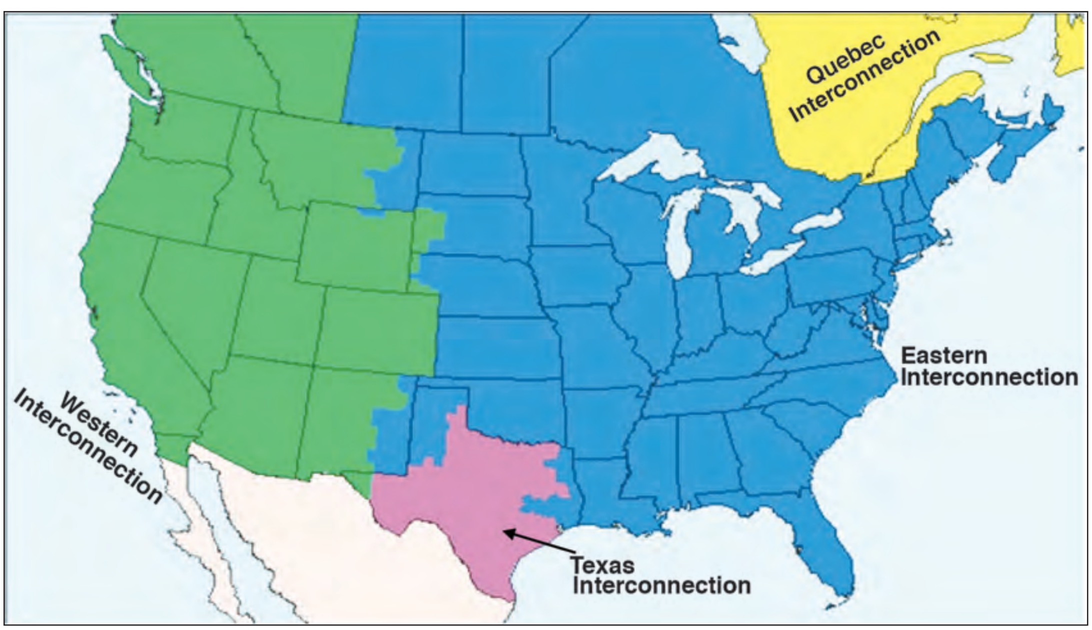
Order 1000 included several reforms with respect to transmission planning by FERC-jurisdictional entities including:

- *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 develop a method for allocating costs for new

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 the Texas Interconnection.



Source: The Land Trust Alliance. http://www.landtrustalliance.org/policy/emerging-issues/energy-development/nced.

transmission facilities that follow principles that FERC sets out, with one set of principles for intraregional facility cost allocation and another for interregional facilities. The methodology can include different cost allocation schemes for different types of projects driven by different needs, i.e., reliability, economic, and public policies.

Hydroelectric and Liquefied Natural Gas

Unless a project has a valid pre-1920 federal permit, non-federal 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 waterpower from a federal dam (such as an Army Corps of Engineers facility); and/or*
- *Is located on a body of water over which 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 process that incorporates interagency processes such as the 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 or operating inside the state waters limit. State waters are generally about 3 nautical miles from shore, but this distance varies in some areas, such as Gulf of Mexico and Puerto Rico where this limit is 9 nautical miles out.

3.4.2 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' operations, 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. 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. For example, Constellation is currently seeking a license renewal from the NRC for the on-site ISFSI at Calvert Cliffs. PPRP is coordinating the State's involvement in the

NRC re-licensing process, which involves reviewing the environmental impacts as described by Constellation; see more information in Section 2.4.1 of this report.

3.4.3 The Role of the EPA

The Clean Air Act (CAA) is the law that defines the responsibilities of the U.S. Environmental Protection Agency (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, the regulations are referred to as New Source Review (NSR). Major NSR covers the construction, modification, or reconstruction of certain "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.

As previously stated, under Maryland PSC regulations, power plants in Maryland are required to obtain a CPCN prior to constructing new power plants or modifying existing power plants. The CPCN serves as the air quality permit to construct for the proposed project, including PSD and NA-NSR permits. For all PSD or NA-NSR permits issued by the State, EPA Region III 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 by the State on issues that are new or developing.

EPA has responsibilities outside the CPCN process as well. 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 the Maryland Department of the Environment (MDE). The draft permits are submitted to EPA Region III for review. Final permits are issued by MDE. The conditions within the permits are federally enforceable and compliance with certain permit conditions requires submittal to EPA Region III.

3.5 Impacts of Other State and Local Decisions

The PSC is responsible for granting or denying CPCNs for new and modified transmission line projects within the state. However, other regulating entities, such as other states and local governments, may influence whether a proposed project can be permitted and/or constructed in its entirety. Transmission line projects that are proposed in multiple states will need to obtain the approval of each state's permitting authority before construction on that portion of the line can commence. For example, the proposed PATH Project (described in Section 2.5.1) would extend across West Virginia, Virginia, and Maryland, and therefore would need to obtain a separate CPCN from the West Virginia PSC, Virginia's State Corporation Commission, and the Maryland PSC, in addition to several other environmental permits within each state. If one of these states were to deny a CPCN application for the construction of the project within that state, the project would likely require a redesign in order to move forward or would be abandoned. The complete listing of permitting and approvals necessary to construct a new transmission line in Maryland is found in Appendix A.

3.5.1 Substation and Converter Station Siting

As part of PSC Case 9198, the PSC determined that a CPCN encompasses all components of a project that are integral to a proposed transmission line, including, where appropriate, substations. This ruling would effectively place the approval of such a substation under the jurisdiction of the PSC. A similar situation would likely apply to the converter stations associated with the HVDC transmission line segments of the proposed MAPP Project.

3.5.2 Entities Eligible to Obtain a CPCN

As part of the decision rendered in PSC Case 9198, the PSC found that that the Potomac Edison Company (doing business as Allegheny Power) may not seek authorization to construct a transmission line on behalf of its non-electric company affiliate PATH Allegheny, LLC. The PSC found that Maryland statute allows CPCNs to be issued only to Maryland electric companies.[17]

In another case, Big Savage, LLC filed an application with the PSC in December 2010 for a CPCN to construct a transmission line from a proposed wind energy facility in Somerset County, Pennsylvania to an existing substation, now owned by Potomac Edison, in Frostburg, Maryland. The PSC declined this application in January 2011 under the basis that: (i) Big Savage, LLC is not a Maryland electric company, and (ii) only the transmission line portion of the proposed wind energy facility would be located within the state. If both the generating facility and "its associated overhead transmission lines" were to be located in Maryland, the application could have been accepted. During the 2011 legislative session, HB 590 was passed to effectively amend PUC §7- 207(a)(2) to define a qualified generator lead line as "an overhead transmission line that is designed to carry a voltage in excess of 69,000 volts and would allow an out-of-state Tier 1 or Tier 2 renewable source to interconnect with a portion of the electric system in Maryland that is owned by an electric company". Subsequently, Big Savage filed an updated application and a CPCN was granted for this project by the PSC in September 2011.

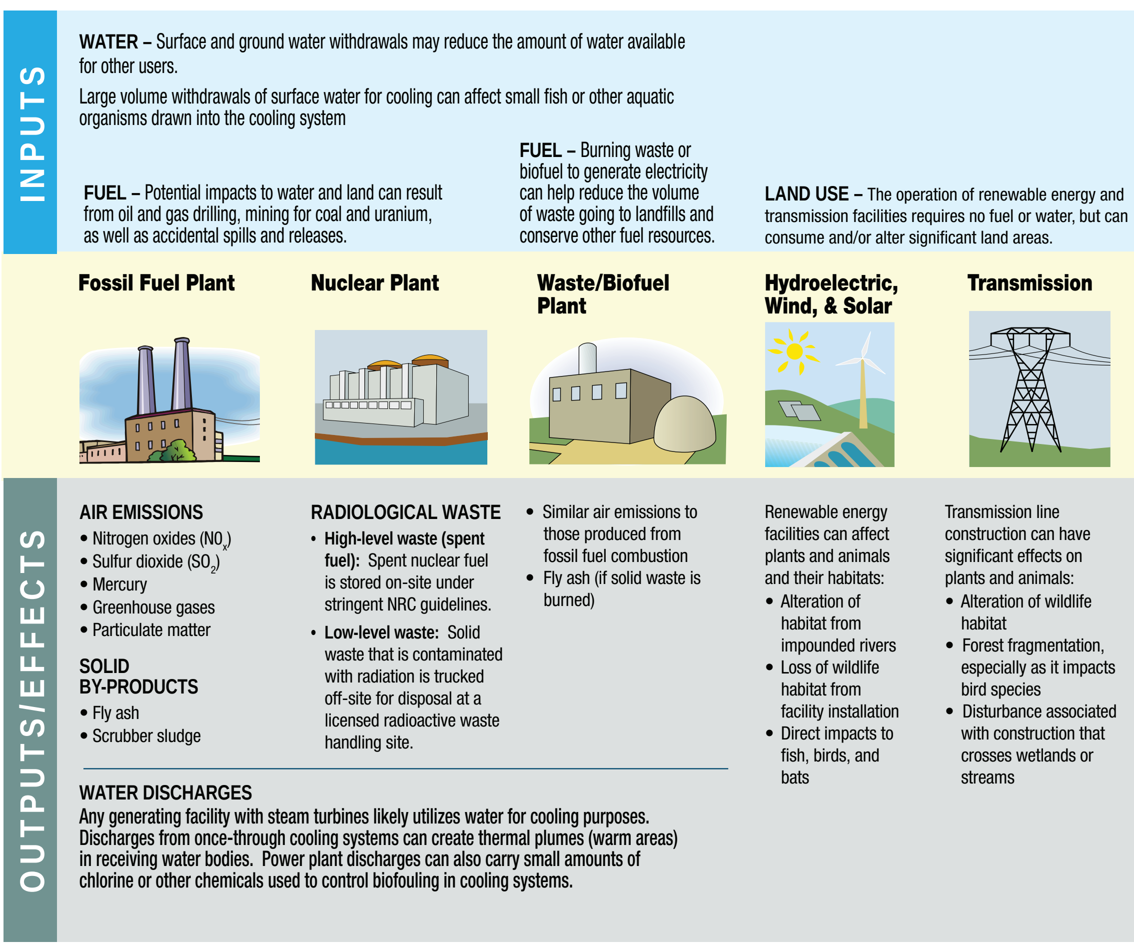
[17] According to PUC §1-101, an "electric company" means a person who physically transmits or distributes electricity in the State to a retail electric customer. A "person" is defined as an individual, receiver, trustee, guardian, personal representative, fiduciary, or representative of any kind and any partnership, firm, association, corporation, or other entity.

Chapter 4 – Impacts of Power Generation and Transmission

Electricity opens a field of infinite conveniences to ever greater numbers, but they may well have to pay dearly for them.

– Winston Leonard Spencer Churchill
Address to the Royal College of Surgeons (1951)

Electricity supply is a public good that 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 figure illustrates some of the primary environmental impacts associated with electricity generation and transmission in Maryland.

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, and/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.

4.1 Impacts from Generating Facilities

4.1.1 Air Quality Overview

The federal 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 cause harmful effects to human health. The year 2010 marked the 40th anniversary of the CAA, which was originally signed on December 31, 1970 by President Nixon, "to foster the growth of a strong American economy and industry while improving human health and the environment".[18] The CAA authorized the United States Environmental Protection Agency (EPA) to develop ambient air quality standards — referred to as National Ambient Air Quality Standards (NAAQS) — for six common air pollutants ("criteria" pollutants). The NAAQS represent the maximum pollutant concentrations that are allowable in ambient air. "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. Table 4-1 lists the current NAAQS.

Clean Air Started Here

The concern with air pollution in the United States is said to have begun in the small town of Donora, Pennsylvania, more than 60 years ago. Although smog was a predominant problem in large cities like Los Angeles dating back to the early 1900s, it was not until October 1948, when emissions from U.S. Steel's zinc and steel mills were said to have killed 22 people and made almost half of Donora's residents sick, that the government acknowledged that air pollution was a problem. In 1949, following this incident, Allegheny County, Pennsylvania adopted a smoke control ordinance. Soon after, the U.S. Air Pollution Control Act of 1955, the first piece of federal legislation to recognize pollution as a problem, was enacted. To promote ongoing efforts to control air pollution, Donora recently commemorated this tragic event by opening the doors to the Donora Smog Museum, whose motto is "Clean Air Started Here".

[18] http://www.epa.gov/air/caa/40th.html

Table 4-1 National Ambient Air Quality Standards as of July 2011

	Primary Standards		Secondary Standards	
Pollutant	**Level[a]**	**Averaging Time**	**Level**	**Averaging Time**
CO (carbon monoxide)	9 ppm (10 mg/m^3)	8-hour	None	
	35 ppm (40 mg/m^3)	1-hour		
Lead	0.15 µg/m^3	Rolling 3-month average	Same as Primary	
	1.5 µg/m^3 (1978 standard)	Quarterly average[b]	Same as Primary	
NO_2 (nitrogen doxide)	0.053 ppm	Annual (arithmetic average)	Same as Primary	
	100 ppb	1-hour	None	
PM10 (particulate matter < 10 microns)	150 µg/m^3	24-hour	Same as Primary	
PM2.5 (particulate matter < 2.5 microns)	1.5 µg/m^3	Annual (arithmetic average)	Same as Primary	
	35 µg/m^3	24-hour	Same as Primary	
Ozone	0.075 ppm (2008 standard)	8-hour	Same as Primary	
	0.08 ppm (1997 standard)	8-hour	Same as Primary	
	0.12 ppm	1-hour[c]	Same as Primary	
SO_2 (sulfur dioxide)	0.03 ppm	Annual (arithmetic average)[d]	0.5 ppm	3-hour
	0.14 ppm	24-hour[d]		
	75 ppb	1-hour	None	

Source: EPA, http://epa.gov/air/criteria.html

[a] NAAQS concentrations are expressed by EPA in different units of measure, depending on the pollutant and averaging period: micrograms per cubic meter (µg/m^3), milligrams per cubic meter (mg/m^3), parts per million (ppm), or parts per billion (ppb).

[b] The 1978 lead standard (1.5 µg/m^3) remains in effect until one year after an area is designated for the 2008 standard, except for nonattainment areas for which there are additional requirements.

[c] EPA revoked the 1-hour ozone standard in all areas of the country; some parts of the country have continuing "anti-backsliding" obligations.

[d] In December 2009, EPA proposed to revoke both the 24-hour and annual average primary SO_2 standard and replace it with a new short-term standard between 50-100 ppb on a 1-hour average basis.

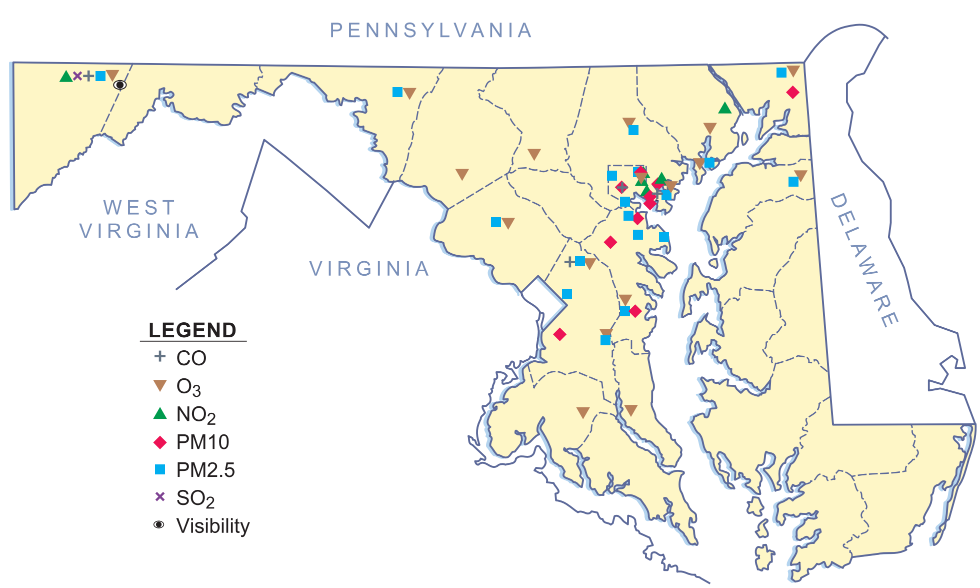
The six criteria pollutants, most of which are emitted by fossil fuel-fired power plants, are as follows:

- *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) – also 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. PM10, for example, contains particles smaller than 10 microns in diameter. PM2.5, also referred to as "fine" particulate matter, is composed of particles 2.5 microns in diameter or smaller.*
- *Carbon monoxide (CO) – formed by incomplete combustion of carbon-based fuels during the combustion process.*
- *Lead (Pb) – a metal emitted into ambient air in the form of PM.*
- *Ozone (O_3) – is 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.*

EPA, along with state and local regulatory agencies, monitor concentrations of the criteria pollutants near ground level at various locations across the country. The monitoring locations in Maryland are shown in Figure 4-1. If monitoring indicates that the concentration of a pollutant exceeds the NAAQS in any area of the country, that area is labeled a "nonattainment area" for that pollutant, meaning that the area is not attaining the national ambient air quality standard. Conversely, any area in which the concentration of a criteria pollutant is below the NAAQS is labeled an "attainment area" for that pollutant.

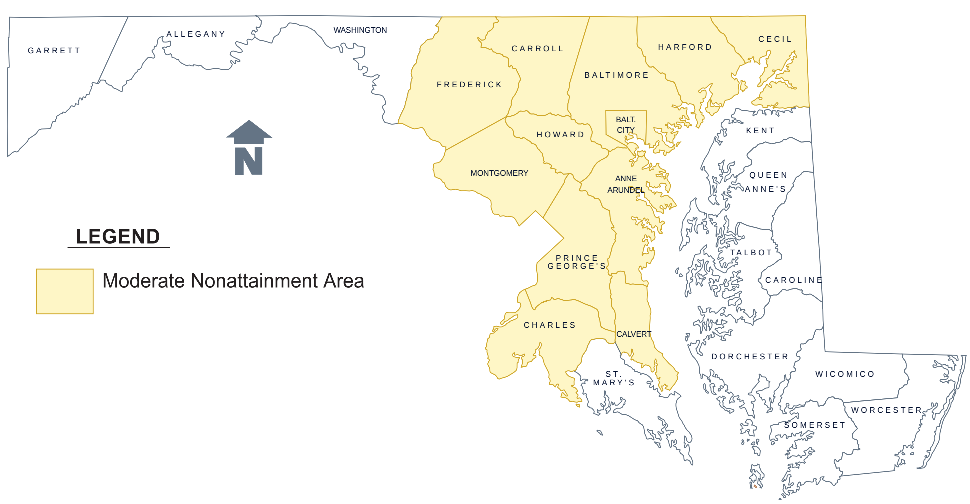
Figure 4-1 Maryland Monitoring Station Locations



The attainment/nonattainment designation is made 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 many air regulatory requirements are based in part on whether a source is located in an attainment area, where emissions must be limited to ensure the air stays clean, 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 (SO_2, NO_2, PM10, CO, and lead). The entire State of Maryland is designated attainment for the 24-hour PM2.5 standard; however, the Baltimore, Washington, D.C., and Hagerstown areas are designated nonattainment for the annual PM2.5 standard. In addition, much of the urbanized portion of Maryland, like densely populated areas across the eastern U.S., is not meeting the NAAQS for ozone. Ozone is recognized as a regional pollutant, rather than a local issue, thus in the CAA, Congress recognized that ozone pollution and its precursors can be transported from state to state. The Act created the Northeast Ozone Transport Region (OTR), comprised of 12 states (including Maryland) and the District of Columbia. As part of the OTR, the entire State must follow nonattainment area requirements as if all counties were ozone nonattainment areas, even though ozone monitoring indicates that many counties are in attainment. Figure 4-2 depicts current ozone nonattainment area designations in Maryland.

Figure 4-2 Ozone Nonattainment Areas in Maryland (1997 Standard)



EPA routinely evaluates the NAAQS to determine whether more stringent or different standards are warranted. For example, EPA has lowered the standard for ozone several times in recent years. EPA had been considering setting a new, lower standard for ozone in 2011; however, in September of that year, the Obama Administration announced that they would withdraw ozone NAAQS at this time. The 2006 ozone standard will be reviewed in 2013, as planned. In one of the more significant changes to the NAAQS in recent years, EPA finalized new, short-term (1-hour) ambient standards for NO_2 and SO_2 in 2010. The standards are stringent and many affected sources are having a difficult time demonstrating that new and modified operations are not affecting the ability of states to meet the new ambient standards. In other recent and upcoming NAAQS actions, EPA is scheduled to review and possibly revise ambient standards for CO, NO_2, SO_2, and PM during 2011.

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 larger sources, which in turn, likely means another round of regulation.

Air Quality Regulatory Challenges Facing Coal-Fired Power Plants

Over the course of 2011, EPA intends to propose or promulgate a series of new air quality regulations related to greenhouse gases (GHGs), hazardous air pollutants (HAPs), and NO_x and SO_2 emissions that have significant implications for power plants and other large stationary sources. Each of these regulations could require significant capital investment by power plants for the installation and operation of new air pollution control systems. In addition to new air quality requirements, EPA has plans to implement new cooling water intake structure requirements under Section 316b of the Clean Water Act, and is actively evaluating the regulatory framework to address coal ash management. These regulatory initiatives could also require substantial investments by plants to comply with the new requirements. This confluence of regulatory initiatives has led many to speculate on the future of coal in the U.S.

Among the most significant new air regulations that will affect power plants are:

- GHG Tailoring Rule for the first time, beginning in January 2011, requires Prevention of Significant Deterioration permit review, including Best Available Control Technology (BACT) level of pollution control, for major sources of GHGs.
- Cross-state Air Pollution Rule (CSAPR), formerly referred to as the “Transport Rule” or the “Clean Air Transport Rule” (CATR), is EPA’s replacement program for the original federal multi-pollutant regulation known as the Clean Air Interstate Rule (CAIR). CSAPR is the latest cap-and-trade program for NO_x and SO_2 emissions from power plants in the eastern half of the U.S. designed to address issues related to ozone and PM2.5 pollution. CSAPR requires substantial reductions in NO_x and SO_2 emissions from affected power plants beginning as early as 2012. In Maryland, CSAPR pollutant caps are lower than the already stringent NO_x and SO_2 limitations on coal-fired power plants established under the Maryland Healthy Air Act (HAA) of 2006.
- New Source Performance Standards (NSPS) for GHGs will establish standards for GHGs from new power plant sources, and emissions guidelines for GHGs from existing power plants.
- Maximum Achievable Control Technology (or “Utility MACT”) Standards for HAPs from power plants was proposed by EPA in March 2011, and replaces the former federal power plant mercury rule, the Clean Air Mercury Rule. The new “Utility MACT” establishes stringent emissions limits for mercury and other metallic toxics, acid gases, and organic air toxics from coal- and oil-fired electric generating units.
- National Ambient Air Quality Standards (NAAQS)—During 2011, EPA is scheduled to review and possibly revise ambient standards for ozone, CO, NO_x, SO_2, and PM. While the NAAQS themselves do not directly affect power plants and other sources, lowering of the ambient standards means that EPA and states must eventually establish more stringent emissions limits and control technology requirements for larger sources like power plants.

Emissions from Power Plants

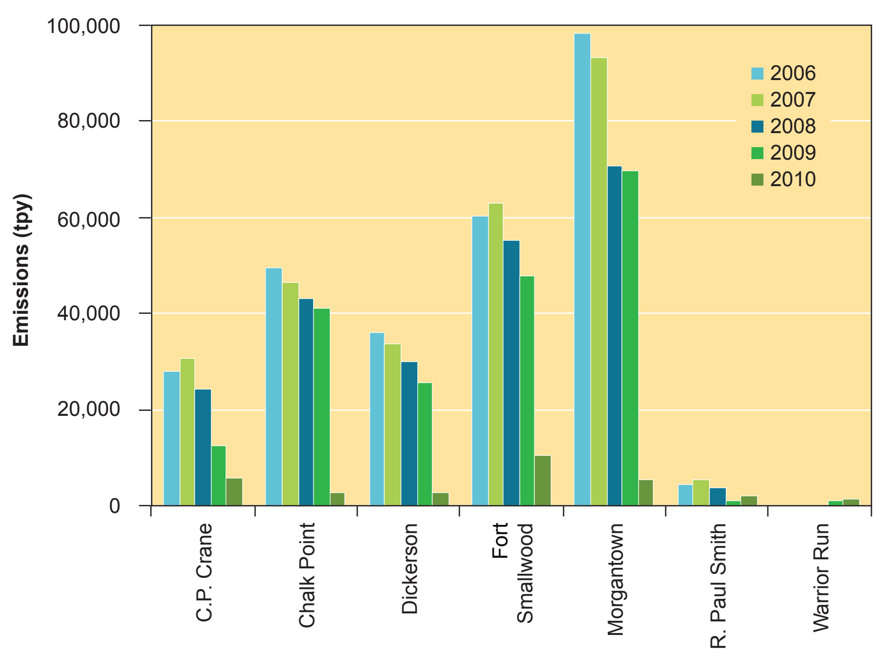
Power plants in the U.S. are a major source of air emissions. They contribute about 19 percent of all NO_x, 66 percent of SO_2, 72 percent of mercury, and about 39 percent of CO_2 emissions emitted by all industrial sectors, including transportation (based on 2008 emissions data)[19]. These emissions are often discussed in terms of three classes of pollutants: criteria pollutants, hazardous air pollutants (HAPs), and greenhouse gases (GHGs).

Criteria Pollutants: SO_2, NO_x, and PM Emissions

Among the six 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. Recently, there has also been an increased focus on PM (both PM10 and PM2.5) emissions, as EPA has recognized that particulates are associated with adverse health effects, including premature mortality, cardiovascular illness, and respiratory illness. EPA continually tries to better understand which attributes of particles may be causing 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 the contributions are from various sources in the different regions of the country. This research has allowed EPA to shift its focus over time from regulating emissions of total suspended particulates to PM10, and most recently to PM2.5.

Coal-fired power plants are significant contributors of SO_2, NO_x, and PM10 emissions nationwide and in Maryland. Figures 4-3 through 4-5 show trends in SO_2, NO_x, and PM10 emissions, respectively, from coal-fired power plants in Maryland during the years 2006 to 2010. The emissions of SO_2 and PM10 are dependent on the types and amounts of coal used at these generating units and the type, age, and configuration of

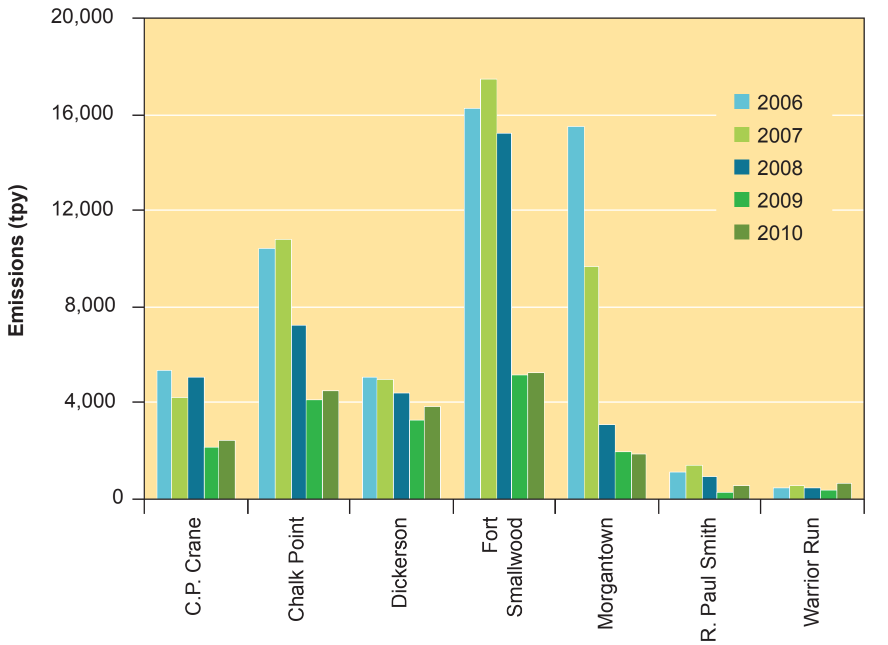
Figure 4-3 Maryland Coal-Fired Power Plant Annual SO_2 Emissions



Note: Fort Smallwood includes the co-located Brandon Shores and H.A. Wagner power plants.
Source: EPA's Clean Air Markets (http://www.epa.gov/airmarkets).

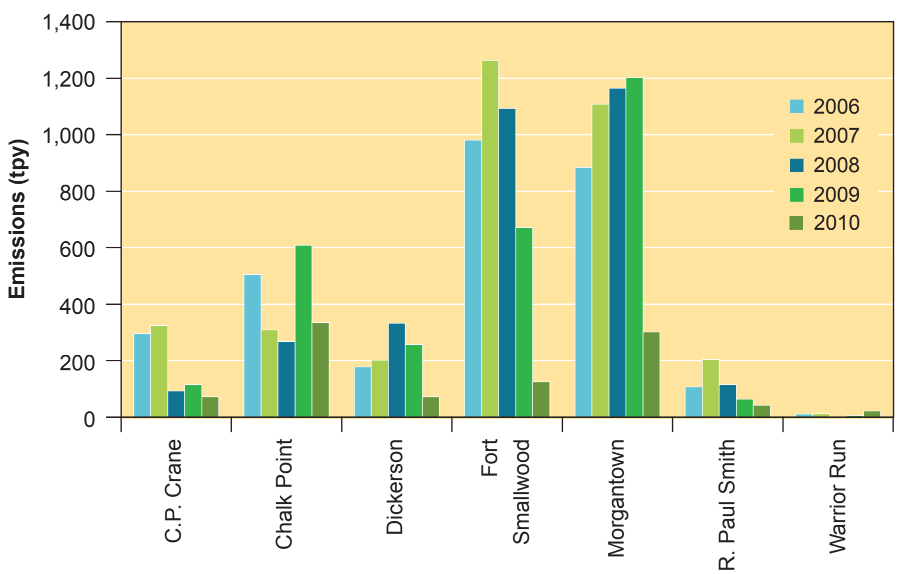
[19] M. J. Bradley & Associates (2010). *Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States.*

Figure 4-4 Maryland Coal-Fired Power Plant Annual NO_x Emissions



Note: Fort Smallwood includes the co-located Brandon Shores and H.A. Wagner power plants.
Source: EPA's Clean Air Markets (http://www.epa.gov/airmarkets).

Figure 4-5 Maryland Coal-Fired Power Plant Annual PM10 Emissions



Note: Fort Smallwood includes the co-located Brandon Shores and H.A. Wagner power plants.
Source: MDE Emission Summary Reports.

existing air pollution control equipment. Most coal-fired power plants in Maryland recently installed state-of-the-art pollution control systems for SO_2, NO_x, and mercury to meet requirements of the Maryland Healthy Air Act (HAA) (see page 84). For example, a wet gas flue gas desulfurization (FGD) scrubber, sorbent injection systems, and fabric filters were installed at Brandon Shores in late 2009 and Wagner switched to burning lower sulfur coal in 2010. With these changes, these two co-located facilities (known as "Fort Smallwood") have significantly reduced their SO_2 emissions. C.P. Crane also switched to burning low sulfur coals in 2010, which should result in significant decreases in SO_2 emissions. Similar significant SO_2 reductions can be seen at Morgantown, Dickerson, and Chalk Point due to the installation of FGD scrubbers at those facilities as well.

Annual emissions of NO_x also depend on the types and amounts of coal burned and pollution control systems in place. However, unlike SO_2 and PM10 emissions, NO_x emissions have been regulated more stringently and for a longer period of time. NO_x emissions from power plants have been declining due to installation of control equipment and process changes. NO_x emissions from Fort Smallwood (Brandon Shores and Wagner) began to be reduced in 2009 with operation of the existing selective catalytic reduction (SCR) systems year-round, which previously operated only during ozone season, on Brandon Shores Unit 1 and Unit 2 and Wagner Unit 3. Additionally, a selective non-catalytic reduction (SNCR) system was installed on Wagner Unit 2 in 2009. NO_x emissions from Crane and Morgantown decreased prior to 2009 due to process control/process optimization software installed at Crane and SCR systems installed on both of the large coal-fired generating units at Morgantown. Additionally, SNCR systems were installed on C.P. Crane Unit 1 and Unit 2 and operations of the systems began in 2009.

Hazardous Air Pollutant Emissions

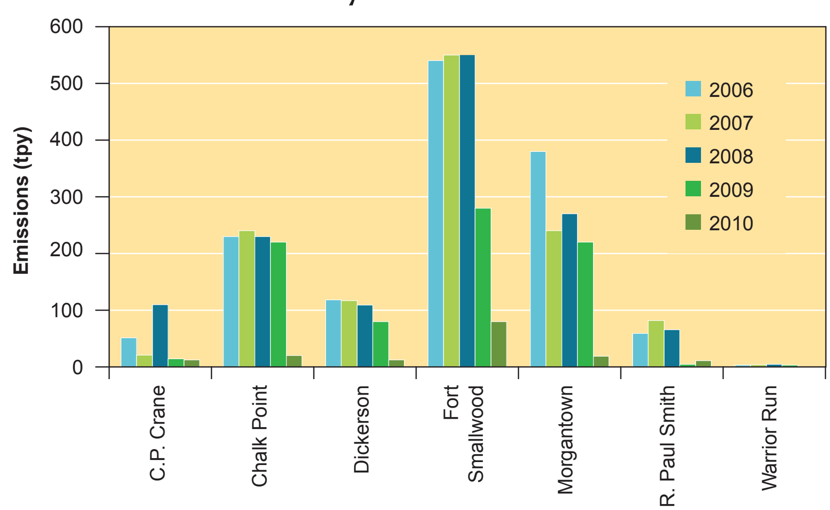
In 1990, Congress amended the CAA to regulate a class of pollutants that cause or might cause an adverse impact to health or the environment. These pollutants are referred to as hazardous air pollutants, or HAPs. There are currently 187 pollutants on EPA's list of CAA HAPs. Although some HAPs can occur 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. Many states, including Maryland, have developed toxic air pollutant (TAP) regulations, fuel burning sources in Maryland are exempt from State TAP regulations.

Among the HAPs emitted by power plants, mercury is a pollutant of particular concern because of its significant adverse health effects. Coal-fired power plants account for nearly 75 percent of the total mercury and mercury compounds emitted in Maryland in any given year. Figure 4-6 presents annual emissions of mercury from Maryland's coal-fired power plants from 2006 through 2010 based on information in EPA's Toxic Release Inventory (TRI).

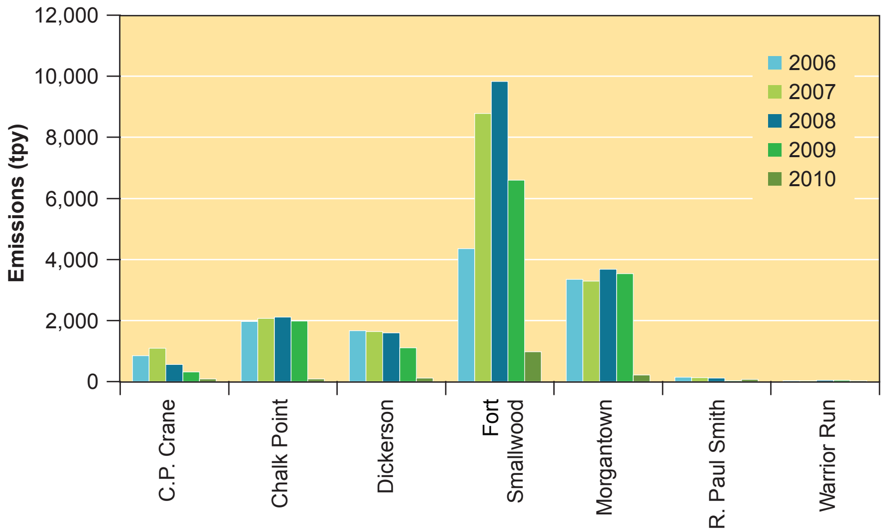
Figure 4-7 presents annual emissions of HAPs, as reported to EPA by

Figure 4-6 Maryland Coal-Fired Power Plant Annual Mercury Emissions



Note: Fort Smallwood includes the co-located Brandon Shores and H.A. Wagner power plants.
Source: EPA's Toxics Release Inventory Reports (http://www.epa.gov/tri).

Figure 4-7 Maryland Coal-Fired Power Plant Toxic Pollutant Emissions

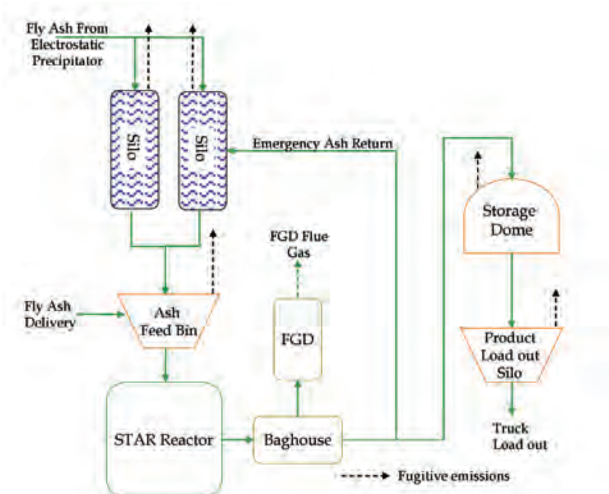


Note: Fort Smallwood includes the co-located Brandon Shores and H.A. Wagner power plants.
Source: EPA's Toxics Release Inventory Reports (http://www.epa.gov/tri).

Morgantown STAR Project Fly Ash Beneficial Reuse Project – Air Quality Impacts

On January 31, 2011, the Maryland Public Service Commission (PSC) granted a Certificate of Public Convenience and Necessity (CPCN) authorizing GenOn Mid-Atlantic, LLC to construct and operate a fly ash "beneficiation" project at the Morgantown Generating Station in Charles County, Maryland. The proposed project includes the installation of a proprietary technology, called a "Staged Turbulent Air Reactor" or STAR reactor, designed to thermally process fly ash from the Morgantown and nearby Chalk Point power plants. The STAR project would handle approximately 360,000 tons of fly ash per year produced primarily at Morgantown and Chalk Point, thereby diverting a substantial quantity of high-carbon fly ash, which would otherwise be sent off-site for landfilling, into a low-carbon material more suitable for commercial reuse as road-building materials.

Morgantown STAR Process Flow Diagram



Although the project has significant environmental benefits, it is not without its air quality concerns. GenOn is equipping the STAR reactor with high efficiency fabric filters to control PM emissions, and an FGD scrubber system to reduce potential SO_2 and other acid gas emissions. Due to the variability of mercury concentrations in fly ash, potential mercury emissions from the STAR process reactor were closely evaluated. In an effort to reduce Maryland's contribution to mercury deposition impacts in northeastern U.S. waterways, mercury emissions from the STAR facility are limited by license to no more than 5 lb/year.

Maryland's coal-fired power plants under the TRI program. The quantity of HAPs reported in the TRI database by power plants is significant, due in large part to the volume of hydrochloric acid (HCl) being emitted from coal-fired power plants. In response to the Maryland HAA, many coal-fired power plants in Maryland are installing FGD scrubber systems, primarily for SO_2 control; however, the scrubbers also reduce HCl and other acid gas emissions.

Greenhouse Gas Emissions

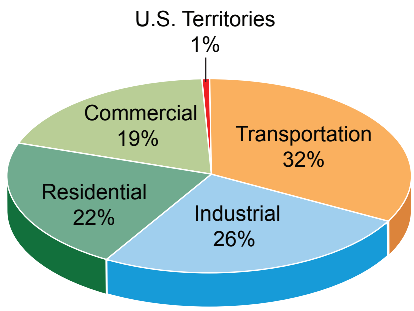
A GHG is broadly defined as any gas that absorbs infrared radiation in the atmosphere. Common GHGs include water vapor, CO_2, methane, NO_x, ozone, hydrochlorofluorocarbons (HCFCs), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). EPA recently issued a Greenhouse Gas Reporting Rule and other regulations (see Section 5.2 for details) that address GHGs. The principal GHGs that enter the atmosphere above natural levels 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—Hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride 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., CFCs, 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.*[20]

According to EPA, total GHG emissions in the United States increased by 7.3 percent from 1990 to 2009; however, GHG emissions decreased by 6.1 percent from 2008 to 2009. The primary factors contributing to the recent decrease in GHG emissions are the decrease in energy consumption due to decrease in economic output, increased usage of lower carbon intensity fuels to generate power, and the increase in natural gas usage due to lower costs.[3] As Figure 4-8 illustrates, the four major sectors contributing to CO_2 emissions from fossil fuel consumption (as defined by EPA) are transportation, industrial, residential, and commercial. The EPA report[3] breaks down the major sectors even further into electricity generation (power plants) and combustion. Figure 4-9 illustrates CO_2 emissions from Maryland power plants for the years 2006 through 2010. In 1990, the electricity portion accounted for 38.4 percent of the total GHG emissions; in 2009, the electricity portion accounted for more than 41 percent of total GHG emissions.

[20] EPA. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009.

Figure 4-8 Breakdown of Annual CO_2 Emissions by Source Type

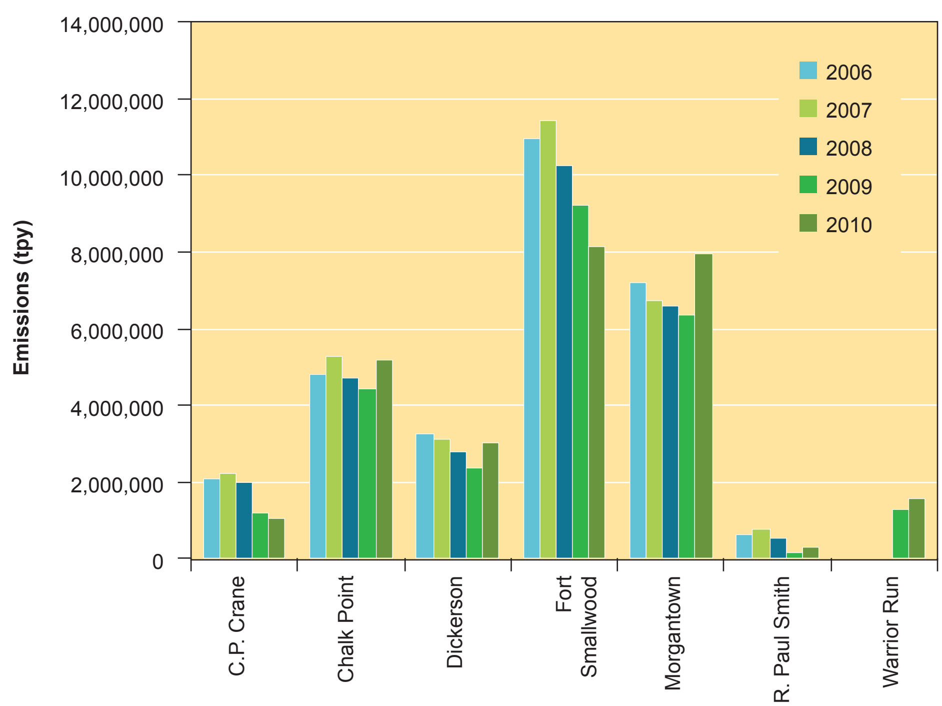


Note: Emissions as reported in Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009, April 15, 2011, EPA Office of Atmospheric Programs (http://www.epa.gov/climatechange/emissions/usinventoryreport.html).

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

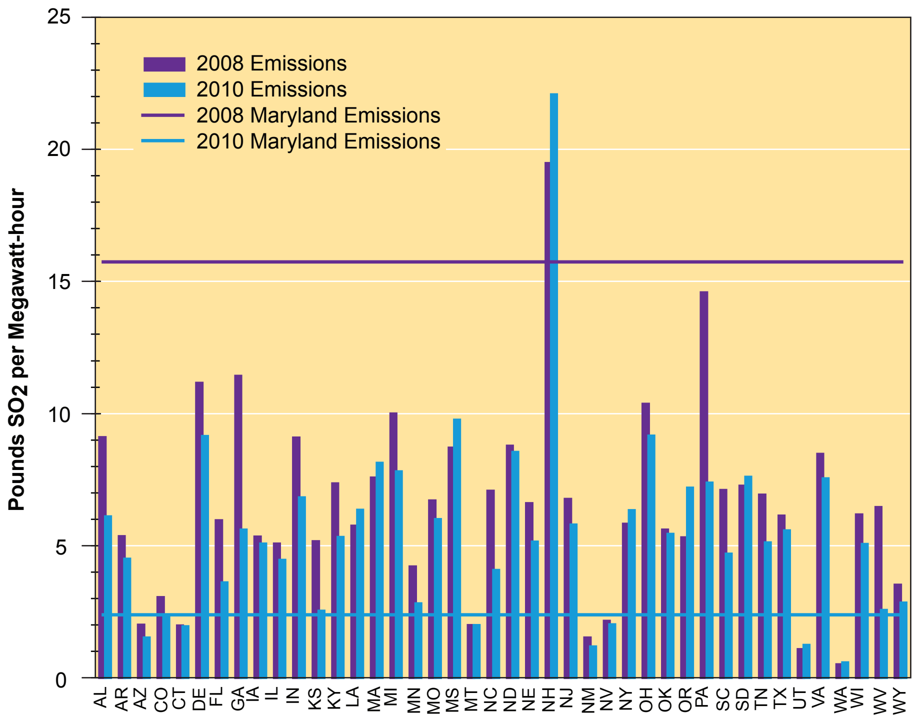
To put Maryland's power plant emissions in perspective, Figures 4-10 and 4-11 present a comparison of SO_2 and NO_x emissions from coal-fired power plants in Maryland with emissions from coal-fired power plants in other states. These figures represent the emissions (in pounds per megawatt-hour (MWh) of power generated) from states in which coal represents a significant proportion of the fuel mix, as reported in EPA's Clean Air Market database. As seen in Figure 4-10, Maryland's power plants in 2008 were collectively among the highest SO_2 emitting plants; however, beginning in 2010, emissions decreased dramatically with the implementation of the HAA. Maryland's coal-fired power plants were among the lower emitting NO_x sources in 2008; NO_x emissions were reduced further in 2010 under the HAA.

Figure 4-9 Maryland Power Plant Annual CO_2 Emissions



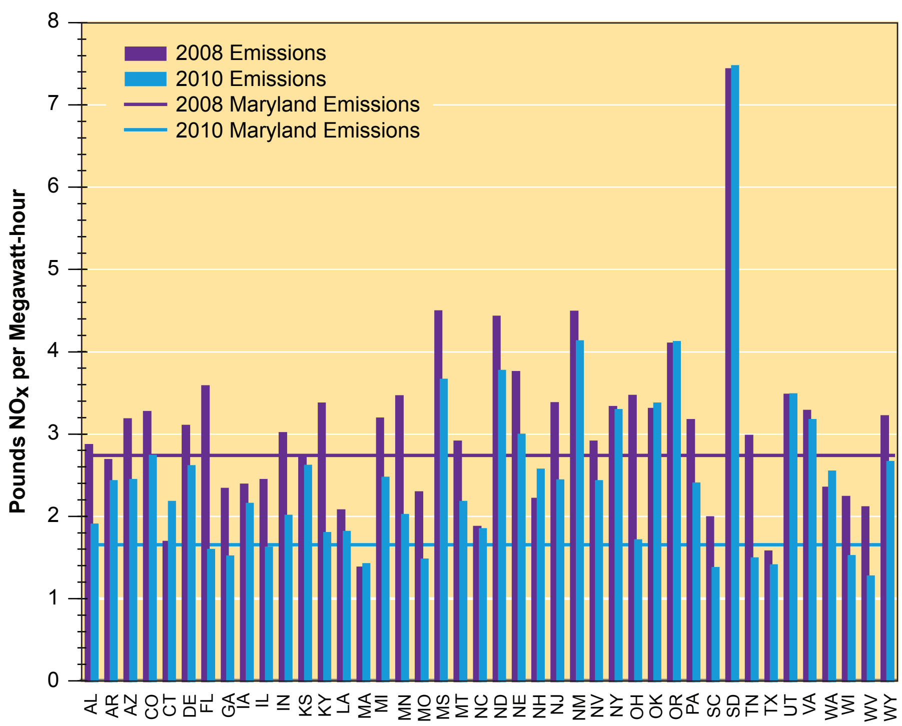
Note: Monitored emissions as reported in Clean Air Markets Data (http://www.epa.gov/airmarkets).

Figure 4-10 Coal-Fired Power Plant SO_2 Emissions for Maryland Compared to Other High-Emitting States



Source: EPA's Clean Air Markets (http://www.epa.gov/airmarkets).

Figure 4-11 Coal-Fired Power Plant NO_x Emissions for Maryland Compared to Other High-Emitting States



Source: EPA's Clean Air Markets (http://www.epa.gov/airmarkets).

Impacts from Power Plant Air Emissions

Acid Rain

Acid rain occurs when precursor pollutants, NO_x and SO_2, react with water and oxidants in the atmosphere to form acidic compounds. These acidic compounds are deposited with precipitation ("acid rain") or as dry particles ("dry deposition"), acidifying lakes and streams, harming forest and coastal ecosystems, and damaging man-made structures.

EPA's Acid Rain Program (ARP) was established under the CAA Amendments of 1990 with the goal of reducing acid rain by limiting NO_x and SO_2 emissions. The program capped total SO_2 emissions from power plants at 8.95 million tons nationally by 2000. The ARP for SO_2 was the first federal cap and trade program and many of the mechanics of pollutant trading systems were established under the ARP. As with regional or national cap and trade programs, SO_2 emissions are controlled with an allowance trading system, under which affected power plants are allocated a certain number of tons of SO_2 annually. These plants must either reduce emissions to stay under the allowance cap or purchase SO_2 allowances from power plants that have "over-controlled" and banked excess SO_2 credits. NO_x emissions under the ARP are controlled with rate-based limits (in units such as pounds per million Btu, lb/MMBtu) applied to certain coal-fired electric facilities.

Efforts to reduce acid rain have been largely successful nationwide. At the end of 2009, national SO_2 emissions totaled 5.7 million tons, which represents a reduction of more than 67 percent from 1980 levels and 64 percent from the 1990 levels, and is below the annual SO_2 allowance of 9.5 million tons. The majority of the reductions from 2008 to 2009, (about 1.89 million tons), came from only six states. Phase II of the ARP limited NO_x emissions from affected facilities, which were either allowed to meet an emissions rate or comply with an emissions averaging plan. As of 2009, all 960 units covered by the ARP achieved compliance with the NO_x emission limitation requirements. NO_x emissions were reduced from 1990 levels of 5.5 million tons to 1.9 million tons by 2009.

The National Acid Deposition Program has been measuring deposition of oxidized nitrogen and sulfur species for over 20 years, and has noted a dramatic decrease nationally in deposition of sulfur species corresponding to the decrease in emissions, as well as a decreasing trend in deposition of oxidized nitrogen species over this time period.

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 decade. 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. It is not emitted directly into the atmosphere in significant amounts but 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 (per MDE, 2009).

Ground-level ozone is a problem, not only because it creates unsightly smog and inhibits visibility, but also because of the adverse human health effects it can cause. Breathing air with high ozone concentrations can cause chest pain, throat irritation, and congestion; it can also worsen pre-existing conditions like emphysema, bronchitis, and asthma. Children and the elderly are especially vulnerable to health problems caused by ground-level ozone.

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 actually reduce emissions or purchase allowances from 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. Several of the coal-fired generating units in Maryland, which are among the larger NO_x sources in the state, have since installed SCR systems.

Another significant federal regulation targeting reductions of NO_x and SO_2 from power plants is the Cross-state Air Pollution Rule (CSAPR) finalized by EPA in July 2011. See page 90 for additional details on CSAPR.

