MARYLAND DEPARTMENT OF NATURAL RESOURCES

Larry Hogan, *Governor*
Boyd Rutherford, *Lt. Governor*
Jeannie Haddaway-Riccio, *Secretary*
Charles Glass, *Deputy Secretary*

December 26, 2019

The Honorable Larry Hogan
Governor, State of Maryland
State House, 100 State Circle
Annapolis, Maryland 21401-1991

The Honorable Delores G. Kelley
Chair, Senate Finance Committee
3 East Miller Senate Building
Annapolis, Maryland 21401-1991

The Honorable Thomas V. Miller, Jr.
President, The Senate of Maryland
State House, H-107
Annapolis, Maryland 21401-1991

The Honorable Dereck E. Davis
Chair, Economic Matters Committee
Room 231 House Office Building
Annapolis, Maryland 21401-1991

The Honorable Adrienne A. Jones
Speaker, Maryland House of Delegates
State House, H-101
Annapolis, Maryland 21401-1991

Re: Submission of the Final Report for the Maryland Renewable Portfolio Standard
Agency: Maryland Department of Natural Resources
Report Authority: Chapter 393 (HB 1414) of the Acts of 2017 (MSAR #11225)

Dear Governor, President, Speaker and Chairs:

Attached is the final report for the Maryland Renewable Portfolio Standard study. The report was created pursuant to Chapter 393 (HB 1414) of the Acts of 2017.

Should you have any questions or comments regarding this report, please feel free to contact our Director, Legislative and Constituent Services, James W. McKitrick directly at 410-260-8112 or by email at jamesw.mckitrick@maryland.gov.

Sincerely,

Jeannie Haddaway-Riccio
Secretary

enclosure

cc: Sarah Albert (5 copies)
James W. McKitrick

MARYLAND DEPARTMENT OF NATURAL RESOURCES

PPES-MRPS-2019
DNR Publication No. 12-091619-167

PPRP

FINAL REPORT CONCERNING THE MARYLAND RENEWABLE PORTFOLIO STANDARD AS REQUIRED BY CHAPTER 393 OF THE ACTS OF THE MARYLAND GENERAL ASSEMBLY OF 2017

December 2019

MARYLAND POWER PLANT RESEARCH PROGRAM

LARRY HOGAN, GOVERNOR
BOYD RUTHERFORD, LT. GOVERNOR

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

Jeannie Haddaway-Riccio, *Secretary*
Maryland Department of Natural Resources

ACKNOWLEDGMENTS

This report was prepared by Exeter Associates, Inc., in coordination with the Power Plant Research Program (PPRP) of the Maryland Department of Natural Resources (DNR). Kevin Porter of Exeter Associates, Inc. was the project manager. Mr. Porter, Matthew Hoyt, and Rebecca Widiss were the primary authors. Important contributions to the report were made by Steven Estomin, Maureen Reno, Cali Clark, Angela Richardson, Peter Hall, Stan Calvert, Jeremy Schein, Stacy Sherwood, William Cotton, Nick DiSanti, and Katherine Fisher.

The authors thank the Maryland Department of Natural Resources and the Power Plant Research Program for their support for this project. In particular, the authors thank Bob Sadzinski and David Tancabel. The authors also thank the members of the Maryland Renewable Portfolio Standard Work Group (see Appendix B) for their contributions. The authors also thank the Maryland Public Service Commission, Maryland Energy Administration, Maryland Department of the Environment, Maryland Office of People's Counsel, PJM Interconnection, National Renewable Energy Laboratory, and Lawrence Berkeley National Laboratory.

The Maryland Public Service Commission provided technical feedback in the preparation and accuracy of this report. The Commission takes no position with respect to any of the regulatory or policy options or recommendations presented.

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PREFACE

In 2017, the Maryland General Assembly enacted House Bill (HB) 1414 directing the Power Plant Research Program of the Maryland Department of Natural Resources to conduct a study of the Maryland Renewable Energy Portfolio Standard (RPS). HB 1414 identified 17 general and specific requirements of the study, including assessment of: the effectiveness of the RPS along several economic and environmental dimensions, the availability and cost of renewable energy resources, the impact of alterations to the Maryland RPS, and the potential to meet future Maryland RPS standards.[1] The complete list of requirements from HB 1414, as included in Chapter 393 of the Acts of the Maryland General Assembly of 2017 (Ch. 393), is reproduced in Appendix A.

PPRP issued a Request for Proposals in October 2017, and ultimately selected Exeter Associates, Inc. (Exeter) of Columbia, Maryland to prepare the study. The Maryland Board of Public Works approved PPRP's contract with Exeter in May 2018, and work commenced in June 2018. PPRP released the *Interim Report Concerning the Maryland Renewable Portfolio Standard* (interim report) in February 2019, and PPRP and Exeter presented a summary of the report to the Maryland House Economic Matters Committee on February 4, 2019. This report is the *Final Report Concerning the Maryland Renewable Portfolio Standard* (final report).

To minimize the costs of the study, PPRP stressed reliance on existing work, such as PPRP's *Long-Term Electricity Report for Maryland* (LTER), issued in 2016, and the *PJM Renewable Integration Study* (PRIS), issued in 2014. The subsequent final report draws from this existing research as well as expands on it in several key ways.

To support the study, PPRP organized the Maryland RPS Work Group, consisting of representatives from the renewable energy industry, electric utilities, environmental and consumer organizations, county and state government, and consultants. The RPS Work Group met four times during report development, both in person and through online webinars. The full list of RPS Work Group members is provided in Appendix B.