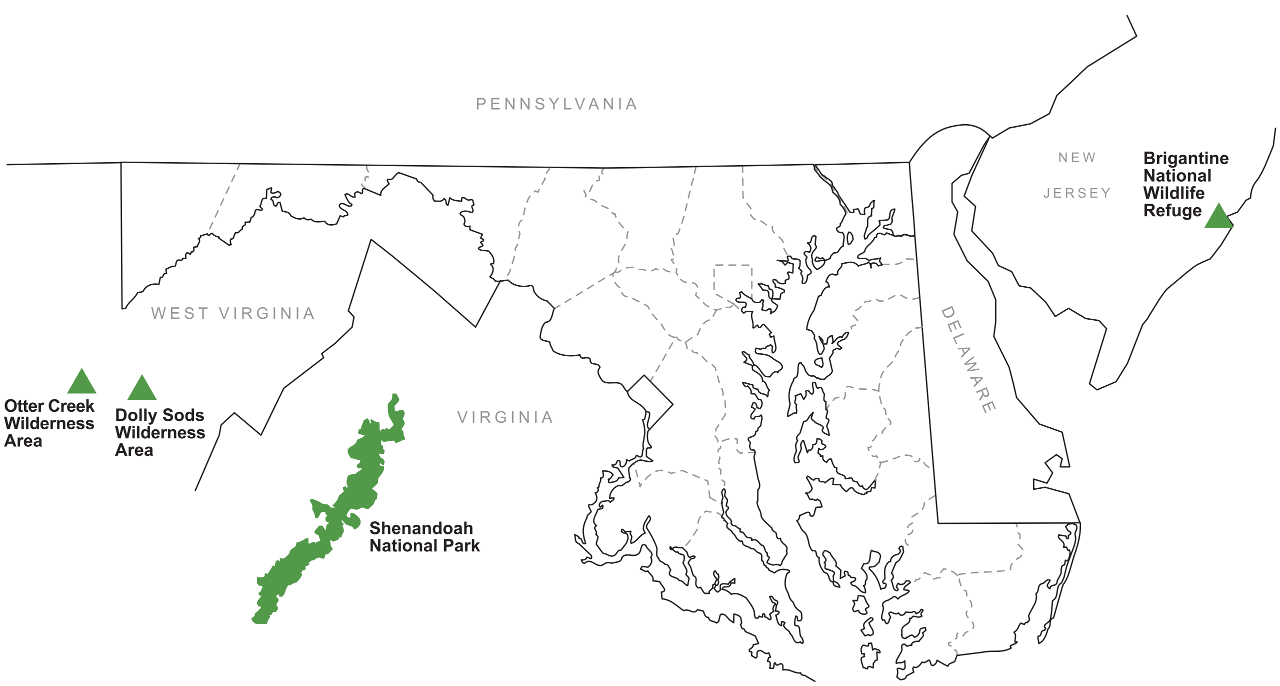
Visibility and Regional Haze

Fine particulate matter, or PM2.5, consists of particles (such as dust, soot, and liquid droplets) that are about 1/30th the diameter of a human hair. PM2.5 can be emitted directly from stacks or created when gases react to form particles during transport in the atmosphere. PM2.5 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:

- *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; and*
- *SO_2 and NO_X emitted from fossil fuel combustion.*

PM2.5 affects visibility, but is not the only contributor to decreased visibility and regional haze. Certain gases and larger particles can also interfere with the ability of an observer to view an object. In general, visibility refers to the conditions which 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 (see Figure 4-12 for Class I areas near Maryland). Since 1988, EPA and other agencies have been monitoring visibility in these areas.

Figure 4-12 Class I Designated Pristine PSD Areas Near Maryland



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 study 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 continues to support and contribute to this ongoing work. 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 which 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 — caused by the increase of chemical nutrients, typically containing nitrogen or phosphorus — 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, reduce 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. Although these goals were once again reaffirmed in the 2010 agreement, the Chesapeake Bay partners have acknowledged that the goals would not be met and EPA has initiated a process of developing a total maximum daily load (TMDL) target for the Bay.[21]

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. Increased efforts have been devoted recently to the role of ammonia in deposition processes.

For more than a decade, PPRP has evaluated the regional sources of NO_x emissions and their impacts on the Chesapeake Bay. As a part of this effort, advanced computer modeling systems are used to simulate the transport and subsequent deposition of emissions from these regional sources to the Chesapeake Bay. The actual loading to the Bay is calculated using a methodology similar to that used by the United States

[21] Details on the Chesapeake Bay TMDLs and Maryland's Watershed Implementation Plan can be found at http://www.mde.maryland.gov/programs/Water/TMDL/ChesapeakeBayTMDL/Pages/programs/waterprograms/tmdl/cb_tmdl/index.aspx.

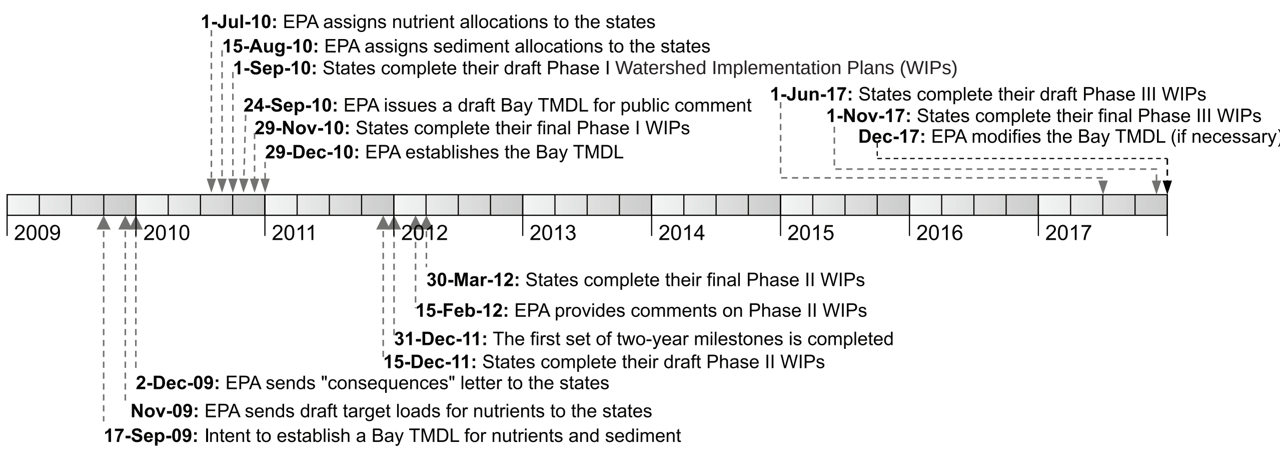
Chesapeake Bay TMDL

The Clean Water Act has a goal to preserve the quality of water bodies and keep them fishable and swimmable. TMDL refers to the maximum amount of pollutants that can be received by a water body and continue to maintain water quality standards. Until December 2010, the Chesapeake Bay was one of the largest and most complex water systems for which EPA had not established a TMDL, although there are TMDLs for many of the tidal segments within the Chesapeake Bay.

The TMDL established by EPA requires significant reductions in the total load of nitrogen, phosphorus, and sediments in Bay waters by the year 2025, with most of the reductions to be achieved by 2017. The Chesapeake Bay watershed covers six states (Maryland, Pennsylvania, Delaware, Virginia, West Virginia, and New York) and the District of Columbia. The development of the TMDL was a coordinated effort of the affected states, EPA, and the Chesapeake Bay Commission. The process of developing the TMDL required in-depth understanding of watershed characteristics, transport and fate characteristics of pollutants, best management practices (BMP), and sources of pollution. A timeline on the TMDL development process for Chesapeake Bay is shown below.

The limits set under the TMDL include 185.9 million pounds of nitrogen, 12.5 million pounds of phosphorus, and 6.45 pounds of sediments per year. The allowable nutrient load is then apportioned between the different jurisdictions. States have the responsibility of determining appropriate pollution control measures and developing Watershed Implementation Plans (WIPs) to ensure progress towards achieving the TMDL. The progress made will be reviewed during a two-year period and appropriate measures will be taken to mitigate impacts further, as necessary.

Total Maximum Daily Load Timeline



Geological Survey for its land-to-bay models. The model allows PPRP to evaluate the relative contribution of Maryland sources and other regional sources to deposition totals. As a part of this study, PPRP has developed a screening tool to evaluate the potential reductions in nutrient loading to the Bay waters due to different emission control policies in different states. Using this scheme, regional and local planning agencies can better develop emission reduction strategies to meet Bay restoration goals.

In a recent update to the modeling analysis, PPRP updated the emissions inventory used in prior modeling analyses with more recent data from the National Emissions Inventory (NEI) for the year 2002. The meteorological data was also updated to a prognostic meteorological data for the year 2002. Based on the modeling analysis, the total nutrient load to the Bay was predicted to be 31.2 million pounds per year. Sources in Maryland contribute approximately 6.6 million pounds of the total load, with mobile sources contributing the most. Other states, which contribute significantly more to the nutrient loading to the Bay than the sources in Maryland, include Virginia and Pennsylvania.

Mercury Impacts

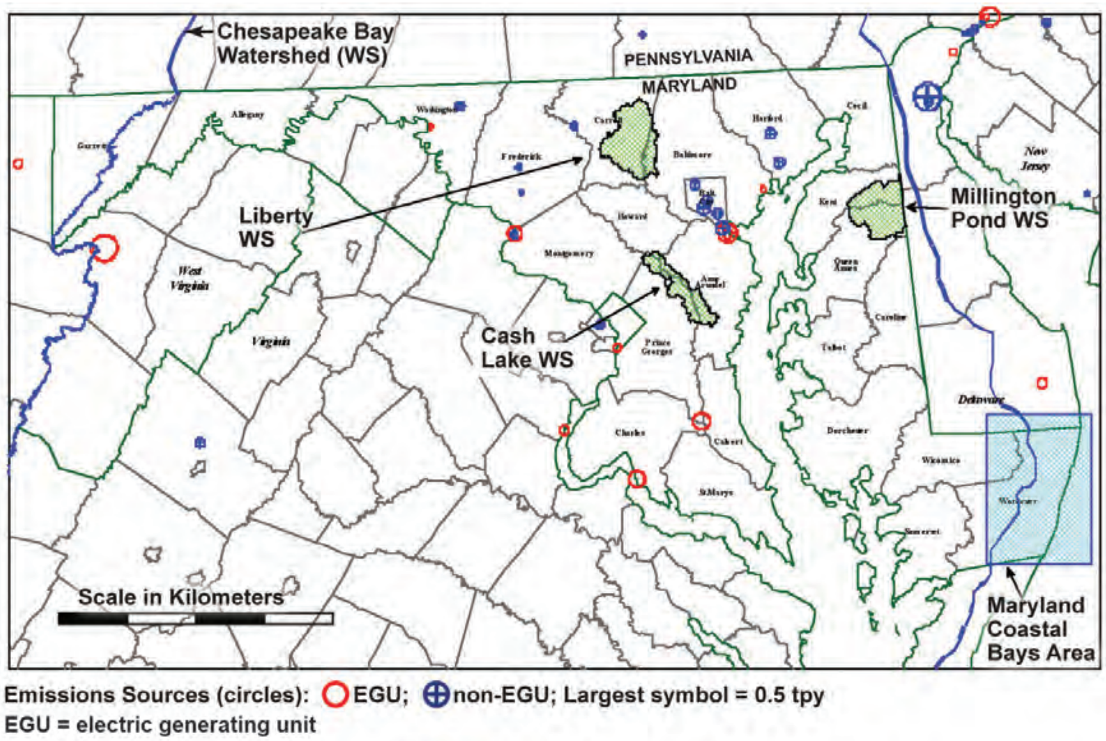
The primary stationary sources of mercury in the U.S. are, in order of decreasing emissions, coal-fired power plants, gold mining, municipal waste combustors, chlor-alkali plants, medical waste incinerators, and cement plants. Emissions from some source categories — notably medical waste incinerators — have decreased dramatically in recent years due to stringent EPA regulations.

Since power plants contribute approximately 75 percent of the total mercury emissions in Maryland, PPRP plays a significant 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 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. A mercury monitor has been in operation in Beltsville, Maryland, since June 2004. In June 2005, PPRP initiated 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 ongoing projects related to the effects of mercury emissions. The first project involves working with the Smithsonian Environmental Research Center and the University of Maryland Center for Environmental Science — 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 another cooperative project with the Maryland Department of the Environment (MDE), researchers are monitoring mercury tissue burden in young fish — a long-term effort that will lead to a better understanding of trends in mercury impacts. PPRP also participates in discussions and planning sessions with the National Atmospheric Deposition Program (NADP) regarding the Mercury Deposition Network (MDN) that measures wet deposition of mercury across the U.S. and Canada, and the new Atmospheric Mercury Network (AMNet) that collects data consisting of speciated mercury concentrations and meteorological data. AMNet is intended to supplement the wet measurement network to lead to more complete understanding of total (wet plus dry) mercury deposition patterns.

In 2002, Maryland issued a state-wide fish consumption advisory for lakes, reservoirs, and other impoundments due to high mercury levels in fish. This advisory is currently still in effect. PPRP has been involved in conducting a complex modeling study to estimate the quantity of mercury from Maryland and other regional sources that is deposited in water bodies throughout the state. The location of sources of mercury emissions in and around Maryland, and the location of some of the water bodies and watersheds evaluated in PPRP's study, are shown in Figure 4-13.

Figure 4-13 Location of Larger Watersheds (WS) and Mercury Sources within Maryland



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. This analysis was based on the projected reductions in emissions from Maryland power plants, which was approximately 90 percent from 2007 base year levels. This analysis predicted that the HAA emission reductions would potentially reduce mercury deposition to these water bodies 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 predominantly influenced by sources from outside Maryland. An analysis of the reductions in load due to actual emissions reductions achieved based on the data for the year 2010 is currently underway.

The Maryland Healthy Air Act of 2006

The Maryland HAA was signed into law in April 2006, and MDE developed enabling regulations for the HAA that became effective in January 2007. The HAA requires substantial reductions in emissions of NO_x, SO_2, and mercury from 15 coal-fired generating units at seven power plants in Maryland. The HAA also requires Maryland to participate in a multi-state program known as the Regional Greenhouse Gas Initiative (RGGI) to reduce emissions of pollutants, including CO_2, that contribute to climate change. HAA-mandated emissions reductions take place in two phases; Phase I began in 2009/2010, and Phase II will begin in 2012/2013, depending on the pollutant.

The HAA regulates NO_x and SO_2 emissions based on a type of pollutant cap and trade program in which the State establishes annual, state-wide total tonnage emissions caps separately for NO_x and SO_2, and then allocates a portion of the annual state-wide caps to each of the 15 individual coal-fired power plant generating units subject to the HAA. Power plant owners can comply by reducing emissions at each unit to meet the unit's cap, or can comply with the caps on a system-wide basis, by over-controlling emissions at some plants and trading the excess allowances to other HAA plants that the company owns and operates in Maryland. The caps are stringent, so although power plants in Maryland have some flexibility in choosing how they will achieve NO_x and SO_2 emissions reduction targets, most of the coal-fired generating units in Maryland have installed major new air pollution control systems to meet HAA NO_x and SO_2 standards.

The mercury provisions of the HAA require each power plant to achieve a percentage reduction in emissions of mercury from a 2002 baseline year of at least 80 percent for Phase I (2010) and 90 percent beginning in Phase II (2013 and thereafter). The control equipment installed and other pollution reduction changes at Maryland's coal-fired power plants are summarized in Table 4-2 and the emission reductions achieved in the first full year of operation of these controls are described below.

Table 4-2 Emissions Controls Installed at HAA Affected Facilities

Facility	HAA Controls		
	NO_x	SO_2	Mercury
Brandon Shores	Operation of SCR year round on Units 1 and 2	Wet FGD on Units 1 and 2	PAC and co-benefit reduction from the SCR/FGD
Wagner	SNCR on Unit 2; SCR on Unit 3	Fuel switching	ACI on Units 2 and 3
Crane	SNCR on Units 1 and 2	Fuel switching on Units 1 and 2	ACI on Units 1 and 2
Morgantown	SCR on Units 1 and 2	Wet FGD on Units 1 and 2	Co-benefit reductions from the SCR/FGD
Chalk Point	SCR on Unit 1; existing SACR on Unit 2	Wet FGD on Units 1 and 2	Co-benefit reductions from the SCR/FGD
Dickerson	SNCR on Units 1, 2, and 3	Wet FGD on Units 1, 2, and 3	Co-benefit reductions from the FGD

ACI = activated carbon injection; FGD = flue gas desulfurization; PAC = powdered activated carbon; SACR = selective auto-catalytic reduction; SCR = selective catalytic reduction; SNCR = selective non-catalytic reduction.

HAA Air Pollution Control Projects

Brandon Shores

Constellation Power Source Generation (CPSG) operates two coal-fired units (Unit 1 and Unit 2) at Brandon Shores that are subject to the HAA. In order to comply with the HAA, CPSG installed and began operation of wet FGD systems for SO_2 and mercury removal, fabric filter baghouses for PM control, powered activated carbon (PAC) injection equipment for removal of mercury, and sorbent injection systems for the reduction of sulfuric acid mist (SAM) on each of the units (Unit 1 in December 2009 and Unit 2 in February 2010). In addition, CPSG began year round operation of the existing SCR systems on Unit 1 and Unit 2 in January 2009 to reduce NO_x emissions (the SCR systems historically operated only during the ozone season).

EPA maintains a database of continuous emissions monitoring data from power plants called the Clean Air Markets Database (CAMD). Information in CAMD for the year 2010 shows SO_2 reductions of approximately 96 percent from the 2009 emissions levels at Brandon Shores and NO_x emissions of approximately 67 percent from 2008. Note that the difference in comparison years is due to the fact that the first compliance year for SO_2 was 2010 and the first compliance year for NO_x was 2009.

Based on stack tests results provided to MDE, mercury emissions from Units 1 and 2 were 47 pounds for the calendar year 2010, which is well below the HAA Phase I mercury cap effective beginning 2010, and just marginally above the Phase II HAA mercury cap of 46 pounds effective 2013 and beyond.

H.A. Wagner Generating Station

CPSG operates two coal-fired units (Unit 2 and Unit 3) at Wagner that are subject to the HAA. In order to comply with the HAA, CPSG installed and began operation of activated carbon injection (ACI) systems in conjunction with existing electrostatic precipitators to reduce mercury emissions in January 2010. To reduce NO_x emissions, CPSG installed and began operation of an SNCR system on Unit 2 in January 2009. Additionally in January 2009, CPSG began year-round operation of the existing SCR system on Unit 3 (the SCR systems historically operated only during the ozone season). According to a CPSG MDE Emission Summary report, SO_2 emission reductions will be achieved by the use of reduced sulfur coals beginning in 2010.

Based on data reported in CAMD for 2010, it appears that NO_x emissions were reduced by approximately 70 percent from emissions in 2008. Based on stack tests results provided to MDE, mercury emissions were 28.5 pounds for 2010, which is equivalent to the Phase II (2013) HAA mercury cap for the facility, suggesting that additional mercury controls may not be required for CPSG to meet HAA mercury standards. Although add-on controls have not been installed at Wagner, CPSG is currently undergoing testing of lower sulfur fuels for compliance with the SO_2 portion of the HAA.

C.P. Crane Generating Station

CPSG operates two coal-fired units (Unit 1 and Unit 2) at Crane that are subject to the HAA. In order to comply with the HAA, CPSG installed and began operation of activated carbon injection systems in conjunction with existing fabric filters to reduce mercury emissions in January 2010. To reduce NO_x emissions, CPSG installed and began operation of SNCR systems on both Unit 1 and Unit 2 in January 2009. Additionally, CPSG received approval from the PSC to burn low sulfur sub-bituminous coal, in addition to the existing bituminous coals, to reduce SO_2 emissions from Crane. CPSG began burning low sulfur coal in 2010.

Based on CAMD data for the year 2010, SO_2 emission reductions of approximately 55 percent from the 2009 levels were achieved at Crane. For 2010, NO_x emissions were reduced by approximately 51 percent below the 2008 emission levels. Based on stack tests results provided to MDE, mercury emissions for 2010 were 7.5 pounds, which is significantly below the HAA Phase II cap of 13 pounds per year.

Morgantown Generation Station

GenOn operates two coal-fired units at Morgantown that are subject to the HAA. Prior to the HAA, coal-fired Units 1 and 2 at the GenOn Morgantown Generating Station were equipped with cold-side electrostatic precipitators (ESPs) for particulate emission control, and a combination of low-NO_x burners (LNBs) and separated overfire air (SOFA) systems to control NO_x emissions. State-of-the-art SCR systems were installed on each unit to provide additional NO_x control beginning in 2007 (Unit 1) and 2008 (Unit 2). GenOn's HAA air pollution control project for Morgantown consisted of wet FGD systems and SAM controls, as well as associated enhancements of the facility necessary for the operation of these systems.

Based on CAMD data, SO_2 emissions from the Morgantown coal units were reduced by 92 percent from 2009 emissions levels with use of the new FGD system. NO_x emissions were reduced by approximately 37 percent below 2008 levels with the year-around use of the SCR systems. Based on stack tests results provided to MDE, mercury emissions totaled 17.8 pounds for Morgantown in 2010, which is well below the HAA Phase II mercury emissions cap of 66 pounds per year.

Chalk Point Generating Station

GenOn operates two coal-fired units at Chalk Point that are subject to the HAA. Pollution control equipment in place prior to the HAA at Units 1 and 2 included LNB with overfire air for NO_x control and ESPs for PM control. A selective autocatalytic reduction (SACR) system was installed on Unit 2 for NO_x control in 2006. As part of HAA compliance, GenOn installed an SCR system on Unit 1, and brought the system on-line in the summer of 2008. The SCR was designed to reduce NO_x emissions by at least 85 percent. To meet HAA SO_2 targets, GenOn installed a wet FGD system on Units 1 and 2 at Chalk Point; the system commenced operations in 2010.

Based on the CAMD data for 2010, SO_2 emissions from Chalk Point were reduced by approximately 94 percent from 2009 levels. NO_x emissions were reduced by 47 percent from emissions reported for 2008. This reduction is likely attributable to year-round operation of the SCR system on Unit 1, which, prior to the enactment of the HAA was only run during the ozone season. Based on stack tests results provided to MDE, mercury emissions from the two coal-fired units at the facility were reported at 18.9 pounds, which is well below the HAA Phase II mercury cap of 54 pounds.

Dickerson Generating Station

GenOn operates three coal-fired units at Dickerson that are subject to the HAA. Prior to HAA, the GenOn Dickerson Generating Station units were equipped with a cold-side ESP and a baghouse for particulate emissions control, and a combination of LNBs and SOFA to control NO_x emissions. As a part of its HAA compliance plan for the Dickerson plant, GenOn installed wet FGD systems on Units 1, 2, and 3. Construction of the FGD system and related limestone handling/unloading systems commenced in January 2008. In addition, Mirant (now GenOn) installed SNCR systems on all three Dickerson coal-fired units to reduce NO_x emissions in April 2009.

Dickerson reported CAMD SO_2 emissions reductions of approximately 90 percent in 2010 from 2009 levels. The use of SNCR systems on all three units resulted in NO_x reductions of approximately 14 percent from NO_x totals reported for 2008. Based on stack tests results provided to MDE, mercury emissions for 2010 were reported at 12 pounds, well below the HAA Phase II cap of 37 pounds.

R. Paul Smith Generating Station

Allegheny Energy Supply (Allegheny) owns and operates the R. Paul Smith generating station in Washington County, Maryland, which consists of two smaller (34 MW for Unit 3 and 75 MW for Unit 4) coal-fired boilers. In June 2008, Allegheny proposed to replace the existing ESP on one of the units (Unit 4) with an Electrostatic Fabric Filter (ESFF) technology, which is a hybrid technology (i.e., cross between an ESP and a baghouse). The ESFF would potentially reduce mercury emissions by 50-85 percent. The generating units are older and operate at low capacity factors, so addition of NO_x and SO_2 pollution control systems could be economically and technically challenging at the plant; however, R. Paul Smith was determined to be a "must run" plant to maintain reliability of the PJM grid. In April 2009, MDE revised the emissions caps for NO_x and SO_2 established under the HAA to new limits that represent the highest emissions reported for the R. Paul Smith units for the years 2001-2004. As a result, the plant was not required to install additional emissions controls for NO_x or SO_2.

HAA Air Quality Benefits

The implementation of the HAA will result in significant positive effects on the environment in Maryland. Significant reductions in SO_2, NO_x, and mercury emissions from coal-fired power plants in Maryland will help the State manage three important environmental challenges:

maintaining PM2.5 concentrations at levels below ambient air quality standards, acidic deposition of sulfur (i.e., acid rain, mercury), and harmful nutrient loading to the Chesapeake Bay. Also, an evaluation of the ozone impacts indicates that the reduction in NO_x emissions will potentially result in reduction in ambient NO_x levels overall.

Recent and Developing National Air Regulatory Drivers Affecting Power Plants

GHG New Source Review: Tailoring Rule

On May 13, 2010, EPA finalized the GHG Tailoring Rule, which is the first federal rule in the U.S. that regulates construction and operation of GHG emissions from major stationary sources. The rule establishes Prevention of Significant Deterioration (PSD) and Title V operating permit requirements for GHG sources that will affect all new and modified power plant projects in Maryland. The rule regulates "greenhouse gases" as the aggregate sum of six gases: CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6.

As per the final rule, which became effective on January 2, 2011, EPA regulates affected sources in three steps. Step 1, which began on January 2, 2011, covers sources that, irrespective of the rule, would be covered by PSD and Title V regulations and that emit more than 100,000 tons per year (tpy) of GHG emissions. Step 2 covers new sources emitting more than 100,000 tpy of GHG and modifications to existing major sources of GHG pollutants (>100,000 tpy) which result in GHG emissions increase of greater than 75,000 tpy. Step 2 of the Rule went into effect on July 1, 2011. In Step 3, which begins on July 1, 2013, EPA intends to regulate sources emitting more than 50,000 tpy of GHGs; details on the sources to be covered in this step will be covered under a separate rulemaking.

As with all pollutants regulated under PSD, sources that trigger PSD for GHGs are required to demonstrate that the project will install and operate a level of pollution control known as Best Available Control Technology (BACT). Because regulation of GHGs is new in the U.S., and given the limited information on GHG BACT to date, this is proving to be a significant effort for affected sources, and for states and EPA regulators. EPA issued initial BACT guidance related to GHG emissions under the PSD program in November 2010, with an update released in March 2011.[22] The BACT guidance identified energy efficiency and carbon capture and storage (CCS) as potential BACT candidates, but acknowledged that CCS would often be eliminated due to its current high economic impact.

The Tailoring Rule has significant implications for sources in Maryland, especially existing and new power plants. Existing sources will be subject to Title V requirements for GHGs beginning in July 2011, depending on potential GHG emissions from the facility; modifications to existing sources that trigger PSD for non-GHG pollutants and emit more than 75,000 tpy of GHGs will be subject to the Rule.

[22] PSD and Title V Permitting Guidance for Greenhouse Gases, prepared by the Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, March 2011.

Cross-state Air Pollution Rule (CSPAR)

The Cross-State Air Pollution Rule ("CSAPR" or "the Transport Rule") was finalized by EPA in July 2011 under the CAA to reduce interstate transport of PM2.5 and ozone. The rule was originally proposed in July 2010 as the Clean Air Transport Rule (CATR). CATR/CSAPR is a replacement for EPA's 2005 Clean Air Interstate Rule (CAIR), the original federal multi-pollutant rule which was challenged in courts. On December 30, 2011, the U.S. Court of Appeals for the D.C. Circuit issued a ruling staying CSAPR pending judicial review.

The rule targets emissions of NO_x and SO_2, as precursors to PM2.5 and ozone, from power plants in the 27 eastern states that EPA determined significantly affect downwind states' ability to meet PM2.5 and ozone air quality standards. The rule is a "cap and trade" based program in which states are allocated state-wide NO_x and or SO_2 budgets. Affected power plants are then allocated emissions budgets and can reduce emissions and/or trade allowances among affected units, as long the state budgets are maintained.

CSAPR establishes four separate programs: an annual NO_x trading program, an ozone-season (summer months when ozone formation is at its maximum due to meteorological conditions) NO_x trading program, and two separate SO_2 trading programs ("SO_2 Group 1" and "SO_2 Group 2"). Group 1 states are subject to more stringent SO_2 reductions beginning in 2014 than Group 2 states. Maryland is a Group 1 state. The first phase of CSAPR was slated to begin January 1, 2012 for SO_2 and annual NO_x, and on May 1, 2012 for ozone-season NO_x reductions. The second phase of the rule begins January 1, 2014 and increases the stringency of SO_2 reductions in a number of states. Given the stay of the rule, the schedule for implementation is unknown. EPA anticipates that power plants will comply with CSAPR by some combination of maximizing or optimizing use of existing NO_x and SO_2 controls, such as SCR and FGD systems; switching to lower sulfur fuels; and/or adding new controls.

Not only are some of the emissions caps lower than in previous federal and state multi-pollutant power plant regulations, but some of the provisions around allowance trading in CSAPR are more stringent than in previous versions of the rule. For example, there are no so-called "early reduction" provisions in CSAPR, unlike other federal and regional cap and trade programs that are in place. Also, there are no provisions to carry over any CAA Title IV Acid Rain SO_2 allowances or former CAIR annual or ozone season NO_x allowances into CSAPR.

For some power plants in Maryland, allocations for SO_2 and NO_x in CSAPR are significantly lower than emission caps established under the Maryland HAA. In particular, NO_x and SO_2 allocations for Constellation plants are lower in the final rule compared to the proposed CATR rule and the HAA emission caps.

Utility MACT Standards for HAPs

On March 16, 2011, EPA proposed a new Maximum Achievable Control Technology (MACT) standard (called the "Utility MACT") intended to reduce emissions of HAPs from power plants. The rule establishes emission standards for new and existing fossil-fueled electric utility steam generating units (EGUs) with generating capacities greater than 25 MW. Specifically, the rule is intended to reduce emissions of heavy metals (mercury, arsenic, chromium, nickel), acid gases (hydrogen chloride (HCl) and hydrogen fluoride (HF)), and other organic HAPs (formaldehyde, benzene, and acetaldehyde) from coal- and oil-fired power plants.

For all new and existing coal-fired EGUs, the rule establishes numerical emission limits for mercury, limits for PM serving as a surrogate for toxic non-mercury metals, and limits for HCl or SO_2 as surrogates for toxic acid gases. For existing and new oil-fired EGUs, the rule establishes numerical emission limits for total metals, HCl, and HF.

For affected power plant sources in Maryland, it is likely that add-on pollution control systems, such as wet FGD systems installed for HAA compliance, may be sufficient for compliance with the Utility MACT mercury and other organic and metal HAPs standards. Based on a preliminary review of select stack tests conducted at power plants in Maryland in 2010, mercury emissions from power plants in Maryland were generally below the proposed MACT standards for all power plants except H.A. Wagner, which may take the opportunity to use the emissions averaging provisions of the rule. Existing sources would be required to meet emission limitations and implement work practice standards within three years of final adoption of the rule signed December 16, 2011; new affected sources would be subject to the standards at start-up.

GHG NSPS

On December 23, 2010, EPA announced its intention to regulate GHG emissions following the settlement of two significant lawsuits under the U.S. Court of Appeals (New York v. EPA and American Petroleum Institute v. EPA). Both cases involved numerous states and environmental groups urging EPA to adopt new GHG emission limits for existing combustion sources. The settlements in these cases required EPA to propose a GHG standard in the form of a New Source Performance Standard (NSPS) for new sources and emission guidelines for existing sources by July 26, 2011 with final action by May 26, 2012 for electric utility generators.[23] EPA has yet to propose a rule.

NSPS apply to new and modified facilities, and are adopted on a source category basis. It is unknown at this time what these emission limits will be; however, it is likely that the NSPS and existing source emissions guidelines will rely upon energy efficiency and possibly CCS.

Boiler MACT

On February 21, 2011, EPA finalized four related rules that regulate HAP emissions from non-utility boilers, process heaters, and commercial and industrial solid waste incinerators (CISWI). The most significant among these rulemakings, which could potentially impact non-EGU boilers at power plants, is the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial-Commercial-Institutional (ICI) Boilers, which is codified under 40 CFR Part 63 Subpart DDDDD. This rule is commonly referred to as the "Boiler MACT" regulation. EPA

[23] http://ag.ca.gov/newsalerts/release.php?id=2016&

proposed revisions to the final rule on December 23, 2011. Sources at power plants that could be affected by this rule include auxiliary boilers and other similar boilers/process heaters not used for power generation. The emission limits and the compliance demonstration requirements in the final rule are dependent on the type of fuel fired and the type of fuel handling and feeding systems. The rule includes emission limits for HCl, mercury, PM, and CO, and work practice standards for dioxin/furans. In addition to complying with emission limits and other monitoring requirements, the final rule requires facilities to conduct a one-time energy assessment of the boiler and the boiler fuel handling system. Existing facilities are required to comply with this rule three years after publication of the final rule in the Federal Register.

4.1.2 Impacts to Water 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. 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.

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 volume of water used in Maryland for power plant operation, potential resource impacts, and methods for minimizing any adverse impacts.

Withdrawal and Consumption Impacts

Most electricity is produced in Maryland by 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 tend to have the largest water withdrawals because of the need to cool and condense the recirculating steam. 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 met by on-site wells or municipal water systems.

Table 4-3 lists all major steam generating power plants in Maryland (excluding self-generators) and quantifies their water withdrawals and consumption for 2009-2010. Cooling water withdrawals at steam electric facilities represent the majority of surface water usage in Maryland. In 2010, combined water withdrawal for all steam generating power plants in Maryland is estimated at 6 billion gallons per day. All other non-power plant users in the state have 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 23 billion gallons per day (actual daily flows in both the Susquehanna and the Potomac fluctuate greatly, both seasonally and from year to year).

Table 4-3 Surface Water Appropriations and Use at Maryland Power Plants with Steam Cycles

Power Plant	Surface Water Appropriation (average, mgd)	2009 Actual Surface Withdrawal (average, mgd)	2010 Actual Surface Withdrawal (average, mgd)	Estimated Consumption (mgd)	Water Source
Once-Through Cooling					
Calvert Cliffs	3,500	3,333	3,257	18	Chesapeake Bay
Chalk Point[a]	720	590	584	N/A	Patuxent River
C.P. Crane	475	293	273	2.0	Seneca Creek
Dickerson	401	322	344	1.3	Potomac River (non-tidal)
H.A. Wagner	940	297	280	1.6	Patapsco River
Morgantown	1,503	1,159	1,237	2.4	Potomac River
Riverside	40	1.59	2.06	0.01	Patapsco River
R. Paul Smith	70	14.8	31.6	0.28	Potomac River (non-tidal)
Wheelabrator	50	22.2	16.4	N/A	Gwynns Falls
SUBTOTAL	**7,699**	**6,033**	**6,025**	**25.6**	
Closed-Cycle Cooling					
AES Warrior Run[b]	0.021	0	0	N/A	City of Cumberland
Brandon Shores	35	0	0	N/A	Patapsco River (Wagner discharge)
Montgomery Co. Resource Recovery Facility	1.342	0.73	0.77	N/A	Potomac River (Dickerson Station's discharge canal)
Panda Brandywine[b]	3	0	0	N/A	Mattawoman WWTP
Vienna	2	0.37	0.02	N/A	Nanticoke River
SUBTOTAL	**41.4**	**1.1**	**0.79**	**0**	
TOTAL	**7,740**	**6,034**	**6,026**	**27**	

Source: MDE WMA

mgd = million gallons per day

[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; data on each cooling system individually are not available.

[b] AES Warrior Run and Panda Brandywine do not have direct surface water appropriations for their total water use, since their cooling water needs are met indirectly through third parties (the city of Cumberland and the Mattawoman wastewater treatment plant, respectively). The surface water appropriation for AES Warrior Run is for back-up water use only. AES Warrior Run used an average of 0.27 mgd of City of Cumberland water in 2009 and 0.25 mgd in 2010. Panda Brandywine used an average of 0.50 mgd of Mattawoman WWTP effluent in 2009 and 0.41 mgd in 2010.

Four steam power plants in Maryland – AES Warrior Run, Brandon Shores, Panda Brandywine, and Vienna – use closed-cycle cooling (cooling towers) exclusively instead of once-through cooling. (Chalk Point has multiple steam boilers, two of which use once-through and two of which use closed-cycle cooling.) 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. According to data reported by the Electric Power Research Institute (EPRI), closed-cycle cooling systems consume on average about 1.5 times more water per MWh than once-through systems.

Nuclear power plants also fall within the steam generating category; however, they use nuclear reactions instead of fossil fuel combustion to create the thermal energy. The existing fleet of operating nuclear facilities generate more waste heat than fossil fuel-fired plants of the same capacity, and according to data from the Nuclear Regulatory Commission (NRC), require 10 to 30 percent more cooling water to produce the same energy. Nuclear stations generally operate at a lower steam temperature and pressure compared to fossil fuel-fired generating plants, which causes a somewhat lower efficiency in the conversion of thermal energy to mechanical and, ultimately, electrical energy. Consequently, more thermal energy is rejected to the cooling system per MWh generated than would be in a fossil fuel plant, and more cooling water is needed to absorb that waste heat.

Maryland has one nuclear power plant operating on the western shore of the Chesapeake Bay, Calvert Cliffs, which withdraws an average of 3.3 billion gallons per day from the Bay. This is the largest single appropriation of water in the State of Maryland, 13 times more than the municipal supply for the Baltimore City metropolitan area of 250 million gallons per day (mgd). While the majority of this water is returned to the Bay, an estimated 18 mgd of Bay water is lost to evaporation as a result of the heated discharge (see Table 4-3). The proposed Unit 3 at Calvert Cliffs would utilize a cooling tower and thus would not withdraw as much Bay water as Units 1 and 2, although its water consumption due to evaporation will be greater.

While water withdrawal is fairly straightforward to determine and well-documented by individual facilities, the net or consumptive use is a more complex analysis. By definition, the 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. This directly affects the use of a waterway for power plant siting or expansion not only for cooling water supply, but induced evaporation due to the return of heated water to a surface water body.

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 are negligible, the release of heated water results in elevated evaporative losses in the receiving waters – and 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 found that the in-stream evaporative loss caused by heated discharges can range up to 2.5 percent of the discharge volume with an average of about 0.6 percent during the summer and 0.5 percent during the winter.

The U.S. Geological Survey (USGS) develops water use reports for the United States every five years.[24] USGS has recognized the importance of consumptive use data collection and analysis methodology so that policy decisions regarding increasingly stressed water resources can be based on facts and sound science. One of the areas of exploration is a task to improve methods for evaluating consumptive use from power plants. Consumptive use can be evaluated through:

- *A statistical analysis of collected data and application of those relationships to determine consumptive uses based on a few driving variables (e.g., cooling process and basic meteorological data);*
- *A deterministic approach by calculating heat transfer in systems and calculating the evaporation and induced evaporation; or*
- *A combination of these methods.*

USGS has performed a data assessment based on reported data and factors affecting consumption, mainly cooling system design. The resulting analysis indicates that the industry reported data is inconsistent with expected consumptive use based on heat transfer analysis (deterministic). USGS is comparing existing data statistically using lumped driving variables (such as type of cooling system), but plans to expand the analysis. Other factors that affect consumption are meteorological data and the condition and configuration of the receiving water body. USGS is exploring ways to collect additional data on consumptive use drivers and variables to support a statistical consumptive use model.

In addition to cooling systems, air pollution control systems at power plants can also require substantial amounts of water. As a result of the Healthy Air Act, Maryland's four largest coal-fired power plants – Brandon Shores, Chalk Point, Dickerson, and Morgantown – have begun operating wet FGD systems. Typically, about 85 percent of the water used in these 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 8 mgd combined. This additional loss is not significant in the tidal estuarine environments at Brandon Shores, Chalk Point, and Morgantown. GenOn, the operator of the Dickerson plant, is required to provide on-site water storage to minimize the potential impacts of its FGD system's water use

[24] http://water.usgs.gov/watuse/

on other users of the Potomac River (see discussion of low-flow issues in the next section).

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 on-site 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 on-site water storage is to reduce the risk of curtailment, not entirely eliminate it.

As an example, Mirant (now GenOn) agreed to incorporate on-site water storage to meet Potomac River low-flow requirements as part of the 2007 licensing case to modify the Dickerson Generating Station for the installation of a wet scrubber. Mirant projected that operating at peak load for 24 hours could create a consumptive use of water slightly over 1 mgd. In addition, there are two combustion turbines at Dickerson that consume additional water under certain operating conditions. To comply with the consumptive use regulations, Mirant proposed to limit Potomac River water consumption to 1 mgd for the FGD unit and the two combustion turbines. In addition, Mirant proposed to use an on-site pond with a capacity of 4.5 million gallons to supplement the water supply during periods of low flow to minimize the risk that generation would be curtailed. PPRP and MDE agreed with this approach for complying with the consumptive use requirements, and the Maryland PSC issued a CPCN with conditions reflecting the approach.

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 not 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 is somewhat higher.

The reuse of effluent from wastewater treatment plants (WWTP) is also becoming more acceptable and viable for power plants. The Panda Brandywine combined cycle facility, located in Prince George's County, currently utilizes about 0.5 to 1 mgd of treated effluent from the Mattawoman WWTP for its cooling water needs. 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. CPV Maryland has proposed a new gas-fired power plant in Charles County that would also use treated effluent as its source of cooling water.

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, aquatic impacts are reduced because effluent reuse does not involve direct withdrawals from a surface water body.

Dry cooling systems are also making significant inroads to the power industry. Once thought infeasible due to their large size, aesthetics, parasitic power use, required land, and capital outlay, dry cooling towers are now being seriously evaluated as potential alternatives to wet cooling systems. Although currently there are no major power plants in Maryland using dry cooling systems, a hybrid dry cooling system has been included in the plans for the proposed Unit 3 development at the Calvert Cliffs power plant. Hybrid dry cooling systems combine both a "wet" portion, like traditional closed-cycle systems, plus an air-cooled "dry" portion. As appropriations for cooling water become more restricted, dry cooling becomes a more attractive option.

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. These plants are: Constellation's Calvert Cliffs Nuclear Power Plant, GenOn's Chalk Point and Morgantown power plants, Southern Maryland Electric Cooperative's (SMECO's) combustion turbine facility (located at the Chalk Point plant), and Panda Brandywine's combined cycle power plant. These five plants have historically withdrawn ground water from three aquifers in Southern Maryland: the Aquia, the Magothy, and the Patapsco. GenOn's Chalk Point power plant began withdrawing ground water from the deeper Patuxent Aquifer in 2010. Two additional power plants utilize ground water: Perryman, located in Harford County northeast of Baltimore, and Vienna, located in Dorchester County on the Eastern Shore. Figure 4-14 shows the ground water withdrawal rates expressed as daily averages from 1975 to 2010 for each of these power plants. The withdrawal rates and associated appropriations limits are also shown in Figure 4-14. As noted in Table 4-4, power plants typically withdraw ground water at rates well below their appropriation permit limits. The average withdrawal for all seven power plants in 2010 was 2.2 mgd compared to a combined daily appropriations limit of 3.8 mgd. The amount of ground water withdrawn by power plants has fluctuated between about 0.9 and 2.2 mgd over the past 36 years.

Three government agencies – the Maryland Geological Survey, the USGS, and PPRP – jointly operate a ground water monitoring program to measure the water levels in these aquifers to ensure the long-term availability of ground water. MDE Water Management Administration (WMA), the permitting authority for all ground water

Figure 4-14 Average Daily Ground Water Withdrawal Rates at Maryland Power Plants

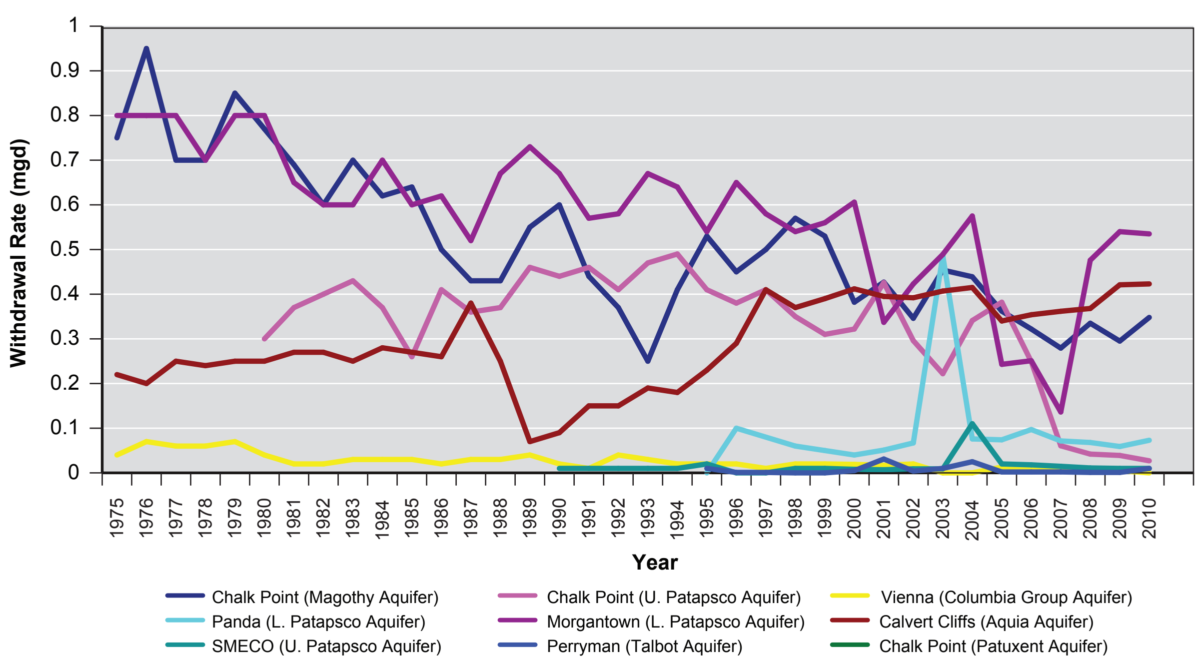


Table 4-4 Average Daily Ground Water Withdrawal Rates at Maryland Power Plants (in mgd)

	Chalk Point (Magothy Aquifer)	Chalk Point (U.Patapsco Group Aquifer)	Chalk Point (Patuxent Aquifer)[a]	Vienna (Columbia Aquifer)	Panda (L.Patapsco Aquifer)	Morgantown (L. Patapsco Aquifer)	Calvert Cliffs (Aquia Aquifer)	SMECO (U. Patapsco Aquifer)	Perryman (Talbot Aquifer)	Total Average Daily Withdrawal
Current Appropriation Limit	**0.66**	**0.66**	**1.02**	**0.05**	**0.064**[b]	**0.82**	**0.45**	**0.02**	**0.1**	**3.8**
1975	0.75			0.04		0.8	0.22			1.8
1976	0.95			0.07		0.8	0.2			2.0
1977	0.7			0.06		0.8	0.25			1.8
1978	0.7			0.06		0.7	0.24			1.7
1979	0.85			0.07		0.8	0.25			2.0
1980	0.77	0.3		0.04		0.8	0.25			2.2
1981	0.69	0.37		0.02		0.65	0.27			2.0
1982	0.6	0.4		0.02		0.6	0.27			1.9
1983	0.7	0.43		0.03		0.6	0.25			2.0
1984	0.62	0.37		0.03		0.7	0.28			2.0
1985	0.64	0.26		0.03		0.6	0.27			1.8
1986	0.5	0.41		0.02		0.62	0.26			1.8
1987	0.43	0.36		0.03		0.52	0.38			1.7
1988	0.43	0.37		0.03		0.67	0.25			1.8
1989	0.55	0.46		0.04		0.73	0.07			1.9
1990	0.6	0.44		0.02		0.67	0.09	0.01		1.8
1991	0.44	0.46		0.01		0.57	0.15	0.01		1.6
1992	0.37	0.41		0.04		0.58	0.15	0.01		1.6
1993	0.25	0.47		0.03		0.67	0.19	0.01		1.6
1994	0.41	0.49		0.02		0.64	0.18	0.01		1.8
1995	0.53	0.41		0.02	0	0.54	0.23	0.02	0.01	1.8
1996	0.45	0.38		0.02	0.1	0.65	0.29	0	0.001	1.9
1997	0.5	0.41		0.01	N/A	0.58	0.41	0	0.001	1.9
1998	0.57	0.35		0.02	0.06	0.54	0.37	0.01	0	1.9
1999	0.53	0.31		0.02	0.05	0.56	0.39	0.01	0	1.9
2000	0.382	0.322		0.019	0.04	0.606	0.412	0.008	0.005	1.8
2001	0.427	0.426		0.017	0.051	0.337	0.395	0.007	0.031	1.7
2002	0.346	0.296		0.02	0.067	0.423	0.392	0.009	0.004	1.6
2003	0.454	0.222		0.022[c]	0.486	0.489	0.407	0.009	0.01	2.1
2004	0.439	0.341		0.008[d]	0.076	0.575	0.415	0.11	0.025	2.0
2005	0.362	0.382		0.013	0.074	0.243	0.34	0.02	0.002	1.4
2006	0.322	0.249		0.009	0.097	0.251	0.354	0.018	0.002	1.3
2007	0.279	0.061		0.009	0.072	0.136	0.362	0.015	0.002	0.9
2008	0.335	0.042		0.008	0.068	0.476	0.368	0.011	0.001	1.3
2009	0.295	0.039		0.005	0.059	0.540	0.421	0.010	0.001	1.4
2010	0.348	0.027	0.813	0.000	0.073	0.535	0.423	0.010	0.010	2.2

Source: U.S. Geological Survey, MDE

[a]Well was installed in 2007. Routine withdrawal did not occur until approximately 2009.

[b]Panda was granted a higher appropriation during construction of its pipeline for conveying treated effluent.

[c]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.

[d]No report ws 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.

appropriations, uses the data from this joint monitoring program to assess the significance of impacts to aquifers when reviewing additional appropriations requests.

Long-term monitoring indicates a steady decline in water levels in the Aquia, Magothy, and Patapsco aquifers. However, these declines are not solely due to withdrawal from 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. Water quantity impacts to each of the four aquifers are summarized below.

- ***Aquia Aquifer at Calvert Cliffs*** – *Water levels in the Aquia Aquifer at Calvert Cliffs have declined approximately 76 feet over the period 1982 to 2009, with most of the decline occurring since 1990. This acceleration in water level decline is due to the withdrawal 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 111 feet and approximately 97 feet, respectively, since 1982. The impacts from the water level decline are considered acceptable given the 315 feet of available drawdown currently estimated in the Aquia Aquifer at Calvert Cliffs based on MDE's available drawdown criteria described above.*
- ***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 withdrawal from the Magothy during the time period 1990 to 2005 by about 44 percent compared to the period before 1980. This reduction has resulted in a commensurate reduction in the rate of water level decline at the facility during this same period. However, water levels continue to decline in the aquifer due to the extensive continued use in Annapolis and Waldorf. The drawdown at Chalk Point between 1975 and 2009 has been approximately 42 feet, and a total of about 82 feet since pumping at Chalk Point began in 1964. Prior to pumping in 1962, the elevation of the potentiometric head in the Magothy formation 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 82 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 declined up to 35 feet at Chalk Point between 1990 and 2007. Recent measurements indicate a total drawdown of nearly 75 feet between 1975 and 2009 at Chalk Point. These declines will not impact the approximately 512 feet of available drawdown in the Upper Patapsco Aquifer at 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 up to 35 feet between 1990 and 2009. Water levels in the vicinity of the Morgantown power plant have dropped several feet since 2006. GenOn also projects increased water demands at the Morgantown power plant following the installation of FGD scrubbers in 2010.*
- ***Patuxent Aquifer at Chalk Point*** *– The water level surface of the Patuxent Aquifer has declined approximately 13 feet as a result of withdrawal at the Chalk Point power plant. Water levels in the vicinity of the power plant have declined approximately 130 feet between 2009 and 2011.*

Impacts to Water Quality and Aquatic Biota

Potential impacts from steam electric power plants on rivers and estuaries may include a reduction in river flow volumes due to evaporative water loss in the plant's cooling system, mortality of aquatic organisms as a result of entrainment in the cooling system, impingement of larger organisms on cooling system intake screens, and elevated temperatures of receiving waters after power plant discharge.

Water usage and the resulting environmental impacts have been monitored by various agencies and organizations. These issues have been a major responsibility of PPRP since it was established in 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. Although permit requirements and regulations may not require an assessment of cumulative effects, the health of the contiguous system is determined by the impact of multiple influences. PPRP has conducted aquatic impact assessment studies at all of Maryland's existing plants and has identified no measurable cumulative adverse impacts. 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.