Scope of Report

Evaluating an RPS is a challenging undertaking, made more complicated by the complexity of energy markets and providing electricity, which entails coordinated activity by a variety of stakeholders located both interstate and intrastate, and the concurrent impact of technical, social, political, regulatory, environmental, and economic conditions. Given these challenges, experts have adopted a wide range of approaches to evaluate the successes and failures of RPS policies.[2]

To address the requirements identified in Table P-1, below, the final report use several methods, including: assessment of existing research, analysis of both public and proprietary data, and input-output (I-O) modeling on both a state and regional level. The final report also applies the LTER's system impact and production cost modeling.

This report is not intended as an exhaustive assessment of all past and prospective impacts of the current Maryland RPS or future versions of the policy. Instead, the report addresses

[1] In addition to the specified requirements, HB 1414 also includes a catchall requirement to study any other matters that PPRP considers "relevant to the analysis of the issues." The Clean Energy Jobs Act (Senate Bill [SB] 516), as passed in May 2019, amended one existing requirement and added one new requirement.

[2] Warren Leon, *Evaluating the Benefits and Costs of a Renewable Portfolio Standard – A Guide for State RPS Programs*, Clean Energy States Alliance, 2012, cesa.org/assets/2012-Files/RPS/CESA-RPS-evaluation-report-final-5-22-12.pdf.

specific topics of interest to the Maryland General Assembly as identified in Ch. 393, which directed DNR to conduct a comprehensive study of the Maryland RPS in cooperation with the Maryland Energy Administration (MEA), the Maryland Department of the Environment (MDE), the Maryland Public Service Commission (PSC), and other state and local units, encompassing the economic, socioeconomic, environmental, and reliability impacts of the Maryland RPS. In 2019, the General Assembly amended one requirement and added one additional requirement for this study to address, as part of legislation increasing the Maryland RPS to 50% by 2030. Table P-1 summarizes the requirements and identifies where they are discussed, in part or in full, within the body of the final report.

Some areas of potential impact are outside the scope of this report. These include: technology forcing; wholesale market price suppression (i.e., "bid-stack" effects); long-term rate stability; fuel security, vulnerability, or diversity; and transmission and distribution costs. Although many of these topics are addressed in brief, they require additional research to fully characterize or quantify.

The goal of the report is to provide Maryland stakeholders a detailed representation of the Maryland RPS. The organization of the report is roughly chronological in nature. Following an introduction that lays out the evolution of the Maryland RPS, the report begins with an evaluation of the effectiveness of the Maryland RPS to date. Next, the report describes the expected impact of the current RPS going forward. Then, after discussing the existing RPS, the report delves into the potential impact of adjustments to the RPS. Finally, the report evaluates non-RPS alternatives, identifies several emerging issues, and concludes.

Table P-1. Location of Analysis Addressing Key Maryland RPS Final Report Topics

Maryland RPS Abbreviated General/Specific Requirement		Chapter/Section #
GR 1	Availability of all clean energy sources at reasonable and affordable rates	2.4, 3.5
GR 2	Economic and environmental impacts of the deployment of renewable energy	2.2, 2.3, 3.3, 3.4
GR 3	Effectiveness of Maryland RPS in encouraging development and deployment of renewable energy	2.1, 3.2
GR 4	Impact of changes to the Maryland RPS	2.6
GR 5	Alternative models of regulation and market-based tools that could promote the goals of the Maryland RPS and Maryland's energy policies	6.1-6.12
GR 6	Potential to alter or otherwise evolve the Maryland RPS to increase or maintain its effectiveness	4.1-4.12
SR 1	Reducing the carbon content of imported power	2.2
SR 2	Net environmental and fiscal impacts from long-term contracts for clean energy	5
SR 3	Whether the RPS is able to meet current and potential future targets without the inclusion of certain technologies	4.13
SR 4	Which industries are projected to grow, and to what extent, as a result of incentives associated with the RPS	3.4
SR 5	Whether public health and environmental benefits from clean energy are being equitably distributed across environmental justice communities	2.5
SR 6	Whether the state is likely to meet its existing goals under the RPS and, if the state were to increase those goals, whether an adequate supply of RECs is available	3.1
SR 7	Additional opportunities to promote local job creation within the industries that are projected to grow as a result of the RPS	3.4
SR 8	System flexibility the state would need under future RPS goals	7.1
SR 9	Role of energy storage	7.1
SR 10	Role of in-state clean energy in achieving greenhouse gas emissions reductions and promoting local jobs and economic activity	2.2, 2.3
	Ratepayer impact of in-state clean energy and all qualified energy as a result of a higher carve-out [1]	3.5
SR 11	Change in solar renewable energy credit prices over the immediate 24 months preceding submission of the interim report to the Maryland General Assembly	Appendix D
SR 12	Costs, benefits, and any legal or other implications of allowing Tier 1 renewable energy resources from anywhere in or off the coast of the contiguous U.S.[1]	4.14
SR 13	Any other matters that PPRP considers relevant to the analysis of the issues identified above	7.2, 7.3

GR = general requirement; SR = specific requirement. See Appendix A for the complete list of assessment requirements.

[1] Added following the passage of the Clean Energy Jobs Act (SB 516), as encoded in Chapter 757 of the Acts of the Maryland General Assembly of 2019 (Ch. 757).

EXECUTIVE SUMMARY

The Maryland Renewable Portfolio Standard (RPS) requires that a designated percentage of the electricity sold by load-serving entities (LSEs) in the state come from eligible renewable energy sources or technologies. Maryland is one of 29 states (and the District of Columbia) with an RPS requirement. The primary way that LSEs comply with the Maryland RPS is through the retirement of Renewable Energy Credits (RECs). A REC is a certificate demonstrating 1 MWh of energy output from a certified renewable energy generator that can be used to meet RPS compliance requirements. Although RECs can only be retired for RPS compliance in a single state,[3] they can be procured from the pool of renewable energy resources supplying power in, or into, the PJM Interconnection, LLC (PJM). PJM is the regional grid operator serving portions or all of 13 states (and the District of Columbia), including Maryland. An LSE can also opt instead to pay an Alternative Compliance Payment (ACP) during a given compliance period in lieu of supplying the minimum percentage of RECs required.

The Maryland RPS was first enacted in 2004 when the Maryland General Assembly passed Senate Bill (SB) 869, the Renewable Energy Portfolio Standard and Credit Trading Act (Maryland RPS Act). Since the law took effect in 2006, the Maryland RPS has been amended 11 times, including as recently as the enactment of the Clean Energy Jobs Act (CEJA) (SB 516) in May 2019, as encoded in Chapter 757 of the Acts of the Maryland General Assembly of 2019 (Ch. 757) (see Figure ES-1). These changes include: adjustments to the percentage requirements; the addition of new eligible resources; changes to where eligible resources can be sourced; and creating carve-outs, meaning in-state set-asides, for solar and offshore wind. The Maryland RPS currently requires that 50% of retail energy sales come from renewable energy resources by 2030, including 14.5% from in-state solar.[4] The RPS also requires the construction of 1,200 megawatts (MW) of offshore wind capacity in waters off the Maryland coast, in addition to 368 MW from two offshore wind projects that have been approved by the Maryland PSC to receive Offshore Wind Renewable Energy Credits (ORECs).

[3] RECs can be traded or transacted until notice is provided to the PJM's Generation Attribute Tracking System (PJM-GATS), the system used to register RPS-eligible facilities and track RECs, that the REC is retired. At that point, the RECs can no longer be transferred to other parties. LSEs then submit RPS compliance reports to the Maryland PSC that indicate the number of RECs that have been retired for purposes of complying with the Maryland RPS.

[4] Ch. 757 specifies a separate solar carve-out of 2.5% for electric cooperative customers in 2020 and later.

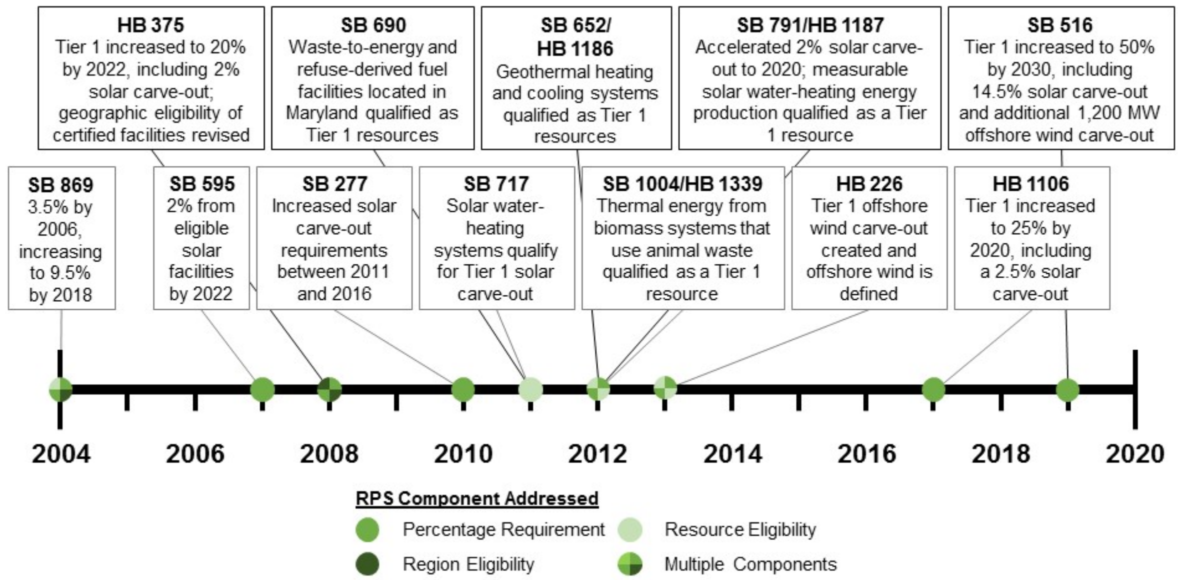

Figure ES-1. Timeline of Changes to the Maryland RPS

The Maryland RPS is complex and intended to achieve a variety of goals that may be working at cross purposes, such as promoting in-state economic development versus minimizing RPS compliance costs. While such trade-offs are likely to be familiar at the conceptual level, this report is intended to shed new light on their specific nature and magnitude.

The Maryland RPS has contributed to new, non-hydro renewable energy development in Maryland and throughout PJM.

A simple approach to measuring the impact of state RPS policies is to compare total historical renewable energy growth to the minimum amount required to meet state RPS requirements. This should not be interpreted as directly attributing growth in renewable energy capacity to state RPS policies; it merely measures the percentage of growth historically in renewable energy capacity versus the amount of capacity required to meet state RPS requirements. Other factors that contribute to renewable energy growth include voluntary green power markets, net metering, and utility purchases or development of renewable energy capacity that are not used for RPS compliance.