In addition to minimizing impacts, several power plants 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). Power plants also 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 that were taken to minimize and mitigate these impacts, are discussed in greater detail below. The impacts associated with cooling water withdrawals in the state are currently being re-evaluated for regulatory compliance because of EPA's revised Section 316(b) regulations of the CWA for existing power plants.

Cooling Water Withdrawal Impacts

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 aquatic organism impacts at 12 major power plants. The studies were used 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 affect ecosystem elements, the cumulative impacts have no significant consequence to Maryland's aquatic resources.

Although entrainment losses for aquatic organisms have been measured, they did not reveal consistent depletions of populations. Even though power plant activities have not substantially decreased populations, the plants modified their operating procedures and constructed on-site 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.

Clean Water Act Section 316(b)

EPA's implementation of CWA Section 316(b) has resulted in updated assessments of the impacts of cooling water withdrawals. EPA phased in the regulation in three steps: Phase I applies to new facilities with a cooling water intake, constructed after January 17, 2002; Phase II was to apply to existing power-producing facilities, effective September 7, 2004, with a cooling water intake design greater than 50 mgd and would have applied to each facility as its National Pollutant Discharge Elimination System (NPDES) permit is renewed; and Phase III would have applied to non-power producing facilities.

Maryland has 12 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), and the remaining nine (Calvert Cliffs, Chalk Point, C.P. Crane, Dickerson, Gould Street, Morgantown, Riverside, R. Paul Smith, and Wagner-Brandon Shores) have conducted a Phase II evaluation.

The Phase II regulations established specific performance standards for reduction of impingement and entrainment. There were 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 the Phase II rule, rejecting many of its provisions (Riverkeeper et al. v. USEPA, decided January 25, 2007). A portion of this ruling was appealed to the U.S. Supreme Court with respect to the cost-benefit test. The court ruled in March 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 issued a proposed revised rule for public comment in March 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.

2011 EPA-Proposed 316(b) Regulations

Summary of Regulations on Cooling Water Intake Structures Proposed by EPA on March 28, 2011:

- Applies to existing facilities withdrawing at least 25 percent water for cooling purposes, with a design intake flow (DIF) > 2 mgd;
- Requires impingement mortality (IM) reduction of 12 percent on an annual average basis and 31 percent on a monthly average basis OR demonstration that the cooling water intake structure has a maximum intake velocity of 0.5 feet per second;
- If the facility uses traveling screens to meet the velocity standard, fish protection measures need to be included;
- If facility draws from ocean or tidal waters, IM of shellfish must be reduced to that achievable with a barrier net;
- If facility has an actual intake flow (AIF) > 125 mgd, they must conduct an entrainment characterization study;
- MDE would establish best available technology standards for entrainment mortality on a case-by-case basis. Public input into this process is required;
- A final rule is scheduled for July 2012. The IM requirements would have to be met within eight years of the final rule, at the latest;
- The Phase I rule still applies to new facilities (with the exception that restoration for mitigation is no longer allowed); and
- New units at existing facilities must have cooling towers as best available technology.

Application to Maryland facilities:

- There are 10 facilities which fall under this rule (see Table 4-3).
- Of these, six have actual or permitted flows (as of 2008) which are > 125 mgd, so would have to comply with the entrainment mortality study.
- These six facilities have also prepared Best Professional Judgment reports under Maryland regulations, including an assessment of technologies that could meet various entrainment and impingement criteria.
- All facilities would likely have to conduct additional studies to comply with the rule, as the Best Professional Judgment reports do not contain all the required information.

Cooling Water Discharge Impacts

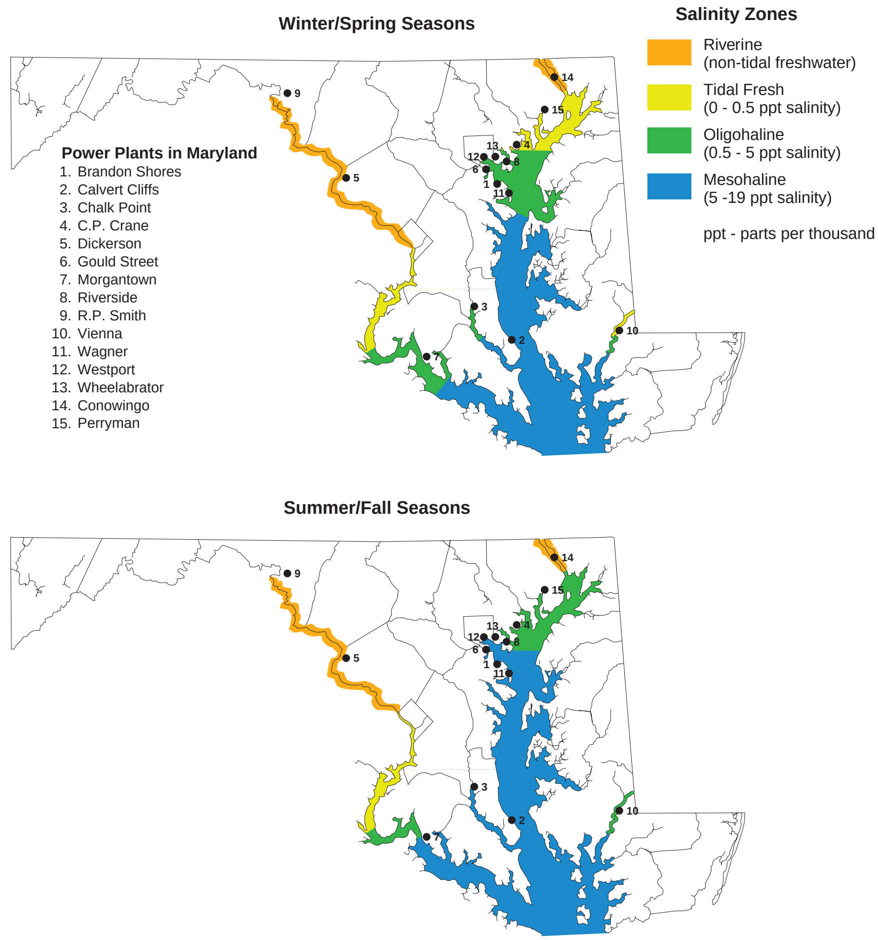
Impacts to aquatic biota from power plant cooling water system discharges include elevated temperatures, discharge of chemicals used for biofouling treatment (e.g., chlorine), discharge of metals eroded from internal plant structures (e.g., copper), and, in the case of Maryland's only nuclear power plant, discharge of radiological materials. 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 riverwater. 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 conducted studies to determine the effects of thermal discharges at each existing power plant in the state. Because different aquatic biota occupies different habitat types in Maryland waters, study results are presented here according to the habitats where power plants are located (see Figure 4-15). The following pages present a brief summary of the findings in those studies.

Mesohaline Habitat – The largest power plants (by generating capacity) in the state discharge into mesohaline habitat 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.

Figure 4-15 Salinity Zones of the Maryland Chesapeake Bay



The effects of thermal discharges from the power plants located in the mesohaline habitats of the Chesapeake Bay have been localized and are 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; new technology would then be considered to reduce thermal discharges.

Tidal Fresh and Oligohaline Habitat – Two plants, Vienna and C.P. Crane, discharge into tidal fresh and oligohaline waters (Chalk Point also discharges into the oligohaline zone during part of the year; see discussion on previous page). PPRP studies showed that the thermal plume at Vienna was small and its discharge effects were negligible. The thermal plume at C.P. Crane 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.

Recently, 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 that the fish populations in the vicinity of the Crane power plant remain unaffected by its thermal discharge. The study showed that differences in the fish community apparent between the 2003-2005 results and the results of the 1979-1980 study reflect long-term changes in the upper Bay fish community and are not suggestive of a plant discharge effect. The results also suggest that there is no consistent effect of the thermal discharge on the fish community composition or distribution.

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 fish movements were blocked by thermal plumes in the plants' receiving waters in these particular habitats.

Nontidal Freshwater Habitat – R. Paul Smith and Dickerson are the only once-through cooling power plants located in nontidal riverine habitat in Maryland. The thermal impact of their discharges on the Potomac River ecosystem was assessed in a long-term freshwater benthic study conducted by PPRP over an eight-year period in the 1980s. While this long-term study documented that the thermal discharges from these two plants 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 is 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 multi-year study of growth and condition of several fish species in the vicinity of the plant. Based on data on fish condition collected over a 21-year period near the plant and at reference locations, there was no indication that fish near the plant were affected by the localized discharge effects on benthic communities.

Chemical Discharges

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, oysters in the vicinity of the Chalk Point, Calvert Cliffs, and Morgantown power plant discharges were found to be bioaccumulating copper that was present in the effluent discharge. The copper resulted from erosion 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 replaced the copper condenser tubes with titanium tubes where this problem was most significant, primarily in estuarine waters. The titanium tubes eliminated the metals erosion, 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 bio-fouling 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 chlorine not be discharged 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. An exception may be granted if a facility demonstrates that more chlorination is needed to control macroinvertebrates. Chlorinated discharge impacts are now considered resolved and no further action is needed.

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. In September 2009, EPA announced plans to revise the existing standards for water discharges from coal-fired power plants to reduce pollution and minimize these effects.

Earlier in 2009, EPA completed a multi-year study of power plant wastewater discharges and concluded that current regulations, which were issued in 1982, have not kept pace with changes that have occurred in the electric power industry over the last three decades. Air pollution controls installed to remove pollution from smokestacks have made great strides in cleaning the air people breathe, reducing respiratory and other illnesses. However, some of the equipment used to clean air emissions does so by "scrubbing" the boiler exhaust with water ("wet" FGD systems) and when the water is not properly managed, it sends the pollution to rivers and other 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.

As part of the multi-year 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. Types of treatment systems for FGD systems include settling ponds, chemical precipitation, biological treatment, constructed wetlands, and zero-liquid discharge. Once the new rule for electric power plants is finalized, EPA and states would incorporate the new standards into wastewater discharge permits. EPA plans to propose a rulemaking for the steam electric power generating industry in July 2012 and take final action by January 2014. More information about EPA's study is provided in a report that was published in October 2009. For more information on wastewater discharges from power plants, please visit: http://www.epa.gov/waterscience/guide/steam/.

As a result of the Chesapeake Bay TMDL (see sidebar on p. 82), all dischargers with NPDES permits, including industrial dischargers such as power plants, will have reduced limits on total nitrogen, total phosphorus, and sediment.

Impacts of Hydroelectric Facilities

While only two large-scale hydroelectric projects (with capacities greater than 10 MW) are present in Maryland, five additional small-scale facilities also generate electricity within the state (see map and table in Chapter 2 on page 28). Hydroelectric facilities may present special environmental concerns that are not encountered at steam electric power plants. Development and operation of hydroelectric facilities can cause three main types of impacts:

Changes in water quality – Impoundments created for hydroelectric dams significantly alter river flow from free-flowing streams to deep water 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 dam. To mitigate these impacts, a procedure known as turbine venting was implemented at Conowingo Dam on the Susquehanna River. This venting allows air to be entrained into the water passing through the turbines and increases the oxygen content of the water. Similarly, an aeration weir was constructed in the Deep Creek Station tailrace to increase oxygen in water from the dam's discharge.

Changes in water quantity – Operating hydroelectric facilities in a peaking mode (in response to peak electrical demand) produces unnatural, and frequently extreme water level fluctuations in impoundments as well as downstream from the dams. Additional small-scale projects may also divert some flow away from the natural streambed. Fluctuations in water level and flow may reduce fish abundance as well as food sources important to fish growth and survival. Several studies, initiated in the early 1990s and completed in 1998 were conducted at Conowingo Dam to determine the minimum flow necessary to protect and enhance aquatic biota as well as whether a continuous flow is needed; these studies are being revisited as a part of the relicensing process (see below).

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. Fish lifts at Conowingo have begun to restore anadromous fish populations upstream of the dam and operational changes have been used to reduce mortality of downstream migrating fish. Studies are continuing at Conowingo to investigate further reductions on migratory fish impacts.

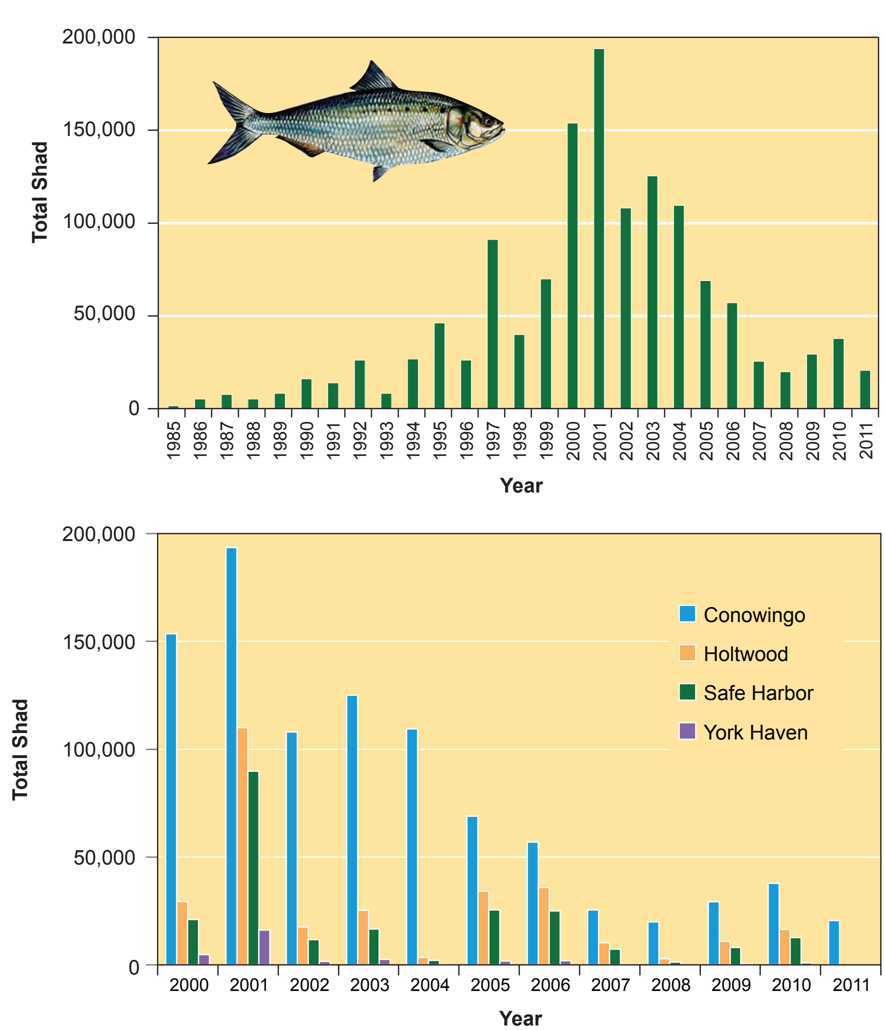
Historically, the Susquehanna River supported large spawning runs of migratory species such as American shad, river herring, and striped bass. The massive anadromous fish migrations extending as far upstream as Cooperstown, New York, were eliminated with the construction of four major hydroelectric facilities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

When the FERC licenses for the four Susquehanna River hydroelectric facilities were being considered for renewal in the early 1970s, a major issue that arose was restoration of migratory fish to the Susquehanna. Participants in the FERC license proceedings included PPRP, on behalf of the State of Maryland; the State of Pennsylvania; the State of New York; the U.S. Fish and Wildlife Service; and several non-governmental organizations (NGOs). The ultimate goal of the resource agencies and NGOs was to restore migratory fish runs throughout the Susquehanna River basin. This goal was pursued through an active restoration program (e.g., trapping and trucking adult fish to areas above the dams, hatchery rearing of larval and juvenile shad for stocking in the river) and the installation of fish passage devices at all four dams.

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. For the first time since the dams had been constructed, the entire Susquehanna River had been re-opened to migratory fish. This has created the potential for shad and other species to move as far upstream as New York State, representing renewed access to well over 400 miles of historic habitat.

Growth of the Susquehanna River shad stock in response to the restoration efforts and installation of fish passage devices has been problematic. Growth peaked in 2001, when nearly 200,000 American shad were passed over Conowingo Dam, but has since declined for reasons that are the subject of ongoing studies (see Figure 4-16). Ongoing monitoring of restoration progress also revealed some issues that need to be addressed. One concern at the present time is the low percentage of shad that are able to move past the Holtwood Dam during high flow years once they have successfully moved past the Conowingo Dam. In 2004, only 3.1 percent of the shad passing over Conowingo Dam succeeded in moving beyond Holtwood Dam. Concerns also exist regarding the percentage of shad that move past York Haven Dam. A more thorough assessment of that issue may not be possible until a higher passage efficiency is achieved at Holtwood Dam. PPRP, working with 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.

Figure 4-16 Number of American Shad Passed at Conowingo Dam from 1985 - 2011 and at Conowingo East, Holtwood, Safe Harbor, and York Haven Dams from 2000 - 2011



The FERC licenses for three of the four lower

Susquehanna facilities expire at the end of 2014, and agency consultation on relicensing is already underway. Fish passage and flow issues are being further studied and addressed as part of this process.

Current Hydroelectric Licensing Projects

Conowingo – Exelon Generation Company is licensed by FERC to operate the 573-MW Conowingo Hydroelectric Project, located on the Susquehanna River in Harford and Cecil counties. The current license for Conowingo was issued in August 1980 and expires on September 1, 2014. Exelon intends to submit an application to FERC for continued operation of the project; this application must be submitted by September 2012. PPRP is coordinating all Maryland agency reviews and providing input on the license application for FERC to consider as part of its review. Some issues that PPRP has recommended for further study during relicensing include upstream and downstream fish passage, flow and water level management, the project's effect on salinity in the Bay, dissolved oxygen (DO) levels, eel passage, sediment and debris management, and recreation. PPRP's goal is to determine appropriate protection, mitigation, and enhancement (PM&E) measures in consultation with MDE and other resource agencies, and ultimately to reach agreement on license conditions prior to Exelon's submission of a final license application to FERC.

Deep Creek Hydroelectric Station: Balancing Multiple Resource Uses

The 3,900-acre Deep Creek Lake was formed in 1925 by the construction of a rockwall dam across Deep Creek, a tributary of the Youghiogheny River. The Deep Creek Hydroelectric Station (DCHS) includes two turbines with a combined generating capacity of about 18 MW.

Operation of the facility affects recreational users of the lake and the river. The Youghiogheny River is Maryland's only designated "wild" river. It supports a trout fishery and is one of the most challenging whitewater runs in the country. In 1994, the owner of DCHS agreed to negotiate conditions to be required under a water appropriations permit administered by MDE. Working with PPRP and MDE, conditions were designed to achieve two objectives: 1) to provide a reliable and economical source of electricity; and 2) to enhance Deep Creek Lake's and the Youghiogheny River's natural and recreational resources.

Lake Water Levels — Recreational lake users typically want minimal and consistent drawdown of the lake during summer, with higher than historic levels (prior to the 1990s) in the autumn to extend the boating season. Water levels are lowered in the fall and winter to prevent ice damage to the spillway. To help evaluate possible alternative operating strategies, a computer model of historical lake inflow, storage, and electricity generation was developed. The model was used to create monthly operating rules for the DCHS that balanced electricity generation with the maintenance of desirable lake water levels.

Downstream Fisheries — Naturally high water temperatures in the Youghiogheny River and low DO levels in the hydroelectric station's discharge historically limited trout habitat. The discharge from the hydroelectric station tends to be cooler than the river because it draws cooler water from the bottom of the lake. PPRP developed a protocol for station operators that calculates the timing and volume of water discharges during periods of peak temperatures in the Youghiogheny River, such that downstream trout habitat is enhanced. The protocol uses river flow and temperature changes, and available predictions of maximum air temperature and cloud cover for the region. The goal is to maintain the river temperature below 25°C. The plant owner also installed structures to aerate discharge water to alleviate the low DO problem.

Whitewater Recreation — The Youghiogheny River is an exceptional whitewater recreation resource that depends on releases from the DCHS for adequate flow volume in most summer months. Whitewater boaters rely on timed and dependable releases from the hydroelectric facility to plan trips in advance. Operation of the facility is scheduled around providing suitable flow for boating at fixed times on most Fridays, Saturdays, and Mondays during the whitewater recreation season (April 15 through October 15), except when lake levels are too low.

Deep Creek Station's water appropriations permit was renewed in 2007 for another 12-year period. MDE, with assistance from PPRP, working with affected stakeholder groups, reviewed the permit conditions and made minor adjustments to the permit with the goal of continuing to promote optimal use of Deep Creek Lake and affected downstream natural resources.

In 2010, a group of stakeholders again requested MDE to consider modifying the permit to maintain higher lake levels during the summer and early fall months. MDE made some minor modifications to the operating rules in response to this request, including raising the upper rule band and allowing for minor excursions above that level, to provide Brookfield Power (the current owner and operator of DCHS) greater flexibility in maintaining higher summer recreational lake levels while still providing for downstream water uses.

Jennings Randolph – In 2008, Fairlawn Hydroelectric Company filed a notice of intent to seek a FERC license for the Jennings Randolph Hydroelectric Project. The proposed project would use the existing Jennings Randolph Dam, owned by the U.S. Army Corps of Engineers (USACE) and located on the Potomac River in Mineral County, West Virginia, and Garrett County, Maryland. The developer's plans include a total installed capacity of about 13 MW, and would not involve any change in the volume or timing of releases compared to current USACE operations. Fairlawn conducted several studies regarding water quality modeling, fish entrainment, wetlands, and protected species, to support its license application to FERC, filed in 2011. PPRP is continuing to evaluate its licensing proposal and to provide appropriate PM&E measures to be made part of its FERC license and state-required water quality certification conditions.

4.1.3 Terrestrial Impacts

Maryland's physiographic diversity, geology, and climate have produced a variety of eco-regions that foster numerous, and sometimes unique, habitats ranging from ocean barrier islands in the east through salt marshes, fields and forests of the coastal plain, into rolling piedmont hills, and on to ancient forested mountains with remnant alpine glades to the west. While human activities (agriculture, urban/suburban development, etc.) have impacted all of these areas to some extent, the majority of the landscape continues to possess 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 species.

The State of Maryland implements a suite of regulations (COMAR Titles 08, 26, and 27) that afford protection to habitats and species in terrestrial and wetland environments:

- *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 PM and other air pollutants; and*
- *Degrade habitats by the permitted discharge of pollutants or from accidental spills.*

New generation facilities may be constructed entirely within an area that is already developed or it may require the clearing of a significant number of acres of natural habitat. The Fairfield Renewable Energy Project, licensed in 2010, has been proposed for development in a heavily industrialized area of Baltimore along Curtis Bay. Although a portion of the project will be developed within the Chesapeake Bay Critical Area, most of the area consisted of buildings and other infrastructure associated with the site's previous use in chemical manufacturing. In contrast, the proposed expansion of the Calvert Cliffs Nuclear Power Plant involved a project site that was extensively forested and previously provided recreational opportunities to the region. How new generation projects affect Maryland's landscape in the future will also depend on the mode of power production. Power plants that use traditional resources such as coal and natural gas are generally confined to an intensively developed installation, whereas newer kinds of renewal energy projects such as from wind and solar require hundreds of acres to install wind turbine and solar panel arrays. For example, PPRP recently reviewed a 20-MW solar photovoltaic project that would occupy up to 270 acres surrounding the Maryland Correctional Institution in Hagerstown.

PPRP's role in the CPCN process is to facilitate compliance with Maryland's environmental regulations and natural resource management objectives. Environmental laws affecting Waterways Construction, Water Quality and Water Pollution Control, and Erosion and Sediment Control require 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 specific conditions to avoid, minimize, or mitigate impacts on natural resources when the effects of the proposed project are particularly compelling. Under these circumstances, conditions placed on a CPCN to mitigate for impacts to wetlands, forests, and sensitive species habitats may often be more stringent than requirements under the individual statutes.

Wetlands

Wetlands are important components the environment, forming the interface between terrestrial and aquatic ecosystems. Wetland communities often consist of a diversity of plant species, a number of which may be species of concern. Wetlands also provide numerous values to 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 surface area); 220 years later, in 2009, Maryland has only about 345,000 acres of nontidal wetlands (4.8 percent of its surface 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. Similarly, the 1994 Tidal Wetlands Regulations were developed to regulate activities in tidal wetlands. Under Maryland's 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. Mitigation ratio 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.

The CPCN process includes assessing potential wetlands impacts and developing appropriate mitigation equal to or greater than those required by these regulations. While wetlands are present at nearly all Maryland's power facilities, impacts to these wetlands are rare. Where especially valuable wetlands are present, the CPCN process can identify special conditions to ensure their protection. For example, the CPCN to construct the Kelson Ridge generating 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.*

Forests

The importance of forest resources is manifold. Forests provide habitat for wildlife including important game species such as white-tailed deer and wild turkey. On the ground, forests filter stormwater of nutrients and other pollutants, and prevent the erosion of the landscape; while in the air, they filter out air pollutants and perform the vital function of producing oxygen. As a forest grows to maturity, it sequesters carbon both as plant tissue and soil-forming materials from dropped leaves and branches. Forests are also important as commercial resources for providing construction materials and as a renewable fuel source. Nevertheless the historic losses of Maryland's forest resources have been compelling, which prompted enactment of the Forest Conservation Act (FCA) in 1991. With the exception of projects located in heavily forested Allegany and Garrett Counties, all construction developments of greater than 40,000 square feet must comply with the FCA. Under the FCA, existing forest condition and character are integral parts of the development planning process, including power plant and transmission line siting, across the State. 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 parameters must be considered before any development disturbs forest resources.

If the applicant demonstrates that clearing of forest will be minimized, an exemption from FCA requirements for rights-of-way and land for construction of electric generating facilities may be granted by the PSC. To date, however, all CPCNs issued since the FCA was enacted have included conditions that ensure applicants comply with the FCA where appropriate. The CPCN process also considers the quality of forest resources lost as conditions are developed. For example, the CPCN to construct the Rock Springs generating facility in Cecil County included restoration conditions to compensate for values of mature forest lost and some of the nitrogen deposition caused by the facility's emissions. Specifically, the applicant was required to plant 50 acres of young trees to replace 20 acres of mature forest. The reforestation was directed to riparian areas to increase the likelihood that deposited nitrogen would be intercepted before reaching Chesapeake Bay tributaries.

Threatened and Endangered Species

Rare, threatened and endangered (RTE) species, whether federally-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 highly specific habitats. Generation projects proposed in Maryland must undergo environmental review by the DNR's Wildlife & Heritage Service (WHS) to identify any RTE species known to occur in the vicinity of the affected area. Any recommendations made by the WHS during the environmental review usually form the basis for conditions in the CPCN. Irrespective of the kinds of habitat involved, areas that support State-listed threatened and endangered flora and fauna are protected under state law. Table 4-5 lists the number of protected species by taxonomic group that the CPCN process considers when evaluating potential adverse effects and developing protective conditions.

Table 4-5 Types of State-Listed Rare, Threatened, and Endangered Species

Group	Number of listed species
Plants	841
Planarians	8
Mollusks	22
Crustaceans	27
Spiders	3
Insects/Collembola	1
Insects/Coleoptera	23
Insects/Diptera	1
Insects/Ephemeroptera	1
Insects/Homoptera	2
Insects/Lepidoptera-Butterflies	39
Insects/Lepidoptera-Moths	23
Insects/Odonata	109
Insects/Trichoptera	1
Fishes	27
Amphibians	11
Reptiles	15
Birds	78
Mammals	31

Although few applications for power generating facilities affect threatened and endangered species, a number of individual cases have considered potential impacts to wildlife species such as bald eagle, tiger beetles, Delmarva fox squirrel, carpenter frog, and plant species such as purple pitcher plant, New Jersey rush, and winterberry. Recently, the proposed expansion of the Calvert Cliffs Nuclear Power Plant required the removal of a bald eagle's nest in the area proposed for Unit 3 construction. Although the bald eagle had been delisted by the U.S. Fish and Wildlife Service under the Endangered Species Act, at that time it was still State-listed as threatened in Maryland (bald eagles have been delisted in Maryland but continue to receive federal protection under the Bald and Golden Eagle Protection Act and Migratory Bird Treaty Act). In this case, the project developer was required to obtain a permit from Maryland DNR for "take," or removal, of the nest as well as a federal permit from the U.S. Fish and Wildlife Service (USFWS). Under the terms of the permit issued by DNR, the removal of the tree must occur outside of the nesting season when the nest is inactive. To mitigate for take of the nest, UniStar committed to protecting an area in the vicinity of the project where bald eagles have historically nested successfully. The CPCN issued for Calvert Cliffs Unit 3 also required UniStar to maintain a buffer distance between any land disturbed during construction and the habitat of the federally endangered tiger beetle, which lives in the eroding cliff faces near the Bay shoreline. Two species of tiger beetle present at the Calvert Cliffs site are on both the federal threatened and State endangered lists.

Wildlife

New generation facilities primarily affect wildlife by removing habitat during construction of the project; however, wind energy projects can also have a substantial impact during 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 lay-down 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 proposed for construction in Maryland have been in the predominantly forested habitats of Garrett and Allegany counties. The forests of western Maryland are considered to be a southern extension of the northern hardwood forests that extend 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.

In Maryland, land-based wind power facilities of less than 70 MW of generating capacity can apply for exemption with the PSC from having to obtain a CPCN. Although this exempts developers from the coordinated PPRP environmental review, they must still comply with all environmental laws and regulations. To date, two projects have been granted exemptions and a third is under consideration before the PSC. All three of these projects are located on mountain ridges that historically have been densely forested. More recently, greater concern has been given to bats, especially to those in the eastern states, where high levels of fatality have been reported at wind power facilities constructed on forested mountain ridge tops.

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 more than a decade of study at a number of wind power facilities in the U.S. and abroad, there is evidence that the numbers of bird fatalities are small at most locations. Per turbine, two to three birds are killed annually 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. It is currently believed that most of the bat fatalities occur during the late summer to fall migration period as bats move to their over-wintering habitat.

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 has been distributed among 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 they 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.

Until recently, wind turbines were not known to have killed any threatened or endangered species of bats. However, it has now been documented that an Indiana bat was killed at a wind energy facility in Indiana. Western Maryland provides year-round habitat to the federally endangered Indiana bat, and the State-listed as In Need of Conservation 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.

An even greater concern for populations of cave-hibernating bats, such as the Indiana bat and more common little brown bat, has developed since White Nose Syndrome (WNS) was found to be severely affecting bats in caves of the northeast. 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 WNS 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 WNS and the growing wind energy industry, has yet to be determined.

In response to limited understanding of the risks to birds and bats from wind energy development, the Maryland General Assembly required that the PSC establish a technical advisory group (TAG) to develop siting guidelines that would seek to minimize the risk to birds and bats. The TAG produced Siting Guidelines to Mitigate Avian and Bat Risks from Wind Power Projects, which addressed five aspects related to wind power development:

1. *Standards that will avoid or minimize impacts on birds and bats from the construction and operation of wind-energy generating facilities.*
2. *A tiered system of standards that vary with the size of the wind-energy generating facility and the associated generating capacity.*
3. *Assessments of avian and bat populations before issuance of a CPCN.*
4. *Additional monitoring studies of avian and bat populations and behavior during and after construction of a wind project.*
5. *Mitigation appropriate to address any impact on avian and bat populations above a threshold level.*

In support of the siting guidelines, PPRP has developed monitoring protocols for birds and bats during pre- and post-construction phases. Pre-construction monitoring protocols for birds include a breeding bird survey and Phase 1 Avian Risk Assessment. Monitoring protocols for bats include using ultrasonic acoustic detectors to measure bat activity and some field captures using mist-netting to establish the presence/absence of endangered or threatened species (i.e., Indiana bat, small-footed bat). Additionally for bats, the project site should be evaluated for habitat suitability. Post-construction monitoring protocols include a study of bird and bat fatalities over a period of three years. Since then, regulations allowing for the exemption of environmental review during CPCN licensing have limited the implementation of Maryland's guidelines; however, the USFWS has recently finalized recommendations for siting wind turbines on land that incorporate many of the same considerations for birds and bats.

4.1.4 Socioeconomics and Land Use Issues

Socioeconomics in PPRP environmental reviews comprises a broad discipline that addresses essentially the human environment. This includes economic, demographic and fiscal considerations, i.e., employment, income, population, housing, and government revenues and expenditures, but also encompasses land use, transportation, cultural resources, and aesthetics.

Economic, demographic, and fiscal issues associated with generation facilities in Maryland are rarely contentious. Construction, even of larger facilities, does not create "boom and bust" employment cycles because adequate labor is within commuting distance of most power plant sites. In most licensing cases for construction and modification of generation facilities, employment demand is within the capacities of local or regional labor markets. As a result, demographic and most fiscal effects, which are employment-dependent, are rarely focal points of concern in the environmental review process.

That does not mean the impacts are inconsequential. The economic benefits from construction, modification and operation of generation facilities are invariably positive, adding jobs and payrolls to host communities and surrounding regions. Through the multiplier effect, direct jobs, purchases of materials and services, and increased spending by employees are translated into additional jobs and payrolls. Investment in power generation often increases the tax base for the host county, sometimes substantially, and usually without additional outlays for public services. Rather than being contentious, economic, demographic, and fiscal impacts from generation facilities are viewed as part of the organic growth of regional economies in Maryland.

Recent socioeconomic reviews of generation facilities in Maryland have required a particular focus on transportation, however, where a recurring issue has been truck traffic. Land use is also a recurring theme.

Transportation

Transportation is a key input to the generation of electricity, particularly generation technologies based on combustion. Typically, fuel must be delivered from the mine or well, and by-products must be disposed. In recent years, Maryland has seen its power generators diversify their transportation options and fuel supplies through the construction of barge unloading facilities at Morgantown and Brandon Shores. Deployment of new pollution control technologies to comply with Maryland's HAA has created a new by-product – gypsum – that must be hauled to markets. In Maryland, both barge and rail are used to transport this bulk commodity.

Morgantown STAR Project

One of the remaining major pollution control by-products from coal combustion is fly ash, captured in electrostatic precipitators from the exhaust stream. Traditionally, fly ash has been transported to landfills in trucks for disposal. In 2010, Mirant Mid-Atlantic, LLC (now GenOn

Cement Production in the U.S. and Maryland

Concrete is the most widely used building material in the world. It is a mixture of two components – aggregates (usually sand and gravel, or crushed stone) and paste (comprised of cement, supplementary cementing materials (SCM), and water). In the United States, about 340 million cubic yards of concrete are used each year and, in 2008, nearly 94 million metric tons of Portland cement was consumed. According to the Portland Cement Association, cement is manufactured domestically at 113 cement plants in 36 states, including two cement plants in Maryland. Most cement shipments are sent to ready-mix concrete operators, with the rest shipped to manufacturers of concrete related products, and lesser amounts to contractors, materials dealers, and other businesses. In 2010, there were 45 ready-mix plants in Maryland and 101 in Virginia, and 25 other cement plants (66 in Virginia). Because of shipping costs, cement is typically purchased from local sources. Nearly 98 percent of cement is shipped by truck.

Mid-Atlantic, LLC) submitted an application to the Maryland PSC to authorize the modification of the Morgantown Generating Station to install a fly ash beneficiation facility to thermally process fly ash into a low-carbon material suitable for beneficial reuse. Under the proposal, fly ash that was transported from Morgantown and Chalk Point to the Faulkner Landfill in Charles County and the Brandywine Landfill in Prince George's County would be processed at the Morgantown Generating Station in a proprietary technology called a Staged Turbulent Air Reactor (STAR) and then transported in bulk via truck to markets. The facility is permitted to process up to 360,000 tons per year. Processed fly ash would be sold as a supplementary cementing material (SCM) for the manufacture of concrete, a substitute for some of the Portland cement in the mixture.

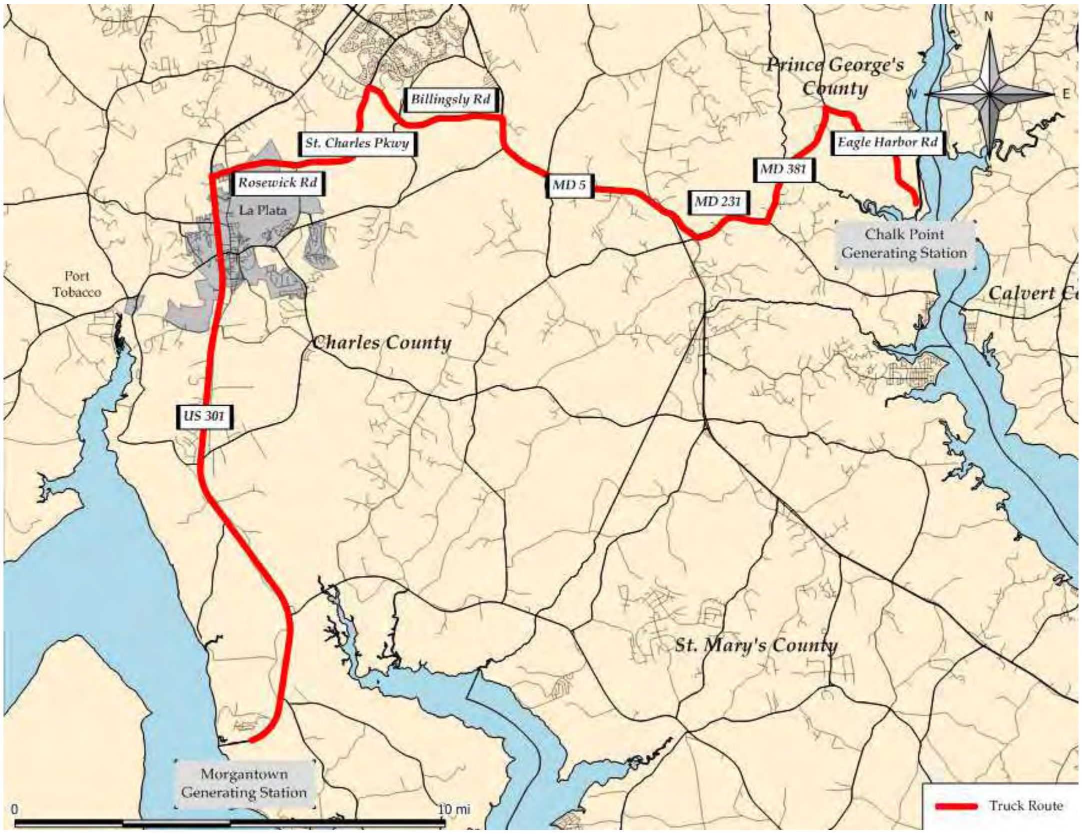
Although the project would increase truck traffic to and from Morgantown only slightly, it would significantly change truck traffic flows from both Morgantown and Chalk Point. From Morgantown, instead of trucks hauling unprocessed fly ash on US 301 to a single destination (Faulkner, or Brandywine after the closure of Faulkner), dry tanker trucks would deliver processed fly ash to concrete manufacturers in and around Southern Maryland in response to demand. The effect, relative to current operations, would be to spatially and temporally distribute truck traffic from Morgantown. However, truck traffic flows from Chalk Point would also change, as unprocessed fly ash would be diverted from the Brandywine Landfill to Morgantown. Although Mirant identified a truck route, shown in Figure 4-17, between Chalk Point and Morgantown consisting of State highways and divided, multi-lane county roads, affected communities expressed concerns about safety and the suitability of these roads for carrying the projected industrial traffic, particularly at a pair of roundabouts at the interchange of MD 231 and the MD 5 bypass in Hughesville. In consultation with the Maryland State Highway Administration (SHA), PPRP was able to show that the proposed truck route was both acceptable and safe and, as a result, recommended a licensing condition requiring Mirant to dispatch trucks transporting unprocessed fly ash to the proposed route, unless a segment of the route is temporarily unavailable or unsafe.

Dry Tanker Truck for Processed Ash Shipment

Fairfield Renewable Energy Project

Truck traffic was also a major consideration in the State's environmental review of a proposed 120 MW renewable energy generating facility on the Fairfield Peninsula in Baltimore. Here, the proposed facility would convert processed refuse fuel (PRF) derived from residential, commercial, and non-hazardous industrial waste, supplemented with automotive shredder residue (ASR), processed urban wood waste, and scrap tire chips. PRF would

Figure 4-17 Truck route between Chalk Point and Morgantown



be manufactured at off-site fuel production facilities and hauled to the Fairfield Peninsula by trucks in transport trailers.

Unlike most generation facilities in Maryland, the project would be located in an urban setting bounded between the Patapsco River and the neighborhoods of Curtis Bay and Brooklyn in Baltimore City. Roads throughout the Fairfield Peninsula carry a large proportion of trucks. The condition of roads leading to and within the peninsula is poor in numerous locations, characterized by potholes, lack of striping, and other deficiencies. In addition, industrial freight traffic has been an ongoing concern for the Brooklyn and Curtis Bay neighborhoods. While recognizing the importance of rail and truck access to nearby industrial activities, residents have complained about noise, road damage, and congestion caused by large trucks in predominantly residential areas. Figure 4-18 shows the Baltimore neighborhoods in the vicinity of the Fairfield Energy Project.

In this context, PPRP looked at expected traffic during both construction and operation of the facility. During construction, transportation impacts would be associated with commuting construction workers and the delivery of material components and construction equipment to the site. Construction worker traffic would generate 154 round-trips per day, on average. With a spatially dispersed labor force and excellent site accessibility via interstate highways and urban arterials, the increment in

Figure 4-18 Location of the Fairfield Energy Project and Surrounding Neighborhoods

traffic generated by construction workers was not expected to affect levels of service on any local road segments or intersections. With an average of 10 deliveries per weekday to the site over the construction period, PPRP concluded that construction truck traffic would have no impact on levels of service. However, PPRP conditioned its recommendation on a prohibition of trucks on residential or business thoroughfares of Curtis Bay and Brooklyn, a restriction that was negotiated by the applicant with community organizations.

Once operational, the facility would be a significant generator of truck traffic. About 200 round-trip truck trips per day would be needed to satisfy the facility's weekly PRF fuel consumption requirements. In addition to this would be deliveries of other waste-derived fuels, other consumables, load-outs of boiler aggregate, and metals recovered from the fly ash waste stream. Trucks would access the site 24 hours per day, seven days per week. Although the City of Baltimore Department of Transportation determined that no mitigation was required for the project, PPRP had concerns that trucks delivering PRF or other bulk materials would adversely congest or compromise the safety of the intersection of Shell Road and Patapsco Avenue, a major arterial in south Baltimore. As a result, it proposed a licensing condition to facilitate the planning, engineering, construction, and funding of geometric improvements to the intersection to accommodate truck traffic resulting from operation of the facility.

Land Use

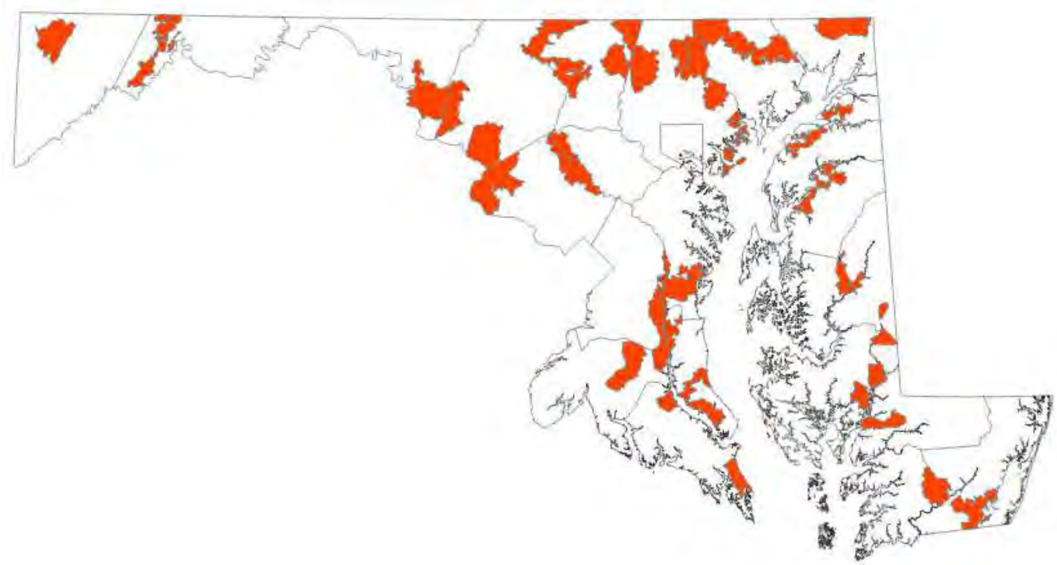
Land has both functional and symbolic value. Through its connections to the past, its cultural associations, and its setting within the visual landscape, land has more than economic value to society. Maryland recognizes this in the many programmatic designations, beyond set-asides such as parks and Wildlife Management Areas (WMAs), that it bestows on land. Some of these are in the form of land preservation easements. The Maryland Agricultural Land Preservation Foundation (MALPF) purchases agricultural preservation easements from landowners to preserve the land for agricultural and silvicultural use in perpetuity. In 2009, MALPF held more than 283 thousand acres in 2,079 easements. The Maryland Environmental Trust (MET) accepts offers of conservation easement which restricts the future uses of a landowner's property and applies to all future owners of the property. At the beginning of 2011, MET held 1,022 easements totaling over 127,000 acres across the State. The Maryland Historical Trust (MHT) acquires historic preservation easements on properties eligible for or listed on the National Register of Historic Places, or properties located within a locally certified historic district. MHT holds preservation easements on more than 600 properties on approximately 9,000 acres in the state. Easements may also be held by counties or by non-profit land trusts.

MHT also administers the Maryland Inventory of Historic Properties (MIHP), a list of all historic properties in the State that have been surveyed and recorded. A property that has been surveyed and included in the MIHP does not mean that it is historically significant or is subject to any restrictions or regulations. However, listing of a property on the MIHP can trigger additional surveys or evaluations for National Register eligibility during PPRP environmental reviews or other State undertakings. The National Register of Historic Places (NRHP) is a list of properties that have been surveyed and evaluated and found to be historically significant at the local, State, or national level. The National Register currently comprises over 1,300 listings in Maryland, including some 200 historic districts. Listing in the National Register confers a measure of protection from harm by federal or State activities through Section 106 of the National Historic Preservation Act.

On a broader scale, Maryland's Rural Legacy Program (RLP) provides "the focus and funding necessary to protect large, contiguous tracts of land rich in natural and cultural resources from sprawl development". Administered by DNR, protection is enabled through easements and fee estates and through the program's support of Rural Legacy sponsors and local governments. The geographic framework for the RLP is the Rural Legacy Area (RLA), a "designated region rich in a multiple of agricultural, natural, forestry or cultural resources". Local sponsors apply for funding to complement existing land conservation efforts or create new ones within the RLA. RLAs are designated and funded annually. As depicted in Figure 4-19, there are 31 RLAs in Maryland comprising 849,449 acres. Within them, 8.1 percent of the land, or 68,676 acres are protected via conservation easements.

The Maryland Heritage Areas Program preserves the State's historical, cultural, archeological, and natural resources for sustainable economic development through heritage tourism. This is accomplished through the local designation and State certification of Heritage Areas, defined by a distinct focus or theme that makes a place or region different from other areas of the state. Activities in each Heritage Area are governed by a management plan that sets forth the strategies, projects, programs, actions, and partnerships that will be involved in achieving its goals.

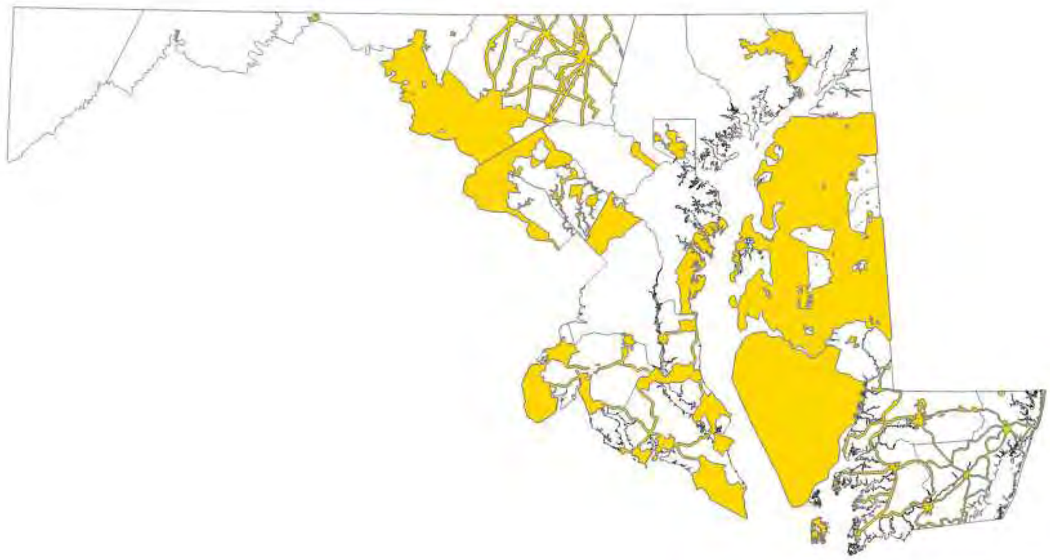
Figure 4-19 Maryland's Rural Legacy Areas



Once certified, a Heritage Area management entity becomes eligible for State-matching grants for operating assistance and marketing activities. Local jurisdictions and non-profit organizations in a Heritage Area may also qualify for State matching grants for planning, design interpretation, and programming. The Maryland Heritage Areas Authority (MHAA), within the Division of Historical and Cultural Programs of the MHT, is responsible for leading Maryland's Heritage Areas program. There are 11 Certified Heritage Areas (CHAs) in Maryland, shown in Figure 4-20.

The degree to which these programmatic designations protect land from activities associated with electric generation varies. 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, such as when a nearby facility alters its setting.

Figure 4-20 Maryland's Certified Heritage Areas



State assessment of the effects of power plant construction and operation on cultural resources is codified under Maryland State law (Article 83B, 5-617 & 5-618 of the Annotated Code of Maryland). The Code requires State agencies to consider the effects of their undertakings on properties included in or eligible for inclusion in the NRHP and the Maryland Register of Historic Properties, and to consult with MHT prior to final action by the agency on a request for a permit, license, or financial assistance.

CHAs are programmatically supported by State agencies. Specifically, when carrying out activities in a CHA, a State agency must:

- *Consult, cooperate, and, to the maximum extent feasible, coordinate their 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.*

Easements, transferable development rights, and fee estates protect specific land parcels within RLAs, but RLA designation, itself, affords no land use protection. A House Bill (HB 1241) introduced in the 2011 legislative session that would prohibit construction of an electric power station or substation (among other non-agricultural uses) in an RLA died in the Maryland General Assembly.

Recent environmental reviews of power generation facilities in Maryland have concerned projects that have had few, if any, adverse effects on land use. For the modification of the Morgantown Generating Station to install a fly ash beneficiation system, PPRP determined that the project would be contiguous to existing structures on lands that have been previously disturbed and are zoned for heavy industrial use. No lands outside the

Morgantown property would be pre-empted from other uses during construction of the project. Although part of the ash handling system connecting the STAR facility to the Morgantown ash silos passes over the Critical Area, it would be supported by an existing elevated pipe support system, and would have no direct additional effects on the Critical Area. The Morgantown site is not within an RLA and no indirect effects on surrounding land uses would result from operation of the STAR facility.

With respect to effects on programmatic land uses in Charles County, PPRP concluded that historic properties outside the boundaries of the Morgantown Generating Station would not be directly affected by construction or operation of the project. The STAR facility would generate a vapor plume that could potentially have an adverse effect on aesthetics, particularly on those occasions when there is extensive vertical and/or horizontal drift, and could affect views from US 301, a designated corridor in the Southern Maryland's Heritage Tourism Management Plan. However, as the scenic content from the corridor towards Morgantown is already compromised and as the plume would not be visible from any of the heritage clusters designated by the Plan, PPRP concluded that it was unlikely that the aesthetic landscape would be significantly affected by the proposed project.

Located on the Fairfield Peninsula in the City of Baltimore, the Energy Answers Fairfield Renewable Energy Project would be constructed on an industrial site that has been previously disturbed. As there are no confirmed archeological sites or cultural deposits within the project boundaries, PPRP, in consultation with MHT, concluded that construction of the project would have no adverse direct effect on cultural resources. Within a highly urbanized setting, the project would not affect any lands within RLAs, the Baltimore Heritage Area, or lands protected under the various land preservation programs.