Given these caveats, estimates from the Lawrence Berkeley National Laboratory (LBNL) indicate that demand created by state RPS policies accounted for about 45% of growth in non-hydroelectric power (hydro) renewable energy generation in the U.S. from 2000-2018. In regions like the Northeast and the mid-Atlantic, state RPS policies are associated with the majority of the growth in non-hydro renewable energy generation.[5]

These trends are reflected in Maryland, where the RPS has contributed to renewable energy development in the state, especially wind and solar energy (see Figure ES-2). Between 2008-2018, non-hydro, utility-scale (>1 MW) renewable energy capacity in Maryland rose from 155 MW to 697 MW, and generation from these resources more than doubled from

[5] Many factors contributed to the growth of renewable energy over the last two decades. LBNL's attribution is based on a comparison of RPS required increases in non-hydro renewable energy generation with actual growth over the same period, all at a state level.

612,485 MWh to 1,531,082 MWh, according to the U.S. Energy Information Administration (EIA).

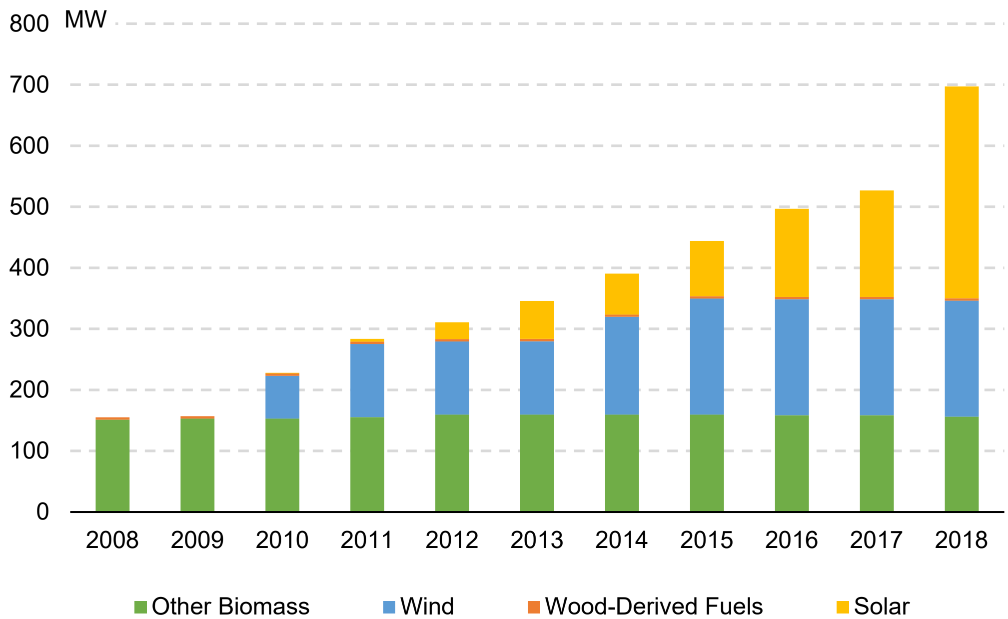

Figure ES-2. Utility-Scale, Non-Hydro Renewable Energy Capacity in Maryland

Source: EIA, "Detailed State Data," 2017. EIA data for 2018 are preliminary (up to date as of May 1, 2019).

Distributed solar (<1 MW) has also grown rapidly in Maryland since the addition of a solar carve-out to the Maryland RPS in 2007. According to PJM's Generation Attribute Tracking System (PJM-GATS), the system used to register RPS-eligible facilities and track REC retirements, over 60% of the solar photovoltaic (PV) capacity in Maryland is from distributed solar as of 2018, totaling over 650 MW. However, in 2017, utility-scale capacity grew more quickly (by capacity) than small-scale PV capacity for the first time.

The contribution of renewable energy to Maryland's capacity and energy mix has roughly doubled since 2008. According to EIA data, large hydro, utility-scale, and distributed renewable energy together made up approximately 11.5% of total Maryland capacity in 2018. Likewise, energy generation from the same renewable energy resources comprised 11.6% of total Maryland electric power industry energy generation in 2018. In 2008, large hydro and utility-scale resources comprised approximately 5% and 5.5% of total Maryland capacity and generation, respectively.

Beyond Maryland's borders, 50% of the PJM-GATS registered renewable energy capacity that has come online since 2004, totaling 9,095 MW, is eligible for the Maryland RPS (see Figure ES-3). Approximately 7,600 MW of this new capacity is wind, with the remainder being primarily solar or landfill gas (LFG) facilities.