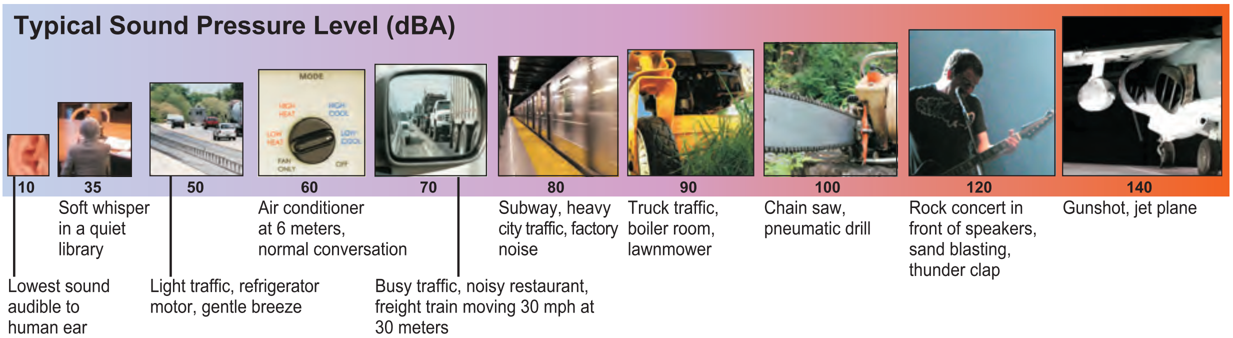
Noise

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 is approximately the smallest change in sound intensity that can be detected by the human ear. An additional 10 units on the decibel scale is perceived subjectively as a doubling of the loudness. Ranges of typical A-weighted sound levels for various common sounds are shown in Figure 4-21.

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.

Figure 4-21 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 the draft federal standards on noise. The State regulations provide certain exemptions for specified noise sources and noise generating activities. For example, the regulations allow for construction activity to generate noise levels up to 90 dBA during daytime hours, but the nighttime standard may not be exceeded during construction. Table 4-6 lists the maximum allowable noise levels specified in the State regulations, by zoning designation and time of day. Some counties and municipalities in Maryland have their own noise limits, including Montgomery County, Charles County, and Baltimore City.

Table 4-6 Maximum Allowable Noise Levels (dBA) for Receiving Land Use Categories

	Zoning Designation		
	Industrial	Commercial	Residential
Day	75	67	65
Night	75	62	55

Note: Day refers to the hours between 7 a.m. and 10 p.m.; night refers to the hours between 10 p.m. and 7 a.m.

Source: COMAR 26.02.03.

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.

In cases where developers propose new generating units on small sites — where the nearest residents may be less than a half-mile away — noise impacts to surrounding communities can be a serious concern. Modeling noise sources and nearest receptors is part of the review of impacts that both the applicant and PPRP conduct in order to assess the noise impacts of proposed facilities. When calculations suggest that the applicable noise limits are likely to be exceeded, measures to meet the allowable levels are recommended and incorporated into the CPCN. If the noise analysis conducted during the licensing review is based on a number of assumptions, and there is uncertainty surrounding the potential for noise-related concerns, PPRP typically recommends that the applicant submit an updated analysis after the specific equipment to be installed has been selected. Furthermore, post-construction monitoring can be performed to verify the noise estimates, once a facility begins operation.

With the increasing interest in renewable energy sources, new generating technology is being developed for which there may be little quantitative information available regarding noise characteristics. Landfill gas and wind power projects are just two examples that have different noise characteristics than conventional power plants. PPRP monitoring of newly constructed landfill gas generating facilities has confirmed that the predictive techniques used during the licensing process are quite conservative; measured noise levels were consistently lower than the estimates calculated during the environmental review process. Until recently, however, Maryland has had no operating wind turbine facilities to allow for similar monitoring of their noise impacts. Now that the Criterion and Roth Rock projects have begun operating, PPRP is developing plans for noise monitoring near those facilities as well. This work will provide important information about the characteristics of wind turbine noise in the ridgetop settings of western Maryland and its potential community impacts.

4.1.5 Radiological Issues

Production of nuclear power in the United States is licensed, monitored, and regulated by the 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 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 4-22 illustrates, natural radiation sources account for nearly 50 percent of the average radiation dose to human beings. Of the remaining approximately 50 percent of the radiation dose to human beings arising from man-made sources, less than 0.05 percent is attributed to commercial nuclear power production.

Figure 4-22 Annual Estimated Effective Dose Equivalent (mrem) to the General Population from Natural and Man-Made Sources

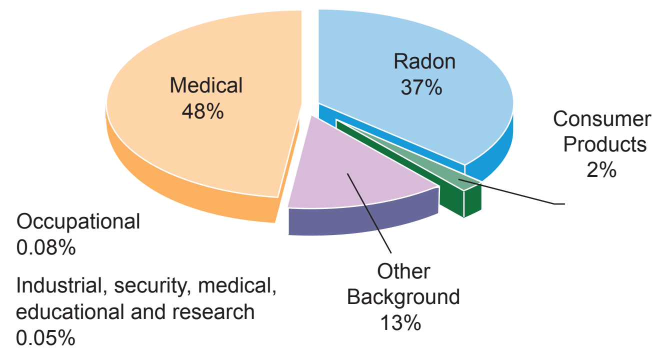


Figure 4-23 shows the locations of nuclear power plants in and near Maryland. Calvert Cliffs Nuclear Power Plant, in Calvert County, is the only nuclear power station in the state. The next closest plant, Peach Bottom Atomic Power Station, is on the Susquehanna River just north of the Pennsylvania/Maryland border. Both of these facilities release very low levels of radionuclides into Maryland's environment. Because of the potential direct impact of releases from these two plants on Maryland's natural resources, PPRP conducts monitoring in the vicinity of Calvert Cliffs and Peach Bottom (Table 4-7). The plant owners, Constellation and Exelon, also conduct environmental monitoring programs near Calvert Cliffs and Peach Bottom, respectively. These monitoring programs are used to assess the radiological effects on the environment attributable to each of the power plants. PPRP publishes its environmental assessments biennially.

Figure 4-23 Nuclear Power Plants In and Around Maryland

Table 4-7 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	St. Mary's County, 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	semi-annually
11. Finfish	1	Susquehanna River	γ	semi-annually
12. Submerged Aquatic Vegetation (SAV)	3	Chesapeake Bay & Susquehanna River	γ	semi-annually

Calvert Cliffs Nuclear Power Plant

Constellation Generation Group owns and operates the Calvert Cliffs facility on the western shoreline of the Chesapeake Bay. Each of the two units are pressurized water reactors with a total generating capacity of approximately 830 MW. The units began service in May 1975 and April 1977. See Section 2.4.1 for information on the licensing status of a third unit at Calvert Cliffs.

As noted above, Calvert Cliffs routinely releases small levels of gaseous, particulate, and liquid radioactive material into the atmosphere and the Chesapeake Bay. The level of radioactivity of these materials at any given time depends on many factors, including plant operating conditions and conditions of the nuclear fuel. Releases of radioactivity to the environment from Calvert Cliffs have been well within the regulatory limits since the beginning of its operation. PPRP has monitored radionuclide levels in the Chesapeake Bay and environment surrounding Calvert Cliffs since 1975.

Radioactive noble gases, primarily isotopes of xenon and krypton, constitute most of the radioactive material released to the atmosphere from Calvert Cliffs. Noble gases are chemically inert, are not readily incorporated into biological tissues, and are not bioconcentrated. They are readily dispersed in the atmosphere, and most have short half-lives, thus, decaying rapidly to stable forms. For these reasons, the noble gases do not represent a threat to human or ecological health. The most recently compiled results (for the years 2008 and 2009) from weekly air and annual vegetation monitoring conducted by Constellation Generation Group 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.

Although atmospheric releases consist mainly of radioactive noble gases, which have little environmental significance, aqueous discharges contain radionuclides that can be accumulated by biota or become trapped in sediments at the bottom of the Bay. Over time, these radionuclides may potentially contribute to a radiation dose to humans by being transported through the food chain. For the Calvert Cliffs plant, the principal environmentally active radionuclides in 2008 and 2009 were primarily forms of radioactive iron, cobalt, iodine, antimony, cesium, nickel, and tellurium. Historically, the quantities of principal environmentally active radionuclides released from Calvert Cliffs and subsequently detected in Bay sediments have been quite small (approximately one percent, or less, of all radioactivity detected in sediments, which includes historic nuclear weapons testing fallout and naturally occurring radionuclides). Total principal environmentally active radionuclide releases have declined over the past two decades due to improvements in coolant water filtration technology. The monitoring program will continue throughout the licensed operating lifetime of Units 1 and 2 as well as the proposed Calvert Cliffs Unit 3, should that additional reactor be constructed. Monitoring by PPRP is conducted to satisfy NRC requirements to verify that any releases from normal plant operations result in potential doses to humans below regulatory limits. The monitoring also meets Maryland requirements to research the environmental effects of electric power generation, maintain State oversight of environmental monitoring, and quantify the environmental impact, if any, of the new reactor at Calvert Cliffs.

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. PPRP has monitored the uptake of radionuclides in test oysters placed seasonally on platforms on the Bay floor in the vicinity of the Calvert Cliffs discharge since 1978. 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 ^{110m}Ag detection reflects a recent downward trend in ^{110m}Ag releases, as well as other principal environmentally active radionuclide releases, from Calvert Cliffs.

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 4-8).

Table 4-8 Comparison of Radiation Doses to Humans and Applicable Regulatory Limits

<table>
<tr><th>Exposure Route</th><th>Maximum Dose Estimate (2008)</th><th>Maximum Dose Estimate (2009)</th><th>EPA Regulatory Limit (40CFR190 Subpart B)</th><th>NRC Regulatory Limit (10CFR50 Appendix I)</th></tr>
<tr><td colspan="5">Ingestion (mrem)</td></tr>
<tr><td>Oyster ingestion, whole body dose (from CCNPP)</td><td colspan="2">< 0.0043 (child)[a]</td><td>25</td><td>3</td></tr>
<tr><td>Oyster ingestion, other organ dose (from CCNPP)</td><td colspan="2">< 0.024 (adult gastro-intestinal tract)[a]</td><td>25</td><td>10</td></tr>
<tr><td>Finfish ingestion, whole body dose (from PBAPS)</td><td colspan="2">< 0.123 (adult)[a]</td><td>25</td><td>3</td></tr>
<tr><td>Finfish ingestion, other organ dose (from PBAPS)</td><td colspan="2">< 0.178 (teen liver)[a]</td><td>25</td><td>10</td></tr>
<tr><td colspan="5">Inhalation (mrem)</td></tr>
<tr><td>Whole body dose (gaseous, from CCNPP)</td><td>0.0012 (child)[b]</td><td>0.00046 (child)[b]</td><td>25</td><td>3</td></tr>
<tr><td>Other organ dose (gaseous, from CCNPP)</td><td>0.0029 (adult skin)[b]</td><td>0.00083 (adult skin)[b]</td><td>25</td><td>10</td></tr>
<tr><td>Whole body dose (gaseous, from PBAPS)</td><td>0.347 (infant)[c]</td><td>0.262 (any age class)[c]</td><td>25</td><td>3</td></tr>
<tr><td>Other organ dose (gaseous, from PBAPS)</td><td>0.468 (any age class skin)[c]</td><td>0.473 (any age class skin)[c]</td><td>25</td><td>10</td></tr>
</table>

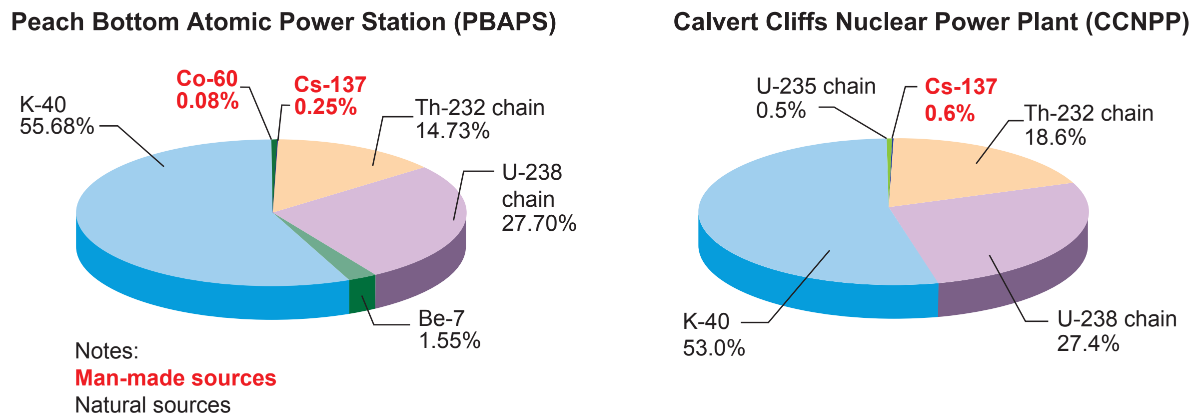
[a] Source: PPRP biennial reports

[b] Source: Annual Radiological Environmental Operating Reports for 2008 and 2009, Constellation Energy Nuclear Group

[c] Source: Annual Radiological Environmental Operating Reports for 2008 and 2009, Exelon Nuclear

Chesapeake Bay 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 seasonally from eight transects extending bayward north and south of the Calvert Cliffs plant. There were three detections of ^{60}Co in Bay sediments during the 2008-2009 reporting period (see Figure 4-24).

Figure 4-24 Proportion of Natural vs. Man-Made Radionuclides in Sediment Samples Near CCNPP and PBAPS



Results of analyses of environmental samples collected in the vicinity of Calvert Cliffs can be found in the periodic environmental reports described above. A comparison of radionuclide concentrations in environmental samples collected in 2008 and 2009 with levels detected since 1978 shows the following:

- *Plant-related radionuclides were not detected in sediments or shellfish during 2008 and 2009;*
- *Although radionuclide concentrations fluctuate seasonally and annually, no long-term accumulation of plant-related radioactivity in Bay aquatic life and sediments is evident;*
- *The radioactivity introduced into the environment by Calvert Cliffs, when detected, is very small compared with background radioactivity 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 4-8).*

In summary, environmental, biological, and human health effects of releases of radioactivity from Calvert Cliffs are insignificant.

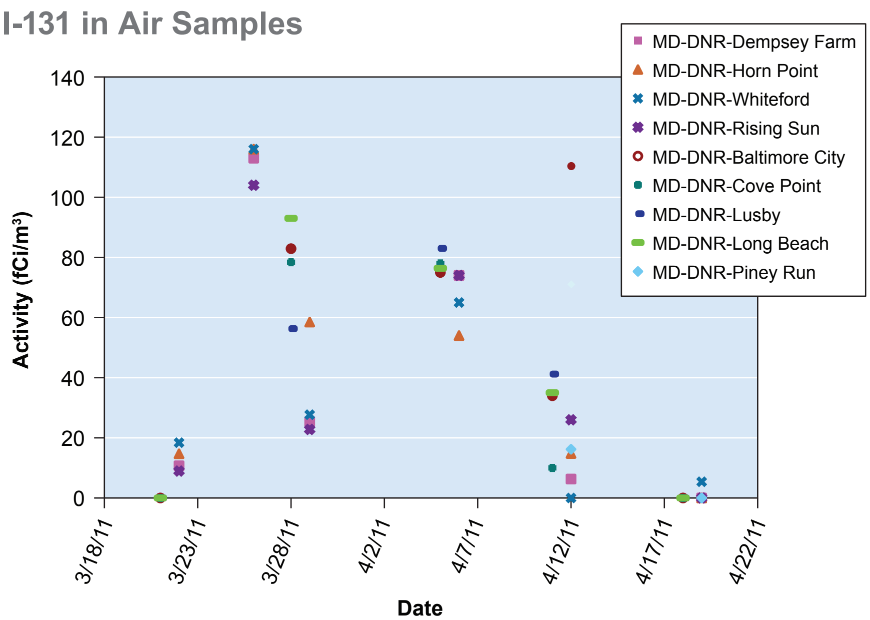
The State of Maryland, the NRC, and Constellation conduct emergency response exercises annually and an in-depth, federally evaluated, ingestion pathway emergency response exercise every six years.

Peach Bottom Atomic Power Station

Exelon Generation Company, a subsidiary of Exelon Corporation, operates Peach Bottom Atomic Power Station (PBAPS). Peach Bottom 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 generating capacity of approximately 1,100 MW. PPRP has monitored radionuclide levels from the plant since 1979.

Emergency Response

In October 2009, PPRP, along with other State agencies and Constellation Energy, participated in exercises to demonstrate and practice Maryland's response to a simulated accident at Calvert Cliffs. The exercises encompassed the implementation of protective actions for all phases (e.g., plume, ingestion pathway, recovery) of the simulated accident, depending on conditions at Calvert Cliffs and simulated impacts to the surrounding environment. The protective actions affected farm operations, drinking water supplies, and human impacts. The exercises involved personnel taking simulated environmental samples in the area surrounding Calvert Cliffs and delivering them to the PPRP Radioecology Laboratory and the Department of Health and Mental Hygiene (DHMH) Radiation Chemistry Laboratory in Baltimore. The entire exercise was evaluated by representatives from the Federal Emergency Management Agency (FEMA).



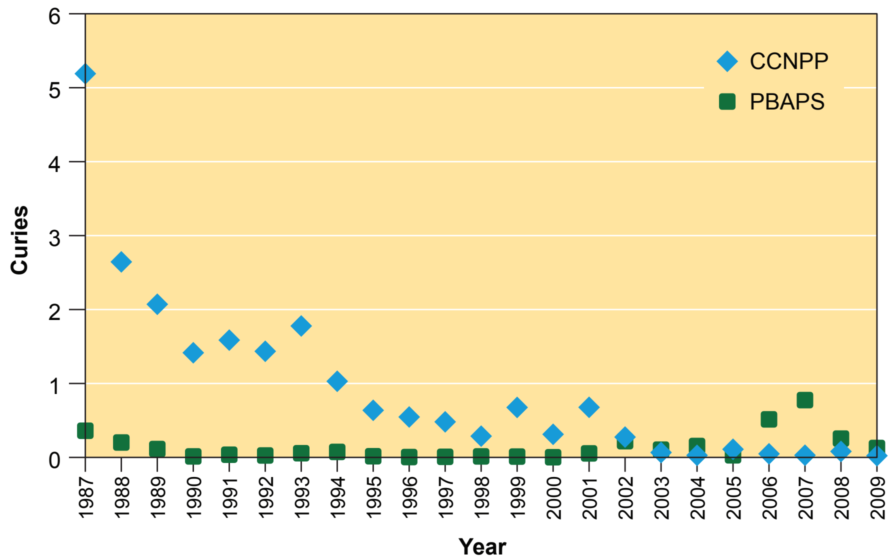
In March 2011, PPRP, DHMH, MDE, and the Maryland Department of Agriculture responded to the accident at the Fukushima Daiichi Nuclear Power Plant in Japan by tracking and monitoring a radioactive plume of I-131 as it reached Maryland on approximately March 22, 2011. Personnel from the above agencies communicated weekly to review air, potable water, and precipitation results and to evaluate the risk to human health and the environment. Radio-iodine concentrations in air samples returned to non-detectable levels by April 27, 2011.

Like Calvert Cliffs, Peach Bottom routinely releases very low levels of gaseous, particulate, and liquid radioactive material into the atmosphere and the Susquehanna River. Estimated doses to humans, based on liquid and atmospheric releases of radioactivity from the plant, have been well within regulatory limits since the beginning of its operation (Table 4-8).

Information from Exelon's monitoring programs shows that in recent years, noble gases accounted for most of the identifiable radioactivity released to the atmosphere by the plant. The most recently compiled results from weekly air and annual vegetation monitoring conducted by Exelon Nuclear and independently by PPRP (for the years 2008 and 2009) indicate that releases of radioactivity to the atmosphere by the Peach Bottom plant were not detectable in air, precipitation, or vegetation.

Of the radionuclides released by Peach Bottom to the Susquehanna River in 2008 and 2009, 99 percent was tritium, which is not bioaccumulated and therefore not environmentally significant. Very small quantities of radioactive cobalt, zinc, iron, chromium, and manganese accounted for most of the remaining liquid radioactive material released. These particular radionuclides are environmentally significant (see Figure 4-25) because they can, if released in sufficient quantities, be readily accumulated by aquatic life such as mussels and finfish.

Figure 4-25 Environmentally Significant* Annual Aqueous Releases, 1989-2009



*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.

Finfish collected semi-annually by PPRP from the Conowingo Reservoir area contained no radionuclides attributable to PBAPS. Radioactivity related to Peach Bottom plant was detected in sediments collected semi-annually down-river of the plant (see Figure 4-24). Historically, less than 20 percent of the radioactivity released in Peach Bottom water discharge is found in sediments of the Conowingo Reservoir. The remaining radioactivity is transported downstream bound to sediment and deposited in the lower Susquehanna River and upper Chesapeake Bay. In recent years, however, radioactivity releases associated with Peach Bottom have been mostly non-detectable in sediments below Conowingo Reservoir and in the upper Chesapeake Bay.

Similar to the studies at Calvert Cliffs, PPRP has estimated radiation doses to individuals consuming finfish using the maximum plant-related radionuclide concentrations found in the finfish near Peach Bottom. However, because the Susquehanna River is a source of drinking water, its ingestion, in addition to fish consumption, may potentially contribute to a human radiation dose. As shown in Table 4-8, the annual total body doses associated with the consumption of finfish and drinking water are well below federal limits. As shown in Figure 4-22, the annual total body dose resulting from consumption of fish and drinking water, relative to other modes of dose accumulation, is small.

Results of analyses of environmental samples collected in the vicinity of Peach Bottom can be found in the periodic environmental reports described above. Comparing PPRP's radiological monitoring of Peach Bottom-related radioactivity of aquatic life and sediments collected from 2008 and 2009 with monitoring results since 1979 shows the following:

- *The levels of plant-related radioactive material detected in aquatic life and sediments represent a small portion of the radioactive material in the Susquehanna River-Chesapeake Bay system compared with that from natural sources and weapons test fallout;*
- *No long-term accumulation of plant-related radioactive material in river biota is evident;*

- *Long-term operation of Peach Bottom Atomic Power Station has not caused significant accumulation of radioactive material within the Conowingo Reservoir; and*
- *Radiation doses to humans due to atmospheric and aqueous releases are well within regulatory limits (see Table 4-8).*

In summary, environmental, biological, and human health effects of releases of radioactivity from Peach Bottom are insignificant.

Radioactive Waste

In addition to the production of atmospheric and liquid effluent releases as a by-product of normal power generation operations, both Calvert Cliffs and Peach Bottom generate radioactive waste products which require disposal.

Low-Level Radioactive Waste (LLRW)

This type of waste consists of materials such as contaminated gowns, toweling, glassware, resin, equipment, 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, waste is dried, compressed, and sealed into high-integrity containers, metal boxes, or 55-gallon drums. These containers may, in turn, be sealed into shipping casks. Low-level radioactive waste from Calvert Cliffs, similar to LLRW from other industries, is transported by truck to licensed radioactive waste processing firms located in Utah, South Carolina, and Tennessee, depending on the type of waste. Other LLRW from Calvert Cliffs may be incinerated, supercompacted, or chemically reduced, depending on the waste processing vendor and type of waste.

High-Level Radioactive Waste (Irradiated Fuel)

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 the protected plant area. These Independent Spent Fuel Storage Installations (ISFSIs) were originally licensed by the NRC for 20 years, although recent regulatory changes now allow a plant operator to apply for a 40-year license period. ISFSI 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. On-site storage facilities, such as the ISFSI, are currently the only long-term storage facilities for irradiated fuel available.

Exelon's dry cask storage facility at Peach Bottom currently has 53 casks loaded in dry storage with 68 fuel assemblies each, for a total of 3,604 assemblies. As of August 2011, Peach Bottom had utilized 83 percent of its currently available storage pad space.

Calvert Cliffs is seeking a license renewal from the NRC for its existing ISFSI, and also plans to request a license modification to accommodate a newer storage cask design. The facility's current ISFSI license, which expires in November 2012, allows for a maximum of 120 horizontal storage modules; 72 have been constructed to date and only 66 have been loaded. Each module can accommodate 48 spent fuel assemblies as currently designed. Calvert Cliffs has filled 53 percent of its currently licensed storage capacity. The application for a renewal of the ISFSI license, which was submitted in September 2010, seeks to extend the license period for an additional 40 years, through 2052.

4.1.6 Power Plant Combustion By-products

Coal, like many fuels, produces gaseous and solid by-products during combustion. The solid by-products result from components of coal not consumed during combustion. This section of the report focuses on the solid coal combustion by-products (CCBs) produced by coal-fired power plants in Maryland. The discussion focuses on the beneficial reuse of CCBs and ongoing research efforts to identify additional uses for CCBs. The ultimate goal is that all CCBs produced in Maryland, including those currently stockpiled, will be reused in environmentally beneficial or environmentally benign ways.

When properly engineered and correctly applied, CCBs can be utilized in civil engineering, mine restoration, and agricultural applications (see Table 4-9). The beneficial use of CCBs as raw materials in applications that are environmentally sound, technically safe, and commercially competitive will lead to a reduction in the disposal of these raw materials and may contribute to reduced GHG emissions. The most direct contribution to reducing GHG emissions occurs when fly ash is used as a supplementary material in concrete and concrete products. By substituting fly ash in place of cement, the carbon emissions associated with cement production are avoided. Each ton of fly ash utilized represents approximately one ton of CO_2 avoided. A continued increase in the beneficial utilization of Maryland CCBs will likely lead to:

- *Decreased need for landfill space;*
- *Conservation and protection of the natural resources of the state;*
- *Reductions in the cost of producing electricity and cost for consumers; and*
- *Substantial savings for end-users of CCBs.*

Table 4-9 CCB Beneficial Use Options

Potential Use	TYPE OF COAL COMBUSTION BY-PRODUCT					
	FBC		Pulverized Coal			FGD
	Fly ash	Bed ash	Fly ash	Bottom ash	Boiler slag	Sludge
ROADWAYS						
Cement/concrete/grout			X	X	X	X
Embankment/structural fill			X	X	X	X
Flowable fill			X	X		X
Road base/subbase			X	X	X	X
Snow and ice control				X	X	
Synthetic aggregate			X			X
Wetland liner						X
RECLAMATION USE						
Abandoned surface mine reclamation	X	X	X			X
Reclamation of existing surface mined lands	X	X	X			X
Subsidence remediation and control	X	X	X	X		X
Underground placement to mitigate AMD	X	X	X			X
Wetland and pond liner	X	X				X
Treatment of coal refuse	X	X				X
AGRICULTURE						
Agricultural liming substitute	X	X				X
Soil amendment	X	X	X	X		X
Pond and animal manure holding facility liner	X	X				X
Livestock feedlot and hay storage pad	X	X	X			X
New soil blends	X	X	X	X		
Commercial fertilizer	X	X	X			
Treatment of bio-solids	X	X	X	X		X
MANUFACTURING						
Paint			X			
Wallboard						X
Roofing granules				X	X	
Cement industry			X			X
Steel industry			X			X
Fillers (plastics, alloys, and composites)			X			
Mineral wool insulation			X			
Ceramic products			X			
Recovery of metals			X			X
OTHER ENGINEERING USES						
Brick			X			
Concrete block			X	X		X
Landfill liner, daily cover, cap	X	X	X			X
Blasting grit				X	X	
Pipe bedding				X	X	
Water filtration					X	
Drainage media				X	X	
Waste stabilization/solidification	X	X	X	X		X
Treatment of sewage sludge	X	X				X
Pond liner			X			X
Dredged material stabilization	X	X	X			X

FBC = fluidized bed combustion; FGD = flue gas desulfurization; AMD = acid mine drainage

CCB Generation

CCBs are produced during the combustion process incident to the production of electricity at coal-burning power plants. According to MDE, in 2010, coal-fired power plants in Maryland generated an estimated 1.8 million tons of CCBs. These CCBs are the non-combustible mineral matter present in coal and any unburned carbon remaining as a result of incomplete combustion.

The two primary types of CCBs produced by Maryland's coal-burning power stations, fly ash and bottom ash, are differentiated by their physical characteristics. The principal difference is that the particles of bottom ash are much larger than particles of fly ash. Fly ash is the finely divided residue or ash that is transported from the furnace along with emission gases. It is captured in electrostatic precipitators or baghouses and has reliable pozzolanic[25] properties. Fly ash is composed of very fine, and generally spherical, glassy particles. Conversely, bottom ash is collected from the bottom of the furnace and is composed of coarser, angular, and porous glassy particles. There is little difference in the chemical makeup of fly ash and bottom ash. During coal combustion, if temperatures are sufficiently high, a portion of the bottom ash will become molten and convert to slag.

The exact chemical nature of CCBs depends upon the nature of the coal burned and the combustion process used. For the most part, power plants in Maryland burn bituminous coal from the eastern United States, which produces predominantly ASTM Class F fly ash. Class F fly ash is distinguished from Class C fly ash by having less than 10 percent calcium (expressed as CaO) by weight. The ash is typically composed of more than 85 percent silicon, aluminum, and iron oxides, much of which is present in glassy aluminosilicates. Class F fly ash may also contain trace metals such as titanium, nickel, manganese, cobalt, arsenic, and mercury. Electric utilities are required to include all applicable constituents of their CCBs when reporting chemical releases through EPA's TRI program. Established in 1986, the TRI is a database maintained by the U.S. EPA listing the quantities of toxic chemicals released to the environment annually by facilities in certain industries. Electric utilities became subject to TRI reporting requirements in 1997.

Two power plant technologies that are relatively new to Maryland are fluidized bed combustion (FBC) and FGD. Both of these technologies include the use of sorbents, such as limestone, during or after combustion to reduce air pollution by removing sulfur compounds from power plant emissions. FBC introduces an alkaline sorbent during combustion while FGD systems introduce sorbent into the flue (exhaust) gas. While the use of sorbents improves air quality, the noncombustible sorbents significantly increase the volume of solid CCBs produced.

FBC and FGD by-products resulting from these air pollution reduction measures contain many of the same chemical components as ordinary coal ash, but they have much larger proportions of calcium sulfate and

[25] Pozzolan is a type of material that, when added in the process of mixing cement, improves the strength of the resulting solid.

sulfite minerals due to reactions between the limestone sorbent and sulfur emissions. They may also contain free lime (unreacted sorbent), causing the ash to be self-cementitious when mixed with the appropriate amount of water.

The AES Warrior Run power plant in Cumberland is currently the only Maryland power plant that uses FBC technology. For FBC, coal and finely ground limestone are fed into the combustion chamber and mixed together by forcing air into the chamber. The heat in the combustion chamber causes the limestone to decompose to an oxide that captures SO_2. FBC units can remove more than 95 percent of the sulfur produced from burning coal. The resulting combined ash is self-cementing: a silica, alumina, and calcium-based material which, when mixed at a ratio of 65 percent solids to 35 percent water, will set up and harden to a cement or concrete-like material with excellent structural and engineering properties.

FGD by-product material is produced when the flue gas enters a spray tower or absorber and is mixed with a sorbent slurry of water and finely ground limestone or lime. The calcium reacts with the SO_2 to form calcium sulfite or calcium sulfate, which are segregated by dewatering and settling. FGD scrubbers were installed at the Brandon Shores, Dickerson, Chalk Point, and Morgantown power plants in 2010, introducing an estimated 550,000 tons of FGD material into Maryland's CCB waste stream. The operation of these plants with FGD scrubbers will generate about an additional one million tons per year in the near future. Fortunately, oxidized calcium sulfite or calcium sulfate (synthetic gypsum) is suitable for use as a natural gypsum substitute and is often used to manufacture wallboard.

In the absence of being placed in accordance with sound engineering principles, landfilled CCBs have the potential to adversely impact Maryland's terrestrial and aquatic resources. The importance of sound engineering and proper placement of CCBs was highlighted at the B.B.S.S. Mine Reclamation Site. Between 1995 and 2007, Constellation Energy Group (formerly Baltimore Gas & Electric) provided Reliable Contracting Co., Inc. with approximately 200,000 to 400,000 tons per year of CCBs, primarily unstabilized Class F fly ash, to reclaim a former sand and gravel mine in Anne Arundel County owned by B.B.S.S., Inc. The site relies on a natural soil cover and its underlying geology to minimize the potential for leachate to impact the regional ground water system.

In October 2006, MDE requested that PPRP provide assistance on an independent evaluation of the source of heavy metals and dissolved sulfate detected in residential wells near the site. A statistical comparison of residential and monitoring well water quality data indicated that fly ash placement in the Turner and Waugh Chapel Pits at the site likely contributed to deterioration of ground water quality in the site vicinity. The site continues to be an issue from the standpoint of contaminating local wells, although Constellation and MDE entered into a Consent Decree in October 2007 with an approach to resolve the identified impacts. Careful planning and execution of the disposal and/or reuse of CCBs is necessary to minimize impact to the surrounding environment.

Regulation of CCBs

Maryland Regulations

Because CCBs were exempted from federal regulation by the Bevill Act, Maryland enacted State regulations for the disposal of CCBs and their use in mine reclamation, effective December 1, 2008. These regulations require permitting of new CCB disposal facilities under the same regulations as industrial solid waste facilities, including landfill siting requirements, landfill design including a clay or synthetic liner, landfill operation and maintenance, and closure and monitoring. Companies producing CCBs are required to file Annual Generator Tonnage Reports detailing the amount of CCBs generated, how they were disposed of or reused, and chemical analyses.

Additional regulations for the beneficial uses and transportation of CCBs were proposed in the Maryland Register on February 26, 2010. The draft regulations included requirements that CCBs that are beneficially used or the products that are made from the CCBs must be shown to be not significantly leachable materials. Although the required leaching procedure has not yet been specified, the parameters that must be tested are identified in the draft regulation. The draft regulations specifically approve encapsulated beneficial uses of CCBs, including concrete, asphalt, wallboard, and filler in plastic. Other unconsolidated (unencapsulated) beneficial uses of CCBs, such as the use of bottom ash as aggregate beneath pavement, pipe bedding, and winter traction control, are permitted with more stringent restrictions.

Federal Regulations

EPA proposed the first federal regulations for CCBs, referred to as coal combustion residuals (CCRs), in the June 21, 2010 Federal Register. EPA previously classified CCRs as an "exempt waste" under the Resource Conservation and Recovery Act (RCRA). To allow for public comment in its decision-making process for the proposed rule, EPA is considering two different classification options with a choice to determine whether existing facilities would be retrofitted to meet the new regulations. The first option would federally regulate CCRs as a RCRA Subtitle C hazardous waste, which would require stringent disposal practices, place time and accumulation limits on generators, and inhibit some commonly practiced beneficial reuses. The second option classifies CCRs as a RCRA Subtitle D non-hazardous waste, which would not require federal permitting, but rather leave regulation to the states. Under either option, most beneficial uses would be supported and not regulated by EPA, although the specific uses to be deemed "beneficial" are not finalized. EPA is expected to issue a final rule in 2012.

PPRP submitted comments to EPA on the proposed rule in November 2010 supporting the Subtitle D approach. In its comments, PPRP asserted that regulation under Subtitle C would not provide additional protection against damage from unlined CCR landfills (where EPA has reported most damage cases) since both approaches include engineering and construction requirements for CCR landfills that would be the same as for municipal solid waste landfills, which are regulated under

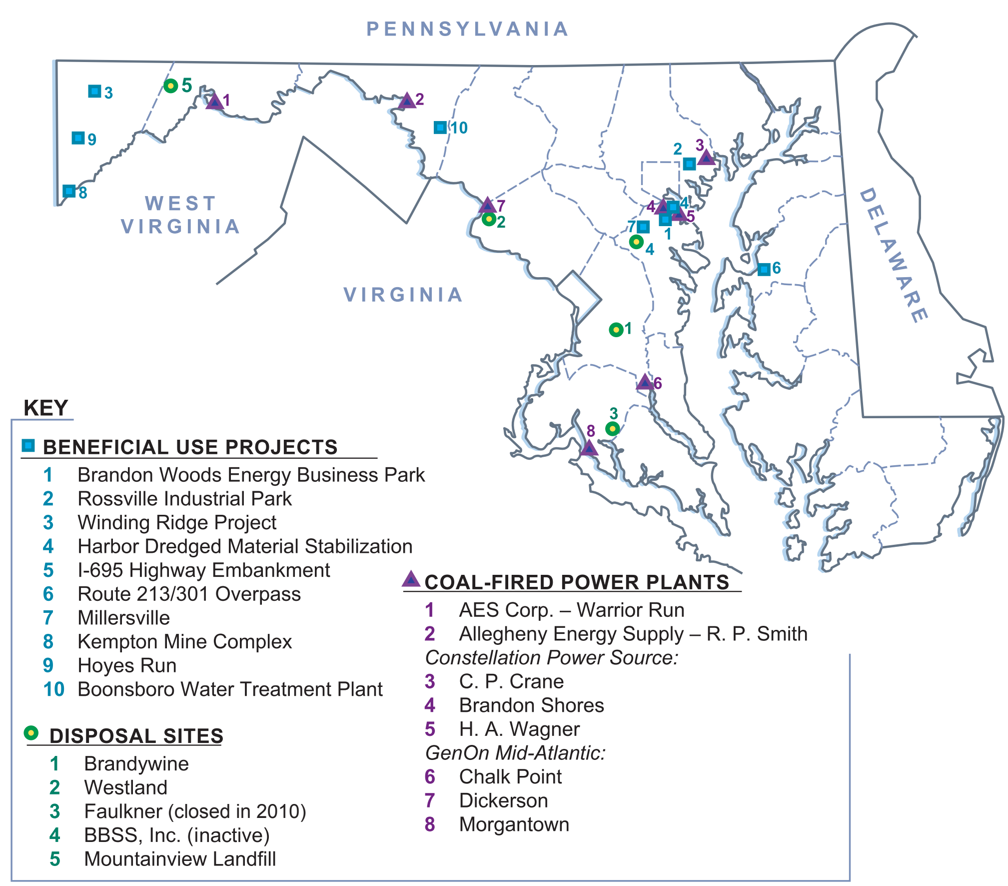
Subtitle D. Additionally, PPRP expressed strong support for the continued use of the Bevill exemption for the beneficial use of CCRs in encapsulated applications. This is especially important for Maryland, since Maryland beneficially uses over 50 percent of the fly ash produced by its power plants.

Disposition and Beneficial Use

Of the approximately 1.8 million tons of CCBs produced by Maryland power plants in 2010, 582,417 tons were placed in disposal sites (see Figure 4-26), with the largest disposal site being the Brandywine ash site in Prince George's County. In contrast, the largest beneficial user, AES Warrior Run, placed all (351,804 tons in 2010) plant-generated CCBs in surface coal mine restoration projects in Western Maryland. In 2010, the remainder of the Maryland beneficial use stream was used in a variety of applications including:

- *Wallboard (449,218 tons);*
- *Concrete, block, and cement manufacturing; grout and flowable fill (390,140 tons of CCBs);*
- *Blasting grit and roofing material (11,721 tons); and*
- *Agricultural uses (776 tons).*

Figure 4-26 Distribution of Maryland CCBs in Beneficial Use Projects

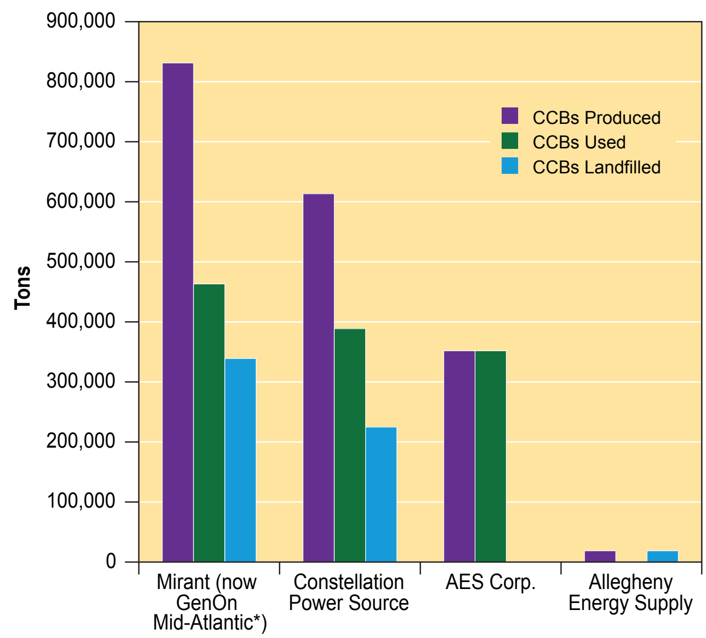


Beginning in 2010, the majority of FGD material generated at GenOn Mid-Atlantic (formerly Mirant Mid-Atlantic) power plants in Maryland was provided to wallboard manufacturers as a replacement for natural gypsum. The Brandon Shores plant, owned by Constellation, disposed of about 43 percent of FGD material in 2010, but plans to increase beneficial reuse by establishing additional users.

Fly ash, bottom ash, slag, and FGD material have different primary beneficial uses because each component has distinct physical and chemical properties suited to a specific beneficial use application. Fly ash is used in the largest quantities and the widest range of applications among the CCBs (see Table 4-9) because of its pozzolanic properties. Use in cement and concrete production tops the list of leading fly ash applications, followed by structural fills and waste stabilization. The relatively uniform spherical shape and particle distribution of fly ash improves properties of flowable fill and the fluidity of grout. For waste stabilization, fly ash can act as a drying agent for wet materials such as sludge, sediment or dredged material. Figure 4-27 highlights the quantity of CCBs generated and disposed by Maryland's coal-fired power plants annually.

The primary beneficial uses for bottom ash are road base/sub base, structural fill, and snow and ice control. Minor uses include concrete, mining applications, and cement clinker raw feed. Bottom ash is also used as fine aggregate in asphalt paving mixtures. Owing to its considerable abrasive properties, slag is used almost exclusively in the manufacture of blasting grit and roofing granules. Primary beneficial use applications for FGD material are wallboard and concrete manufacturing, mining applications, structural fill, and agricultural applications. Structural fill and concrete manufacturing account for the majority of the beneficial use of FGD material. Although agricultural use as a soil conditioner currently accounts for only a small fraction of FGD material reuse, agricultural application has the potential to exceed the volume of FGD material used in wallboard manufacturing. Maryland's use of FGD material for agricultural purposes has been limited due to issues regarding land application within the Chesapeake Bay watershed.

Figure 4-27 CCB Generation and Disposal, 2010



*GenOn's total CCBs produced includes 29,077 tons of CCBs (on and off-spec gypsum) that were produced, but had not yet been disposed of or sold, and were being temporarily stored on site at the end of 2010.

Maryland FGD Installations and Synthetic Gypsum Production

By-product Generated by FGD Units in 2010

Plant	Mass (tons)
Morgantown	234,285
Chalk Point	120,718
Brandon Shores	108,233
Dickerson	91,739

Source: MDE, 2010

Four Maryland power plants have installed FGD scrubbers, which began full-time operation in 2010. Although the scrubbers reduce air emissions, they also significantly increase the volume of CCBs produced by adding synthetic gypsum to the waste stream. Synthetic gypsum can be beneficially utilized in the production of wallboard and cement, and in agricultural applications. Since synthetic gypsum contains mercury that is present in the flue gas of coal-fired power plants, concerns have been raised regarding the potential for mercury exposure from wallboard, the leading reuse option. A study by Shock et al. in 2009 found that both synthetic and natural (mined) gypsum contain mercury, although synthetic gypsum typically has higher levels of mercury. When measuring the volatilization of mercury from both natural and synthetic gypsum wallboard, the results (0.92 ± 0.11 and 5.9 ± 2.4 ng/m^3, respectively) were well below the EPA reference concentrations for elemental mercury in indoor air of 300 ng/m^3, the Agency for Toxic Substances and Disease Registry minimal risk level of 200 ng/m^3, and even the background mercury concentrations for indoor air.

CCB Marketing Activities

Through the development of innovative uses and unique methods, Maryland has been successful in marketing a large proportion of its CCBs. Cement plants commonly purchase CCBs for use as raw materials due to the savings in using a waste product; however, this practice can be problematic because power plants may cease production or experience fluctuations in generation. The Maryland Environmental Restoration Group (MERG) has developed an unprecedented partnership with Allegheny Energy Supply's R. Paul Smith Power Station in Williamsport, Maryland. R. Paul Smith maintains a legacy ash pile that has been accumulating since 1947 when the plant opened, offering an uncommon opportunity to provide ash to industry without interruption. Between fall 2009 and summer 2011, MERG mined about 148,200 tons from the pile, estimated to hold over 2 million tons of ash.

GenOn Mid-Atlantic recently updated its Morgantown Generating Station near Newburg, Maryland, to improve the marketability of its fly ash. On January 3, 2012, GenOn began the operation of a technology known as the Staged Turbulent Air Reactor (STAR). The STAR facility thermally processes ash to remove residual carbon, eliminating a step in preparing the ash for use in concrete applications, and making it more desirable to the cement industry. Annual projections of up to 360,000 tons of fly ash from GenOn's Morgantown and Chalk Point plants will be diverted from disposal in landfills and processed through the STAR Facility.

R. Paul Smith Legacy Ash Pile

Despite being underutilized, FBC ash generated at the AES Warrior Run power plant also holds marketing potential. This self-cementitious ash has great buffering capacity, making it useful for AMD mine reclamation projects. The plant currently transports all ash to surface mines for use as cover mixed with the overburden. PPRP conducts demonstration projects and research to develop methods of using this FBC ash to address the impacts of historic mining in Western Maryland. Some examples are discussed in the following section.

PPRP Demonstration Projects

With the beneficial reuse of about 66 percent of all CCBs generated, Maryland is above the national utilization rate of 41 percent, as reported by the American Coal Ash Association for 2009. Since 1994, PPRP has supported research and demonstration projects regarding beneficial reuse of CCBs, particularly those applications that could use massive quantities of CCBs.

This research led to systematic investigation of the severely disturbed mined lands of Maryland to determine how stabilized CCBs, with or without other materials, might be used to return these areas to constructive use, reduce acid mine drainage, prevent further subsidence, and restore natural drainage patterns. To facilitate the overall CCB research program, PPRP supports a geographic information laboratory and mapping service in the Geography Department and a leachate testing capability in the Chemistry Department at Frostburg State University (FSU). PPRP has also established a materials science laboratory that is operated by the Western Maryland Resource Conservation and Development Council, Inc. (RC&D).

Several field-scale projects have been initiated or completed to demonstrate various grouting applications of CCBs.

Winding Ridge Project – Monitoring effluent from the Frazee Mine on Winding Ridge began in 1995 to establish a baseline to measure the effectiveness of backfilling this small mine with CCBs. It was partially filled with 5,600 cubic yards of fly ash, FBC material, and mine water in 1996 to determine if this would reduce acidic drainage. Regular monitoring has shown that the placement of stabilized CCBs in the mine reduced the pre-existing heavy metals in the effluent to levels below detection limits, and that the use of CCBs has not contributed additional metals. The project received international recognition at the World of Coal Ash Conference in 2007.

Siege of Acre Project – An isolated segment of Kempton Mine 42 was found to be producing unusually acidic drainage with a pH of 2.2. A DOE grant was obtained to drill observation holes to the three tunnels that make up the segment and to plan grouting to cover the 750 feet of exposed mine pavement and debris in each tunnel.

Kempton Man Shaft Project – In 2003, fly ash, FBC material, and mine water were used to perform intrusion grouting around this 420-foot mine shaft at Kempton, Maryland, in an effort to reduce the cone of depression it creates in the regional water table under the sensitive wetlands on the North Branch of the Potomac River. The impact of the grouting continues to be monitored.

McDonald Mine Project – In August 2005, the McDonald Mine in the Georges Creek Coal Basin blew out and overwhelmed the doser treating its effluent. PPRP and the Maryland Bureau of Mines are collaborating 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.

Hoyes Run Project – 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. The solution channels generally filled with stream sediment and debris and were thus candidates for sealing with permeation grouting using conventional chemical grouts. However, when conventional chemical grouting was tried, these grouts expanded with such pressure that partings in the streambed rocks 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.

In addition to these demonstration projects, PPRP supports research that can be used by others for implementing CCBs and waste-to-energy ash in beneficial applications. Some studies of special note include:

Weathering Studies of CCB-based Pozzolan Stabilized Materials (PSM) – Ongoing research has been conducted by the Western Maryland RC&D at the PPRP Materials Science Laboratory (MSL) to establish the use of PSM as a flowable fill for abandoned underground mine applications. Initiated in June 2005, CCB weathering experiments document the physical and chemical degradation of CCB grout that could occur if placed as cover on abandoned underground mine pavement and exposed to AMD. Results to date indicate that stabilized CCBs demonstrate great potential for neutralizing AMD if placed in stream beds or as a covering on abandoned mine pavement.

Pervious Concrete – PPRP is partnering with W. R. Grace and Lafarge to develop a marketable pervious concrete mixture that maximizes the beneficial use of Maryland-generated CCBs while minimizing the potential for environmental impacts. Pervious concrete is a type of pavement that is engineered to contain interconnected void spaces that allow storm water to drain through the pavement and infiltrate into ground water, rather than running off. As such, it is an effective way of mitigating pollution problems associated with storm water runoff. Pervious concrete is composed of the same materials as traditional concrete (Portland cement, aggregate, and pozzolan), but in different proportions and with very coarse-grained aggregate so that packing is minimized. This type of product could include CCBs in several ways: Class F fly ash can be used as pozzolan material, Class C fly ash could be used to provide Portland cement, and bottom ash could be used as aggregate. To date, the project team has cast several core samples that have been tested for physical properties. Plans are underway to begin testing some of these cores for their potential to leach when exposed to ambient precipitation.

Dredged Material (DM) Stabilization – PPRP is a member of the DM Management Program Innovative Reuse Committee providing guidance on the beneficial use of massive amounts of material including DM and CCB blends. As an additive to DM, CCBs promote drying and conditioning of an otherwise poor engineering material. Preliminary and ongoing laboratory tests of Baltimore Harbor DM blended with Maryland CCBs have resulted in a structurally stable material with excellent engineering properties. Research is ongoing at the MSL.

Cost Studies – PPRP has developed cost estimates for placing fly ash and FBC material in abandoned underground mines as grout to become stabilized material and for placing Class F fly ash and lime kiln dust, the most plentiful high lime content industrial waste product available in Maryland, to trigger the pozzolanic reaction in fly ash to become stabilized material in pit mines. These estimates suggest the use of CCBs in these applications will be cost competitive when mine filling is required.

Investigation of Works Progress Administration (WPA) Maryland Mine Sealing Program – The largest mine sealing program ever undertaken in Maryland was that of the WPA in the 1930s. It was largely judged a failure in terms of reducing acid mine drainage. The extent of the Program and reasons for its failure to impact acid mine drainage were investigated as guidance for large-scale use of CCBs in mine applications.

4.2 Impacts from Transmission Lines and Other Linear Facilities

More than 2,000 miles of electric power transmission line (69-kV or higher) rights-of-way are located throughout Maryland. These rights-of-way are constructed and maintained as long, linear corridors that are often markedly distinct from the surrounding environment. The corridors may cross streams and rivers, split patches of forest, traverse farms and open areas, run alongside roads and through residential areas, or span wetlands and other sensitive habitats, resulting in a variety of effects.

In general, overhead transmission line corridors vary from approximately one hundred to several 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 often cross natural features such as streams and floodplains, but because of their relatively narrow width, it is usually possible to avoid wetlands, forests, rare species habitat, historical and archeological sites, and scenic viewsheds. Several new transmission lines have been proposed across Maryland recently in response to PJM's transmission planning and federal studies that indicated that the northeastern U.S. is in critical need of increased transmission capacity and reliability. Furthermore, offshore windpower facilities proposed for near the Maryland coast would require both offshore transmission and additional large capacity transmission lines on the Eastern Shore. 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.

As described in Section 2.5, there are several major transmission lines, as well as numerous smaller projects, throughout the state that are currently in various stages of review/approval. PPRP reviews the environmental impacts of proposed transmission line projects from a number of perspectives. The review considerations and typical impacts are summarized in the following subsections.

4.2.1 Air Quality

The State of Maryland relies upon PJM, a regional transmission organization, to coordinate movement of wholesale electricity in the Mid-Atlantic region, as described in Section 3.2. A portion of PJM's role is to ensure that the transmission system achieves a set of reliability criteria/standards established by PJM, the North American Electric Reliability Corporation (NERC), and other local entities. Based on evaluations completed by PJM as part of its Regional Transmission Expansion Plan, PJM has identified near-term reliability concerns.

In response, multiple high-voltage, multi-state transmission lines are being proposed that will affect the PJM region (including Maryland), ultimately creating a flux in electrical generation patterns. Generally, power generation west of Maryland is dominated by coal-fired units; while to the east, it is dominated by gas- and oil-fired units. Construction of transmission lines that may facilitate the import of power generated by coal-fired plants could result in an increase in emissions of air pollutants associated with the power consumed in Maryland.

There are several current transmission scenarios (new and upgraded transmission lines) through which regional generation and emission patterns may change. Some currently proposed transmission scenarios include: construction of the TrAIL Project (completed in May 2011), the reconstruction of Dominion's Mt. Storm to Doubs 500-kV line (to be competed by 2015), construction of Dominion's Suffolk/Thrasher 230-kV line (to be completed in 2011), the completion of portions of PPL's Susquehanna-Roseland project (to be completed by 2012), and potential construction of PATH (currently suspended) and MAPP (currently delayed).

To gain a better understanding of the effect on air quality of changing generation patterns that may result from the construction of new transmission lines, PPRP evaluated the work of Resources for the Future (RFF), which assessed changes in generation and emissions of NO_x, SO_2, PM, CO_2, and Hg using the Haiku electricity market model. The Haiku model runs accounted for capacity planning, investment, and retirement over multiple years. However, since the completion of the Haiku study by RFF, several changes that affect the study outcome have occurred – notably the suspension of the PATH and MAPP projects and changes in a number of regulatory initiatives that can potentially affect electricity generation throughout the U.S. While considering that the Haiku analysis has not been updated to reflect these developments, PPRP's study concluded that, based on the Haiku projections of worst-case outcomes, the overall effect of transmission line construction on air quality in Maryland will be relatively insignificant.

4.2.2 Impacts to Vegetation and Land Cover

Any transmission line right-of-way in Maryland that is longer than a mile or two will generally pass through several land cover types, including forested areas, agricultural lands, residential and urban development, and infrastructure, such as roads, power facilities, airports, and military bases. Along the transmission line corridor, mixed hardwood and coniferous forests, agricultural field edges, and undeveloped pockets within urban areas provide wildlife habitat. Often times the corridor will be located adjacent to or across streams and their associated riparian and wetland areas.

In existing transmission line rights-of-way, past maintenance activities will have shifted the vegetation toward low-profile species, such as grasses, ferns, flowering plants or forbs, shrubs, and tree saplings. Figure 4-28 shows an example of typical transmission line vegetation management practices in Maryland. Many of the species present in the right-of-way may be non-native 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 4-28 An Example of Typical Transmission Line Vegetation Management in Frederick County, Maryland

Source: K. Sillett, Versar Inc.

Maintaining a cleared transmission line right-of-way through a forest splits the forest into disconnected pieces and can provide invasive species with routes into the forest interior. The effects are less severe in agricultural areas, particularly if the transmission developer permits continued use of the land for crops or pasture. In residential or commercial areas, environmentally sensitive maintenance of rights-of-way can actually augment nearby streams and wildlife habitat, thereby providing buffers that can help mitigate environmental degradation from urban development and runoff.

When a new transmission line is built, there can be additional, temporary impacts from construction access by cranes and other heavy equipment, construction traffic on unpaved access roads, boring for transmission line pole foundation installation, and wire installation activities. Activities to minimize construction impacts normally include restoration of contours to pre-construction conditions and controlling erosion until re-vegetation stabilizes the disturbed areas. The Maryland State agencies generally recommend that the vegetation be restored to native species and the natural functions of the pre-construction ecosystem be protected.

Transmission companies are required by federal authority to maintain rights-of-way in a condition that assures the reliable delivery of power in accordance with national safety standards. Although it has been common practice to achieve this goal by clearing and mowing the right-of-way, such vegetation management practices may be unnecessarily excessive especially in sensitive areas and through forested habitat.

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, the PSC has estimated that fallen trees and branches are the largest cause of power outages for lower voltage distribution lines in Maryland, accounting for almost two-thirds of the 6.5 million customer-hours of electric service interruption in the state in 2006. 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, using equipment and data collection procedures provided by DNR, 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 develop improved maintenance practices that identify and remove hazardous trees while protecting valuable tree resources and forest habitat.

4.2.3 Impacts to Streams, Rivers, and Watersheds

Transmission line rights-of-way crossing streams, rivers, and their watersheds can create temporary ecological impacts during construction, and permanent ecological impacts afterward when degraded habitat is maintained. Constructing and maintaining transmission lines can also affect streams near the right-of-way both directly and indirectly. The 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. Increased sediment can lead to changes in stream morphology and diminished water quality, ultimately degrading the ecological condition of the stream. Removing vegetation from the riparian area reduces stream shading and decreases the amount of leaf litter, woody debris, and rootwads present in the stream system. This may result in increasing water temperatures and a reducion in habitat and food sources that threaten survival and reproduction of cold water species, including brook trout. In most cases, long-term effects can be minimized by placing transmission line towers far enough from the stream bank, so that the wires span the stream and associated riparian area. This configuration is particularly effective at reducing impacts if the right-of-way is maintained in natural vegetation in the riparian area. However, older rights-of-way are often entirely cleared.

Large rivers are often 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 4-29, includes six towers in the river and is currently being considered for a second crossing. All of Maryland's major rivers, both tidal and nontidal, are crossed by transmission lines. At present, only one of these crossings — SMECO's transmission line between St. Mary's County and Calvert County near the mouth of the Patuxent River — is accomplished by 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 currents and erosion patterns, and potential hazards to navigation. Above the waterline, the towers may provide nesting and roosting opportunities for some birds, while interfering with others.

Figure 4-29 Existing 500-kV Transmission Line Crossing of the Potomac 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. To minimize such effects, the State agencies typically recommend that towers be located as far from stream banks as possible, and require vegetation and construction management practices that minimize the movement of disturbed soil and construction debris toward streams.

Impacts to Scenic Rivers

A Scenic River is defined 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" [Natural Resources Article, 8-402(d)(2)]. The Wild and Scenic Rivers 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.

Recent projects involving Maryland Scenic Rivers and their watersheds include the PATH project (the Potomac River in Frederick County and the Monocacy River), the Monocacy-Ringgold-Catoctin project (the Monocacy River), the Bagley-Graceton and Conastone-Graceton rebuilds (Deer Creek), and the MAPP project (the Patuxent River). Special attention is paid during the review of these projects to river and stream crossings in these watersheds, especially concerning riparian loss and erosion leading to downstream sedimentation.

Frequently, transmission structures also significantly degrade the visual environment along the river. A number of Maryland's designated scenic rivers, including the Patuxent River, the Monocacy River, and portions of the Potomac River, have incurred viewshed impacts from existing transmission line crossings. An underground crossing, however, may eliminate or minimize visual impacts (see Section 2.5.2 for additional details).

Impacts to the Chesapeake Bay

The Chesapeake Bay is Maryland's largest and most unique water resource. Almost all of the state's watersheds drain into the Bay, and its health is directly affected by human activities in these watersheds, in the tidal rivers that flow into it, and in the wetlands that surround it. To protect the Bay from adverse impacts of shoreline development, Maryland has defined a "Critical Area" that includes, in addition to the waters of the Bay 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

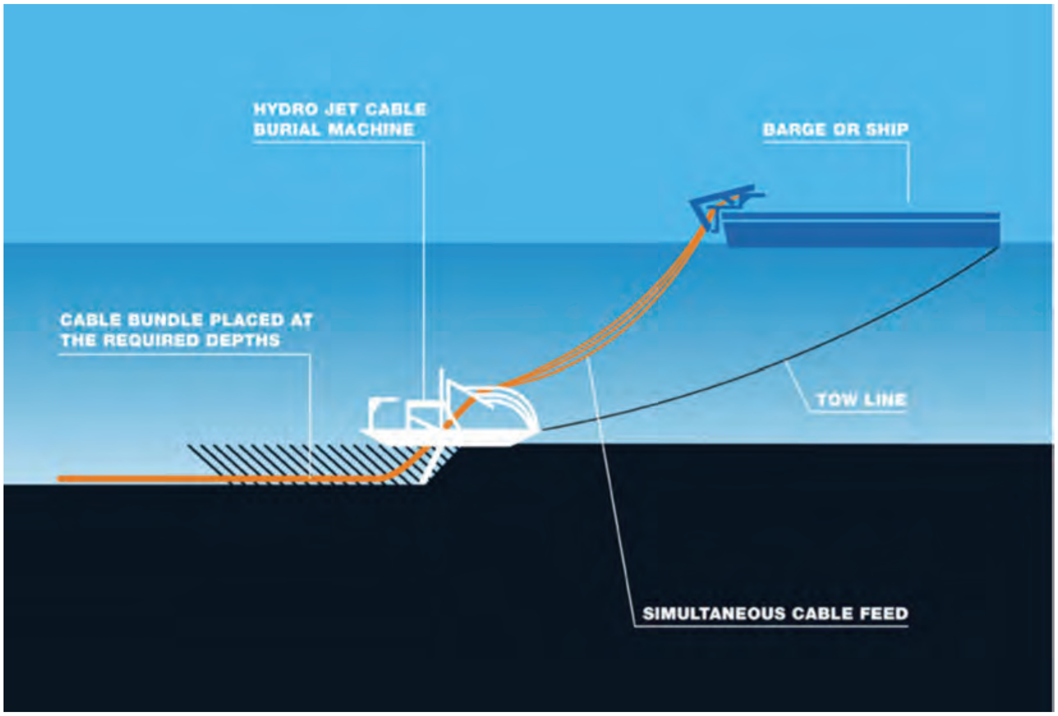
State and local governments to assess impacts caused by construction disturbances, run-off, and activities within the 1,000-foot buffer zone. Any projects which may directly or indirectly affect the Critical Area in the state, including transmission line rights-of-way, are required to seek and obtain approval from the Critical Area Commission.

Although there are no existing transmission line crossings of the Bay itself, recent technology advances have dramatically improved the feasibility and cost effectiveness of a submarine cable installation in the Bay. A submarine transmission line across the Bay would be expected to have multiple short-term, acute impacts caused by construction activities, and long-term impacts from construction disturbance, maintenance activities, and the operation of the electric power line once it is energized. Underwater cables exist in several areas of the United States, including Long Island Sound, Raritan Bay, and San Francisco Bay, although none are as productive and biologically diverse as the Chesapeake Bay. Additionally, as underwater cable technology improves the transmission capacity, there is increasing potential for greater effects on the environment once the cable is operational.

Installation of underwater cables can involve the use of horizontal directional drilling (HDD), the use of a jet plow, trench excavation, or a combination of these techniques, to place cables several feet deep in the bottom sediments. Under some circumstances, such as rocky hard bottom, the cable is just placed directly on the bottom. This latter technique affords the least protection from currents and man-made disturbance, such as being hooked by an anchor. The HDD technique uses pressurized drilling muds, which may be released accidentally through 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 cable is even placed in the trench. During installation, which is depicted in Figure 4-30, a large jet plow 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.

Undersea cable installation and operational effects on turbidity, alterations of nutrient and dissolved oxygen concentrations, thermal changes, electromagnetic fields produced by the cables, salinity, and physical barriers on or in the bottom sediments, are key areas of consideration during project review. 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. Oysters and other shellfish that ingest these bacteria pose a human health risk.

Figure 4-30 Illustration of an Underwater Cable Installation Using Jet Plow Technology



Source: http://hudsonproject.com/project/description/

Aquatic habitats may be affected by re-suspension of sediments during construction or maintenance of the cables that may release contaminants or nutrients into the water column. The depth profile of the Bay, and its tidal influences, would allow disturbances that re-suspend sediments or contaminants to have effects well beyond the immediate physical footprint of the cable path, such as adjacent oyster and clam beds. A disturbance that transects the Bay or its tributaries, either short-term or long-term, could impact 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, and overwintering sea ducks and many other sensitive species.

Submarine cables offer visual and engineering advantages compared to overhead lines across water bodies. In any specific area, these advantages have to be compared with the impacts to the biological communities that inhabit the bottom, and the food chains that depend on them. In Maryland, the laws that protect non-tidal wetlands and the Critical Area around the Chesapeake Bay require thorough environmental evaluations before building these types of underwater transmission lines.

Impacts to Ground Water

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 or the Potomac Edison Monocacy-Ringgold-Catoctin projects) 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 areas such as the Eastern Shore where the proposed 640-kV direct-current portion of the MAPP project would be located. As structure heights increase for higher voltage overhead transmission lines, the required drilling depths will likely be deeper than that of the SMECO or MRC projects; therefore, the tower foundation and cable conduit drilling depths need to be compared carefully to the depth to ground water for many proposed transmission line projects in Maryland.

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.

4.2.4 Impacts to Wetlands

Wetlands are among Maryland's most valuable natural resources. Tidal wetlands are protected by the Critical Area Act, and non-tidal wetlands — including wetlands in utility rights-of-way — fall under the Non-Tidal Wetlands Protection Act. Maryland's overall goal is no net loss of non-tidal wetlands acreage or function. To acheive this goal, the State requires that any unavoidable wetland losses be replaced at least acre for 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, or USACE or both.

While new routes are usually planned so as to avoid wetlands, rights-of-way constructed prior to the Non-Tidal Wetlands Protection Act were often less favorably sited, and many undesirable wetland impacts exist.

Wetland impacts result when vegetation, soil, or water flow is altered by a transmission line right-of-way, either directly or indirectly. In the past, transmission line access roads within wetlands were often particularly damaging, 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. In addition, without proper management practices, invasive plants tend to colonize areas on and directly adjacent to a dry elevated road bed and compete with the adjacent wetland plants for sunlight and water. As a result of vigilant permitting oversight by MDE, USACE, and DNR, and appropriate planning by the utilities, transmission line access roads are now rarely constructed in wetlands. The preferable access for pole placement and line maintenance near wetland areas is via access points on either side of the wetland, avoiding direct impacts. Where upland access is not possible, matting can often be placed over the wetland area to minimize damage from equipment and activities, without building permanent roads.

Indirect construction and maintenance impacts to wetlands are primarily caused 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 prior to construction by use of appropriate best management practices. They can also be minimized prior to construction through the use of EPA-approved and appropriate herbicides to eliminate non-native invasive species in or near wetland areas, and refraining from mowing or using other equipment within wetlands areas. Overall, transmission line construction has the least impacts on wetlands when poles are placed in uplands on either side of a ravine, well away from wetland areas, or in horizontally-bored duct banks below the wetland.

4.2.5 Impacts to Wildlife

A large portion of the transmission line rights-of-way in Maryland are located in otherwise 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 forest interior-dwelling (FID) species, and often provides a corridor for invasive species that compete with or prey upon native forest species. The effects are particularly severe near forested streams and wetlands as discussed in Sections 4.2.3 and 4.2.4. While there are less significant impacts in shrub-scrub and agricultural habitat areas, the maintenance of the right-of-way in a mowed state can 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, because individuals that attempt to cross the cleared area can be exposed to a high risk of predation.

Forest interior habitat may support many species, including but not limited to Forest Interior Dwelling Species (FIDS) of 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 non-interior areas. FID species, 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 FID birds generally requires several hundred acres. According to the Natural Heritage Program, the populations of many FID birds are declining in Maryland, often because of loss of suitable amounts of habitat. Thus, the effect on FID species 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. The U.S. Fish and Wildlife Service and the Avian Power Line Interaction Committee have cooperatively developed guidelines to help prevent injuries to birds that contact power lines. The State uses the voluntary guidelines, which were released in 2005, 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.

4.2.6 Impacts to Threatened and Endangered Species

Most rare, threatened, or endangered species are composed of small populations that occupy localized 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, eagle nests have been found on transmission line towers (see Figure 4-31). In other places, rare species such as the showy goldenrod (*Solidago speciosa*) have colonized the right-of-way. On the other hand, when a potential transmission line route in western Maryland was investigated recently, it was found to cross a wetland system containing 11 rare, threatened, or endangered species. The wetland, including

Figure 4-31 Eagle's Nest in a Trasmission Tower

a sphagnum peat bog and associated meadow with surrounding brushy areas and hemlock forest, is a designated Non-tidal Wetland of Special State Concern. The impacts of a new transmission line right-of-way across this wetland would be significant.

The Maryland DNR Wildlife and Heritage Service, 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 also 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 adequate surveys have not yet been conducted. When habitats and potential habitats are identified in the vicinity of a proposed project, specific recommendations are made for field surveys and for protecting or mitigating impacts to any populations present, including avoiding disturbances during breeding seasons or migrations, controlling hydrology 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.

4.2.7 Impacts to Maryland's Green Infrastructure

DNR, through programs such as the Green Infrastructure Assessment, has established land conservation strategies to preserve and enhance the State's ecological health. DNR's programs assess ecological habitat, coordinate management efforts, and acquire natural lands where possible. DNR's Green Infrastructure network comprises areas of large, contiguous forest habitat, known as hubs, and narrower natural corridors that connect the hubs to allow their faunal and floral populations to interact.

Rights-of-way that are constructed through Green Infrastructure hubs and corridors split them into small, disconnected pieces (fragments) and diminish their ability to function as integrated habitat units. While the area of the removed forest may not be great, there may be severe consequences for the species that depend on the hub or corridor habitat. Invasive plants such as Japanese honeysuckle, 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 mitigate some of these effects.

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 to be employed only if it is not possible to bypass the Green Infrastructure system and align the new transmission line with pre-existing disturbed and degraded areas.

4.2.8 Cumulative Effects

The impacts imposed by transmission line rights-of-way can 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 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 would suggest.

Cumulative effects can be assessed in several ways. The effect of multiple stresses on an ecosystem is usually measured 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 restricts development in all sensitive habitats around Chesapeake Bay and its tidal tributaries. Individual resources, on the other hand, are handled 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 Non-Tidal Wetlands Protection Act.

Forest clearing in a right-of-way provides an example of the nature of cumulative effects. The proposed MAPP project will require expanding the cleared width along an existing right-of-way in southern Maryland. Although the additional clearing is only 100 feet and may not have large local consequences, overall, it amounts to hundreds of acres of forest loss. The permanent removal of this much forest is a significant 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 in excess of 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.

4.2.9 *Vegetation Management Alternatives for Transmission Line Rights-of-Way*

Traditional Management

Traditional 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 as described in the preceding sections.

Guidelines of the Working Committee on Utilities

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 to assure that 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 be used, targeting only trees which could cause damage to the line.*
- *The right-of-way edges through forests or timber areas should be curved, undulating boundaries, not straight "walls" that create a "tunnel" effect.*
- *Small trees and plants should be used to feather the height of the right-of-way vegetation from grass and shrubbery near the center to larger trees at the edges.*

NERC Regulations

Improperly maintained vegetation in a transmission line right-of-way can disrupt the integrity of the system and cause power outages. NERC, operating under the oversight of FERC, develops and enforces reliability standards for transmission lines. Current best practices and requirements for reliability are codified in the NERC Transmission Vegetation Management Program (TVMP)[26], which is currently under revision. The revised standard requires transmission owners to have a TVMP for all transmission lines operated at 200-kV and above, in addition to designated sub-200-kV lines, 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, taking into account voltage, sag under maximum load, and wind velocity on conductor sway. Minimum vegetation clearance distances (MVCD) are required for alternating current voltages. The calculated minimum distances to prevent spark-over between conductors and vegetation at various altitudes and

[26] http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

operating voltages were derived using a proven transmission design method. 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 Practice in Maryland

The NERC regulations can be met by the traditional approach, but they do not require it. The alternatives suggested in the Guidelines of the Working Committee on Utilities, and other advanced techniques, can be implemented as long as the required clearances are maintained. In general, most Maryland utilities use uniform, system-wide practices that may exceed NERC requirements. After forested land is cleared to create a transmission line right-of-way, a number of 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 neo-tropical and migrant land birds, reptiles, and amphibians.

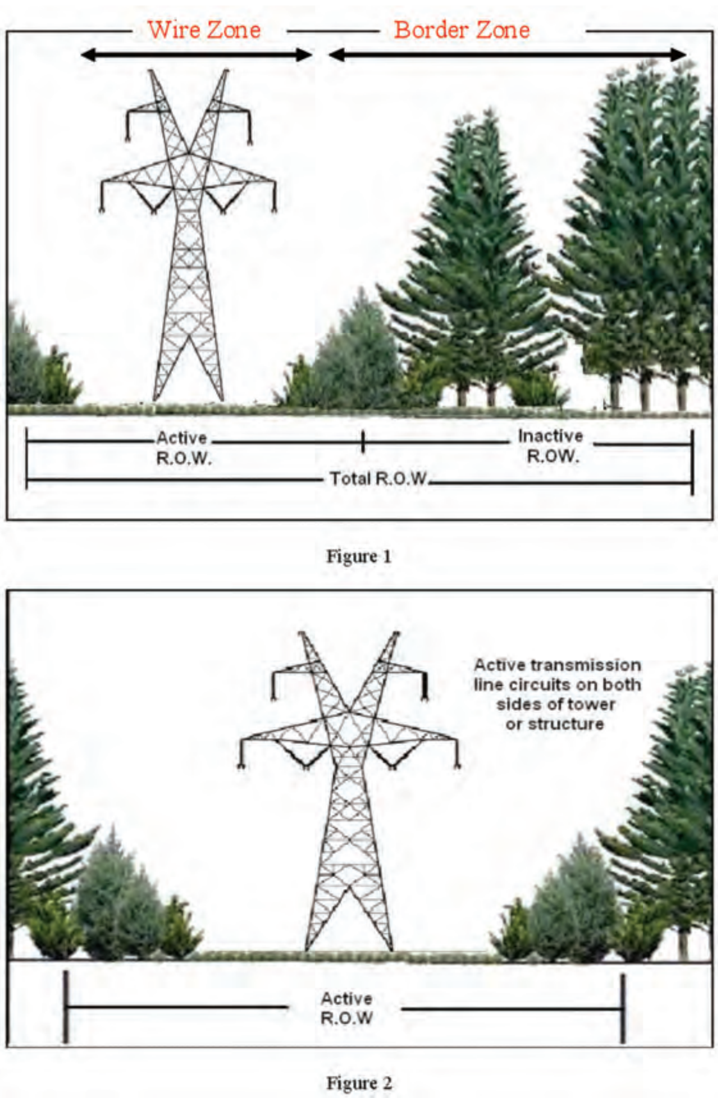
Leaving the right-of-way in a natural state to the maximum extent possible is the best alternative for protecting wildlife in sensitive areas. Creating curved or wavy right-of-way boundaries and piling brush from the cleared right-of-way so that it provides wildlife habitat would help mitigate impacts from right-of-way clearings in forested areas. Feathered, or soft edges, as shown in Figure 4-32, can be used to 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", would also reduce 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.[27]

State Conditions for Approval

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

[27] http://training.fws.gov/DivisionSites/TEMP/ImageLib/Video.html

Figure 4-32 Transmission Line Vegetation Management using the Feathering Technique



Source: Images adapted from NERC Standard FAC-003-2 Technical Reference, September 2009.

has, through its membership in the MERTT Council, compiled information on innovative practices that reduce adverse effects on local wildlife and plant communities, such as reduced mowing frequencies. Several of Maryland's utilities have adopted maintenance programs to improve wildlife habitats in 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 actually 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.

4.2.10 Socioeconomics and Land Use Issues

Due to their linear nature, high-voltage transmission lines affect the socioeconomic environment in fundamentally different ways than power generation facilities. Extending miles, but within a corridor typically between 100 and 200 feet, and with a vertical component that seldom exceeds 200 feet, most socioeconomic impacts from transmission lines are spatially concentrated within a relatively narrow band on either side of the right-of-way. Transmission lines are generally considered a negative externality by nearby landowners because of perceived or real effects upon views, health, and property values. Others, particularly visitors to an area (tourists) or transient viewers such as commuters, may also perceive power lines as a disamenity, although primarily for their impact on aesthetics.

Dual HVTL corridor in Rappahannock County, Virginia

It is important to distinguish between transmission line projects that rebuild or add circuits to an existing corridor and those that create a new right-of-way. Impacts associated with the former are incremental, affecting land uses that have coexisted beside an existing transmission line for years and often decades. On the other hand, transmission line projects constructed within a new right-of-way can have significantly greater socioeconomic consequences. Projects that rebuild a transmission line to a higher voltage or add circuits may require taller structures and additional conductors, increasing the line's visual footprint and projecting more vertical and horizontal lines upon the landscape, but years of coexistence has usually added extensive vegetation buffers along right-of-way edges, mitigating the impacts on adjacent land uses.

Recent PPRP socioeconomic reviews of transmission line rebuilds have focused on transportation issues and direct land use impacts. Transmission line construction is not particularly labor intensive and requires few materials. As a result, transportation issues associated with transmission line construction are usually focused on oversize/overweight load considerations and access to the right-of-way.

To the extent that any loads of materials or equipment are oversized or overweight, a hauling permit is required by the Maryland SHA. An oversize load is one whose width exceeds 8 feet 9 inches, height exceeds 13 feet 6 inches, or length exceeds 55 feet. An overweight load is one that exceeds 45 tons. SHA permits pertain to State maintained roads and bridges only. Several counties and the City of Baltimore issue hauling permits for local roadways, but others do not. Similarly, construction of an access road from a State highway is subject to the terms of an SHA District Office permit. Construction of an access road from a non-state public road is subject to permit requirements of the Public Works Department of the host county.

Direct impacts on land use from transmission line rebuilds are usually associated with excavation and grading for structure foundations, temporary construction staging areas, and access roads. Where locations of cultural resources within or adjacent to the right-of-way are known and could potentially be adversely affected, PPRP, in consultation with the MHT, has conditioned past licensing recommendations on additional archeological assessments, protective measures such as perimeter fencing, or other mitigation to protect these resources. Some disruption of normal economic activities, such as farming, on land within the right-of-way is often a consequence of construction within existing rights-of-way. Although this is a concern to PPRP, the amount of acreage affected is usually quite small and the adverse effects are temporary.

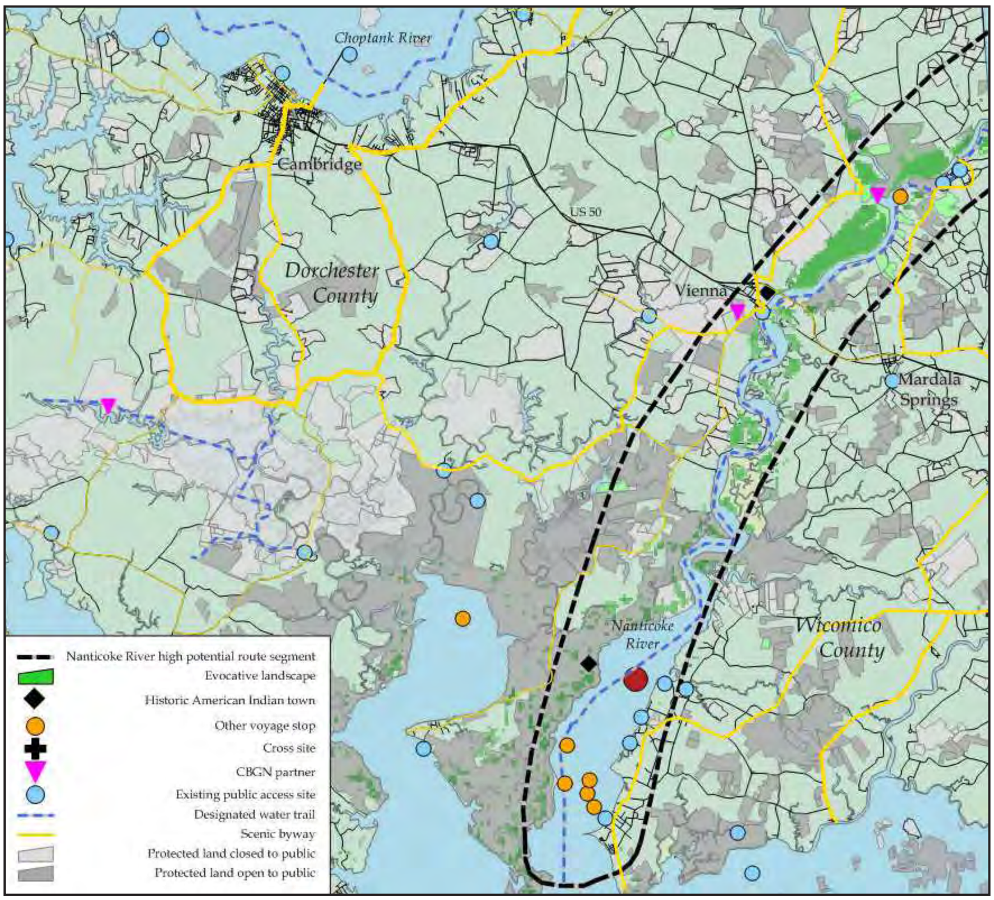
A significant proportion of most existing high voltage transmission line corridors traverse or bypass natural areas, farms and forest lands, and historic properties. Through the conservation efforts of the State, local governments, and private land trusts, many properties adjacent to rights-of-way are protected by easement, transfer of development rights or other land preservation program. Particularly where preservation goals include protection of scenic resources, PPRP recognizes the discord between transmission line siting and land preservation. However, rights-of-way predate most land conservation initiatives where rebuilds of existing transmission lines have been proposed. Because transmission corridors appear to have no diminishing influence upon land preservation activities, PPRP's recent environmental reviews of proposed rebuilds have concluded that the various programmatic land use designations granted to neighboring parcels along the right-of-way would be unaffected by these projects.

Land preservation and cultural resource concerns are considerably more important when a new right-of-way is required for a transmission line. One of the goals of land preservation is to protect Maryland's most treasured landscapes and natural and agricultural resources for future generations. Scenery is also an important component of Maryland's CHA management plans and of heritage tourism throughout the state. Therefore, land preservation has a significant economic dimension as well. Many state land preservation entities, including heritage area and RLA management entities, and multi-state non-profit organizations, such as the Journey Through Hallowed Ground Partnership, are regionally focused public and private partnerships that are particularly sensitive to development that conflicts with their management plans.

On the Eastern Shore, the region's cultural identity is being promoted by several heritage tourism initiatives where landscape plays a critical role in the presentation of the region to visitors. For example, Dorchester County is host to the Heart of the Chesapeake Certified Heritage Area (HCCHA). Heritage themes in the HCCHA Management Plan include preserving Chesapeake landscapes and recognizing the past and present significance of agriculture of the area. Separately, the Maryland Park Service is developing a new State Park in Dorchester County dedicated to Harriet Tubman. Slated to open in 2013, the park is being designed to offer a distinctive landscape of marshes, woodlands, and fields that are reminiscent of the backdrop for Harriet Tubman's early life on the Eastern Shore. Further south, the Lower Eastern Shore Heritage Area (LESHA) spans Somerset, Wicomico, and Worcester counties. Landscape is central to the presentation of the Lower Eastern Shore in the LESHA Management Plan.

Between Dorchester and Wicomico counties, the Nanticoke River is the focus of a major federal heritage initiative. The National Park Service's (NPS's) comprehensive management plan for the Captain John Smith Chesapeake National Historic Trail identifies the Nanticoke River as one of the trail's 10 management segments and a place where Smith made a significant voyage stop. NPS's trail management emphasizes interpreting and protecting the world of the Chesapeake that Smith encountered in his voyages, and recognition of the need to identify, evaluate, and protect cultural and natural resources important to the National Historic Trail. Significantly, the NPS identified the visible shoreline of the Nanticoke River as one that is generally evocative of the 17th century. The location of the NPS Nanticoke River Trail management segment is depicted in Figure 4-33.

Figure 4-33 NPS Nanticoke River Trail Management Segment for the Captain John Smith Chesapeake National Historic Trail



Throughout Maryland, roads and waterways are essential linkages for orienting visitors to heritage resources. On the Eastern Shore, Michener's Chesapeake Country Scenic Byway, the Blue Crab Scenic Byway, the Chesapeake Country National Scenic Byway, and the Harriet Tubman Underground Railroad form a road network stretching from Kent Island to Chesapeake City. SHA's State Scenic Byways are roads with historical, cultural, natural, archaeological, and/or recreational qualities that promote Maryland's unique heritage. Water trails and public waterway access sites are promoted through DNR's Maryland Water Trails and Public Access Planning Program. Water trails on the Eastern Shore characterize the landscape as predominately rural with expanses of agricultural and forest lands.

Of course, landscape and cultural heritage issues are not confined to the Eastern Shore. For example, the coexistence of federal and State heritage tourism programs is particularly pronounced in mid-Maryland where the Heart of the Civil War CHA, the Journey Through Hallowed Ground National Heritage area, and the Appalachian Trail overlay Frederick and Washington counties, all of which have preservation of scenic landscapes as a management goal.

Without careful review and evaluation, new or widened transmission corridors could significantly alter landscapes these and other land preservation programs seek to protect. PPRP recognizes the importance of Maryland's heritage to the local and State economy and will continue to engage stakeholders in future environmental reviews of proposed transmission lines.

The adverse effect of transmission lines on residential property values is an issue that has been increasingly raised in permitting cases in Maryland. Although a considerable amount of research has been done to examine property value effects on noxious or hazardous facilities, less has been done in associating conventional generating facilities, high voltage transmission lines, and new technologies, such as wind farms, to property values. As a result, residential property value impact estimates have lacked the credibility needed to influence public policy decisions related to the siting of energy facilities.

Even research that focuses only on high-voltage transmission lines is ambiguous. A recent review[28] summarized the literature as follows:

- *Of 38 studies, about one-half reported negative property value effects while the other half found none;*
- *Property value effects, when found, were small (< 10 percent), and usually in the range of 3-6 percent;*
- *Property value effects, when found, declined rapidly with distance, having virtually no effect at about 300 feet;*
- *Studies that investigated sales over time found that property value effects decline over time; and*
- *Heightened perceptions of risk from EMF health effects have not altered the relationship between property values and proximity to transmission lines.*

There is even less evidence on the effects of transmission lines on agricultural land values. The few studies available in the literature suggest that proximity to transmission lines has no effect upon the selling price per acre; one undated study on the sale of farmland under easement for high voltage transmission lines or underground gas pipelines found no effect of the easement on the sales price.

Though little hard evidence is available, concerns about property value effects from transmission lines and substations continue to be raised by opponents of rights-of-way and substations, including the proposed

[28] Chalmers and Voorvant, 2009

PATH Kemptown Substation. As a consideration in its environmental reviews, PPRP is continuing its focus on property value effects from electric transmission and transmission facilities through both ongoing reviews of published literature and sponsored research. Improved statistical methods and continued data mining of Maryland Property View data is expected to yield additional insight into land value impacts from electric generation and transmission facilities.

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Chapter 5 – Energy Policy and Technology for a Sustainable Future

We are like tenant farmers chopping down the fence around our house for fuel when we should be using Nature's inexhaustible sources of energy — sun, wind and tide. I'd put my money on the sun and solar energy. What a source of power!

– Thomas A. Edison

Our energy future is complex; it is interrelated with a variety of environmental and social issues. This chapter discusses some of these issues related to sustainable energy and how Maryland is seeking to craft a more sustainable energy future. Maryland's definition of sustainability is the use of resources wisely today to ensure future generations have the same or better opportunities. Sustainable energy practices involve the efficient use of energy and associated resources. Accordingly, Maryland has adopted goals to reduce the state's energy consumption and promote the use of renewable energy sources. This chapter describes these sustainable energy efforts and puts them within the context of federal initiatives and technological advances.

5.1 Electricity Policies for Sustainability

Technological advancements and the use of renewable sources are necessary to support sustainable electricity generation. Equally important is the implementation of effective energy efficiency and conservation measures that reduce the need for additional generation resources. The State continues to evaluate policies that encourage energy innovation, energy efficiency, conservation, and renewable resource development.

5.1.1 Maryland RPS

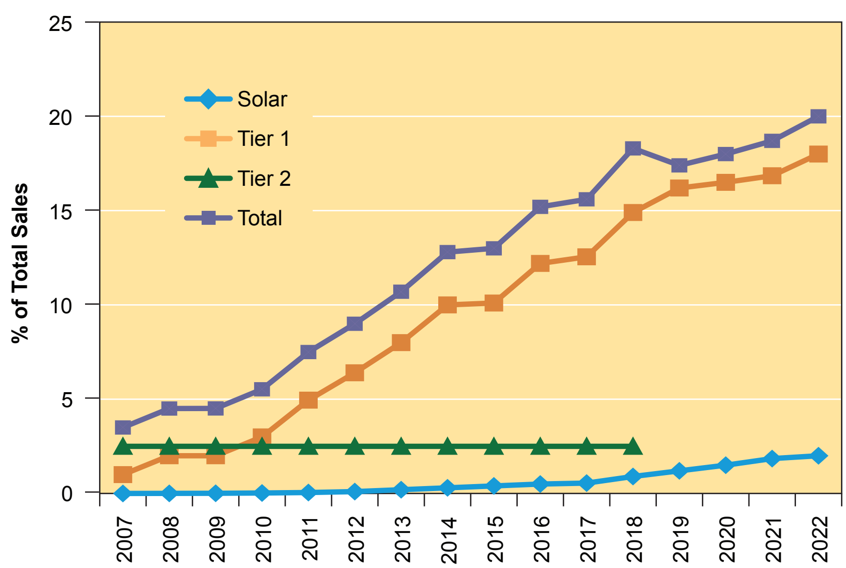
The Maryland Renewable Energy Portfolio Standard (RPS) became law in May 2004. The RPS requires an electrical supplier to provide a certain percentage of its electricity resources from Maryland-certified Tier 1 and Tier 2 renewable resources. The 2004 RPS law was modified by legislation enacted in 2007, 2008, 2010, and 2011. The current RPS law contains these provisions:

- *Tier 1 renewable resources include fuel cells that produce electricity from other Tier 1 renewable fuel resources, geothermal, hydroelectric facilities under 30 MW, methane, ocean, poultry litter-to-energy, qualifying biomass, solar, wind, waste-to-energy, and refuse-derived fuel. The Tier 1 requirement began at 2 percent and increases annually to 20 percent in 2022.*
- *The solar energy set-aside requires that a certain percentage of energy supply must come from in-state solar facilities. This requirement increases annually to reach 2 percent in 2022.*

- *Existing hydroelectric facilities over 30 MW qualify to meet the Tier 2 standard. Tier 1 resources may also be used to meet the 2.5 percent Tier 2 standard. Tier 2 will sunset in 2018.*

Figure 5-1 illustrates the renewable sources that are required, shown as a percentage of total energy sales over time. If a supplier does not provide the required amount of renewable electricity to their customers, it must pay a non-compliance penalty, referred to as an alternative compliance payment (ACP). These payments amount to $0.04 for each kilowatt-hour (kWh) short of the Tier 1 resource requirement and $0.015 for every kWh short of the Tier 2 requirement. The penalties for the solar energy set-aside start at $0.45/kWh in 2008, decrease to $0.40/kWh for 2009 through 2014, to $0.35/kWh in 2015 and 2016, to $0.20/kWh in 2017, and then by $0.05/kWh every other year to $0.05/kWh by 2023.

Figure 5-1 Maryland RPS Summary



The Maryland Public Service Commission (PSC) is charged with ensuring compliance with the RPS and certifying eligible facilities. Certifying a renewable energy facility requires determining whether each facility meets the standards set forth in the Maryland RPS. The facility must operate within the PJM footprint or a PJM-adjacent control area if the electricity is delivered into PJM, and must be classified as either a Tier 1 or Tier 2 facility. Maryland has 920 MW of certified in-state renewable energy capacity, around half of which is from Tier 1 sources. There are about 2,400 renewable energy facilities certified by the Maryland PSC, providing about 4,250 MW of renewable capacity in PJM (see Table 5-1). According to the 2011 Inventory of Renewable Energy Generators Eligible for the Maryland Renewable Energy Portfolio Standard, there are over 5,700 MW of additional Tier 1 and Tier 2 eligible resources in PJM not currently certified under the Maryland RPS.

Electricity suppliers are required to submit annual compliance reports by April of the following year. Table 5-2 shows the aggregate supplier

Table 5-1 Maryland RPS Certified Capacity as of September 2011 (MW)

	Tier 1							Tier 2	
	Solar[a]	Wind	Hydro	Landfill Gas	Biomass	Black Liquor	Municipal Solid Waste	Hydro	Total
Maryland	26.0	120	20	14	---	25	241	474	920
Delaware	1.1	---	---	25	---	---	---	---	26
Washington, D.C.	0.6	---	---	---	---	---	---	---	0.6
Illinois	10.2	547	---	76	---	---	---	---	633
Indiana	---	500	---	---	---	---	---	---	500
Kentucky	---	---	---	---	---	---	---	---	---
Michigan	---	---	---	---	---	---	---	---	---
New Jersey	---	---	---	41	---	---	59	---	100
North Carolina	0.02	---	---	---	---	---	---	---	0.02
Ohio	0.3	---	---	---	17	44	---	---	61
Pennsylvania	6.0	498	33	139	18	58	85	450	1,285
Tennessee	---	---	---	---	---	---	---	---	---
Virginia	1.0	---	18	26	80	95	60	---	280
West Virginia	0.02	264	6	---	---	---	---	169	439
TOTAL	**45**	**1,928**	**76**	**321**	**115**	**222**	**445**	**1,092**	**4,243**

[a] Only in-state solar resources can be used to meet the solar set-aside requirement, but solar resources from within PJM as a whole can be used for Tier 1 compliance.

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.

Source: PPRP's 2011 Inventory of Renewable Energy Generators Eligible for the Maryland Renewable Energy Portfolio Standard.

Table 5-2 Maryland RPS Compliance

RPS Compliance Year		Tier 1 Solar	Tier 1 (non-solar)	Tier 2	Total[a]
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

[a] Some electricity suppliers retire more RECs than required.

obligation and the renewable energy credits (RECs) and ACPs that were submitted from 2006 to 2009. The 2008 RPS compliance year was the first year with a solar energy requirement (0.005 percent). As can be seen from Table 5-2, most suppliers opted to pay the solar compliance fees, resulting in revenues to the state of $1.2 million in 2008 and more than $1.1 million in 2009. Several new large-scale solar facilities have been approved by the PSC in the last three years and the pace of solar development has been increasing (see further discussion in Section 2.1.5).

5.1.2 Energy Efficiency and Conservation

EmPOWER Maryland

In July 2007, Governor Martin O'Malley announced a new energy initiative called EmPOWER Maryland with a goal of reducing Maryland's per capita energy consumption and peak demand by 15 percent by 2015. This initiative was encoded into law in 2008 with House Bill 374, the EmPOWER Maryland Energy Efficiency Act of 2008 (EPM Act). The EPM Act seeks 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, the four investor-owned electric utilities operating in Maryland, along with the State's largest cooperative, 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 codes and standards. The Maryland Energy Administration (MEA) is charged with implementing programs and tracking progress toward the reductions to be achieved by State-administered programs. MEA is sponsoring several rebate, grant, and loan programs for energy efficiency improvements in the state to help meet these reduction goals.

EmPOWER Maryland Utility Energy Efficiency and Conservation Programs

The EPM Act directs 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 EMP goals, and also to assess the program's potential impacts on electricity rates, jobs, and the environment. The Maryland PSC approved BGE's energy efficiency and conservation programs in 2008 and they were launched in 2009. Programs for Delmarva Power (Delmarva), Potomac Electric Power (Pepco), Allegheny Power (now Potomac Edison), and Southern Maryland Electric Cooperative (SMECO) received final implementation approval in August 2009 and were fully launched by mid-2010. The programs offered by the utilities include rebates for ENERGY STAR products, energy audit and retrofit assistance, and incentives for energy efficient new construction. In addition, all of the utilities have been directed by the PSC to include a series of programs targeting low-income consumers.

EmPOWER Maryland Utility Peak Demand Reduction Programs

Demand reduction activities can change how energy is utilized in order to make more efficient use of existing resources. This can involve installing automated control systems to turn out lights, power down equipment when it is not in use, and cycle air conditioners and heaters on and off. This can also consist of changing the patterns of energy use, such as shifting some activities from peak demand times to a time when energy is less in demand overall (off-peak periods).

The EMP Act directed utilities to reduce per capita peak demand by 15 percent from 2007 levels by the end of 2015. The utilities, with the exception of Potomac Edison, have been implementing programs to meet these goals. BGE has implemented its Peak Rewards program, which is an automatic air conditioner and heat pump cycling program for residential customers. Pepco and Delmarva are operating an Energy Wise Rewards program and SMECO is running CoolSentry; both are residential direct load control programs for air conditioner cycling. Potomac Edison cites a lack of any cost-effective mechanism to meaningfully reduce peak demand.

EmPOWER Maryland Reductions

In the EMP Maryland program filings, the utilities calculated the energy and demand reductions each of the approved programs were projected to achieve. The utilities estimated their programs would be able to achieve between 60 to 90 percent of their energy reduction target amounts and exceed the demand reduction targets. Energy reductions beyond these

Impacts of EmPOWER Maryland

By the end of 2010, the EmPOWER Maryland utilities' portfolio of energy efficiency and conservation and direct load control programs had installed 5,476,571 energy savings measures for 765,625 participants. Overall, these programs achieved 662 MW in reported peak demand reductions and nearly 669,000 MWh in reported annualized energy savings.

	2009 Savings		2010 Savings		Totals to Date	
	MW	MWh	MW	MWh	MW	MWh
Allegheny[a]	0.04	63	4.86	14,296	4.9	14,359
BGE	341	97,372	209	355,784	550	453,156
Delmarva	3.93	11,035	14.5	12,328	18.4	23,363
Pepco	11.1	64,974	58.5	94,577	69.6	159,551
SMECO	8	33	11.4	18,461	19.4	18,494
State Total	364	173,477	298	495,446	662	668,923

[a]Allegheny Power became Potomac Edison following the merger of Allegheny Energy with FirstEnergy in February 2011.

amounts did not meet their cost-effective tests. The PSC subsequently approved these utility programs along with the utility-estimated achievable energy reduction targets. The PSC Staff have developed their own forecast of expected energy reductions. Staff's estimated reductions projected to 2015 are as follows:

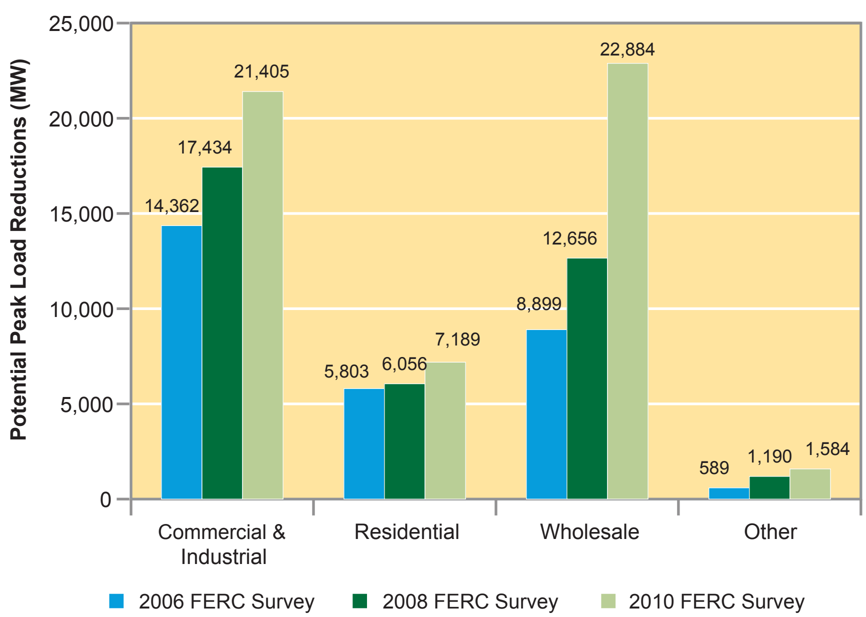
- *Energy Efficiency and Conservation Programs: 4 million MWh (73 percent of the total utility-estimated reductions); and*
- *Demand Reduction Programs: 2,932 MW (138 percent of the total utility-estimated reductions).*

5.1.3 Demand Response

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 willing to reduce electricity consumption in response to a request from the system operator or utility can be used as an alternative to supply resources when the power grid is in need of more electricity. Section 2.1.4 presents more information on how demand response works as a supply resource.

Demand response is a fast-growing alternative supply resource, which is facilitated through programs undertaken by electric utilities and demand response providers and is supported by state and federal policies and programs. FERC has become increasingly involved in efforts to support and develop demand response resources. A survey of U.S. demand response programs completed by FERC for 2010 outlines the growth in demand response participation over the last four years since the first survey was conducted for 2006. FERC estimated that the total potential contribution from demand response programs was 53,063 MW, about 7.6 percent of U.S. peak demands, which is an increase of about 17,000 MW since the 2008 survey and over 23,000 MW since the 2006 survey (see Figure 5-2).[29] Note that these estimates are based on data from survey respondents as well as estimated information for the entire survey population including non-responding entities.

Figure 5-2 National Demand Response Potential



The Energy Independence and Security Act of 2007 directed FERC to

[29] FERC, "2010 Assessment of Demand Response & Advanced Metering," Staff Report, February 2011.

develop a national action plan for promoting and facilitating demand response. In June 2010, FERC released the *National Action Plan on Demand Response*, which outlines a framework for the implementation of cost-effective demand response development.[30] This plan seeks to improve coordination between utilities, consumers, demand response providers, and federal, state, and local governments through:

- *Creating a broad coalition to coordinate and combine the demand response efforts of public and private organizations;*
- *Developing technical assistance related to demand response that is available to support state and local decision-making;*
- *Creating a national communications plan for demand response; and*
- *Supporting and expanding new analytical tools and materials for demand response analysis and assistance.*

FERC is also involved in formulating harmonized rules for compensating demand response in wholesale markets. In March 2011, FERC released a final rule regarding compensation for demand response resources in ISO/RTO wholesale energy markets. The rule establishes that, where it is cost-effective to do so, demand response resources are to be paid the full wholesale price of energy for the amount of reduction achieved.

Demand Response in PJM

As noted in Chapter 2, demand response is a growing resource within PJM, reaching 9.4 percent of peak load resources in the 2014/2015 RPM capacity auction. PJM has become concerned with reliability issues that may be associated with high levels of demand response acting as capacity resources. Demand response in the form of utility-operated Active Load Management (ALM) programs were first implemented in 1991. Analysis at that time indicated that ALM was best utilized as a peak shaving device for high demand days, which, on average, would occur 10 days in a year. Based on the ALM program in place, PJM set the following rules for load management:

- *Customers must be interruptible for up to 10 times per summer and for up to six hours each time over the 12:00 p.m. to 8:00 p.m. time period for all summer weekdays (referred to as the 10/6 rule); and*
- *The amount of ALM was limited to 5 percent of the forecasted unrestricted peak load for each zone.*[31]

Demand-side management programs have evolved into many different products since the requirements were first set for ALM. Demand response is now utilized in various forms in both energy and capacity markets and often managed by independent curtailment service providers (CSPs) with large aggregate portfolios. As such, demand response now provides reliability benefits to the PJM grid, sometimes in place of more expensive supply-side resources. However, given the limitations of the 10/6 rule, there is a maximum level of demand response penetration after which PJM would not be able to reliably

[30] FERC, "National Action Plan on Demand Response," June 17, 2010.
[31] Updated analysis in 1995 increased the ALM limit to 7.5 percent.

meet peak loads. Subsequently the rules, established with more limited applications of ALM in mind, had to be updated.

In May 2010, PJM released an updated analysis, *Demand Resource Saturation Analysis*, which examined the effects of higher levels of demand response on the reliability of the PJM grid. The analysis indicated that PJM can be reasonably confident that it would not need to call on demand response resources outside their six-hour window so long as the demand response does not exceed 4.7 percent of PJM peak load available capacity.