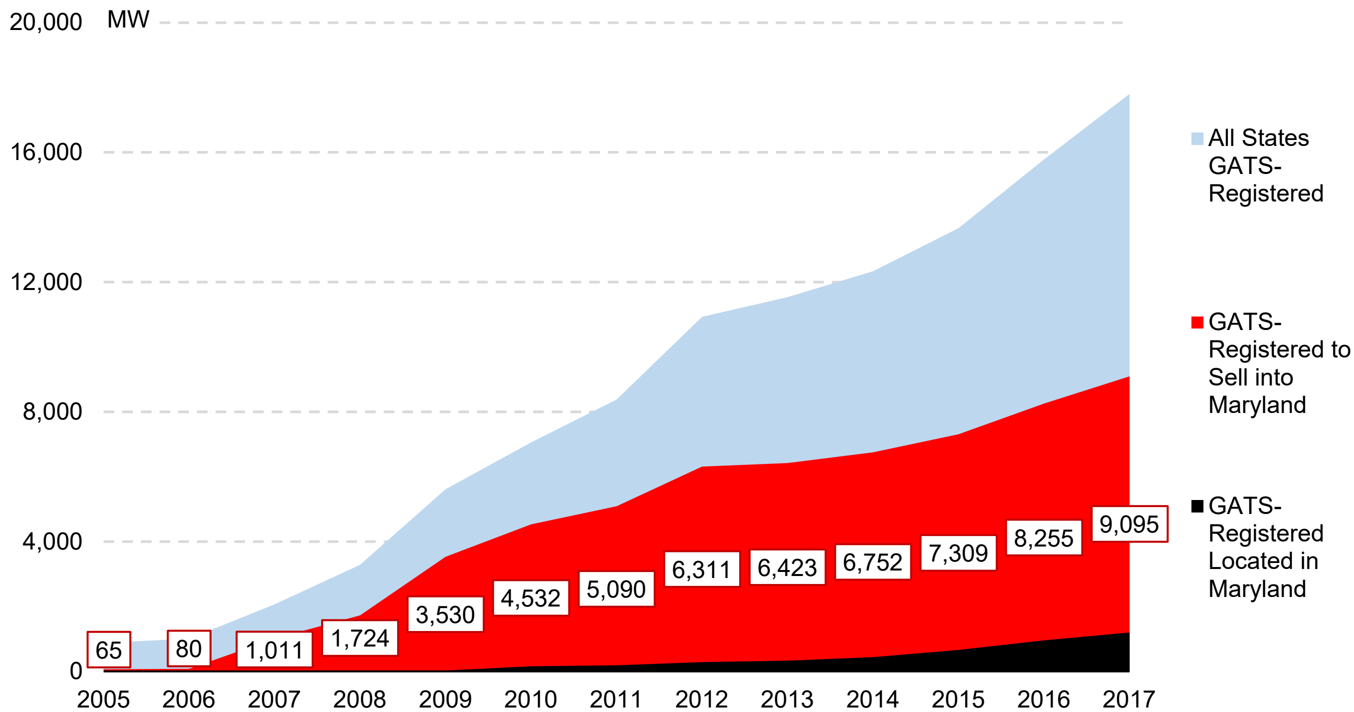

Figure ES-3. Cumulative PJM-GATS Registered Renewable Energy Nameplate Capacity

Source: PJM-GATS.

Note: Inclusive of capacity that has come online since 2005. Each category is inclusive of the category or categories beneath it.

To date, Maryland RPS requirements have been achieved at costs that can be considered relatively reasonable and affordable, representing at most 1.8% of retail electricity bills.

LBNL and the National Renewable Energy Laboratory (NREL) have concluded that, nationwide, RPS costs are historically less than 2% of retail electric rates, and that Maryland compliance costs are on par with or lower than other restructured states in PJM.

For the final report, the ratepayer impacts of RPS policies in Maryland and other PJM states are estimated using LBNL and NREL's approach: RPS compliance costs are assumed to equal the costs of procuring RECs, and the payment of ACPs. These costs can be divided by total annual retail electricity costs, which are themselves the product of annual retail electricity sales and average retail electricity prices, to derive a percentage rate impact of an RPS on retail ratepayers. It is important to note that this is a simple approach that excludes positive or negative externalities associated with state RPS policies, such as any price suppression impacts of renewable energy displacing other sources of generation, or transmission or system integration costs.

Total RPS compliance costs in Maryland increased from $14.7 million in 2011 to $135.2 million in 2016, then fell to $72.9 million in 2017, as shown in Figure ES-4. The growth in costs through 2016 corresponds with increasing Maryland RPS requirements, higher demand for RECs in and outside of Maryland, and/or increased Tier 1 REC prices in most years during this time frame. The drop in Maryland RPS compliance costs in 2017 follows a significant decline in Tier 1 REC and solar REC (SREC) prices. (Note that immediately after the enactment of Ch. 757 in 2019, spot market prices for SRECs increased to over $50/MWh, but Tier 1 REC prices did not change significantly.)