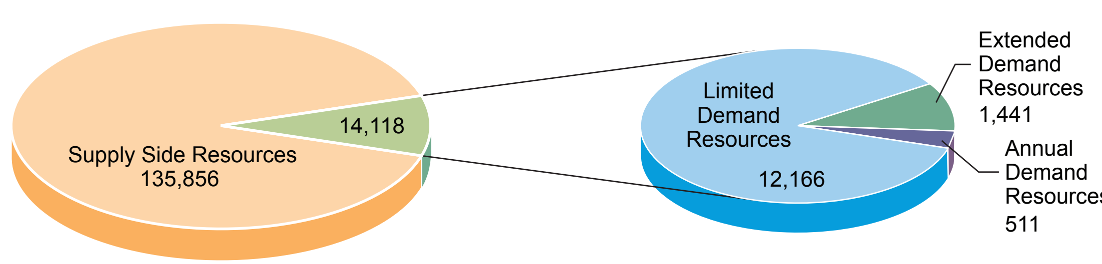
PJM initiated a stakeholder process to develop demand response reforms that would address the reliability issues outlined in the analysis. The reforms, which were implemented in January 2011, include retaining the existing 10/6 demand response product but limiting it to a level that will not compromise reliability (now referred to as Limited Demand Resources). In addition, PJM introduced two new demand response products:

1. ***Annual Demand Resources*** *– demand response resources that must be available on any day of the year for an unlimited number of interruptions for a maximum of 10 consecutive hours during the following times – 10:00 a.m. to 10:00 p.m. for May through October, and 6:00 a.m. to 9:00 p.m. for November through April.*
2. ***Extended Summer Demand Resource*** *– demand response resources that must be available on any day from May through October from 10:00 a.m. to 10:00 p.m. for up to a maximum of 10 hours at a time.*

PJM now includes the three demand response products as separate categories in the RPM capacity auctions and will conduct additional studies to determine the maximum amounts of each resource that can be included without compromising reliability. The initial PJM analysis estimated that Extended Summer Demand Resources could comprise up to approximately 11 percent of total capacity resources while maintaining adequate system reliability.

The latest RPM auction occurred in May 2011 for the 2014/2015 delivery year (the base auction takes place three years prior to the start of an actual delivery year). A total of 149,974 MW of capacity was procured during the base auction, including 14,118 MW of demand response resources (see Figure 5-3).

Figure 5-3 PJM Capacity Resources (MW) for 2014/2015 Delivery Year



5.1.4 Distributed Generation

Most on-site systems are used to supply emergency power, but there are instances where these emergency units can be operated as part of load management and load response programs, which has led to concerns that this might adversely affect air quality in Maryland. In response to these concerns, in May 2009, MDE adopted regulations to limit NO_x emissions from stationary generators. The regulations do not apply to testing and maintenance for any engine that operates as a redundant system for power that is located at a nuclear power plant, hospital, or NASA. Engines that are fueled by natural gas or propane are also exempted.

Interconnection standards are the technical rules a customer must follow to connect a generation facility to the electric grid. FERC has jurisdiction over large generation facilities that connect to the transmission system and these interconnections are coordinated by PJM. Smaller distributed generation (DG) facilities, however, generally connect to the distribution system and are therefore regulated by the State. In 2008, the Maryland PSC finalized and adopted small generation interconnection standards for utilities when connecting generators up to 10 MW in capacity to the distribution system.

Net metering refers to a billing arrangement between the retail customer with an eligible on-site DG facility and the utility where 1 kWh generated by a customer's on-site DG system is worth the same amount as 1 kWh of grid electricity consumed by the customer. When the customer's on-site generation is producing more electricity than the customer is using, that excess electricity is fed back into the grid. At the end of each month, a customer's bill will reflect the net electricity use, which equals electricity consumed minus electricity fed to the grid. Net metering is also regulated by states and most often restricted to facilities with a capacity of 2 MW or less.

Maryland's net metering rule was originally implemented in 1997 and extensively amended since then. The net-metering rules apply to all utilities — investor-owned utilities, electric cooperatives, and municipal utilities. To be eligible, the electricity must be generated by on-site systems at residences, businesses, schools, or government facilities using solar, wind, biomass, fuel cells, micro-cogeneration, anaerobic digestion, or closed conduit hydroelectricity. Important details of Maryland's net metering policy include:

- *Net metering is available statewide until the aggregate capacity of all net-metered systems reaches 1,500 MW.*
- *System size is generally limited to 2 MW, and systems must be primarily intended to offset all or a portion of a customer's on-site energy requirements.*
- *Net excess generation is carried forward from one billing period to the next until the customer's consumption eliminates the credit or until the customer is paid for the accrued generation credit at the end of a 12-month period. The dollar value of net excess generation is equal to the average generation or*

commodity rate that the customer-generator would have been charged over the 12-month period, multiplied by the number of kWh of net excess generation.

- *Customers own and have title to all RECs associated with electricity generation by net-metered systems.*

In June 2010, the PSC issued a report showing that a total of 13.6 MW of net-metered capacity was installed in Maryland, which is far below the current 1,500 MW cap. The majority of this net-metered capacity (almost 13 MW) is small-scale solar photovoltaic (PV), with the remaining 600 kW being small wind turbines.

5.1.5 Green Power Programs

In 2001, Executive Order 2001.01 set a goal to procure six percent of state electricity needs for state facilities as green electricity. In July 2006, the goal was revised and the State committed to obtaining 10 percent of its electricity supply from Tier 1 resources. From 2002 to 2007, the Maryland Department of General Services (DGS) obtained a portion of its energy supply from green power sources through their competitive auctions (see Table 5-3). For the 2009 auction, the DGS relied on the winning suppliers meeting their renewable RPS requirements. In December 2009, Governor Martin O'Malley announced that in partnership with the University System of Maryland, the state would be purchasing renewable energy from four projects being awarded contracts through the Generating Clean Horizons initiative. The University System of Maryland's Board of Regents and the DGS approved the awards for the renewable energy projects in 2009, which will provide almost 23 percent of the institution's and State agencies' annual electricity needs. The awards, in the form of 20-year power purchase agreements, are for the following:

- *All of the output from a 55-MW wind facility being planned near Keyser, West Virginia by US WindForce of Greensburg, Pennsylvania.*
- *Most of the output (13.5 MW) of a 14.5-MW solar project that Constellation Energy Group is planning to build on the Mount St. Mary's University campus near Emmitsburg, Maryland. The $60 million project will consist of thin-film PV cells on 100 acres leased from the university, which will be buying the remaining capacity.*
- *Up to 55 MW from an up to 600 MW offshore wind facility that Bluewater Wind, a unit of Princeton, New Jersey-based NRG Energy Inc., was planning to build off the coast of Delaware. However, Bluewater Wind announced in December 2011 that it was cancelling the project (see Section 5.4.1).*
- *10 MW of the 50-MW Roth Rock wind facility built atop Backbone Mountain in Garrett County, Western Maryland.*

Green Power Communities

Some communities in Maryland have joined with the EPA in a voluntary program to become Green Power Communities (GPCs). GPCs are villages, towns, cities, counties, or tribal governments where green power is purchased collectively by the local government, businesses, and residents in amounts that meet or exceed a GPC purchase requirement. These purchase requirements are set by EPA based on the community's annual electricity use. Currently, four communities in Maryland are GPCs: Brookeville, Edmonston, Hyattsville, and Rockville.

In September 2011, the EPA announced the winners of a national, year-long competition among the GPCs, known as the Green Power Community Challenge. There were two winners, one for the highest usage of green power and one for the highest green power percentage of total electricity use. The community of Brookeville, Maryland won the challenge for the highest percentage of green power use, with the local government, residents, and businesses working together to obtain 45 percent of the community's electricity from green power sources.

During the competition, EPA's GPCs used more than 3.3 billion kWh of green power, equal to preventing carbon dioxide emissions from the electricity use of more than 284,000 homes.

U.S Environmental Protection Agency's (EPA's) Green Power Partnership

The Green Power Partnership is a voluntary program that supports the organizational procurement of green power. The Top 20 College & University list represents the largest purchasers among higher education institutions. The combined green power purchases of these organizations amounts to nearly 1.3 billion kWh of green power annually. In Maryland, several educational facilities are listed as large green power purchasers. The University of Maryland is a significant purchaser of green power. As of January 2011, the University appears as No. 6 on the EPA's listing of Top 20 College and University largest green power purchasers. It has an annual green power usage of 66,000,000 kWh, which translates into about 26 percent of its total electricity use.

Table 5-3 State Green Power Purchases

Contract Start Date	Length (months)	Territory	Total MWh/year Purchased	MWh/year of Green Power	Percent of Total
July 2002	24	BGE	1,600,000	96,000	6
October 2003	29	Conectiv	106,000	6,400	6
July 2004	24	BGE	862,000	112,000	13
January 2007	24	All	1,479,000	3,900	0.3
June 2009	36	BGE, Pepco	950,000,000	[a]	[a]
June 2009	24	Allegheny[b], BGE, Delmarva, Pepco	500,000,000	[a]	[a]

[a] For the 2009 auction, DGS required only that the suppliers meet their Maryland RPS obligations.
[b] Allegheny Power became Potomac Edison following the merger of Allegheny Energy with FirstEnergy in February 2011.
Source: Communications with MEA and DGS, August 2009.

5.2 Greenhouse Gas Policies

The effect human activities have on climate change continues to receive global attention. The scientific community is increasingly pointing to evidence that the average global temperature is rising and that carbon dioxide (CO_2) and other greenhouse gases (GHGs) are present in the atmosphere at record high levels compared with both the recent and distant past. These concentrations in the atmosphere are potentially being caused or exacerbated by emissions of GHGs from human activities, such as industrial processes, fossil fuel combustion, changes in land use, and deforestation.

The term "climate change" is used more commonly than "global warming" or "greenhouse gas effect" to allow for a broader understanding of the potential implications of increased GHG levels in the atmosphere. Some of the potential impacts 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 droughts and floods, threats to biodiversity, and a number of potential challenges for public health.

Maryland has been working diligently to reduce the impact on the climate from sources in the State. In April 2007, Governor O'Malley established the Maryland Climate Change Commission and mandated that the State join the Regional Greenhouse Gas Initiative (RGGI), which is aimed at reducing CO_2 emissions from the electricity sector.

During the 2009 legislative session, the Maryland Legislature passed the Greenhouse Gas Emissions Reductions Act of 2009 (GGRA), committing the State to reduce GHG emissions by 25 percent below 2006 levels by 2020, a key recommendation of the 2008 Climate Action Plan developed by the Maryland Climate Change Commission (see Section 5.2.2). The GGRA also requires that Maryland prepare a plan to meet a longer-term goal of reducing 2006 GHG emissions by up to 90 percent by 2050, while also promoting new "green" jobs, protecting existing jobs, and positively influencing the State's economy. Maryland's commitment to other regional initiatives such as the Low-Carbon Fuel Standard will help the State obtain the goals of the GGRA. The latest regulatory development around GHGs is the State's implementation of GHG reporting and control technology regulations driven by the Clean Air Act affecting power plants and other large stationary sources.

5.2.1 Regional Greenhouse Gas Initiative

In 2005, the Governors of Delaware, Connecticut, Maine, New Hampshire, New Jersey, New York, and Vermont signed the RGGI Memorandum of Understanding (MOU) creating the first cap-and-trade program for CO_2 in the United States. In January 2007 Massachusetts and Rhode Island joined the MOU. Maryland, as required by the Healthy Air Act of 2006 (HAA), signed the MOU joining RGGI on April 20, 2007. Under RGGI, CO_2 emissions from fossil-fuel fired electricity generating units with nameplate capacities of 25 MW or greater are capped from 2009 through 2014 at a level roughly equal to projected 2006-2007 emissions levels. RGGI then mandates a 10 percent reduction (2.5 percent per year) by 2018. This phased approach to CO_2 emissions reductions is designed to provide regulatory certainty for electricity generators to begin planning for, and investing in, lower-carbon alternatives without creating dramatic electricity price impacts. There are 17 power plants in Maryland that are subject to the RGGI cap.

The RGGI MOU outlines the CO_2 allowance allocations for each member state. These budget allocations, shown in Table 5-4, were negotiated in 2005, based on actual annual 2000 to 2002 emission rates and including expected capacity additions and demand growth to create an estimate of 2006-2007 emissions. Maryland's annual RGGI budget starts at 37.5 million tons of CO_2 per year for the first five years then reduces 2.5 percent per year to about 33.8 million tons in 2018. Maryland holds just under 20 percent of the total regional budget of nearly 188.1 million tons.

Contrary to what was expected when the CO_2 state apportionments were negotiated, emissions in the power sector have fallen in the last few years due to the economic downturn combined with increases in conservation and demand response (see Table 5-4). As a result, state-wide emissions from power plants subject to RGGI are, with the exception of Rhode Island, below the negotiated apportionment amounts. Maryland CO_2 emissions in 2009 were nearly 32 percent below the State's established RGGI budget. Although 2010 CO_2 emissions were slightly higher than those in 2009 for all RGGI states, they were still well below the respective state allocated budgets.

Table 5-4 CO_2 Emissions by RGGI Sources

State	Historic Emissions (million tons of CO_2)									Annual Allocated Budget 2009-2014 (million tons of CO_2)	RGGI Emissions (million tons of CO_2)	
	2000	2001	2002	2003	2004	2005	2006	2007	2008		2009	2010
Connecticut	11.97	10.99	9.84	9.26	9.98	11.32	10.76	10.05	8.99	10.70	7.32	8.53
Delaware	7.31	7.61	7.62	7.63	7.88	8.30	7.56	8.74	7.62	7.60	3.71	4.30
Massachusetts	25.45	25.40	25.28	27.22	26.37	26.64	23.45	25.37	21.44	26.67	18.66	19.80
Maryland	38.45	36.98	37.08	37.06	36.28	37.26	35.23	35.70	32.38	37.50	25.57	27.96
Maine	3.16	5.52	5.78	5.52	5.19	4.59	3.37	3.53	3.69	5.95	3.64	3.94
New Hampshire	5.18	4.86	5.56	8.48	8.81	8.97	7.57	7.31	7.10	8.62	5.77	5.90
New Jersey	21.95	20.18	21.15	2.54	21.13	22.07	20.79	21.85	20.60	22.89	16.36	19.68
New York	69.81	65.55	61.37	62.13	62.61	62.72	53.64	55.72	48.35	64.31	37.70	41.95
Rhode Island	2.96	1.78	3.25	2.67	2.22	2.69	2.63	3.16	3.29	2.66	3.42	3.50
Vermont	0.024	0.022	0.052	0.012	0.015	0.0078	0.0063	0.0061	0.0026	1.23	0.0020	0.0038
10 State Total	186.26	178.90	176.93	180.52	180.50	184.57	165.00	171.44	153.46	188.08	122.15	135.56

Source: RGGI, Inc. website. http://www.rggi.org/

A RGGI "model rule" issued in August 2006 details the operating rules for the RGGI cap-and-trade program. The model rule stipulates that a minimum of 25 percent of each state's emissions allowances are to be used for consumer benefit and/or strategic energy purposes. The member states have decided to auction nearly all of their allowances in quarterly regional auctions, described below.

Allocation of the Strategic Energy Investment Fund

As of the June 2011 auction, Maryland has raised over $167 million in RGGI proceeds. This revenue is directed to the Maryland Strategic Energy Investment Fund (SEIF), which is administered by the MEA, and is used to benefit Maryland residents by supporting efficiency, conservation, and other demand response programs; residential energy bill assistance; renewable energy deployment; and climate change outreach and education. The SEIF is allocated in accordance with The Strategic Energy Investment Act of 2008 as follows:

- Up to 50 percent - Low income energy assistance;
- 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 $4 million - Administration of the Fund

RGGI Allowance Auctions

Under RGGI, power plants must essentially pay for the right to emit CO_2. For each ton of CO_2 emitted, power plants must purchase one RGGI allowance. At the end of each three-year compliance period, the first of which is from 2009 - 2011, power companies must submit allowances to RGGI that cover each ton of CO_2 emitted from applicable generating units over the prior three years.

RGGI allowances are sold at single-round, uniform price, sealed-bid format, quarterly auctions in lots of 1,000. Allowances are identified with a vintage for the year they are issued, with up to 50 percent of future vintage allowances able to be offered for sale in advance of their annual allocation. Any type of entity may apply to participate, but each participant is limited to purchasing no more than 25 percent of the total available allowances in any one auction. Thus far, a majority of the allowances have been purchased by electric generators or their affiliates, ranging from 65 percent (December 2009) to 97 percent (December 2010) of the total allowances sold. A reserve, or minimum, price of $1.89 per allowance has been established for the auctions beginning in 2011 (up from $1.86 in 2009). The minimum price is indexed to the Consumer Price Index.

Since the first quarterly auction in September 2008, allowance clearing prices have ranged from the reserve price of $1.86 to $3.51, as shown in Table 5-5. According to Potomac Economics, the RGGI independent market monitor, the CO_2 allowance auctions thus far have raised no material concerns regarding the auction process or its results and there has been no evidence of collusion or manipulation by bidders and the vast majority of bids were submitted in line with competitive expectations.

In late May 2011, New Jersey Governor Chris Christie announced that his state would withdraw from RGGI at the end of 2011. In early June 2011, the New Hampshire House and Senate passed S.B. 154, a shoreland protection bill that included an amendment to also remove the state from RGGI. This bill, however, was vetoed by Governor John Lynch. Despite these events, many climate finance experts expect the RGGI program to continue as planned and that regional cap-and-trade systems will continue to spread in the U.S. and Canada.

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 will be 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, but that amount can be increased to 5 percent if the 12-month rolling average allowance price is $7.00 or more and to 10 percent if the 12-month rolling average allowance price is greater than $10.00 for two consecutive 12-month periods. Currently, no offset projects have been awarded offset allowances under RGGI; however, an application was filed in September 2010 by Innoventive Power, LLC for an energy efficiency offset project at the NY Methodist Hospital in Brooklyn, New York.

Table 5-5 RGGI Allowance Auctions

Auction Date	Allocation Year	Total RGGI Allowances Sold	Clearing Price	Maryland Allowances Sold	Maryland Revenues (million USD)
Sep 25, 2008	2009	12,565,387	$3.07	5,331,781	$16.4
Dec 17, 2008	2009	31,505,898	$3.38	5,331,781	$18.0
Mar 18, 2009	2009	31,513,765	$3.51	5,331,783	$19.9
	2012	2,175,513	$3.05	399,884	
Jun 17, 2009	2009	30,877,620	$3.23	5,331,782	$18.0
	2012	2,172,540	$2.06	399,884	
Sep 9, 2009	2009	28,408,945	$2.19	5,331,782	$12.4
	2012	2,172,540	$1.87	399,884	
Dec 2, 2009	2009	28,591,698	$2.05	5,331,782	$11.5
	2012	2,172,540	$1.86	294,317	
Mar 10, 2010	2010	40,612,408	$2.07	7,878,873	$17.0
	2013	2,137,992	$1.86	368,169	
Jun 9, 2010	2010	40,685,585	$1.88	7,528,873	$14.9
	2013	2,137,993	$1.86	3767,444	
Sep 10, 2010	2010	45,595,968	$1.86	5,681,334	$11.0
	2013	2,137,992	$1.86	231,008	
Dec 1, 2010	2010	43,173,648	$1.86	4,316,922	$8.4
	2013	2,137,991	$1.86	206,358	
Mar 9, 2011	2011	41,995,813	$1.89	7,528,873	$14.9
	2014	2,144,710	$1.89	376,444	
Jun 6, 2011	2011	12,537,000	$1.89	2,245,541	$4.6
	2014	943,000	$1.89	190,346	
Sep 7, 2011	2011	7,487,000	$1.89	1,336,077	$2.5
	2014	0	--	0	
Total to Date					**$169.6**

Source: RGGI, Inc., website. http://www.rggi.org/co2-auctions/results

Offset projects that currently qualify under the RGGI model rule are:

1. *Landfill Methane Capture and Destruction – projects that capture and destroy methane from landfills that are not subject to the New Source Performance Standards (NSPS) for municipal solid waste landfills.*
2. *Reduction in Emissions of Sulfur Hexafluoride (SF_6) – projects that prevent the release of SF_6 to the atmosphere, through capture and storage, recycling, or destruction.*
3. *Sequestration of Carbon Due to Afforestation – projects that sequester carbon through the conversion of land that has been in a non-forested state for at least 10 years to a forested condition.*
4. *Reduction or Avoidance of CO_2 Emissions from Natural Gas, Oil, or Propane End-use Combustion Due to End-use Energy Efficiency – projects that reduce CO_2 emissions by reducing on-site combustion of natural gas, oil, or propane in either an existing or new commercial or residential building by improving the energy efficiency of fuel usage and/or the energy-efficient delivery of energy services.*

5. *Avoided Methane Emissions from Agricultural Manure Management Operations – projects that destroy methane generated by anaerobic digesters and the uncontrolled anaerobic storage of manure or organic food.*

Maryland Offset Projects

In Maryland, two additional potential offset projects are being explored, specifically the restoration of salt marshes and terrestrial sequestration through urban forestry. 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 through organic and mineral accretion in conditions of rising sea levels. Marsh decline, however, is becoming more prevalent throughout the region, which leads to a decrease in carbon storage. Through the placement of artificial sediment, it is possible to restore these marshes, allowing them to rebound and promote carbon sequestration. In order for the salt marsh restoration to be successful, the new marsh surface must accrete with sea level rise.

PPRP is assisting with a current effort by Restore America's Estuaries to develop a formal offset protocol for salt marsh systems. A key task during this development is to further investigate the methane emissions associated with these systems to determine the net GHG emission reductions that can be achieved. As part of a plan developed under the GGRA, DNR has identified three components to promote wetland carbon sequestration: the Blackwater National Wildlife Refuge, a PPRP study project in Dorchester County, and a Sea Level Affection Marshes Model. Maryland has great potential for reducing GHG emissions through sequestering carbon in restored wetlands and marshlands around the Chesapeake Bay. The estimated GHG reductions from these three projects ranges from 0.5 – 0.65 million metric tons (MT) CO_2 equivalent (CO_2e).

Blackwater Tidal Marsh Sequestration Project – PPRP, the U.S. Department of Energy (DOE), and several other partners are collaborating with the University of Maryland on the Blackwater Project to learn more about carbon sequestration in tidal marshes. There are potentially as much as 20,000 acres available for this project, which would not only sequester thousands of tons of CO_2 annually, but would also provide increased habitat for birds, terrestrial animals, and aquatic life that live in the area or use it for stopovers during their annual migrations. Wetlands can store up to 2.5 tons of carbon per acre. The research team examined natural and man-made, or restored, marsh cells to better understand how marsh restoration may be used to offset CO_2 emissions. The goal of this project is to develop a terrestrial carbon sequestration protocol that is generally applicable to estuarine wetlands and tidal marshes and which will lead to projects that produce carbon offsets.

Dorchester County Wetlands Study – PPRP conducted a study of wetlands in Dorchester County to demonstrate the potential opportunities for carbon sequestration resulting from the protection and restoration of wetlands. Dorchester County in Maryland was chosen as the study location because it contains extensive coastal marshes.

Areas for potential restoration were identified within the study area using DNR's Green Infrastructure data. Satellite-derived net primary productivity of the wetlands is used to estimate gross sequestration, and net accumulation was estimated based on the current understanding of carbon dynamics in coastal wetlands.

Sea Level Affection Marshes Model – DNR utilized this model to identify areas known as wetland transition zones, or areas projected to convert into wetlands. These identified areas will become targeted areas for wetland restoration and land conservation, which is expected to help maintain coastal wetlands into the future. Future carbon sequestration can be quantified within these targeting zones, and will be achieved through wetland restoration and establishment as inlands become wetter.

The second type of offset project Maryland is pursuing is urban forestry. Urban forestry projects involve the implementation of programs within urban communities to plant and grow trees. This program provides two means for reducing CO_2 emissions. First, carbon is sequestered in the growing of trees due to an increase in biomass. Second, there is an associated avoidance of emissions through energy conservation, as the trees can provide shade with a natural cooling effect for residences and other buildings in the community. There is an interest among various State agencies and community groups to pursue urban forestry projects as an alternative to other, more traditional afforestation projects.

5.2.2 Maryland Commission on Climate Change

The Maryland Commission on Climate Change (MCCC) was established under an Executive Order in April 2007, with a primary mission to develop a Maryland Climate Action Plan (CAP). The MCCC consists of the leaders of 16 State agencies and six members of the General Assembly. It is organized into working groups, including the Scientific and Technical Working Group (STWG), chaired by the University of Maryland Center for Environmental Science and MDE; the Greenhouse Gas & Carbon Mitigation Working Group (MWG), chaired by MDE and MEA; and the Adaptation and Response Working Group (ARWG), chaired by DNR and the Maryland Department of Planning.

In August 2008, the MCCC released the final version of the Maryland CAP, [32] which was the first plan in the country to connect cutting edge climate science with both climate mitigation and climate adaptation planning. The CAP contains the comprehensive assessments and strategies developed by each of the working groups, which included 61 policy options, programs, and measures to reduce GHG emissions within the state and to help the State respond and adapt to the impacts of climate change, such as sea level rise. These policy options cover a wide range of sectors, such as energy supply, transportation, agriculture, forestry and waste, where GHG emissions can be reduced and/or carbon can be sequestered. Table 5-6 lists the recommended policy options that focus on reducing GHG emissions attributed to the energy supply sector and their implementation status, according to the MCCC's November 2010 CAP update report.

[32] The final CAP is available on MDE's website: http://www.mde.maryland.gov/programs/Air/ClimateChange/Pages/Air/climatechange/legislation/index.aspx

One of MCCC's key policy recommendations from the MWG was to set a GHG reduction goal from 2006 baseline of 25 percent by 2020. This exact goal was then codified into law when the Maryland General Assembly passed the 2009 GGRA, which is described in Section 5.2.3. Also during the 2009 legislative session, the implementation of four key mitigation policies (RGGI, EmPOWER Maryland, Maryland's RPS and the Maryland Clean Cars Program) from the CAP were identified as having the potential to achieve 60 to 70 percent of the 2020 GHG emission reduction goal. The implementation of remaining mitigation policies proposed in the CAP are predicted to achieve the final 30 to 40 percent of the GHG reductions needed to reach the 2020 goal.

Table 5-6 Energy Supply Sector Policy Options for Greenhouse Gas Reduction

Policy Number	Policy Name	Projected 2008 - 2020 GHG Reductions ($MMtCO_2e$)	Projected Cost Effectiveness ($\$/tCO_2e$)	Lead Agency	2010 Implementation Progress
ES-1	Promotion of Renewable Energy Resources	3.3	$30.30	MEA	• Actions taken to promote RPS (See ES-7)
ES-2	Technology-focused Initiatives for Electricity Supply (biomass co-firing, energy storage, fuel cells, clean energy incentives)	U	U	MEA	• MEA, the Department of General Services, and the University System launched the Generating Clean Horizons Initiative, resulting in Power Purchase Agreements with three utility-scale renewable developments (65 MW of onshore wind and 17 MW of thin film solar). • MEA supported successful 2010 legislation to make fuel cells eligible for net metering.
ES-3	Cap and Trade (supporting state and federal programs)	17.0	U	MDE	• Maryland participated in all RGGI auctions and commenced a MD CO_2 Budget Trading Program
ES-4	Carbon Capture, Storage, and Reuse	Study presented in CAP for informational purposes only; no action has been taken.			
ES-5	Clean Distributed Generation and Combined Heat & Power	13.0	$14.40 - 37.50	MEA	• Actions taken to promote RPS (See ES-7)
ES-6	Integrated Resource Planning (with or without re-regulation)	U	U	PSC	• The PSC evaluates Maryland's long-term generating needs and electric companies' plans for meeting those needs annually and publishes a *Ten Year Plan*. • The EmPOWER Maryland Act calls for a 15 percent reduction in state per capita energy consumption and peak demand by 2015. Utilities are responsible for 10 percent (see Section 5.1.2).

(continued on next page)

Table 5-6 Energy Supply Sector Policy Options for Greenhouse Gas Reduction (continued)

Policy Number	Policy Name	Projected 2008 - 2020 GHG Reductions ($MMtCO_2e$)	Projected Cost Effectiveness ($\$/tCO_2e$)	Lead Agency	2010 Implementation Progress
ES-7	Renewable Portfolio Standard (RPS)	100.7	$25.70	MEA	• Maryland's RPS goal is for the state to obtain 20 percent of its electricity from renewable resources by 2022 (see Section 5.1.1).
					• MEA advocated for successful legislation to accelerate the near-term solar RPS requirement and to reauthorize the Maryland renewable energy production tax credit, offering up to $2.5 million to eligible taxpayers.
					• MEA awarded hundreds of grants (from $1,000-10,000) to homeowners and businesses for wind, geothermal and solar PV systems.
					• MEA developed and implemented Project Sunburst, a rebate program offering up to $1,000 per KW of solar PV capacity installed on public buildings, incentivizing 10 MW of new solar projects in the state.
ES-8	Efficiency Improvements and Repowering Existing Plants	17.9	$21.80	MEA	• Advocated for federal climate legislation that would establish a price on carbon, incentivizing existing plants to operate more efficiently.
ES-9	Carbon Tax	Study presented in CAP for informational purposes only; no action has been taken.			
ES-10	Generation Portfolio Standard (1,125 lbs CO_2e/MWh)	62.6	$42.40	MDE	• As per the PSC's recommendation, MDE has deferred State action pending the adoption of a national GPS.

Notes: $MMtCO_2e$ = million metric tons of CO_2 equivalents; U = unquantified; ES = energy supply

Source: Maryland Climate Action Plan, 2008; and November 2010 Update Report.

5.2.3 Maryland Climate Change Legislation

Over the last several years, Maryland has enacted several pieces of legislation that will help the State, both directly or indirectly, meet its climate change goals. These bills target emissions from power plants and vehicles, spur development of renewable energy, and set energy efficiency and conservation goals (see Table 5-7).

During the 2009 session, the legislature passed the GGRA via House Bill 315/Senate Bill 278. The main points of this legislation include the following:

- *Requires the State to reduce GHG emissions by 25 percent below 2006 levels by 2020.*

- *Directs MDE to develop and adopt a GHG reduction plan by 2012 that will not adversely impact the economy.*
- *Requires that MDE update its GHG emission inventory every three years.*
- *Contains a provision where the manufacturing sector is only subject to federal and RGGI regulations. (Emissions from this sector are small, constituting only 4 percent of Maryland's total GHG emissions.)*

Table 5-7 Maryland Legislation to Reduce GHG Emissions

Legislation	**Description**
Renewable Energy Portfolio Standard (HB 1308), 2004; Revised 2007, 2008, 2010, & 2011	Established a renewable portfolio standard for electricity supply. Amendments accelerated the RPS to 20 percent by 2022.
Healthy Air Act of 2006 (HB 189)	Established a ceiling on NO_x, SO_2, and mercury emissions from power plants and directed the State to join RGGI.
The Clean Cars Act of 2007 (HB 44)	Adopted California's stringent vehicle emissions standard beginning in model year 2011.
EmPOWER Maryland Energy Efficiency Act of 2008 (HB 374)	Set a target of reducing the State's per capita electricity consumption and peak demand by 15 percent by 2015.
Regional Greenhouse Gas Initiative – Maryland Strategic Energy Investment Program (HB 368)	Created a fund using RGGI proceeds to invest in energy efficiency and renewable energy.
Several Bills for Renewable Energy Grant and Incentive Programs (HB 714-2004, SB 361-2005, SB 314-2006, HB 377-2008, SB 565-2008)	Provided tax incentives and/or grants for renewable energy resources, including solar, geothermal, biofuels, and wind.
Maryland Clean Energy Center, 2008 (HB 1337)	Established the Maryland Clean Energy Center as in information clearing house and to lead collaborative efforts to promote clean energy development.
Greenhouse Gas Emissions Reduction Act of 2009 (HB 315/SB 278)	Codified the GHG goals from the MCCC Climate Action Plan and authorized MDE to pursue the recommended measures.
Smart, Green, and Growing – Maryland Sustainable Growth Commission, 2010 (HB 474/SB278)	Established the Maryland Sustainable Growth Commission to advise on growth and development issues in the State

5.2.4 Federal Clean Air Act Greenhouse Gas Initiatives

Based on policy initiatives and key court decisions, EPA began the process of regulating GHGs under the Clean Air Act. There are several key regulatory initiatives in process that will affect power plants.

Greenhouse Gas Reporting Rules

In October 2009, EPA published the first comprehensive national system for reporting emissions of CO_2 and other GHGs produced by major sources of GHGs in the United States. This reporting rule (40 CFR Part 98) was developed, as required, by the Consolidated Appropriations Act of 2008.

The rule requires affected facilities to develop a GHG Monitoring Plan, track certain operating and production information, and report GHG emissions data annually. The rule applies to three categories of sources: listed source categories regardless of GHG emission rates, listed source categories that emit more than 25,000 MT CO_2e per year, and stationary combustion sources (with an aggregated maximum rated heat input capacity of greater than or equal to 30 MMBtu/hr) that emit more than 25,000 MT CO_2e per year.

The reporting rule currently covers 42 source categories and roughly 13,000 facilities (including direct emitters and suppliers of fuel and industrial GHG). These 42 source categories generate approximately 85 – 90 percent of the nation's GHG emissions. The rule provides a phased reporting deadline based on source category type, with some facilities commencing reporting of 2010 data in 2011, including Maryland's power plants. Other facilities, such as those containing emissions sources associated with CO_2 injection and geologic sequestration, begin reporting in 2012 on data collected in 2011.

Under the rule, reporting is to occur by March 31st each year for prior year emissions. However, for the 2011 reporting year, first-time reporting facilities have been granted an extension to September 28th. Reporting is completed using the electronic GHG reporting tool (e-GGRT) developed by EPA.

GHG Tailoring Rule

As described in Chapter 4, EPA issued the GHG Tailoring Rule on May 13, 2010. This rule is one of the first at the national level to regulate GHG emissions from major stationary sources under the Clean Air Act and will affect power plants in Maryland and across the U.S. significantly. The Rule addresses Prevention of Significant Deterioration (PSD) and Title V operating permit requirements for GHGs. It regulates the pollutant "GHG" as the sum of six compounds: CO_2, methane (CH_4), nitrous oxide (N_2O), hydrofluorcarbons (HFCs), perfluorocarbons (PFCs) and sulfur hexafluoride (SF_6). Sources that trigger PSD for GHGs will be required to conduct a Best Available Control Technology (BACT) analysis for GHGs. EPA issued BACT guidance related to GHG emissions under the PSD program in November 2010.[33] The BACT guidance identified energy efficiency and carbon capture and storage (CCS) as potential BACT candidates. EPA acknowledged that CCS would often be eliminated due to its current high economic impact.

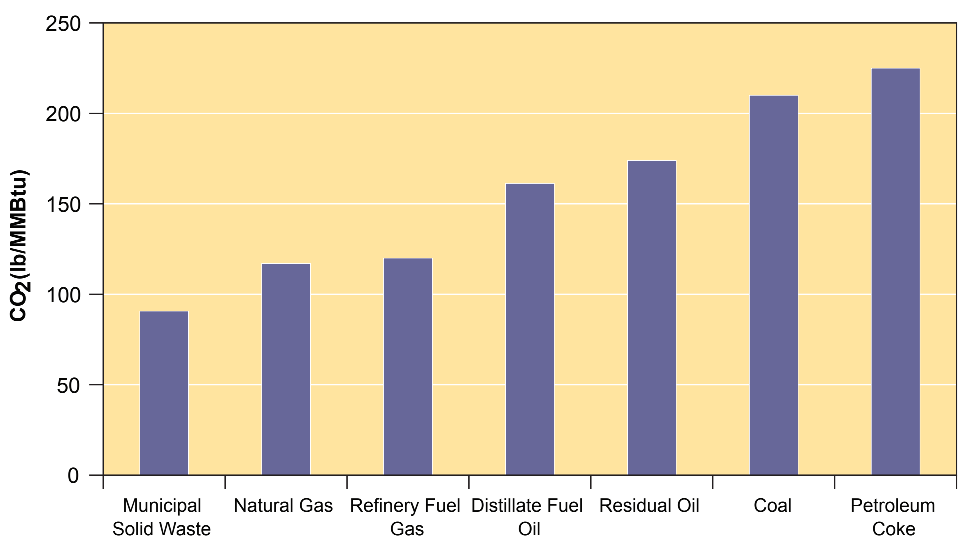
5.3 Coal-fired Generation and CO_2

Coal is abundant in the U.S. and coal-fired electric generating units are effective in meeting baseload, intermediate load, and peak demands given their high reliability. On the other hand, energy conversion from traditional coal-fired power plants generates the highest levels of CO_2

[33] PSD and Title V Permitting Guidance for Greenhouse Gases, Prepared by the Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, November 2010.

emissions on a per-unit-of energy basis of all the fossil fuels available, aside from petroleum coke. CO_2 is produced as a combustion product of any carbon-containing fuel. All fossil fuels contain significant 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 generally amount to approximately 1 ton per MWh of electricity generated, compared to 0.4 to 0.6 ton per MWh[34] from natural gas-fired generation (e.g., combined cycle/simple cycle gas turbines). Figure 5-4 shows the approximate level of CO_2 formed when combusting various fossil fuels. As shown in the figure, the combustion of natural gas yields approximately 40 to 50 percent less CO_2 than the combustion of coal and petroleum coke, and approximately 25 to 30 percent less CO_2 than the combustion of distillate and residual oil.

Figure 5-4 CO_2 Emissions from the Combustion of Fossil Fuels



Source: U.S. Energy Information Administration (http://www.eia.doe.gov/oiaf/1605/coefficients.html).

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 recent regulatory drivers facing the electric utility industry. CO_2 mitigation for coal-derived power is a highly debated topic; however, there are several options that can be effective:

- *Improving generation efficiency (providing a reduction in overall CO_2 emissions per megawatt of electricity generated), either through the development of new plants or upgrading existing facilities;*
- *Substituting a fraction of the coal with a carbon-neutral fuel such as biomass (biomass co-firing). Some modern coal-fired boiler designs are currently*

[34] Sherwell, J., Flynn, P., and Ross J., "IGCC: Opportunities for Alternative Energy Technologies in Maryland", Maryland Power Plant Research Program Publication No. DNR-12-5182010-454, June 2010.

capable of accommodating up to 20 to 30 percent biomass co-firing, with a corresponding reduction in CO_2 emissions; and

- *CO_2 capture and geological storage; federal programs are beginning to provide support to validate this option.*

Currently, three general methods are available to capture CO_2:

- *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/ CO_2 mixture, thus producing a CO_2-rich flue gas that is easier for CO_2 capture. Oxyfuel firing methods have been demonstrated in several projects abroad. Several feasibility studies are currently underway for options using advanced supercritical plants.*

Located in Cumberland, Maryland, the AES Warrior Run power plant has been capturing a small portion of its CO_2 emissions for use in the food and beverage industry since 2000. This 180-MW circulating fluidized bed generating unit uses a post-combustion monoethylamine flue gas scrubber system to removed approximately 110,000 MT CO_2 from a 2 to 3 percent slip-stream 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 large, steel storage tanks until it can be shipped off-site for beneficial use.

Numerous carbon capture demonstration projects are currently under development in the U.S. Most of these projects are funded by DOE's National Energy Technology Laboratory programs and are designed to achieve a target CO_2 capture efficiency of 90 percent, a resulting 35 percent or less increase in the cost of electricity, and to capture and sequester or beneficially use at least 300,000 tons of CO_2 per year. These projects incorporate the full range of existing carbon capture technologies, as well as test the viability of emerging innovative methods, such as cryogenic and phase-changing sorbent capture. The projects are in various stages of development; however, most are several years away from commercial-scale testing. The key barriers to carbon capture technology implementation for new and existing power plants are the lack of federal climate change regulations and large capital and operating costs, which are currently projected to increase the cost of electricity by as much as 80 percent. The beneficial use of captured CO_2 prior to storage to create value-added products or services may alleviate some of the economic burden.

5.3.1 Potential for CO_2 Storage and Beneficial Use for Maryland Sources

The capture and subsequent beneficial use and/or storage of carbon emissions continue to gain interest as methods of reducing and mitigating GHG emissions in the U.S. Furthermore, there is potential for geologic formations in and near the state to serve as possible carbon storage sites. The next two sections describe the potential CO_2 storage sites and beneficial use options for Maryland sources.

Storage of CO_2 from Maryland Sources

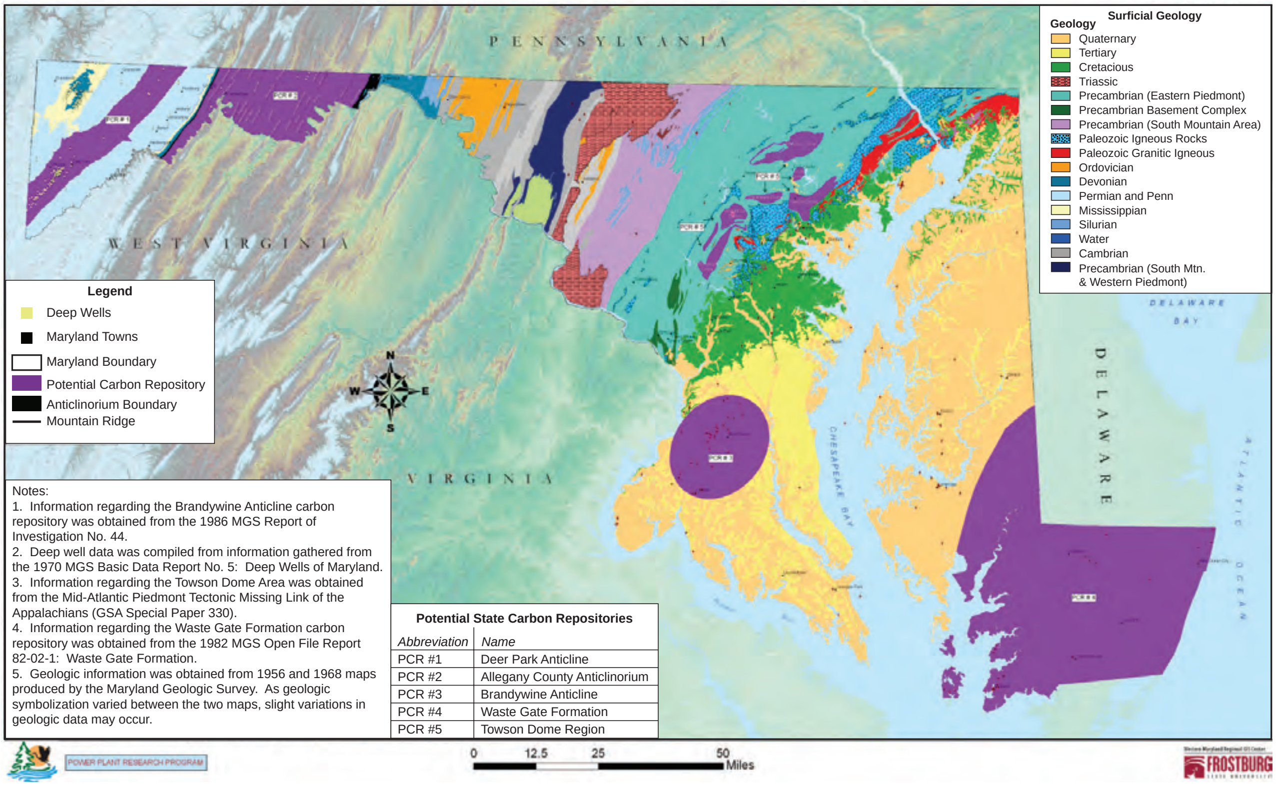
Carbon capture and storage technologies can be employed to reduce emissions by sequestering CO_2, either terrestrially or geologically. Terrestrial sequestration options include eroded and non-eroded cropland, marginal land, mineland, and wetlands and marshlands (see page 184). Restoring these areas allows carbon to be sequestered in the soil and in plant matter that develops. Geological sequestration, on the other hand, involves pumping CO_2 into underground storage reservoirs. The primary types of geological reservoirs are depleted oil and gas fields, unmineable coal seams, and deep saline formations. A co-benefit to geological sequestration in oil and gas fields, is that the pressurized CO_2 displaces residual oil and gas allowing more of the resource to be extracted. 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 benefits — potential storage capacity in the U.S. is very large and many are close to existing large CO_2 point sources.

The Midwest Regional Carbon Sequestration Partnership (MRCSP) was established by the U.S. DOE to assess the technical potential, economic viability, and public acceptability of carbon sequestration within an eight state region — Indiana, Kentucky, Maryland, Michigan, New York, Ohio, Pennsylvania, and West Virginia. The MRCSP region has great potential for sequestration in geological and terrestrial sinks. In Maryland, depleted or nearly depleted natural gas reservoirs and unminable coal seams in Garrett and Allegany counties are suitable for geological carbon storage. Potential exists within the State of Maryland for future sequestration as well as utilization of CO_2. The geology of the western portion of Maryland is especially attractive for the possible storage and use of CO_2 in enhanced coalbed methane recovery. Additionally, potential exists for CO_2 storage in other formations in the central to eastern portion of the state. Specifically, it has been suggested that the Taylorsville Basin, a Triassic Rift Basin underlying the Coastal Plain sediments that extends from southern Maryland into Virginia, may be an appropriate formation for CO_2 storage due to its geologic characteristics. Another candidate formation for carbon sequestration exists in the Coastal Plain of Maryland, the Waste Gate Formation. This stratigraphic unit was identified in the 2005 MRCSP Phase I Report. Figure 5-5 shows the locations of potential geologic sequestration sites in Maryland.

Beneficial Use of CO_2

An increasing global concern over CO_2 emissions coupled with complicated economics has resulted in the development of techniques to use CO_2 rather than simply sequestering it. Recent studies encourage the acceptance of CO_2 as a commodity, in response to its usefulness in enhanced recovery of oil and gases. As attitudes toward carbon capture,

Figure 5-5 Potential Geologic Repositories for CO_2 in Maryland



Source: Frostburg State University.

storage, and use improve, issues such as economics, technology, and global policy become increasingly important. Although the potential for CCS projects has been demonstrated, the execution of CCS is often cost-prohibitive due to the expense of capture and transport, which typically accounts for 70 to 90 percent of the total implementation costs. Many studies suggest regional reuse of CO_2 as the best technique.

In the United States, most CCS projects are located in the southern and western states, where mature oil fields are prevalent. A leading company, Denbury, has found success in developing CO_2 reserves for enhanced oil recovery (EOR). In 2010, they made several improvements to CCS projects, including completion of the 325-mile "Green Pipeline," which extended their CO_2 reserves to the southeast Texas oil fields. This addition is part of an 800-mile network of pipelines in the Gulf Coast region, where Denbury has been producing natural sources of CO_2 for EOR uses over the past 11 years. Although the company now owns all producing CO_2 wells in the Gulf Coast region, they have begun to acquire anthropogenic sources. To support the production of mature oil fields in the Rocky Mountain region, both natural and man-made CO_2 reserves were purchased for transport via the "Greencore Pipeline," scheduled for construction beginning in 2011. Denbury has been successful in the use of CO_2, demonstrating the changing attitude toward CO_2 as a commodity.

U.S. Increases Focus on CO_2 Use for Enhanced Recovery

The United States leads the world in both the number of CO_2 EOR projects and in the volume of resulting oil produced, largely due to favorable geology. The Permian Basin, located in West Texas and southeastern New Mexico, contains the vast majority of global CO_2 EOR activity. However, a growing number of CO_2 enhanced oil, gas, and coal bed methane projects are being launched across North America, effectively establishing a CO_2 commodity market. Seeing the benefits of this use, DOE recently shifted the focus of its clean coal research program from just CO_2 storage to utilization in enhanced recovery. This beneficial use not only facilitates the production of otherwise stranded domestic oil and natural gas resources, potentially offsetting the large costs of CO_2 capture and compression necessary for CCS applications, but also sequesters significant volumes of CO_2 in ultimately played out oil and gas reservoirs.

A North American project, which has proven to be a successful end-to-end CCS operation, is the Weyburn-Midale CO_2 Project. This project was initiated in 2000 and involves capturing CO_2 from the lignite-fired Dakota Gasification Company synfuels production plant located in North Dakota. The CO_2 is transported 205 miles via pipeline and then injected into the Weyburn oilfield in Canada. The CO_2 is utilized to increase oil and gas extraction from Weyburn, which previously had declining production rates. It is anticipated that the Weyburn Project will extend the life of the Weyburn field by approximately 20-25 years, with an estimated total increase in oil recovery of 34 percent. Monitoring is being conducted as part of this project to evaluate the extent of CO_2 storage and to ultimately assess the technical and economic feasibility of geological storage of CO_2 in oil reservoirs, develop implementation guidelines for such projects, and identify the associated risks, especially the long-term risks of leakage.

Shell has initiated the Quest CCS project in cooperation with the federal and provincial governments of Alberta, Canada, who will provide $865 million in funding over the next 15 years. The Quest project is expected to capture over one million tons of CO_2 per year from Shell's oil processing plant in Edmonton. The CO_2 will be geologically sequestered in an attempt to reduce the footprint of Shell's Athabasca oil sands project, and the first injection is scheduled for 2015.

The United Arab Emirates (UAE) continues to be a leading nation in CCS research. The state-controlled companies Adma-Opco and Adco are currently studying the behavior of CO_2 injected into offshore oil fields and its effect on EOR. Since 2009, Adco has captured 60 tons of CO_2 daily from industry for injections into the Rumaitha pilot well in the Bab field. These two subsidiary companies of the state have reported positive results from the pilot injections. Another company, Masdar, is planning a multibillion dollar CCS network in the UAE to capture CO_2 from a steel plant in Musaffah and transport it through a 500-km pipeline for EOR in the Abu Dhabi oil fields. Dubai Petroleum has begun work on what Oil & Gas Journal has called "the world's largest CO_2 capture and EOR project". The first phase of injection planned for 2012 will use CO_2 captured from a power plant, at a volume of about 10 times the annual carbon production of the AES Warrior Run plant in western Maryland. The project exemplifies great potential for the use of CO_2 in lieu of simple sequestration.

Although many nations have adopted the concept of CO_2 as a commodity, there are unresolved issues regarding CCS projects. As a leading country in carbon capture and use, the UAE has been working with the United Nations to encourage them to include CCS as an accepted technology in their Clean Development Mechanism. In addition to the issue of worldwide acceptance of CCS, the issues of technology, infrastructure, and economics require continued research. Global policy issues involve the debate over CCS as a worthwhile investment, and whether CO_2 used for economic gain, like EOR, would be considered eligible for carbon credits. Technological issues suggest the need for further study to assure that carbon is permanently sequestered and that the potential for future leaks is minimized. A worldwide effort to examine the issues and improve techniques and policy would facilitate the success of global CCS development.

5.3.2 Unconventional Gas Resources and Their Impacts

Unconventional gas resources, while very plentiful in the United States, have not played a significant role until recently in meeting U.S. gas demand. It has not been until the last two decades that unconventional resources have been leveraged to a significant extent. This is, in part, due to the costs of recovering these reserves relative to conventional gas recovery, as well as more recent technological advances that have been made in gas production.

The natural gas industry characterizes "unconventional gas" as gas that has formed in rock formations which are not permeable, and more specifically, do not allow for the natural migration of gas to collect in large quantities between permeable and impermeable rock layers.[35] Gas that collects between permeable and impermeable rock formations by natural migration is what makes up our "conventional" gas reserves.

Historically, natural gas production in the U.S. was predominantly from conventional sources, but over the last few decades, unconventional gas has become increasingly more important as a result of significant technological improvements made since the late 1980s. In particular, advances in horizontal or "directional drilling" and hydraulic fracturing techniques are allowing developers to tap into deep gas reserves that had been inaccessible or, even if physically accessible, were not economically viable to exploit. During the late 1980s and early 1990s, the exploration and production of unconventional gas reserves were also accelerated in part due to tax incentives designed specifically to spur development.[36] Over the last decade, further improvements in technology and economies of scale contributed to significant growth in unconventional gas production. By 2009, domestic unconventional gas production exceeded that of conventional gas. The U.S. Energy Information Administration predicts that by 2035, total domestic production will grow by about 20 percent, with unconventional gas resources providing around 75 percent of total U.S. gas production.