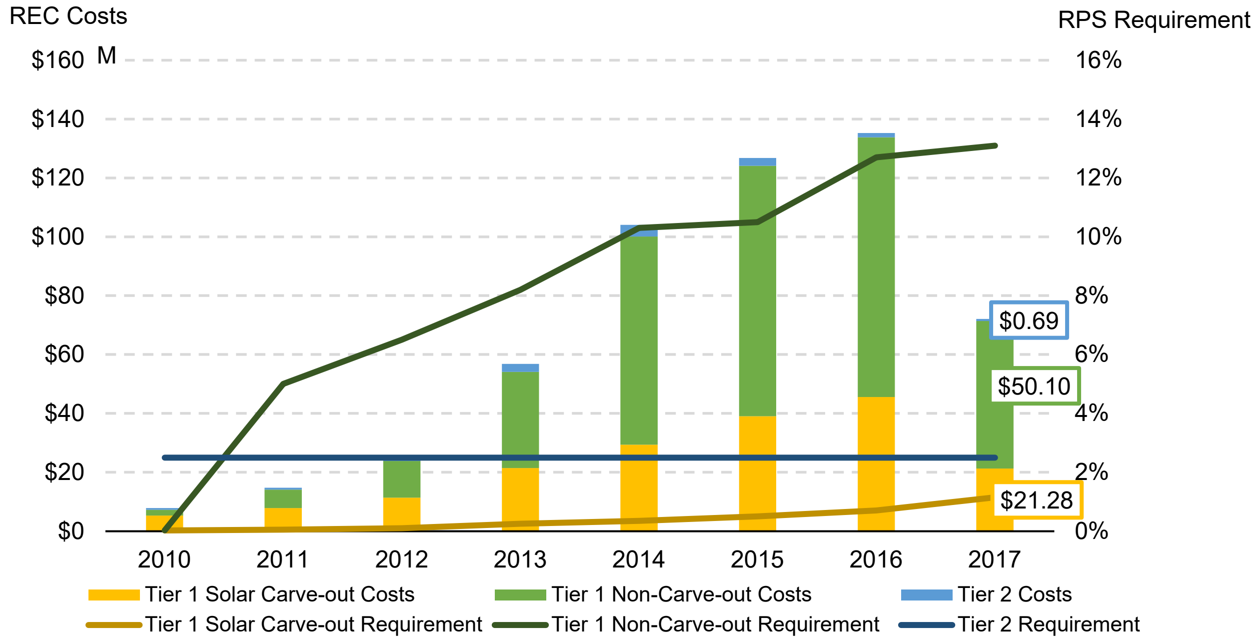

Figure ES-4. Maryland's Annual Total RPS Compliance Costs (RECs) Compared to Requirements

Source: Maryland PSC 2018 *Renewable Energy Portfolio Standard Report*.

Note: Call-out boxes for 2017 show total RPS compliance costs ($millions), by Tier.

As a percentage of retail electric utility bills, compliance costs for the Maryland RPS peaked at 1.8% in 2016 before falling to approximately 1% in 2017 (see Figure ES-5). This trend parallels the rise and fall of total Maryland RPS compliance costs, primarily because average retail rates in Maryland have remained relatively flat, or have slightly fallen, for all customer classes over the past several years. The solar carve-out has been a significant portion of RPS compliance costs in Maryland. In 2017, the 1.15% solar carve-out represented 30% of RPS compliance costs in Maryland. Over the prior six years, the carve-out represented between 28-53% of RPS compliance costs in Maryland.

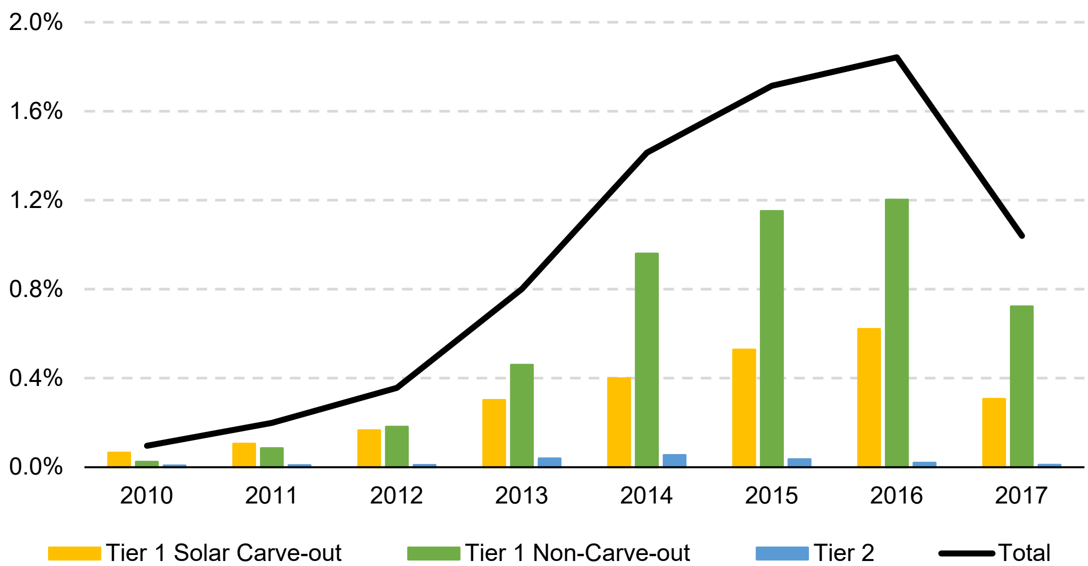

Figure ES-5. Maryland RPS Ratepayer Impact as a Percent of Total Retail Bills

Maryland's RPS compliance costs, as a share of retail bills, place it in the middle of PJM states (see Figure ES-6). The diversity in compliance costs reflects the diversity of RPS policies across PJM: the lower RPS requirements or more expansive resource eligibility rules reduce ratepayer impacts, while the opposite can apply to higher and/or more stringent RPS requirements, especially if there are resource-specific carve-outs. Ohio represents one extreme; as of 2019, its RPS was set at 5.5% with a 0.22% solar carve-out, after having previously been frozen at 2.5% with a 0.15% solar carve-out for two years (2015 and 2016). A variety of technologies are eligible for the Ohio RPS, including municipal solid waste (MSW), LFG, and biomass. As a result, the impact of the Ohio RPS on ratepayers is the lowest in PJM. New Jersey has the highest RPS ratepayer impact in PJM; as of 2019, its RPS was 20.975% (14.175% Tier 1, 2.5% Tier 2 with a 4.3% solar carve-out). The higher RPS and the higher solar carve-out in New Jersey are primary factors for New Jersey's higher RPS ratepayer impact. Maryland's "middle" position reflects a blend of factors. For instance, the state has both higher RPS requirements than certain states (Illinois, Michigan, Ohio, Pennsylvania) and more expansive resource eligibility rules than others (Delaware, District of Columbia), as discussed later in the report.