Deposits of unconventional natural gas exist in Western Maryland in the Marcellus Shale formation, a geologic feature in the Appalachian Range that generally stretches from West Virginia into central New York, as seen in Figure 5-6, and the Utica Shale formation, depicted in Figure 5-7. In fact, there are many shale gas formations, including several others in the U.S., such as the Barnett and the Eagle Ford. Geologists have long known about the natural gas resources contained within these formations, but had not considered the gas economically recoverable until recent advances in drilling technology. Production wells have been drilled into the Marcellus Shale formation in the states of New York, Pennsylvania,

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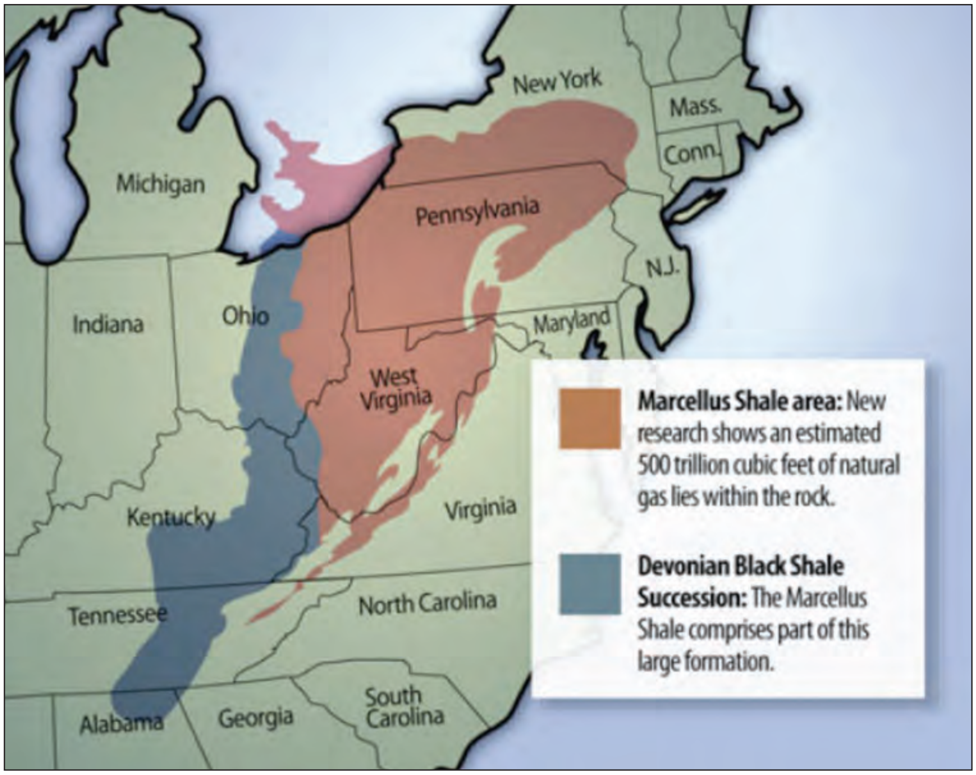
35 http://www.enerdynamics.com/documents/Insider91807_000.pdf

36 http://www.eia.doe.gov/oiaf/analysispaper/unconventional_gas.html

Figure 5-6 Location of the Marcellus Shale Formation

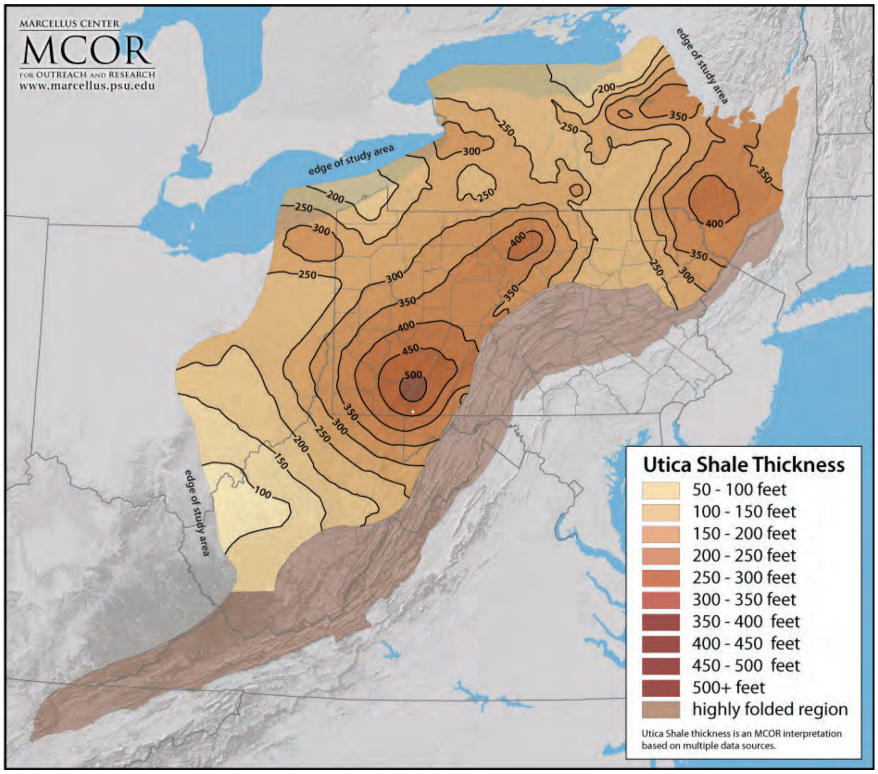


Ohio, and West Virginia, but not yet in Maryland. MDE has received multiple permit applications for drilling in the Marcellus Shale, but there is still much uncertainty regarding the environmental impacts of hydraulic fracturing. In 2010, EPA began addressing questions regarding the impact of hydraulic fracturing on water supplies, water quality, and air quality, among other issues, and is currently examining the practice more closely. In August 2011, DOE released a report indicating that hydraulic fracturing presents risks to the air, water, and land that must be addressed by energy companies and federal and state regulators.

Availability of vast reserves of economically viable, domestic unconventional gas, such as from the Marcellus, has the potential to change the face of the electric generation fuel mix in the United States. Additional gas supply may spur 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 will likely experience a shift in the coming decades as natural gas resources displace coal resources throughout the PJM region.

Burning natural gas results in lower direct emissions of GHG (and other pollutants) on a per-MW basis than burning coal (see Figure 5-4). Therefore, for example, switching from coal to natural gas may qualify under the Clean Air Act as the BACT level of pollution control for GHGs

Figure 5-7 Location of the Utica Shale Formation



from power plants. Because it is generally considered a "clean" fuel, many consider natural gas to be a transitional fuel over the next several decades from the use of fossil fuels to renewable energy sources and other low- or no-GHG emitting fuels. However, the hydraulic fracturing processes used to capture unconventional gas stored in shale formations may result in GHG emissions, which has prompted some researchers to investigate the "carbon footprint" of natural gas use — from the production through combustion — more carefully.

Researchers at Cornell University[37] evaluated the GHG footprint of shale gas reserves, including emissions of methane during hydraulic fracturing to extract the gas. Methane, a primary component of natural gas, is a powerful GHG that is 21 times more effective in trapping heat in the atmosphere than CO_2 over a 100-year period. In addition, methane contributes substantially to the GHG effect on shorter time scales, and is an important gas to mitigate to reduce near-term warming. The researchers' results suggest that the GHG footprint of shale gas is greater than that of conventional gas, due in part to the release of significantly more (at least 30 percent and possibly twice as much) methane emissions during the drilling and extraction processes, compared to conventional gas production. The study concludes the GHG footprint is even greater than that of coal over certain time scales and under certain conditions.

[37] Howarth, R.W., R. Santoro, A. Ingraffea. 2011. *Methane and the Greenhouse-gas Footprint of Natural Gas from Shale Formations, A Letter*. Climatic Change, DOI 10.1007/s10584-011-0061-5.

On the other hand, researchers at Carnegie Mellon recently completed a life cycle assessment of GHGs from unconventional gas production in the Marcellus.[38] A life cycle assessment evaluates the impacts of a process, product, or system holistically over its entire life cycle from raw materials extraction to manufacturing, use, and end-of-life. Carnegie Mellon's results suggest a smaller difference in the GHG footprint between conventional and unconventional gas, and generally lower life cycle GHG emissions from use of unconventional natural gas to generate electricity than from coal. There is a substantial amount of life cycle assesement and GHG footprinting research being conducted that will provide additional insights into the broader implications of the use of conventional and unconventional gas in the U.S. energy sector.

5.4 Generation Technology and Innovation

As detailed in Chapter 2, historic methods of generation in Maryland have been mainly fossil fuel combustion-based, with some non-combustion methods, such as hydroelectric and nuclear generation. In recent years, however, there has been an emphasis within the state on the development of renewable energy sources (see Section 2.1.5). Fossil fuel energy sources generally have greater impacts on the environment than their renewable counterparts. Although the timeframe for when the demand for coal, oil, and natural gas will outweigh economically feasible supply (often also referred to as the "peak") is widely debated, these resources are indisputably finite.

In general, electricity in the United States is generated by large centralized power stations (typically 300 – 3,000 MW) and is delivered to load centers by the regional transmission and distribution networks. An alternative to this traditional system is distributed generation, which is small-scale energy generation (typically 1 kW – 5 MW) that is located close to the point of use. Home-based solar, wind, and geothermal installations are examples of distributed generation that are gaining in popularity, as described in Section 2.1.3.

Long-term trends will likely involve a surge in renewable energy project development and technology advancement, such as more efficient solar energy on a utility-scale, increasing amounts of wind energy being integrated into the electric mix, and some innovative offshore generation technologies. Furthermore, advances in energy storage technologies, such as more efficient batteries and flywheels (discussed in Section 5.5.2) will improve the reliability of renewable energy sources.

5.4.1 Offshore Wind Energy

Wind energy is becoming increasingly more common throughout the U.S. and more desirable in Maryland. With the State's greatest wind energy potential located offshore, the possibility of developing a wind facility off the coast of Maryland has begun to receive growing attention in recent years.

[38] Jiang, M., W.M.Griffin, C. Hendrickson, P. Jaramillo, J. VanBriesen, A. Venkatesh, *Life Cycle Greenhouse Gas Emissions of Marcellus Shale Gas*, Environ. Res. Lett. 6 (July-September 2011) 034014 doi:10.1088/1748-9326/6/3/034014.

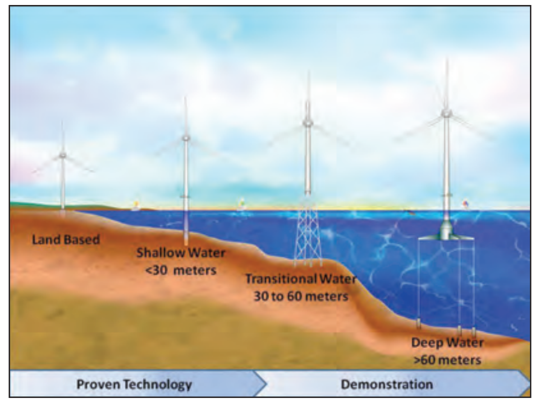
To date, no offshore wind facilities have been developed in United States waters. Nonetheless, 12 countries now have offshore wind plants providing energy to their grids—Denmark, Belgium, China, Finland, Ireland, Germany, Italy, Japan, Netherlands, Norway, Sweden, and the United Kingdom. By the end of 2010, these countries had a total of 47 offshore wind projects representing over 3,000 MW of generating capacity.

NREL estimates the installed capital costs for an offshore wind facility at approximately $4,250 per kW of capacity, which equates to installed costs of roughly $2.1 billion for a 500 MW facility.[39] The capital costs of offshore wind can vary widely depending on technical aspects of the specific project. Note that there is also an innate level of uncertainty around this estimate because of the relative newness of the industry and the lack of U.S. experience. Capital costs of onshore wind facilities, by comparison, are typically around $2,000 per kW—about half the installed cost of offshore wind.

There are a number of factors that can be attributed to the higher capital costs for offshore wind facilities, as compared to onshore wind facilities. In general, it is more complicated, and therefore more expensive, to perform work at sea than on land. Offshore wind turbines require more complex foundations and specialized installation vessels. Generally, capital costs are expected to increase with greater water depths. Access to the development site is limited and will often require additional logistical planning, when compared to land-based projects. Depending on the project, the developer may be required to purchase and install the submarine transmission cables necessary to import the energy to shore. Capital costs for offshore wind facilities are also expected to increase when projects are sited farther from shore, because longer power cables would be required and project logistics become increasingly complex. Nonetheless, as offshore wind technology matures, prices are expected to decline.

Offshore Wind Technology

To make offshore wind energy more cost-effective, some manufacturers are now designing larger wind turbines capable of generating significantly more electricity than traditional onshore wind turbines. New onshore turbines typically have a rated capacity between 1.5 and 3 MW, but several manufacturers are now considering 10 to 20 MW turbine designs for future offshore wind plants. As shown in the picture, new technologies are also under development to place these larger turbines at greater depths.



Source: NREL. http://www.nrel.gov/wind/pdfs/40745.pdf.

Offshore Wind Energy Activities in Maryland

Permitting Issues

Offshore wind power is new to the United States energy industry, so there is relatively little institutional knowledge about the resource. As such, the regulatory and institutional structures for offshore wind energy are just beginning to emerge. Offshore wind energy facilities will require regulatory approval from both federal and state agencies, and in many cases local agencies as well.

[39] U.S. DOE, National Renewable Energy Laboratory. *Large-Scale Offshore Wind Power in the United States* (September 2010). http://www.nrel.gov/wind/pdfs/40745.pdf.

Maryland Coastal Atlas

In June 2010, Governor O'Malley released Maryland's Coastal Atlas, an online mapping and planning tool that allows users to visually analyze and explore data for coastal and ocean planning activities, including renewable offshore energy exploration. The Coastal Atlas is the result of a collaborative effort among Maryland DNR, MEA, Towson University, the University of Maryland, The Nature Conservancy, and the National Oceanic and Atmospheric Administration.

The data available through the Coastal Atlas include physical characteristics, human uses, and ecological resources. This tool serves to assist State agencies, offshore wind developers, and affected stakeholders in selecting areas where offshore wind energy projects may be most compatible with existing uses and natural resources.

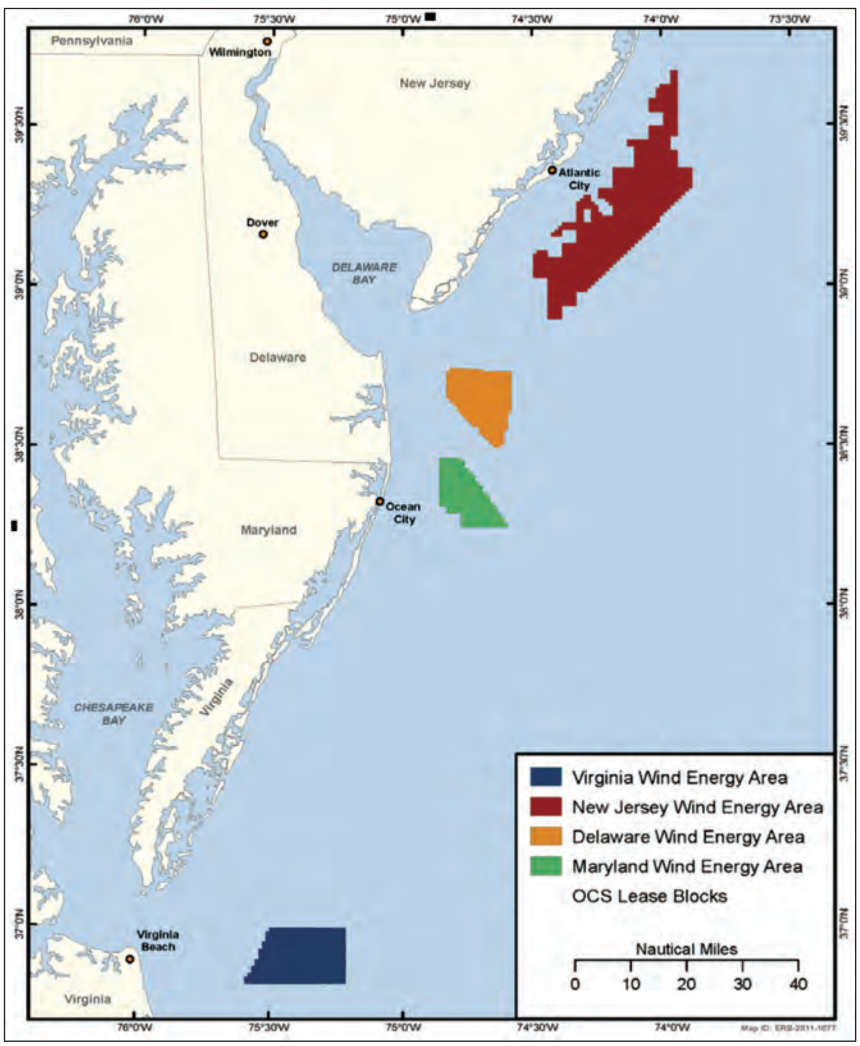
Under the Energy Policy Act of 2005, the U.S. Department of the Interior's Bureau of Ocean Energy Management (BOEM), formerly the Minerals Management Service, is the lead federal agency responsible for leasing in federal waters (greater than three nautical miles from shore) for ocean energy technologies. BOEM's authority covers offshore renewable energy developments, including commercial-scale wind power projects. Dependent upon the situation, lease issuance will be based on either a competitive or non-competitive process. Once a potential developer is selected and granted leasing rights by BOEM, the project will undergo an environmental and permitting review process, which may take years to complete, before construction may begin. This process typically includes the following:

- *A National Environmental Policy Act (NEPA) review is required, calling for an Environmental Assessment, and likely a full Environmental Impact Statement (EIS) if the project's impacts are deemed significant enough.*
- *The project must be in compliance with each relevant state's coastal management program as administered under the Coastal Zone Management Act.*
- *In accordance with Section 10 of the Rivers and Harbors Act, a permit is required from the U.S. Army Corps of Engineers (USACE) for construction of any structures that would obstruct navigable waterways of the United States.*
- *In accordance with Sections 401 and 404 of the Clean Water Act, project developers would also have to obtain a permit from the USACE for the dredging and backfilling that would be required for project construction.*
- *FERC approval is needed before a project can begin to transmit energy into the electrical grid.*
- *The Federal Aviation Administration must be notified of any construction exceeding 200 feet in height.*

- *The U.S. Coast Guard must grant permission to establish aids to maritime navigation.*
- *Finally, as the lead federal agency, BOEM must approve all plans, including:*
    - *the Site Assessment Plan;*
    - *the Construction and Operations Plan (COP); and*
    - *the Decommissioning Plan.*

In July 2011, a revised map of the lease area that is being considered for potential offshore wind development was released, see Figure 5-8. Turbines could be placed within a 94 square-nautical mile area between 10 and 27 nautical miles offshore from Ocean City, Maryland. Wind facility developers will need to review the available sites when the lease area is finalized and decide whether to propose any turbine sites directly off Maryland's short Atlantic coastline.

Figure 5-8 Wind Energy Areas Under Consideration by BOEM



Source: BOEM, 2011. http://www.boemre.gov/offshore/RenewableEnergy/SmartFromTheStart.htm.

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.

Offshore Wind Energy Activities in the Region

A few projects along the Atlantic coast are paving the way for offshore wind utilization in our area:

Lillgrund Offshore Wind Facility

A service vessel makes its way toward the Lillgrund wind power facility - Sweden's largest offshore wind installation. The 48 turbines have a capacity of 2.3 MW each, and together generate 330 GWh annually. The facility began commercial operation in 2008.

Source: http://www.oceanpowermagazine.net/?p=2390

Cape Wind Project in Massachusetts – The Cape Wind Project is to be built on Horseshoe Shoal in Nantucket Sound, off the coast of Cape Cod. The project will be about five miles from Hyannis and even further from most Cape Cod beaches. The developers plan to paint the supporting towers to blend in with the sea and sky. The distance offshore results in visibility of only a half-inch above the horizon on clear days. As currently designed, the project will consist of 130 wind turbines and provide up to 468 MW. The project has undergone a NEPA review with a final EIS and Record of Decision issued by BOEM, authorizing the construction of the project. Furthermore, BOEM has approved the COP, as submitted by Cape Wind Associates. The COP would allow construction to begin as early as the fall of 2011; however, financing has been a significant hurdle.

Deepwater Wind in Rhode Island – Deepwater Wind is proposing to build a 1,000 MW offshore wind project off the coast of Rhode Island, with an accompanying transmission network to serve multiple states. Called the Deepwater Wind Energy Center, the project would include 200 large turbines in the deep ocean waters of the Southern Rhode Island Sound, with most turbines between about 20 and 25 miles from shore. Deepwater Wind estimates the $5 billion project could produce power at the cost of about 15 to 16 cents/kWh.

Bluewater Wind Project in Delaware – For several years, NRG Bluewater Wind planned a wind power facility off the coast of Delaware, with a generating capacity of up to 600 MW. In 2008, Delmarva Power committed to purchasing 200 MW of Bluewater's future electricity output. However, the developer has been unable to secure financing, and in December 2011 NRG announced that it was canceling the project.

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 a number of 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.

Atlantic Wind Connection

The Atlantic Wind Connection (AWC) project is the first offshore backbone electrical transmission system proposed in the United States. Instead of having each offshore wind project develop a radial line to shore, the AWC project will develop a comprehensive connection system to integrate offshore wind energy into the electrical grid. The project would enable 6,000 to 7,000 MW of offshore wind energy capacity to be integrated into the PJM grid. An additional side-benefit would be increased reliability and reduced transmission congestion in the heavily congested northeast corridor by providing an additional backbone transmission link. The AWC project is led by the independent transmission company Trans-Elect with Atlantic Grid Development as the project developer and Good Energies, Google, and Marubeni Corporation as financial sponsors.

Source: Atlantic Wind Connection. http://atlanticwindconnection.com/

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 populations:** *Site-specific research is necessary to gain a better understanding of the potential impacts to marine populations. 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.*
- **Avian 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. Another concern regarding avian populations is the possible fragmentation of their ecological habitat network (e.g., migration pathways, breeding, and feeding areas).*
- **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. Studies conducted for onshore 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. In March 2011, the developers of the Cape Wind project and Hy-Line Cruises announced the creation of a joint venture to offer 'ecotours' of the offshore wind facility.*
- **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, and warning lights); however, a risk assessment for the Horns Rev II wind facility located outside of Denmark concluded that the likelihood of ship-to-ship collision is "significantly higher" than the probability of a vessel colliding with a wind turbine.

5.4.2 Fuel Cells and Hydrogen

Hydrogen is not only the most abundant element in the universe, making up about 75 percent of all matter, but it also contains the most energy of all fuels (Table 5-8). Hydrogen, however, is very rare on Earth in its elemental form and must be produced from other compounds before it can be utilized as an energy source. There are various ways to produce hydrogen. Hydrogen-rich natural gas and coal can be broken down to harvest the hydrogen. Hydrogen can also be extracted from water and chemical or biological compounds. For example, biohydrogen can be produced from algae that will release hydrogen instead of oxygen in a sulfur-deprived environment. It can also be produced from certain types of bacteria feeding on wastes in a bioreactor.

Table 5-8 Energy in Fuels

Fuel Type	Btu/lb
Hydrogen	55,000
Natural Gas	21,148
Gasoline	20,700
Diesel	19,800
Coal	15,000

The most efficient use of hydrogen is in fuel cells. Fuel cells create electricity quietly and reliably, and emit only water. The DOE's Hydrogen Program is conducting extensive research and analysis into safely and efficiency producing, transporting, and storing hydrogen. The program aims to enable commercialization of portable, stationary, and transportation fuel cell applications.

Commercial deployments increased significantly in 2010, with the Hydrogen and Fuel Cell Technical Advisory Committee announcing that over 400 fuel cell installations were completed throughout the year, largely due to funding from the American Recovery and Reinvestment Act (ARRA). In addition, over 400 fuel cell forklifts were sold in the fourth quarter of 2010, without the aid of federal government subsidy, and an additional 290 forklifts were placed through ARRA in the first half of 2010. U.S. fuel cell back-up power installations have seen growth as well, due to government grants and federal early adoption, and fuel cell systems were noted throughout 2010 as being used more frequently in retail stores, office buildings, and manufacturing facilities for heat and/or power generation.

Utility-scale fuel cell installations have been proposed in the United States, but they are rare. In November 2010, FirstEnergy Corp. and

Ballard Power Systems launched a 1 MW fuel cell at FirstEnergy's Eastlake Plant in Ohio. The multi-year demonstration project is being conducted in collaboration with the Electric Power Research Institute, and the facility is designed to generate electricity from hydrogen during peak demand periods. The system consists of nine proton exchange membrane fuel cells, with heat and water as its only by-products. The generator is believed to be the largest fuel cell installation operating worldwide. In Maryland, EPA proposed to build a 1 MW fuel cell facility at a site on Ft. Meade in Anne Arundel County in 2002, but those plans were later dropped.

5.4.3 Advances in Energy Generation

There have been recent advances in utility-scale solar (see Section 2.1.5) and offshore wind (see Section 5.4.1) technologies and incentives, making these renewable energy sources more attractive for future generation in Maryland. In addition, cutting-edge research on energy generation techniques is creating a picture of the future that seems more science fiction than fact. New emerging technologies encompassing biological processes, nanotechnologies, and greater understanding of the properties of magnetism are resulting in innovative and novel methods for creating electricity. This section outlines just a few of the ways in which current research may alter the future of electricity generation.

Biotechnology

Biological processes naturally utilize waste materials, including CO_2, as a food source, transforming them to usable fuels. Researchers have been examining various types of algae and bacteria for many years, with the aim of using these organisms to create fuel on an industrial scale. A Maryland company, Zymetis, Inc., is just one of many making significant advances in this field by working with a bacterium, *Saccharophagus degradans*, that was discovered several years ago in the marshes of the Chesapeake Bay. This particular bacterium is very efficient at eating dead plant material and solid waste and breaking them down into glucose, which in turn can be used to make fuel. Researchers have genetically altered the bacterium to produce more of the key enzyme it uses to break down material, and are moving towards being able to use the process on an industrial scale.

PetroSun's saltwater pools in Rio Hondo, Texas

Source: maps.google.com

Algae are a large and diverse group of simple organisms containing only a nucleus enclosed within a membrane and chloroplasts bound in one or more membranes. Nearly all algae employ photosynthesis to consume CO_2 and produce oxygen as a by-product. Algae grow rapidly, can double their mass several times a day, and can be produced using ocean water and wastewater. Research is currently being conducted in the U.S. to grow algae using wastewater and flue gas CO_2 from power plants, which has the co-benefit of reducing the plant's GHG emissions. Additionally, algae can contain high amounts of lipids (oils) and are biodegradable and relatively harmless to the environment. Researchers have been working to create efficient and economical methods for growing and harvesting algae for the purpose of converting them into various fuel sources, including biodiesel, biobutanol, biogasoline, methane, and hydrogen.

The first North American commercial algae-to-biofuels facility began operation in April 2008. This facility, located in Rio Hondo, Texas, will produce an estimated 4.4 million gallons of "algal oil" and 110 million pounds of biomass per year using a series of saltwater ponds covering 1,100 acres. The algal oil can be refined into fuel, such as biodiesel or jet fuel, and the biomass can be fed to cattle as a protein supplement or fermented into ethanol. It is estimated that if all of the petroleum fuel in the U.S. were replaced with algae biofuels, an area only slightly larger than the State of Maryland would be required to produce it[40] – making algae a much more efficient user of land than corn or soy ethanol, for example.

Kinetic Generation Devices

Innovative ways to harness kinetic energy from everyday things is leading to small-scale electricity generation from the movement of normal items in our surroundings. Most of these applications would only provide peak load shaving; however, on a large scale, could help reduce transmission issues.

A new technology by AEST, Inc. of California is called the Dragon Power Station™ and is activated when heavy duty vehicles drive over plates embedded into the road. The pressure on the plates initiates a hydraulic pumping system that turns a generator to produce electricity. Fluxxlab, a small New York firm made up of two architectural design graduates, has created the Revolution Door, an adapted revolving door, which can harvest the energy created every time the door spins. The tiny amount of electricity generated can be stored for potential uses such as lighting.

A Burger King franchise has installed a speed bump designed to harness the kinetic energy produced by the hundreds of cars that pass through the drive-thru at its high-traffic restaurant in Hillside, New Jersey each day. Customers waiting for their meals roll through a section of the drive-thru lane lined with metal plates that move down and up as the cars head to the next window. The MotionPower™ technology, developed by Burtonsville, Maryland-based New Energy Technologies, is designed to convert this otherwise wasted energy from cars, trucks, and heavy vehicles into clean electricity. A similar technology, piezoelectric generation, utilizes devices under the asphalt to produce electricity from

[40] http://www.washingtonpost.com/wp-dyn/content/article/2008/01/03/AR2008010303907.html

pavement vibrations caused by vehicles traveling on the highway. These types of technologies could be used to augment or replace conventional electrical supplies for powering roadway signs, street and building lights, storage systems for back-up and emergency power, and other electronics, appliances, and even devices used in homes and businesses. The company is currently planning field tests for buses, long-haul trucks, and big rigs.

On a much smaller scale, the David A. Ambler Student Recreation Fitness Center at the University of Kansas recently retrofitted 15 elliptical machines with ReRev devices made by Florida-based SunQuest energy. The devices draw on kinetic energy created by an individual's workouts and reroutes that energy back into the building's electric grid. SunQuest claims a ReRev device can generate enough electricity from a typical 30-minute workout to power a laptop for an hour, a television for 15 minutes, or a compact fluorescent light bulb for 2.5 hours. Furthermore, researchers are inventing ways to harvest energy from simple human motion through knee-mounted devices that can generate energy from a person's stride. One example is the Biomechanical Energy Harvester created by Bionic Power, Inc., which consists of an aluminum chassis and generator mounted on a customized orthopedic knee brace. This technology could potentially power prosthetic limbs, medical implants, and portable devices, such as MP3 players, GPS locators, or mobile phones, and provide light-weight portable energy for military personnel, eliminating the need for a heavy backpack battery.

5.5 Innovations in Transmission Technologies

New emerging transmission technologies will enable a new generation of grid equipment that will be able to endure higher electrical and mechanical stresses and provide greater power transfer capacity and greater flexibility. Currently available technologies are already able to provide twice the capacity of similar traditional equipment with half the energy losses.

5.5.1 High-Voltage Transmission Line Technologies

Electricity can be transmitted several ways and at various voltages. The majority of current bulk power transmission systems in the U.S. consist of overhead AC transmission lines that are generally rated at 230-kV or higher. As described in Section 2.5.2, high-voltage direct current lines (HVDC) comprise only about 2 percent of the total installed high-voltage transmission line mileage. Direct current systems have mainly been used for large scale one-way bulk power transfers, such as undersea cables, or to transmit power over long distances. HVDC systems are capable of carrying significantly more power over longer distances with fewer losses than traditional AC systems. Ultra-HVDC systems are being installed outside the U.S. in overhead configurations that operate at 800-kV and can carry 6,000 MW of electricity. The proposed Mid-Atlantic Power Pathway (MAPP) project (see details in Section 2.5.1) would utilize 640-kV HVDC technology capable of carrying 2,000 MW of electricity. If constructed, this would constitute the first HVDC project in Maryland.

HTS cable at the LIPA substation

Source: Monica Heger, IEEE Spectrum, 2008.

The technology with some of the greatest potential for future transmission grid improvements is high-temperature superconductors (HTS), which will typically be designed for underground installations. Advances in materials sciences are steadily increasing the temperature requirements for superconductivity, which function only in extreme cold. These HTS can potentially carry up to 100 times more power with few, if any, line losses as there is no electrical resistance in superconducting wires. The DOE's Office of Electric Delivery and Energy Reliability's Superconductivity Program estimates that HTS power cables, fault current limiters, transformers, generators, and motors will be available for full-scale commercial use by 2012.

A nearly half-mile 138-kV HTS cable was energized in 2008 as part of the Long Island Power Authority grid. The current in the Long Island cable is carried through HTS wires, which exhibit zero resistance when cooled to about -321°F with liquid nitrogen. Several smaller scale demonstration projects are in progress worldwide. There are currently no proposed HTS systems in Maryland.

5.5.2 Electricity Storage Technologies

Electricity storage technologies might serve to support intermittent renewable resources such as wind and solar. Electricity storage devices currently in use include pumped hydroelectric power, flywheels, batteries, and compressed air facilities.

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 20 GW of 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 services. A one-MW array of lithium-ion batteries owned by AES Energy Services, LLC began offering regulation service in the PJM market in 2009. A handful of energy companies are beginning to test the use of batteries for grid management and energy storage. AEP installed a 1.2 MW battery system in West Virginia in 2006, to test the storage technology and to help fill capacity gaps and flatten the load in the region. 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, ranging from 250 to 500 kW, are being deployed in the U.S. and Asia.

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 20 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.

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.

Beacon Power Flywheels

In November 2009, construction began on a 20 MW flywheel energy storage plant in Stephentown, New York. The plant, a project of the Beacon Power Corporation, will be the first utility-scale facility of its kind supplying grid services in the United States. The flywheels have the ability to address both generation and load, acting in a load capacity by recharging using grid energy, and as a generator by releasing energy back to the grid. Flywheel energy storage systems also have a quicker reaction time than other regulation resources, meaning just 1 MW of this project may be able to displace between 2 to 17 MW of traditional regulation resources. Expected to fill about 10 percent of the New York ISO's frequency regulation requirement, this project involves the installation of 200 flywheels on the 3.5 acre site and costs roughly $69 million. The project was energized in July 2011.

Diane Greer, "Running Near Empty: Power Sector Seeks Financial Fuel to Keep Projects Moving," ENR New York, March 7, 2011. http://newyork.construction.com/new_york_construction_projects/2011/0307_RunningNear.asp

5.6 Smart Grid and Cybersecurity

The smart grid concept embodies the idea of bringing the electric grid into the computer age. Smart grid proponents believe that the 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 "smart" devices containing microprocessor or computer technology. This enables real-time balancing of generation and electric delivery via information flow through intelligent systems. Currently grid operations are based on the balance of supply and demand between generators and utility customers. Balance is achieved through monitoring of demand and adjusting supply accordingly. The smart grid of the future will be mutually self-sustaining and self-correcting between energy suppliers and users, and largely self-balancing to ensure reliability in real time.

5.6.1 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 "sense" electrical outages based on clusters of unresponsive meters, costs for all parties are lowered as meters can indicate (either directly or implicitly) the need for maintenance, and the meters themselves can be read remotely via cellular, other wireless, or landline 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.

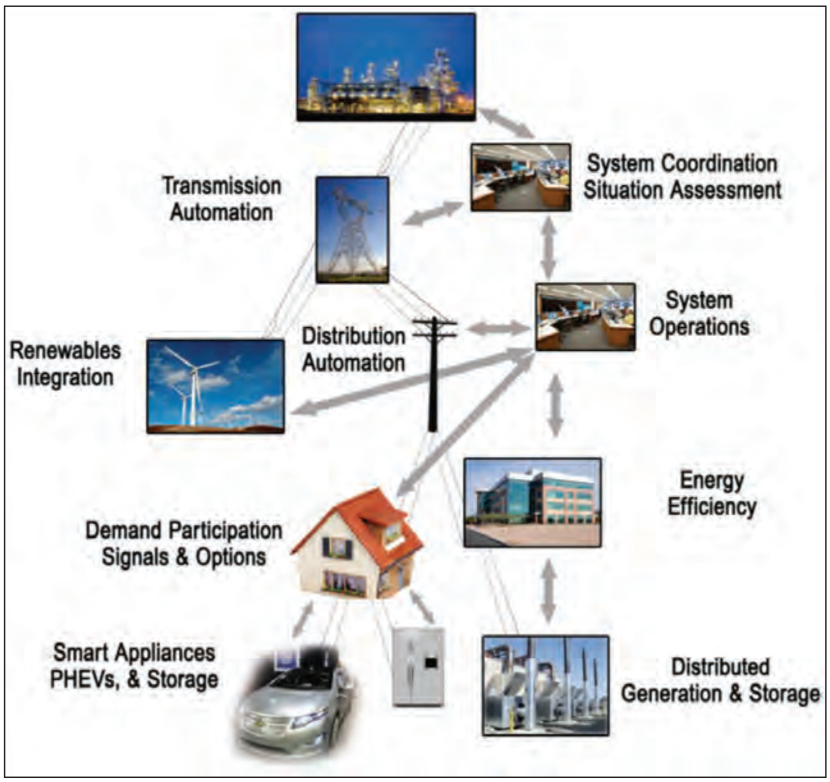
Maryland's major utilities are among the Nation's most aggressive in pursuing the deployment of AMI and the enrollment of customers on dynamic rates. In April 2007, the Maryland PSC approved an initial AMI pilot proposed by BGE to "gather statistically significant, measurable and meaningful information as to the potential positive effect of AMI on reducing peak system demand." Given the success of BGE's pilot activities, the Maryland PSC approved its proposal for full smart meter deployment in August 2010. The proposal lays out a timeline for deploying approximately 1.36 million advanced electric meters and 730,000 gas meters over five years. BGE has forecast over $2 billion in benefits from its AMI deployment in the form of avoided maintenance costs, operational efficiency, and lowered electricity market prices.

Elsewhere in PJM, the State of Pennsylvania has mandated the full deployment of smart meters in all major utility footprints by 2025. If these deployments are followed by the expansion of dynamic rate structures, this will have the general impact of lowering PJM capacity and energy prices owing to the use of demand response to offset energy usage at times of highest need.

5.6.2 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 5-9). 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 temperature, 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, and lighting), can dynamically match customer price points with electrical system needs.

Figure 5-9 Smart Grid Integration



Source: U.S. DOE, "Smart Grid System Report". July 2009.
http://www.smartgrid.gov/sites/default/files/resources/systems_report.pdf

5.6.3 Cybersecurity

The increasingly digital and interconnected nature of the nation's electrical grid exposes these crucial systems to the threat of infiltration and attack. 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 cyber attacks.

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.

To address these issues, in 2008, FERC, through Order 706, adopted a set of Critical Infrastructure Protection (CIP) standards proposed by NERC. These standards identify "Critical Cyber Assets", the definition of which is flexible to accommodate changing grid infrastructures, applications, and technologies. Typically, however, critical cyber assets are facilities where the operation of them directly impacts a considerable portion of the grid, such as the PJM's automated dispatch systems or the systems at a utility level which relay PJM price signals to customers via AMI.

The U.S. Congress is considering measures to increase federal oversight of cybersecurity associated with federal computer networks and critical infrastructure owned by the private sector. 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 become increasingly relevant to electricity reliability in Maryland and nationwide as smart grid technology grows increasingly common.

5.7 Plug-In Electric Vehicles

5.7.1 Plug-in Electric Vehicle Technology Overview

Over the next two decades it is expected that increasing electrification of the transportation sector in the form of plug-in electric vehicles (PEVs) will have a significant effect on the electricity system. PEVs come in three major types:

- *Battery Electric Vehicles (BEVs) have a battery that can be recharged through an external connection to an electricity source and runs only on the batteries. An example of a BEV is the Nissan Leaf.*
- *A Plug-in Hybrid Electric Vehicle (PHEV) has an internal combustion engine that can take over when the battery runs down. PHEVs have larger batteries than traditional hybrid vehicles, allowing them to be operated in all-electric driving mode for short distances, while the internal combustion engine effectively provides for an unlimited driving range. Toyota makes a PHEV Prius.*
- *An Extended-Range Electric Vehicle (ER-EV) is essentially a BEV with a small internal combustion engine, which acts only as a generator to recharge the batteries for longer range. The engine does not power the wheels. An example of an ER-EV is the Chevrolet Volt.*

Conventional hybrid electric vehicles (HEVs) have been on sale for over 10 years and are fundamentally different from PEVs. HEVs have a small on-board electric motor and battery that is recharged by vehicle operation, generally while braking. The batteries in HEVs cannot be recharged externally; hence they are not included with the PEV definition.

Regardless of whether a consumer owns a BEV, PHEV, or ER-EV, driving habits are expected to remain unchanged, and therefore, battery charging requirements will be similar. The versatility offered by PHEV and ER-EV back-up engines is especially appealing to consumers concerned about the range limitations of all-electric vehicles, making consumer adoption of PHEVs and ER-EVs in significant numbers more likely. Additionally, once "range anxiety", as it has been termed, is no longer an issue due to the combustion engine back-up, consumers will not need to worry about charging their vehicles while away from home. Therefore, the majority of PEV charging will likely be on residential-level electric distribution systems.

DOE's Office of Energy Efficiency and Renewable Energy (EERE) has an electric vehicle research program. EERE has identified four charging infrastructure terms based on voltage levels:

- ***Level 1*** *– attaches to a 120-volt AC circuit such as typically found in a home. This charger can provide a continuous maximum charge at 1.44 kW.*
- ***Level 2*** *– attaches to a 240-volt AC circuit such as is used by larger appliances like clothes dryers. This charger can provide a continuous maximum charge at 7.68 kW.*
- ***Level 3*** *– generally a high-voltage charger supporting more than one vehicle. Energy to vehicle can be 440-volt DC or higher.*
- ***Fast Charge*** *– returns 50 percent of a battery's capacity in under 30 minutes. This is generally an off-board DC charger for large batteries, usually at Level 3 voltage.*

Plug-in Electric Vehicles (PEVs)

BEV

PHEV

ER-EV

As discussed earlier, the majority of PEVs will likely be charged at home using the existing AC distribution infrastructure. EERE transportation data indicate that more than 90 percent of vehicle trips are less than 30 miles. Currently PEVs achieve approximately 4 miles/kWh, which is expected to increase to 5 miles/kWh in the next few years. Therefore, average daily PEV charging requirements will be approximately 6 to 8 kWh, depending in part on the size of the battery. The residential retail electricity price in Maryland is approximately $0.14/kWh. Therefore, an 8 kWh daily charge on a PEV would cost about $1.12, making the monthly charge for a consumer that commutes a total of 30 miles to/from work about $22. By comparison, the monthly charge for the same commute using a gasoline-powered passenger vehicle averaging 30 miles per gallon with a gasoline price of $3.50/gallon would be around $69. Figure 5-10 compares the average annual usage of home electrical

Figure 5-10 Comparison of Electricity Usage

Annual Energy Usage - Electrical Appliances	
Home Heating System	3,524 kWh
Central Air Conditioning	2,796 kWh
Refrigerator/Freezer	2,610 kWh
Water Heater	2,552 kWh
Chevy Volt	2,520 kWh
Clothes Dryer	1,079 kWh
Lighting	940 kWh

Source: EPRI, presentation by B.K. Gross, August 2009. http://mydocs.epri.com/docs/SummerSeminar09/1cGross.pdf

appliances to the estimated amount of electricity that a Chevrolet Volt would require under typical driving conditions.

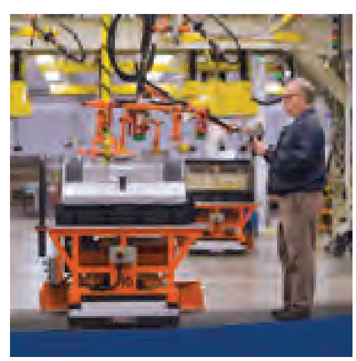
Battery Technology

The core component of the PEV is the battery, which is also what adds the most extra cost. The traditional battery used in automobiles is the lead acid battery, which can provide a high current but only for a short duration. Lead acid batteries are cheap to construct, but are very heavy and cannot provide power for a sustained amount of time. The first hybrid vehicles used nickel metal hydride (NiMH) batteries. NiMH batteries are lighter with a more sustained energy output, but are expensive to manufacture. In the last few years, manufacturers have been focusing on various lithium-ion based batteries. Lithium-ion technology is superior in terms of energy density and weight, so physically smaller batteries can provide significant amounts of power allowing manufacturers to minimize the weight and size burden in a vehicle. Lithium-ion batteries are the dominant technology used in PEVs currently entering the marketplace. Additional advantages of lithium-ion batteries are that lithium is an abundant resource and can be recovered and recycled.

Lithium-ion batteries have been used extensively in consumer electronics, which are generally viewed as disposable. The duration the batteries will be usable in vehicles has not yet been demonstrated, but research seems to suggest that a useful life of 10 years can be reasonably expected. Battery life is mainly affected by cycling frequency and temperature. Cycling refers to the process of charging and discharging a battery. Lithium-ion batteries are degraded when they are deeply discharged or left for long periods of time in a highly charged state. To mitigate these effects, vehicle manufacturers are building in high and low charge

California Study to Reuse PEV Batteries

The California Center for Sustainable Energy (CCSE) is leading a study on reusing PEV batteries. CCSE, along with partners San Diego Gas and Electric Company (SDG&E), AeroVironment Inc., and Flux Power Advanced Energy Systems, were awarded a $992,000 research grant from the University of California, Davis (UC Davis) to design the best method of repurposing spent PEV batteries as electric storage devices. After a PEV battery is no longer suitable for use in a vehicle, the battery will still retain 70 to 80 percent of its residual capacity and can be utilized for stationary energy storage and other smart grid applications. The study will evaluate three different types of PEV batteries at test sites that will allow SDG&E to remotely charge and discharge them in response to simulated and real grid conditions. SDG&E will also determine if specific battery chemistry or a particular battery management system is superior for overall lifetime battery value. The research project will be overseen by the UC Davis Institute of Transportation Studies.



Source: https://energycenter.org/index.php.

reserves. For example, the Chevrolet Volt contains a maximum of 16 kWh of energy capacity, but uses only about 50 percent or 8 kWh of that capacity. The Volt battery system is restricted to cycling from a maximum of 80 percent charged to a minimum of 30 percent charged. Lithium-ion batteries are also affected by temperatures, both operating temperature and ambient temperature. PEVs are built with onboard battery cooling systems that keep the battery cool during vehicle operation. However, consistent exposure to high ambient temperatures while the vehicle is not in operation can adversely affect lithium-ion battery life. While it is still uncertain how lithium-ion battery life may be shortened by high ambient temperatures, recent analysis has suggested that constant exposure to temperatures of about 90°F and higher could reduce battery life by half.[41]

5.7.2 Environmental Benefits of PEVs

In order to assess the environmental benefits of PEVs, it is necessary to compare emissions from electric vehicles to emissions from an internal combustion engine (ICE). When running on electricity, PEVs do not emit any pollutants through the tailpipe exhaust; however, there are emissions associated with the generation of electricity used to power the vehicle, unless of course, all the electricity comes from a clean resource, such as solar or wind.

Nonetheless, according to data from the EPA's Emissions & Generation Resource Integrated Database (eGRID), electricity generation in the U.S., produces an average of approximately 1,300 lbs/MWh of CO_2e. More specifically, in the region that encompasses Maryland, defined as the ReliabilityFirst Corporation eastern zone; electricity generation produces an average of about 1,065 lbs/MWh of CO_2e. Therefore, assuming a BEV is driven 12,000 miles per year[42] at 4 miles/kWh, its expected contribution to annual emissions in Maryland equates to about 1.45 MT of CO_2e per year.

According to an estimate from EPA, the average ICE passenger vehicle produces approximately 5.2 MT CO_2 on an annual basis. In addition to CO_2, automobiles produce methane and N_2O from the tailpipe, as well as HFC emissions from leaking air conditioners. CO_2 accounts for about 95 percent of vehicle emissions, while the other three gases make up about 5 percent. When accounting for these additional GHGs, the EPA estimates that the average passenger vehicle produces about 5.5 MT CO_2e per year—almost four times the level of emissions associated with a BEV in Maryland.

5.7.3 Potential Impact of PEVs on the Electric Grid

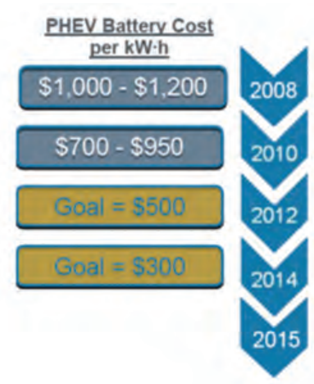
Integrating PEV charging into the electric grid comes with both costs and benefits. As PEV charging will be mainly conducted at the distribution level, this is where impacts will first be seen. From a kW standpoint, a PEV represents approximately half the load of a typical home. Utilities have expressed concerns that residential neighborhood

[41] Pesaran, A.A., "Battery Pack Thermal Issues and Solutions for PHEVs", NREL, presentation at Plug-in 2009.
[42] 12,000 miles per year is the baseline used by the EPA to estimate the greenhouse gas emissions from a typical passenger vehicle.

DOE Battery Technology Program

The price of the batteries adds a significant cost increase to PEVs versus conventional vehicles. Current lithium-ion PEV batteries add approximately $8,000 to $11,000 to the price of a PEV with a 40-mile all-electric range. The DOE Battery Technology Program has set a goal of significantly reducing PEV battery costs per kWh of storage capacity by 2015.

Source: P. Davis, DOE, "United States Department of Energy Vehicle Technologies Program," presentation to the Maryland PSC Technical Conference on PEVs, October 2010.



transformers may become overloaded as more PEVs are introduced into an area. Utilities will likely need to upgrade their existing distribution grids. Most consumers arrive home and plug their vehicles in between 4:00 and 8:00 p.m., which is still during the evening peak load period. Unmanaged PEV charging could cause problems if all PEVs are charged during this time period. Utilities, however, seem confident that PEV charging can be managed and shifted to night-time hours when overall loads are lowest (i.e., during off-peak hours), especially with the increasing deployment of smart grid components and two-way communications. AMI-enabled dynamic rate structures in Maryland can provide economic incentives for PEV owners to charge their vehicles during non-peak hours. Such incentives could allow a significant level of PEVs to charge simultaneously without requiring any upgrades to the existing generation and transmission systems.

Impacts on the Transmission Grid and Electric Generation

Transmission system impacts will likely be minor until PEV penetration reaches a relatively high level (25 million PEVs in PJM would be about 45 percent of the total vehicle fleet). Transmission and generation are constructed to meet peak-level demands, and therefore, during non-peak periods, considerable amounts of transmission and generation capacity sit idle. Excess transmission and generation capacity is especially available during the lowest-load night-time periods. This means that with managed charging that shifts the majority of the PEV load to night-time hours, there is more than enough existing capacity to meet foreseeable PEV demand. PJM has estimated that the current transmission and generation capacity on its system could handle over 25 million PEVs, if the vehicles are manage-charged at night (see PJM PEV Capacity sidebar). Studies by DOE's Pacific Northwest National Laboratory estimate that up to 70 percent of the entire national light-duty vehicle fleet could be converted to PEVs and the charging requirements be supported by current transmission and generation capacity, if the PEVs were manage-charged at night.[43]

Managed-charging can be accomplished through AMI-enabled dynamic rate structures. As explained in Section 5.6.1, AMI provides the necessary technology for the dissemination of high-resolution (≤ 1 hour) prices to end-use customers; thus creating economic incentives for customers to charge their vehicles during the lowest load night-time hours (i.e., when electricity is least expensive). Furthermore, with an increasingly developed smart grid, AMI customers will likely be able to use computer

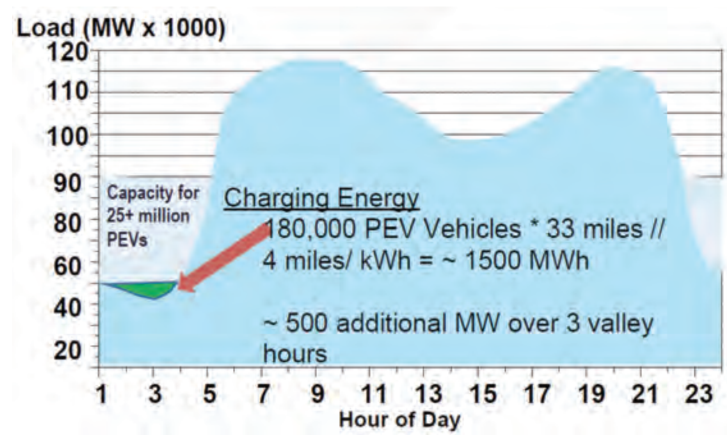
[43] PNNL, "Impact Assessment of Plug-In Hybrid Vehicles on Electric Utilities And Regional U.S. Power Grids Part 1: Technical Analysis," 2007. http://www.euec.com/getattachment/euecjournal/Paper_4.pdf.aspx

programs that can automatically control charging of their PEVs depending on real-time electricity prices throughout the night.

PEV charging can also be managed with conventional time-of-use rate structures. These rate schedules generally offer reduced rates per kWh on a pro-rated basis for off-peak charging, with incremental rate increases for vehicle charging during partial-peak and on-peak demand times.