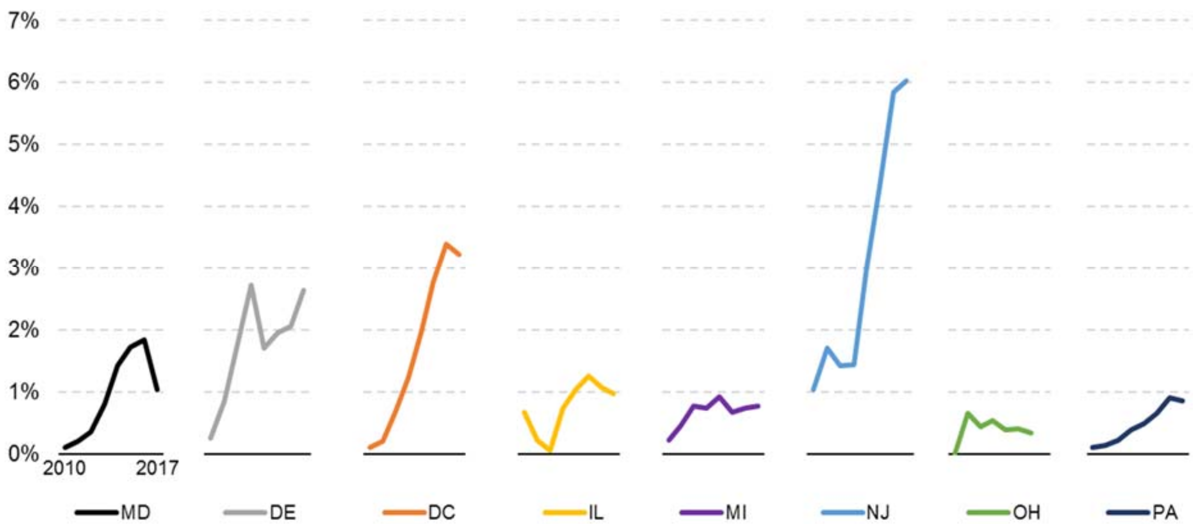

Figure ES-6. RPS Ratepayer Impact as a Percent of Total Retail Bills Across PJM, 2010-2017

Based on NREL data, there appears to be sufficient renewable energy generation available at relatively reasonable rates. The Maryland Public Service Commission (PSC) applies a "just and reasonable" standard when it assesses regulated utility rates. No equivalent standard applies to RPS compliance. This is because the provision of electric generation is considered competitive in Maryland, and it is not regulated by the PSC. However, the procurement of RECs can be said to result in "reasonable" rates if it is the result of a competitive market process. Several aspects of Maryland's REC market support this characterization: nearly 66,000 generators are registered to provide Maryland RECs, well over 100 LSEs are responsible for procuring RECs, and REC sales are tracked in a transparent manner by PJM.

The affordability of RECs can be determined by gauging the use of ACPs, which are set at the level beyond which RECs are no longer considered affordable. To date, Maryland has met its renewable energy requirements in every year since the inception of the RPS, and LSEs have done so with minimal use of ACPs. Specifically, LSEs have successfully procured RECs to meet over 99% of Tier 1 non-carve-out and Tier 2 RPS obligations in all years. This indicates that renewable energy resources are both sufficiently available and obtainable at relatively affordable rates.

RECs retired for Maryland RPS compliance are diverse in fuel type. Half are from facilities that were in operation before the enactment of the RPS in 2004.

Between 2008-2017, Maryland relied on six primary fuel sources (wind, black liquor, hydro, wood/biomass, MSW, and LFG) to meet the Tier 1 non-carve-out portion of its RPS. Wind, black liquor, and MSW, as shown in Figure ES-7, grew the most during this period, in terms of the number of RECs retired. (Note that MSW became Tier 1-eligible in 2011.) However, only wind experienced a significant increase in its percentage share of RPS compliance. Largely as a result of this trend, Maryland's reliance on carbon-free technologies for Tier 1 RPS compliance has risen steadily, reaching over 62% RPS compliance in 2017.