PJM PEV Capacity

Using the Obama Administration's goal of one million PEVs by 2015, PJM estimated about 180,000 PEVs would be in the PJM area. Assuming 33 miles per average trip at 4 miles/kWh, PJM estimates that managed night-time charging would have little impact on the PJM system. In fact, the PJM system's existing capacity could support over 25 million PEVs without any transmission upgrades or new generation.



Source: PJM, "Grid Impacts & Implications," presentation at the Maryland PSC Technical Conference on PEVs.

With managed-charging, PEVs actually represent many potential benefits to grid operations, as well as PEV owners. For example, a fleet of PEV vehicles could provide reliability to the grid, while earning a stable stream of revenue. Fleet vehicles are ideal candidates for providing large-scale services to the grid, because they have the advantage of predictable and schedulable usage. PEVs have the capability of both receiving and transmitting electricity from their batteries, so the battery storage capacity of a large fleet can offer several valuable services to grid operators, including:

- ***Reserves:*** *For reliability purposes, PJM must maintain a certain level of capacity reserves in case of system interruptions. PJM operates markets for reserve services where a CSP could offer aggregated PEV batteries as a single capacity reserve.*
- ***Regulation:*** *Regulation refers to the automatic response to minute-to-minute deviations in the demand/supply balance on the grid. Regulation involves very small fluctuations for which storage devices are ideal as fast-responding resources.*
- ***Emergency Load Curtailment:*** *PJM sometimes needs to call upon load to curtail during system emergencies. PEV managed-charging can be quickly shut down or cycled to immediately reduce system load.*

Fleets of local transit buses, school buses, and delivery trucks (e.g., FedEx or UPS) are examples of the types of vehicle fleets that could provide the above mentioned services to the electrical grid. It is important to emphasize that buses and trucks burn much more fuel than passenger automobiles, so replacing these trucks with new electric vehicles or converting them to hybrid electric vehicles would result in significant fuel savings. Furthermore, such conversions would result in significant reductions in GHGs emissions.

PEVs can also provide aggregated benefits to the electrical grid on a smaller scale (i.e., through residential customers). The average consumer operates his or her vehicle for only a few hours per day. For the remaining time, a PEV would theoretically be plugged in somewhere (at home or a parking lot at work) and accessible to grid operators. PEV batteries can be aggregated into significant storage capacity and offered into wholesale markets by CSPs in the same way that demand response is currently aggregated and sold. CSPs can include local utilities that can aggregate many PEVs connected to the residential network or parking garages where commuters plug in their vehicles during the day. As with demand response, all of these are paid services provided through PJM-administered markets (for a more detailed explanation of the various PJM markets please see Appendix B). CSPs can bid the services into the wholesale markets, collect revenues from PJM, and pay PEV owners for the use of their batteries.

5.7.4 Maryland PEV Activities

On April 22, 2011, eight PEV charging stations were unveiled at Baltimore/Washington International Thurgood Marshall Airport. The stations are part of the Electric Vehicle Infrastructure Program initiative, launched in 2010 by MEA using ARRA funding. The State is planning to install 65 PEV stations across the Baltimore-Washington, D.C. metro area. Fifty-five are being developed by the Baltimore Electric Vehicle Initiative in partnership with SemaConnect and Autoflex. The other 10 are being developed by the City of Baltimore.

In the 2011 Legislative Session, the General Assembly passed SB 179 (HB 164) that requires the PSC to establish a pilot program for electric customers to recharge electric vehicles during off-peak hours in cooperation with at least two electric companies. The pilot program is to include incentives for all customer classes, which may include time-of-day pricing, credits on distribution charges, rebates on the cost of charging systems, demand response programs, or other incentives as approved by the PSC. A report on the pilot program is due to the Governor and the General Assembly in February 2015.

Many regulatory issues still need to be resolved, such as who should pay for any required distribution system upgrades and whether PEV charging should be metered separately and/or charged under different electricity rates. Regulatory issues surrounding how public charging stations should be treated also need to addressed. In March 2011, the Maryland PSC opened Case No. 9261, as an investigation into the regulatory treatment of PEV charging stations. The proceeding will examine whether public charging station owners should fall under the category of an "electricity supplier" and be subject to PSC regulations applying to such. The PSC will also consider whether "some form of regulation may be necessary for assessing reliability of the electricity supply because of, among other things, the vehicles' ability to inject electricity into the grid, [and] the possibility that a "clustering" of charging stations could overload transformers and cause service interruptions on local distribution networks."[44]

[44] Maryland PSC, "Notice Initiating Proceeding and Notice of Status Conference," Case No. 9261, March 7, 2011.

Two other PEV-related bills were passed during the 2011 Legislative Session. SB 176 (HB 167) establishes the Maryland Electric Vehicle Infrastructure Council, to be made up of various interested stakeholders from both the public and private sector. The Council will develop an action plan for integrating PEVs into the state's electric grid, assist in developing and coordinating PEV-related standards, help increase consumer awareness of PEVs, develop policies to support fleet purchases of PEVs, and encourage local and regional PEV efforts. SB 177 (HB 163) provides for a state income tax credit for 20 percent of the cost of electric vehicle charging equipment, up to a maximum of $400 per charging station, for the tax years 2011 through 2013. The credit is limited to one recharging system per individual and 30 recharging systems per business entity.

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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.

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.

Base-load plant
A power plant built to operate around the clock. Such plants typically have low operating costs and high capital costs. Coal and nuclear-fueled plants are typical base-load plants.

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.

Bottom ash
A coal combustion by-product 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, typically expressed 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.

Closed-cycle cooling
Type of cooling that involves recirculating water in cooling towers.

Coal combustion by-products (CCBs)
Solid by-products 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 non-peak 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.

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 by-product 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.

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 by-product, 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 non-hazardous industrial waste, which can be burned to produce energy.

Radionuclides
Naturally occurring or man-made 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. Ten Northeastern and Mid-Atlantic states, including Maryland, have capped and will reduce CO_2 emissions from the power sector 10 percent by 2018.

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 end-use 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 on-site 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.

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.

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Appendix A – Permits and Approvals for Power Plants and Transmission Lines in Maryland

Under Maryland regulations, an 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) permits for new major power plant sources in Maryland are part of the CPCN. As with all major source 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 licensing conditions during the CPCN process. Certain required permits, most notably the Clean Air Act Title IV Acid Rain Program permits, are issued separately by EPA; however, the State does incorporate Acid Rain Program requirements into the conditions of the CPCN. On the other hand, several of the permits and approvals that power plants need to operate in Maryland are issued and enforced by the Maryland Department of the Environment (MDE). For example, facility-wide Title V Operating Permits are administered by MDE.

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). It should also be noted that the CPCN process supersedes local zoning requirements. PPRP considers land use compatibility and zoning designations as part of the overall project evaluation; however, an applicant does not need to obtain formal zoning approval from the local planning authority.

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
CPCN	Certificate of Public Convenience and Necessity	Maryland Public Service Commission (PSC)	Incorporates several State and federal permits and approvals — those incorporated into CPCN are highlighted
AIR QUALITY			
Air Quality Permit to Construct	Applies to any minor new, modified, or reconstructed sources of air pollution	PSC/Maryland Department of the Environment (MDE)	Constitutes "minor NSR construction permit", see PUC 7-208
Nonattainment Area New Source Review (NA-NSR)	Required for new or modified major sources that emit VOCs or NOx; requirements and limitations are location-specific	PSC/MDE	Requires Lowest Achievable Emission Rate (LAER), offsets, and alternatives analyses, see PUC 7-208
Prevention of Significant Deterioration (PSD)	Required for major new or modified sources in attainment areas with potential emissions over 100 tons per year	PSC/MDE	Requires air quality monitoring, Best Achievable Control Technology (BACT), ambient impact analyses (modeling), impact on surrounding Class I areas, see PUC 7-208
Title V Operating Permit (federal) and Maryland Permit to Operate	Facility-wide permit to operate	MDE	Title V operating permit application may be filed in conjunction with CPCN, see EN 2-405
Title IV - Acid Rain Permit	Covers "affected" power plant generating units for minor SO_2 emissions	MDE	Requires continuous emission monitoring, recording, and reporting; acquisition of SO_2 allowances
Clean Air Act 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
Clean Air Interstate Rule (CAIR)	The rule uses a cap and trade system to reduce sulfur dioxide (SO_2) and nitrogen oxides (NO_x) by 70 percent.	MDE	Applies to 28 eastern states and the District of Columbia
WATER QUALITY AND USE			
Waterway Construction	Applies to construction within State wetlands and waterways	MDE/USACE	Wetland 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/NOAA	State and federally coordinated program
Chesapeake Bay Critical Areas Act	Protects MD's Critical Areas, which is all land within 1,000 feet of the Mean High Water Line of tidal waters or the landward edge of tidal wetlands and all waters of and lands under the Chesapeake Bay and its tributaries.	DNR/County/ Municipality	Enforced at the local or county level

Subject	Description	Regulatory Entity Issuing Permit in Maryland	Comments
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/ NPDES Permit	Combined state and federal permit for industrial wastewater and possibly storm water discharge to state waters. Must meet applicable federal effluent guidelines, satisfy state water quality standards, and comply with Section 316(b) regulations regarding surface withdrawals	MDE	Individual NPDES permits may include discharge of storm water associated with industrial activities. If not, 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 non-process water	MDE/USACE	640 acre drainage area, 20 foot or greater embankment, high hazard class, natural trout water
Maryland Water Quality Certification	CWA Section 401, for construction in wetlands	MDE	Wetland impact determination necessary
Surface Water Withdrawal Permit/ Water Appropriation & Use Permit	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.
Public Water Supply Line Connection	A variety of Clean Water Act permits, SHPO clearance, NRCS consultation, floodplain permitting, and road boring permits	County/ Municipality	
Tidal Wetland Permit	Joint state-federal review and permitting for tidal wetland impacts	PSC/MDE Water Management Administration (WMA)/USACE	Wetland impact determination necessary
Non-Tidal Wetlands Permit	Joint state-federal review and permitting for non-tidal wetland impacts	MDE WMA/ USACE	Wetland impact determination necessary
Groundwater Withdrawal	Required for any groundwater withdrawal	PSC/MDE	Requires submittal of application to Water Management Administration for any withdrawal of groundwater for use in project (sanitary water, process water, cooling, etc…). Also have to conduct impact assessment.

Subject	Description	Regulatory Entity Issuing Permit in Maryland	Comments
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 exce eds an average of 20,000 gallons per day for any consecutive 30-day period
Threatened and Endangered Species Clearance	State-implemented program under the Endangered Species Act; includes field investigations and data research	DNR Heritage and Biodiversity Conservation Programs	Coordinate with US Fish & Wildlife Service and NOAA
Stack or Turbine Height Notification (FAA)	Notify Federal Aviation Administration (FAA) of stack or turbine height	FAA	200 feet above ground level and higher stacks or wind turbine structures
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) 16 ft. wide, 16 ft. high, 150 ft. overall length, 132,000 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 SHA-owned Land	For projects that are proposed for location on property owned by SHA.	State Highway Administration (SHA)	
Approval for Solid Waste Disposal	If waste, such as fly ash, is taken off-site, it must be taken to a properly permitted facility	MDE	
Notification of Regulated Waste Activity	For waste oil, universal waste, hazardous waste, disposal registration, RCRA modification	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	Required if proximity to airport or landing strip within 1 mile of any portion of the proposed route
PCB Registration	Covers disposal of electrical transformers that previously contained PCBs which are proposed to be disposed at a Class I or II residual waste landfill	EPA	Thresholds are 50 to 500 ppm PCBs for transformers and other PCB-containing wastes
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

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. Those consumers who do not select a supplier or are unable to receive service from a competitive supplier are provided with electricity service by their regulated utility, which contracts with wholesale suppliers on behalf of its consumers, under the supervision and guidance of the Maryland Public Service Commission. 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 Regional Transmission Organization are bilateral transactions, where 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, 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).[1]

[1] 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.

The primary purpose of financial trading is to protect against expected price volatility and 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, the New York Mercantile Exchange, or Chicago Board of Trade 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 below: 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 electricity system functioning (the Capacity Market and the Ancillary Services Market). These markets are competitive and suppliers and buyers submit bids and offers. 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). A load serving entity is any supplier, including regulated utilities providing standard offer service or default service, that 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 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 where 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 LMP for any generation that exceeds their day-ahead scheduled quantities as 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 as 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 where 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 reserve margin of an additional 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. LSEs can acquire capacity in one of several ways, including procuring generating resources (either through construction or purchase), purchasing capacity under a bilateral agreement, or participation in the PJM capacity market.

The current PJM capacity market is based on PJM's Reliability Pricing Model (RPM), and was 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, i.e., the level of revenue that a power plant developer would require 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.

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 (LDAs).[2] 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 entered into bilateral contracts with capacity owners, do not own generation capacity, and have not opted for the Firm Resource Requirement (FRR) alternative.[3] 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 2012 through May 2013 was held in May 2009). 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 curve and supply curve. The capacity resources that clear the BRA receive the market-clearing price and assume the obligation to provide capacity in the relevant planning year. Failure to satisfy that obligation entails significant penalties.

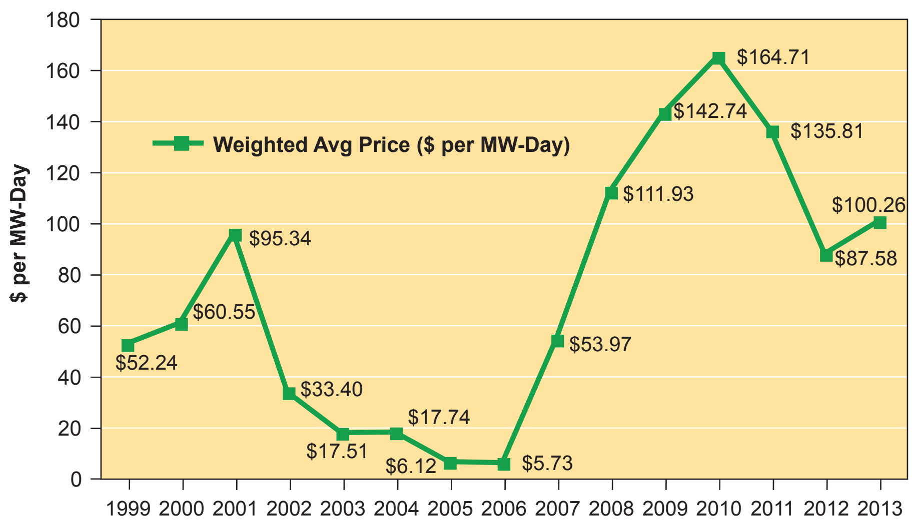
PJM may conduct "incremental auctions" following the BRA. The purpose of the incremental auctions is to allow cleared resources in the BRA to adjust the capacity quantities bid (for example, for planned resources that may not become available in the quantities expected or for unanticipated additional quantities). Additionally, PJM can use the incremental auction option to secure additional capacity if the peak load forecast is increased.

[2] PJM divides the PJM region into deliverability areas based on transmission connections and constraints.

[3] 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 and subject to PJM approval.

Since the introduction of the RPM capacity market, the price for capacity has increased significantly throughout the PJM region. Figure B-1 shows historic capacity prices along with RPM prices out to 2013 arising from the PJM auctions.

Figure B-1 Average Annual PJM Capacity Prices



Source: Monitoring Analytics, "2010 State of the Market Report for PJM," March 10, 2011.

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 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 energy 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 reserves and generator responses to economic signals. The regulation requirement is set daily and is equal to 1 percent of the forecast peak load. The PJM regulation market accepts bids from generators and fast-responding load resources and electricity storage systems. These entities enter an offer price for the day and if called upon are paid the current daily price for regulation service.

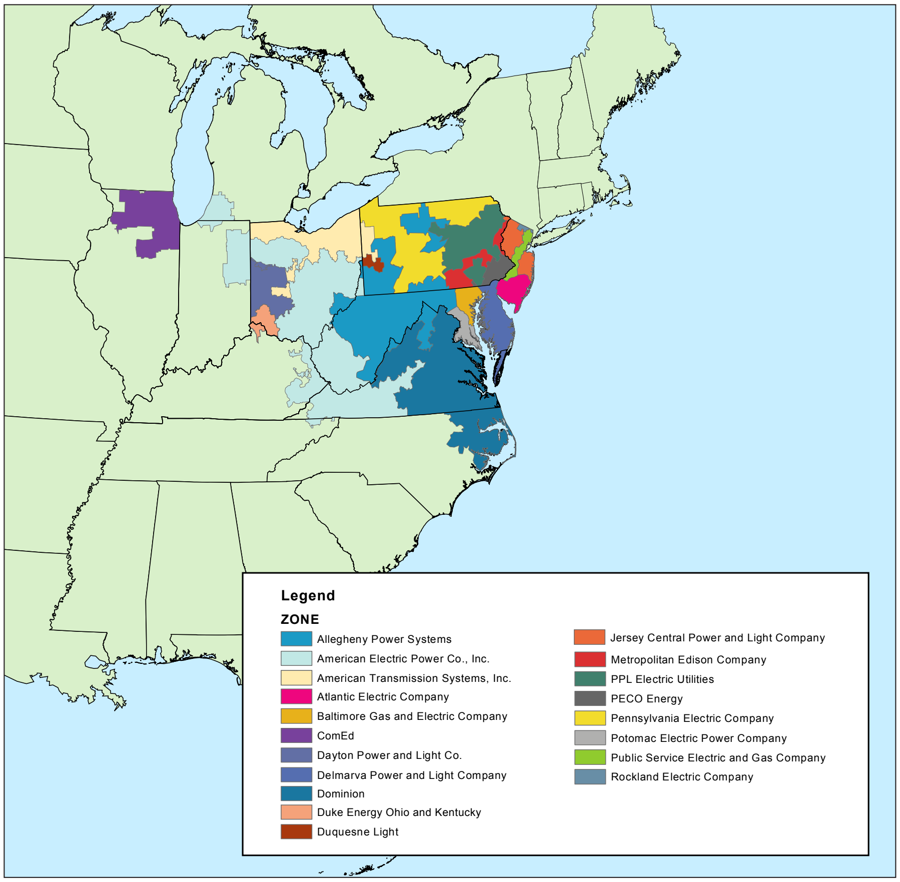
Reserves represent the generating capability that is standing by ready for service in the event of a disruption on the power system, such as the loss of a generator. These operating reserves, the standby generation made available to serve load in case there is an unplanned event, are not the same as the 15 percent reserve requirement, which is an annual capacity obligation based on the average of the five highest seasonal peaks. The 15 percent annual reserve requirement refers to the overall amount of extra capacity that must be maintained in the PJM system as a whole in order to maintain a specified level of reliability. In other words, the PJM system must always maintain a condition where overall generation ability exceeds overall electricity use by 15 percent. The operating reserves refer to the amount of generation kept in standby mode so it can be called upon in case of an emergency, such as a major unit tripping offline. 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 to do so. Primary reserves are those resources available within 10 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 several different zones (shown in Figure B-2) organized primarily according to the 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-2 PJM Zones



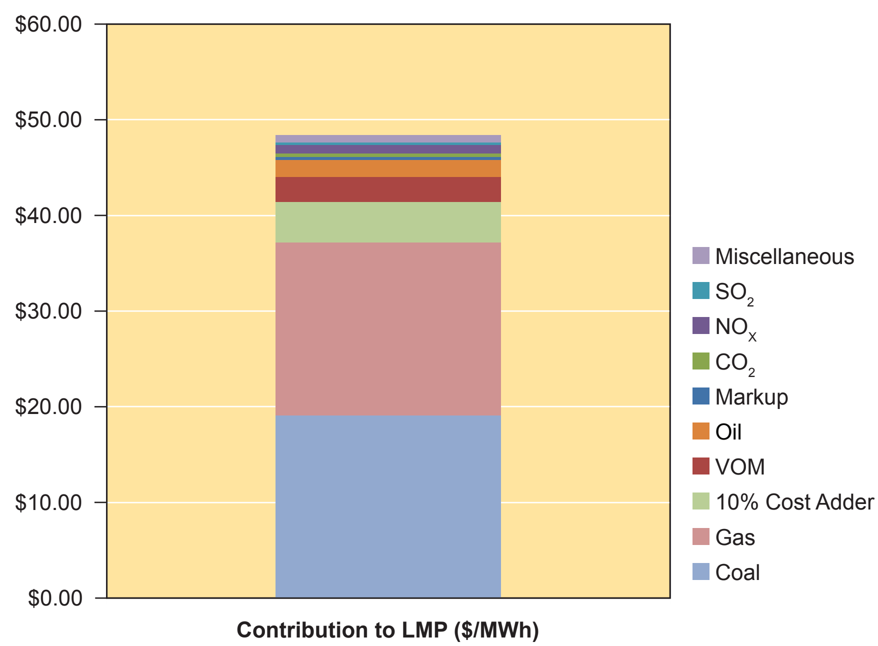
LMPs, as established at each zone, can be summarized according to time of day; peak hours are Monday through Friday (except holidays) from 7:00 a.m. to 11:00 p.m., off-peak are the remaining evening, weekend, and holiday hours. Table B-1 provides the PJM average and median prices experienced over the 2010 calendar year.

Table B-1 PJM Off-Peak and On-Peak Simple Average LMP for 2010

	Day Ahead ($/MW)		Real Time ($/MW)	
	Off-Peak	On-Peak	Off-Peak	On-Peak
Average	$37.46	$52.67	$37.44	$53.25
Median	$33.73	$45.48	$31.83	$43.20

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-3). 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 2010, the capital and fuel supply costs of coal-fired generators made up 39 percent of the annual average LMP, while gas-fired generators made up 37 percent. Variable operating and maintenance costs (VOM) contributed 5 percent of the LMP and PJM's Cost Adder contributed 9 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, this 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.[4] In addition to fuel costs, other factors contributing to price levels include environmental costs, non-fuel operating costs, and profit margins. Cost for compliance with CO_2, NO_X, and SO_2 emissions regulations contributed approximately 4 percent to the total LMP. All generators, however, are paid the LMP in their zone; the PJM Market Monitor estimates these cost factors for informational purposes only.

Figure B-3 Components of Load Weighted Annual Average LMP (2010)



Average annual LMPs have been rising since the late 1990s, more than doubling from 1998 to 2008 (see Table B-2). LMPs in 2009 and 2010 were significantly lower than in 2008, due mainly to reduced electricity demand as a result of the recession. 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. Figure B-4 depicts fuel costs for electricity suppliers between 1996 and 2009. Natural gas prices have declined significantly since the highs reached in 2008. Along with the recessionary effects, this decline in the cost of natural gas has put downward pressure on the market prices for electric power.

The cost of uranium fuel (not shown in Figure B-4) is only a small part of the overall operating and maintenance cost for a nuclear facility. However, the price of uranium has increased significantly over the last decade, rising from $12.14 per pound in 1998 to $45.86 per pound in 2009.

[4] PJM, "A Review of Generation Compensation and Cost Elements in the PJM Markets," 2009.

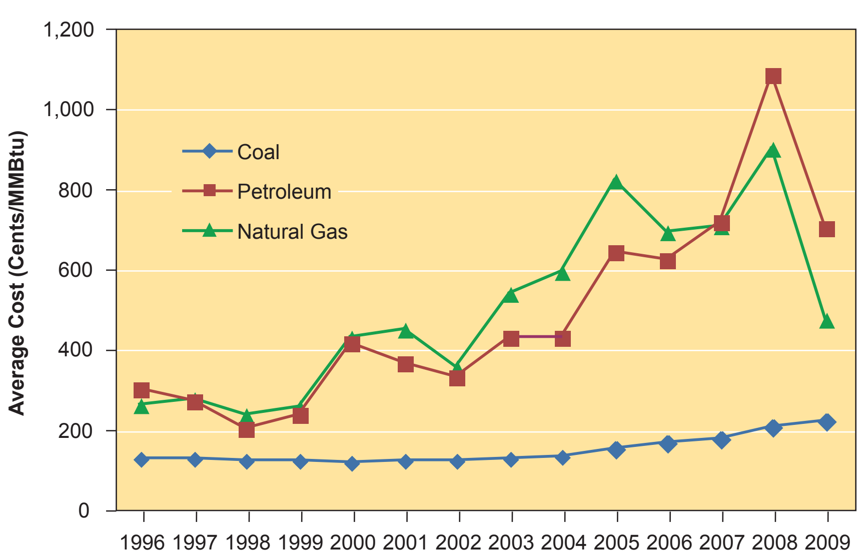
A pound of uranium provides approximately 171 MMBtu; therefore, the cost to the electric power industry was approximately 27 cents per MMBtu in 2008.

Table B-2 PJM Load-Weighted Day-Ahead Average LMP

Year	LMP per MWh	Change from Previous Year	Percent Change
1998	$24.16	NA	NA
1999	$34.07	$9.91	41.0%
2000	$30.72	($3.35)	(9.8%)
2001	$36.65	$5.93	19.3%
2002	$31.58	($5.07)	(13.8%)
2003	$41.23	$9.65	30.6%
2004	$42.87	$1.64	4.0%
2005	$62.50	$19.63	45.8%
2006	$51.33	($11.17)	(17.9%)
2007	$57.88	$6.55	12.8%
2008	$70.25	$12.37	21.4%
2009	$38.82	($31.43)	(44.7%)
2010	$47.65	$8.83	22.7%

Source: Monitoring Analytics, "2010 State of the Market Report for PJM," March 10, 2011.

Figure B-4 Fuel Costs for the Electric Power Industry



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 states that comprise PJM (see Table B-3). Additional information on congestion is provided in Chapter 2 of this CEIR.

Table B-3 Real-Time Annual Load-Weighted Average LMP for 2010

State	LMP
Delaware	$55.09
Illinois	$36.21
Indiana	$39.06
Kentucky	$40.96
Maryland	$58.86
Michigan	$40.23
New Jersey	$56.00
North Carolina	$53.80
Ohio	$39.47
Pennsylvania	$49.49
Tennessee	$41.99
Virginia	$54.24
West Virginia	$41.72
District of Columbia	$57.36

Source: Monitoring Analytics, "2010 State of the Market Report for PJM," March 10, 2011.

Appendix C – Forecasting Electricity Load Growth in Maryland

Introduction

From the early 1980s through the enactment of Maryland's Electric Customer Choice and Competition Act of 1999, the Power Plant Research Program (PPRP) undertook the development of independent, long-range forecasts of electric energy sales and peak demands for each of the four investor-owned electric utilities that operated in the state. With the enactment of competitive restructuring, Maryland's traditional electric utilities no longer had the responsibility of ensuring adequate electricity generation in their respective service areas. As a consequence, developing independent forecasts of electric energy sales and peak demands on a utility-by-utility basis no longer served the purpose of allowing an independent assessment of utility planning to meet future power supply requirements. To accommodate the new electric utility industry structure, PPRP modified its forecasting to take instead a statewide approach to forecasting demand.

In the last few years, the ability of the market to deliver adequate capacity resources and the increasingly regional nature of resource planning in political/regulatory boundary-spanning markets has prompted regulators to institute regional resource planning requirements for utilities and regional transmission operators. In Maryland, the PJM Interconnection is the regional transmission operator and is now responsible for conducting regional transmission planning. As part of transmission planning, PJM creates an annual forecast of electricity load growth in the PJM footprint. Additionally, the Maryland PSC is increasingly directing the utilities to perform capacity adequacy planning. PPRP's last electricity demand forecast was conducted in 2006 and, due to the forecasting functions being taken over by the other entities, PPRP now relies on the forecasts being prepared by the utilities and PJM. This appendix provides the results of the most recent (2011) PJM load forecast of electric energy consumption in Maryland.

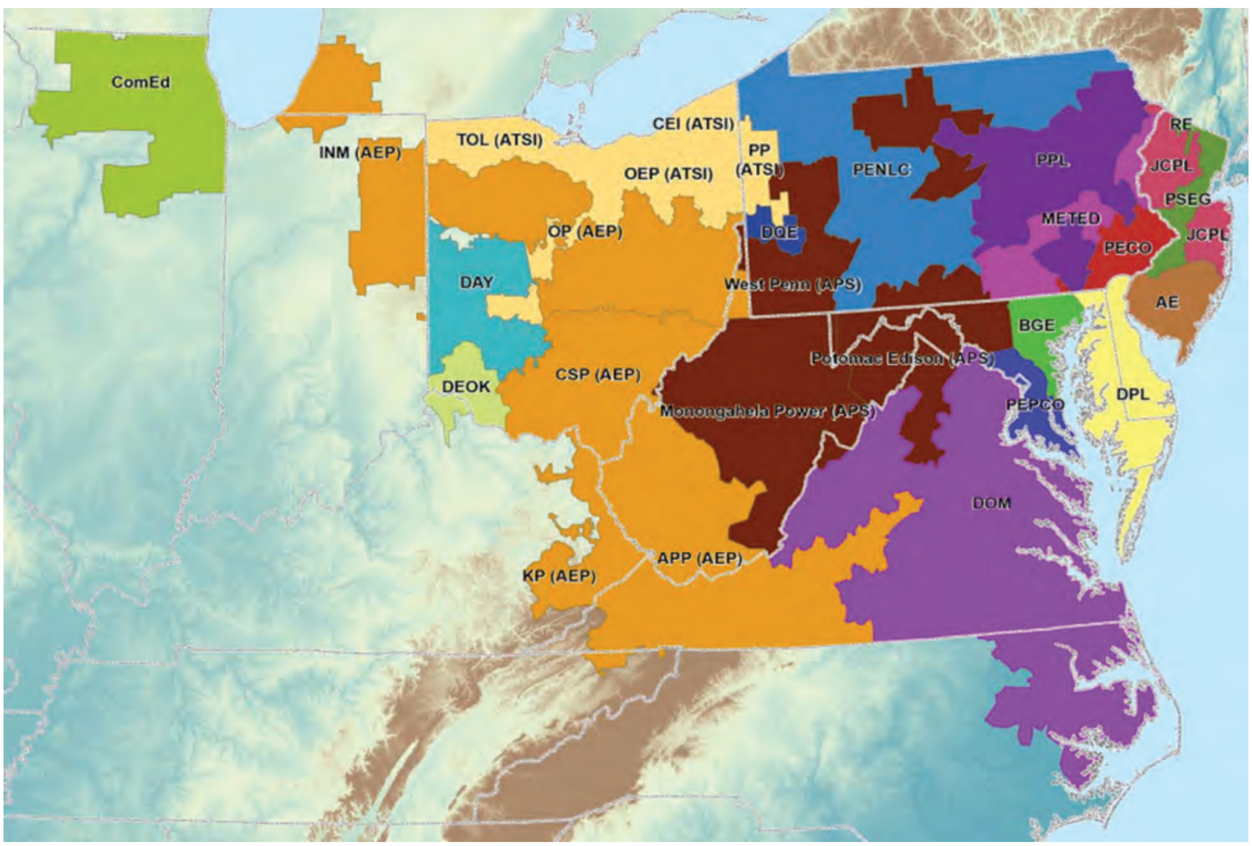
Methodological Summary

PJM conducts load forecasts by PJM zone (see Figure C-1), which are based largely on the boundaries of the primary electric company in the region. Maryland is a part of four separate PJM zones, only one of which is entirely located within the state.

- **APS** – this is a large zone encompassing all of Allegheny Power's utility services geographic area, which includes West Penn Power Company (Pennsylvania), Monongahela Power Company (West Virginia), and the Potomac Edison Company (Western Maryland, Virginia, and West Virginia). Maryland is only a very small portion of this zone; according to Allegheny Power's end-use electricity sales data, 15 percent of utility electricity sales and 17 percent of its customers in 2008 were in Maryland.

- **BGE** – this zone consists of the Baltimore Gas & Electric service area. This is the only zone entirely within the state.
- **DPL** – this zone coincides with Delmarva Power's geographic service area covering all of Delaware and the Eastern Shore region.
- **Pepco** – this zone includes all of Potomac Electric Company's geographic service area, which includes the District of Columbia and Montgomery and Prince George's counties, along with southern Maryland.

Figure C-1 PJM Load Forecast Zones



Source: *PJM Load Forecast Report, January, 2011.*

PJM collects load data for each electric distribution company on its system used for operational analysis to derive seasonal load profiles and weather normalization factors, and for preparing the various charts and tables contained in the PJM Load Forecast Report. PJM uses econometric multiple regression models to estimate the daily peak load for each of the zones. Economic drivers can be included at the national, state, or metropolitan level. PJM uses Gross Metropolitan Product as its base economic statistic and demographic data. For the peak demand forecast, the hourly load data is the dependent variable; for the energy forecast, it is daily energy consumption.

In contrast to past PJM forecasts, the 2011 forecast includes the electrical demand of two new regions: Duke Energy Ohio/Kentucky (to be integrated in 2012) and American Transmission Systems, Incorporated (ATSI) to be added in 2011. The addition of these two regions should have little impact on Maryland electricity prices as transmission constraints already limit the amount of cheaper energy that can be imported into PJM's Mid-Atlantic region (where all of Maryland's zones excluding APS are located) from the Western Region (where Duke and ATSI will be integrated into the PJM system).

Methodological Review

Seeking to improve their forecasting process, PJM commissioned a study to evaluate their current forecasting methodology and identify potential improvements. The resulting report, delivered in 2010 by consulting firm ITRON, concluded with four primary suggestions:

1. Utilize an alternative approach to the construction of economic variables, ITRON's "Index 1".
2. Include variables that capture the impact of changing electricity rates ("rate shift") on customer demand and consumption behavior.
3. In addition to the Moody's economic forecast used in past PJM forecasts, include a forecast from a second vendor, Global Insight.
4. Weight each vendor's forecast based on historical accuracy.

The suggestions were not incorporated into the 2011 Load Forecast Report (produced in December, 2010) as PJM did not have enough time to fully evaluate the potential impacts, but these will be considered for inclusion in the next forecasting cycle.

Consumption and Demand Projections

The effects of the economic recession resulted in a net reduction of overall electricity consumption throughout the PJM market (see Table C-1). Consumption dropped 30,000 GWh between 2008 and 2009 and despite a modest rebound in 2010 energy demand has yet to fully recover. Many (though not all) PJM zones experienced negative growth in electricity consumption. Peak summer demand (normalized for weather) saw a similar pattern. In the zones that include Maryland, the

Table C-1 PJM Historical and Projected Energy

PJM RTO Unrestricted Load (GWh)		
Year	Energy (GWh)	Annualized Growth Rate#
2003	675,439	--
2004	689,523	2.0%
2005	712,246	3.3%
2006	694,971	(2.4%)
2007	724,454	4.2%
2008	714,108	(1.4%)
2009	680,767	(4.7%)
2010*	699,331	2.7%
2011	719,782	2.92%
2015	775,825	2.10%
2020	817,369	1.57%
2025	850,264	1.31%

*Data from 2010 is estimated energy consumption from the 2011 Load Forecast.

#Actual change in the case of historical data, all other changes use 2010 as the reference year.

RTO = Regional Transmission Organization

Source: *PJM 2011 Load Forecast Report. January 2011.*

effects of the recession were mixed. While growth was at least slowed in all zones, BGE and PEPCO still experienced peak growth. However, APS and DPL both experienced a contraction in peak demand between 2008 and 2009, although this demand experienced some rebound in 2010.

At the time of the previous CEIR, PJM anticipated that renewed economic growth would eliminate the lingering effects of the recession, projecting an economic rebound returning annual load growth to the projected average annual growth rate of 1.6 percent for the next 10 years. Thus far, load growth between 2009 and 2010 has exceeded this average prediction. PJM's forecast still maintains a 1.6 (1.57) percent growth in electricity consumption over the next 10 years. This holds true for the Maryland-spanning zones (Table C-2).

Table C-2 PJM Energy Consumption Forecast by Zone

Electricity Consumption (GWh)					
Year	APS	BGE	DPL	Pepco	Total
2009*	47,545	34,158	18,782	32,384	132,869
2010*	48,481	33,927	18,864	32,162	133,434
2011	50,298	35,504	19,509	33,372	138,683
2012	51,197	35,960	19,640	33,938	140,735
2014	52,349	36,785	19,992	34,726	143,852
2016	53,258	37,764	20,362	35,421	146,805
2018	53,992	38,514	20,636	35,953	149,095
2020	55,185	39,308	21,101	36,706	152,300
2022	56,098	40,266	21,429	37,527	155,320
2024	57,243	41,190	21,857	37,953	158,243
Electricity Consumption Average Annual Growth Rates					
2010-2014	1.94%	2.04%	1.46%	1.94%	1.90%
2014-2020	0.88%	1.11%	0.90%	0.93%	0.96%
2020-2024	0.92%	1.18%	0.88%	0.84%	0.96%

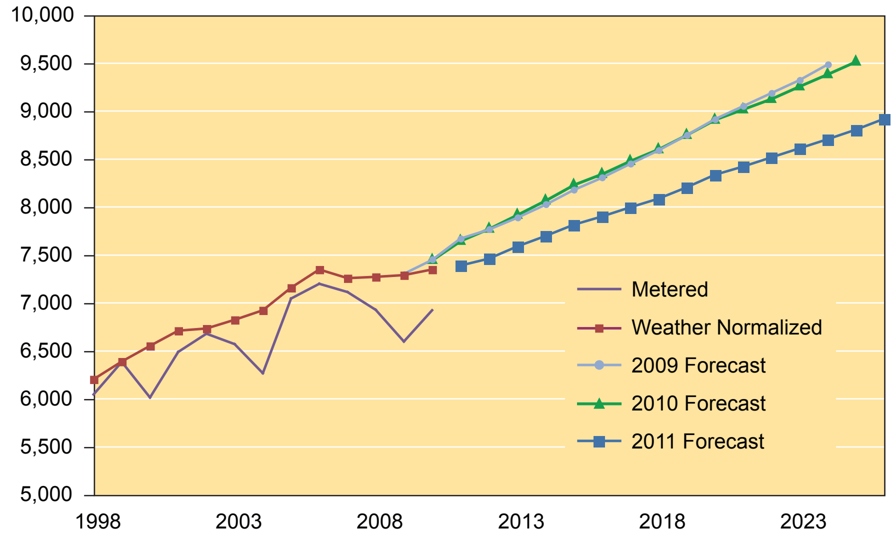
* 2009 and 2010 are estimates from the 2010 and 2011 Load Forecast Reports.
Source: Forecasts are from PJM's 2011 Load Forecast Report

Table C-3 Maryland Transmission Zone Forecast Revision 2010 to 2011

	Absolute (MW)	Percentage
BGE	-268	-3.50%
DPL	59	1.40%
PEPCO	-158	-2.20%
APS	-217	-2.40%

Peak demand growth has not matched the growth in overall electricity consumption, and PJM has considerably revised its projections of peak growth downward between the 2010 and 2011 load forecast reports (see Table C-3). This revision is depicted graphically in Figure C-2, which plots the historical and forecast consumption peaks in the BGE zone. Still, peak consumption is expected to grow at over 1 percent annually for the next 15 years, in aggregate, for the Maryland zones (Table C-4).

Figure C-2 BGE Zone Historical and Forecast Peak Demand



Source: *PJM Load Forecast Report, January 2011.*

Table C-4 PJM Summer Peak Load

Year	APS	BGE	DPL	Pepco	Total	Annualized Growth Rate#
2003	8,373	6,822	3,811	6,277	26,283	--
2004	8,348	6,922	3,810	6,391	25,471	0.7%
2005	8,630	7,160	4,070	6,810	26,670	4.7%
2006	8,550	7,350	4,100	6,920	26,920	0.9%
2007	8,620	7,260	4,130	6,950	26,960	0.1%
2008	8,843	7,270	4,010	6,930	26,642	(0.2%)
2009	8,490	7,290	3,960	6,960	26,700	0.2%
2010	8,620	7,350	4,050	6,990	27,010	1.1%
Forecast Values						
2011	8,655	7,388	4,148	6,986	27,177	0.62%
2015	9,100	7,814	4,328	7,339	28,581	1.14%
2020	9,513	8,336	4,561	7,654	30,064	1.08%
2025	9,934	8,807	4,808	7,960	31,509	1.03%

Source: *PJM 2011 Load Forecast Report, January 2011* and Historical Load Forecast Reports.
#Actual change in the case of historical data, all others use 2010 as the reference year.

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Appendix D – Determinants of Electricity Demand Growth in Maryland

Introduction

This appendix provides an overview of the basic theoretical foundations upon which forecasts rest, and an analysis of the trends of some of the economic and non-economic determinants of the demand for electricity. The Maryland data presented here have been 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 can include income, the price of electricity, and employment; non-economic variables can 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.

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 the appendix, 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 D-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 presents a brief summary.

Theoretical Foundations for Econometrically Modeling the Demand for Electricity

"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.

Table D-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

The residential demand for electricity is assumed to result from the exercise of choice by which the consumer maximizes his welfare 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. In the PPRP forecast studies, the demand for electricity is assumed to result from decisions made by the producer to maximize profits. 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 non-residential 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. Residential demand is, therefore, forecasted on a per customer basis, which, when multiplied by the projected number of residential customers, provides a forecast of total residential demand. 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. Employment is used in lieu of, and as a proxy for, output since no satisfactory time series of output data are available at a suitably disaggregated level.

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 electricity-consuming appliances as consumers must evaluate the use of a more constrained budget. Second, an income change will induce changes in the stock of electricity-consuming appliances as consumers are capable of purchasing more, fewer, or more electricity-intensive devices. As income changes, therefore, the demand for electricity will rise or fall. The PPRP forecast studies demonstrate 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. Real per capita income figures are reported in Table D-2 for the Maryland regions defined in Table D-1. Table D-2 summarizes historical and projected data as well as average annual growth rates for the period 1990 through 2020. As shown by the historical data, the rate of income growth has remained constant or slowed for all regions in Maryland. For the state as a whole, growth in real per capita income declined to 1.79 percent per year between 2000 and 2005, compared to an average annual growth rate of 1.90 percent between 1990 and 2000. All regions, with the exception of Southern Maryland (owing to its proximity to Washington, D.C. and federal government employment opportunities, which drive up wages), 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 even 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 during which a number of residents lost their incomes and placed relative downward pressure on wages as the competition for the few available jobs became more intense.

A forecast by the Maryland Department of Planning for 2010-2015 sees a substantial increase in the rate of income growth. As the nation (and Maryland) emerge from the recession and the economy once again begins growing, income is likely to follow the economy's upward trajectory.

Income growth once again slows (but is never negative) between 2015 and 2020 as the economy returns to standard rates of growth lower than those expected during the rebound period following a recession.

Table D-2 Historical and Projected Per Capita Income for Maryland, 1990-2020

Region	Per Capita Income (2000 $)						Annualized Growth				
	1990	2000	2005	2010	2015	2020	'90-'00	'00-'05	'05-'10	'10-'15	'15-'20
Maryland	$28,389	$34,261	$37,442	$39,560	$43,718	$46,387	1.90%	1.79%	1.11%	2.02%	1.19%
Baltimore	$27,082	$33,281	$36,837	$39,039	$43,326	$46,174	2.08%	2.05%	1.17%	2.11%	1.28%
Washington Suburban	$33,172	$38,987	$42,191	$44,321	$48,398	$51,035	1.63%	1.59%	0.99%	1.78%	1.07%
Southern Maryland	$24,848	$30,375	$32,099	$34,966	$38,978	$41,510	2.03%	1.11%	1.73%	2.20%	1.27%
Western Maryland	$19,485	$23,399	$25,417	$27,449	$30,953	$33,193	1.85%	1.67%	1.55%	2.43%	1.41%
Upper Eastern Shore	$24,306	$30,212	$32,700	$31,870	$39,184	$41,794	2.20%	1.60%	-0.51%	4.22%	1.30%
Lower Eastern Shore	$20,950	$24,185	$26,571	$28,125	$31,149	$33,103	1.45%	1.90%	1.14%	2.06%	1.22%

Source: Prepared by the Maryland Department of Planning, Planning Data Services, October 2009. Historical data, 1970-2000 from the U.S. Bureau of Economic Analysis.

Employment Trends

Non-residential 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 can be used. Non-farm employment has typically been relied upon for this purpose. By virtue of the necessity of having 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 D-3.

Table D-3 Historical and Projected Employment for Maryland, 1990–2020

Region	Total Jobs (thousands)						Annualized Growth				
	1990	2000	2005	2010	2015	2020	'90-'00	'00-'05	'05-'10	'10-'15	'15-'20
Maryland	1,702	2,075	2,760	3,092	3,344	3,466	1.14%	1.58%	0.72%	1.44%	0.89%
Baltimore	985	1,133	1,403	1,528	1,626	1,687	0.86%	1.25%	0.74%	1.33%	0.81%
Washington Suburban	468	659	965	1,097	1,195	1,237	1.29%	1.72%	0.70%	1.49%	0.90%
Southern Maryland	41	51	93	125	149	160	3.03%	3.52%	1.38%	2.14%	1.22%
Western Maryland	88	97	118	131	139	140	1.10%	1.10%	0.23%	1.06%	0.82%
Upper Eastern Shore	56	60	82	99	115	120	1.89%	3.00%	0.84%	2.40%	1.42%
Lower Eastern Shore	65	74	98	110	121	122	1.16%	1.85%	0.21%	1.06%	0.90%

Source: Historical data from the U.S. Bureau of Economic Analysis, Tables CA25 and CA25N. Projections from 2010 to 2030 prepared by the Maryland Department of Planning, Planning Data Services, October 2009.

As shown in Table D-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 population movements and the recession. Growth is projected to be most rapid in the Southern Maryland region and slowest in Western Maryland and the Lower Eastern Shore. Baltimore has emerged from a recent trend of lower employment growth to have a relatively higher rate of forecasted employment. For the state as a whole, overall employment trends track those in Baltimore and the Washington Suburban region as these areas simply contain the largest number of jobs. Both Baltimore and Washington Suburban, and subsequently the State of Maryland in aggregate, will see relatively similar growth patterns in the next decade.

The current economic downturn is likely to greatly affect employment, as well as energy consumption, and has considerably slowed the overall growth rates between 2005 and 2010. Maryland's unemployment rate rose from 3.7 percent in February 2008 to 6.7 percent in February 2009 and then 7.4 percent in January 2010. However, Maryland has still fared better than the United States as a whole. In January, 2010, the nationwide unemployment rate was 9.8 percent. Manufacturing output is likely to decline in Maryland as well, with a resultant energy usage by commercial and industrial customers below prior expectations. As with per capita income, the anticipated growth rebound out of the recession has considerably increased the forecast of job creation in the 2010-2015 timeframe relative to the recent, much less robust growth between 2005 and 2010.

Current forecasts of economic indicators (income and employment) universally assume relatively rapid growth over the next half decade as the United States emerges from the recession of the past three years. However, if these rosy predictions of economic recovery, 1.44 percent annual employment growth and 2.02 percent annual per capita income growth, are not realized, or simply realized more slowly, the continuing Maryland PSC 10-Year Plan (and PJM 15 year) forecasts will, by virtue of relying on overly optimistic expectations for economic indicators, predict growth in electricity consumption that does not appear as quickly as expected.

Population Trends

Population is an important causal variable because population trends are used to project 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) typically will result in higher demand. While smaller households use less electricity in absolute, the relationship between size and usage does not scale linearly as household electricity uses (such as heating and lighting) decline at rates lower than 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 D-4 and D-5.

Population data at regional and state levels are reported in Table D-4. The table summarizes historical and projected data, as well as average annual rates of growth for the period 1990 through 2020. The rates of growth in population have been positive since 1990 for every region of Maryland. Between 1990 and 2005, population growth in Maryland has been approximately one percent per year on average. The growth in population for the state is projected to rise during the 2010 to 2015 period and then slow between 2015 and 2020. 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, although the latter is expected to see growth accelerate between 2010 and 2020. Baltimore's growth rates will be the lowest during the same period.

Table D-4 Historical and Projected Population for Maryland, 1990-2020

	Total Population (thousands)						Annual Rate of Growth				
Region	**1990**	**2000**	**2005**	**2010**	**2015**	**2020**	**'90-'00**	**'00-'05**	**'05-'10**	**'10-'15**	**'15-'20**
Maryland	4,781	5,296	5,572	5,774	6,038	6,276	1.03%	1.02%	0.71%	0.90%	0.78%
Baltimore	2,348	2,512	2,602	2,677	2,778	2,848	0.68%	0.70%	0.57%	0.75%	0.49%
Washington Suburban	1,636	1,870	1,985	2,062	2,150	2,244	1.35%	1.20%	0.76%	0.85%	0.85%
Southern Maryland	229	281	319	340	372	404	2.10%	2.57%	1.26%	1.80%	1.67%
Western Maryland	224	237	243	250	262	275	0.53%	0.54%	0.58%	0.93%	0.94%
Upper Eastern Shore	181	209	228	242	261	281	1.48%	1.70%	1.20%	1.56%	1.47%
Lower Eastern Shore	163	187	196	204	215	225	1.36%	0.94%	0.81%	1.06%	0.98%

Source: Projections for the Baltimore Region based on Round 7C from the Baltimore Metropolitan Council of Government's Cooperative Forecasting Committee. Projections for the Washington Suburban Region based on Round 8.0 of the Metropolitan Washington Council of Governments Cooperative Forecasting Committee. Aggregated Data Prepared by the Maryland Department of Planning, November 2010.

Household data for the state are shown in Table D-5. The table shows a summary of historical and projected data, as well as average annual rates of growth for the period 1990 through 2020. 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 1990, household size in each of the six Maryland regions has been declining, and the decline is forecast to continue through 2020. For the state, the average household size was 2.67 people in 1990, which declined to 2.61 in 2000 (representing an average rate of decline of about 0.24 percent per year) and further declined to 2.59 in 2005 (a decline of 0.13 percent per year, on average, compared to 2000). Household size is expected to decline to 2.52 people in 2020.

Table D-5 Historical and Projected Number of Households and Average Size of Households in Maryland, 1990-2020

	Number of Households (thousands)						Average Annual Rate of Growth				
Region	**1990**	**2000**	**2005**	**2010**	**2015**	**2020**	**'90-'00**	**'00-'05**	**'05-'10**	**'10-'15**	**'15-'20**
Maryland	1,749	1,981	2,094	2,181	2,309	2,423	1.25%	1.12%	0.81%	1.15%	0.97%
Baltimore	868	959	998	1,039	1,093	1,133	1.00%	0.80%	0.81%	1.03%	0.71%
Washington Suburban	593	681	726	752	792	833	1.40%	1.27%	0.71%	1.04%	1.04%
Southern Maryland	75	98	112	120	134	147	2.63%	2.77%	1.43%	2.13%	1.89%
Western Maryland	85	91	94	97	103	108	0.69%	0.80%	0.53%	1.17%	1.13%
Upper Eastern Shore	67	80	87	93	102	110	1.80%	1.86%	1.25%	1.82%	1.66%
Lower Eastern Shore	62	73	78	81	86	91	1.64%	1.21%	0.79%	1.37%	1.14%
	Household Size						**Average Annual Rate of Growth**				
Maryland	2.67	2.61	2.59	2.57	2.54	2.52	-0.24%	-0.12%	-0.13%	-0.24%	-0.20%
Baltimore	2.64	2.55	2.53	2.50	2.47	2.44	-0.35%	-0.12%	-0.26%	-0.28%	-0.22%
Washington Suburban	2.71	2.70	2.69	2.69	2.66	2.64	-0.05%	-0.10%	0.02%	-0.20%	-0.19%
Southern Maryland	2.97	2.83	2.80	2.78	2.73	2.70	-0.50%	-0.19%	-0.18%	-0.32%	-0.22%
Western Maryland	2.52	2.44	2.41	2.40	2.38	2.35	-0.34%	-0.23%	-0.04%	-0.22%	-0.20%
Upper Eastern Shore	2.65	2.58	2.56	2.55	2.52	2.50	-0.28%	-0.17%	-0.05%	-0.24%	-0.17%
Lower Eastern Shore	2.50	2.43	2.39	2.38	2.35	2.33	-0.31%	-0.32%	-0.07%	-0.28%	-0.15%

Source: Pre-2005 historical data from the U.S. Census. Forecasts prepared by the Maryland Department of Planning, November 2010.

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 non-residential, as well as into economic and non-economic 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 non-economic explanatory variables affecting residential electricity consumption. This appendix also shows trends in employment, which affect the non-residential 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 the demand for electricity should continue to grow in Maryland.

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