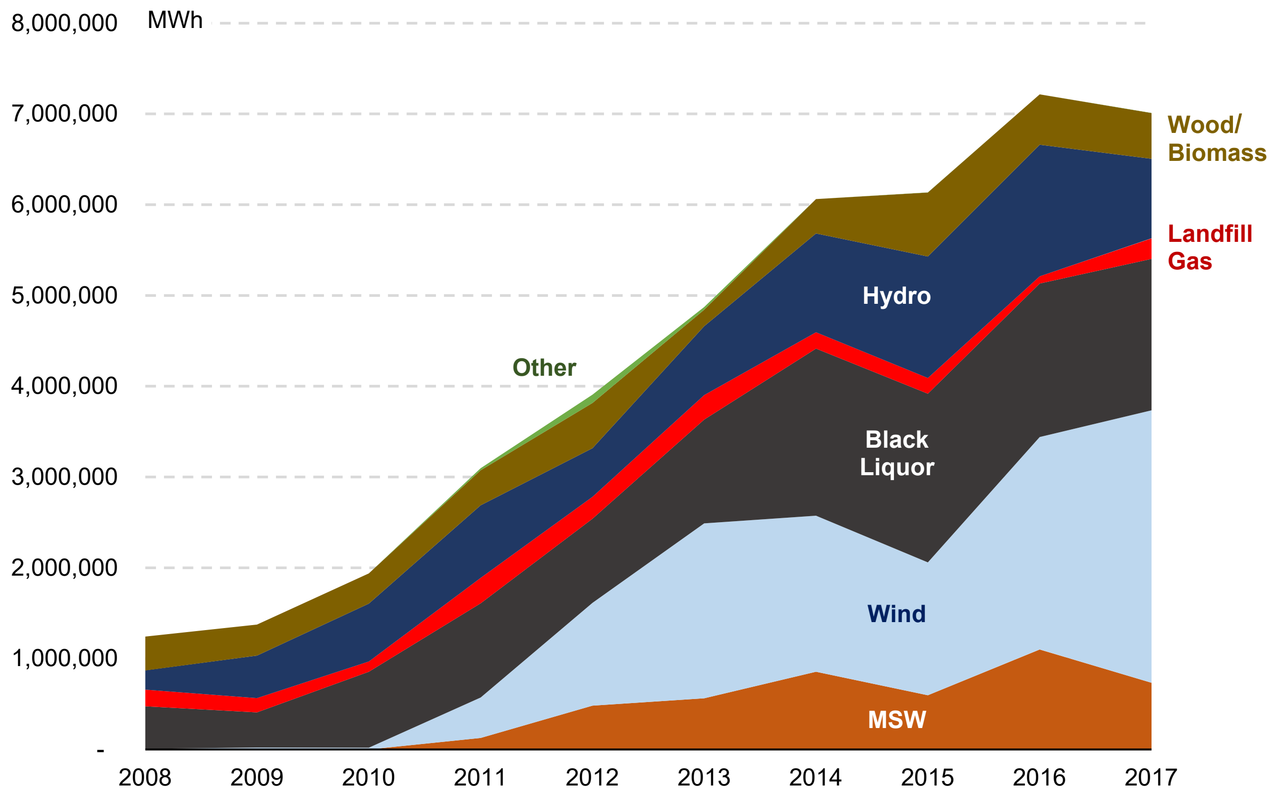

Figure ES-7. RECs Retired for Tier 1 Non-Carve-out Maryland RPS Compliance, by Fuel Source

Source: PJM-GATS.

The resource mix used to fulfill Maryland's Tier 1 non-carve-out RPS requirement is on par with Pennsylvania's, and is more diverse than the other three mid-Atlantic states in PJM that have RPS requirements (Delaware, New Jersey, and the District of Columbia) (see Figure ES-8). This reflects differences in resource eligibility. While carbon-emitting resources are eligible for Tier 1 compliance in both Maryland and Pennsylvania, they tend to be considered Tier 2 resources in other states (e.g., MSW in New Jersey), have never been or are no longer accepted for RPS compliance (e.g., black liquor in all three other states), or face higher eligibility thresholds (e.g., biomass must be greater than 65% efficient in the District of Columbia).

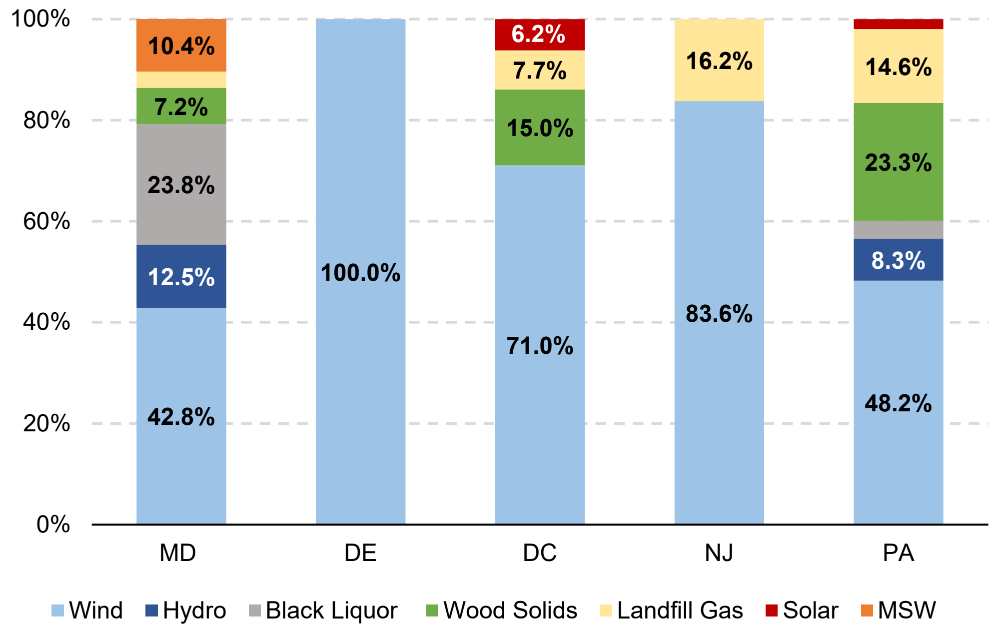

Figure ES-8. RECs Retired for Tier 1 Non-Carve-out RPS Compliance in mid-Atlantic States in PJM, by Fuel Source (2017)

Source: PJM-GATS.

The Maryland RPS does not have a vintage requirement, meaning existing and new generation facilities are eligible for the RPS (see Figure ES-9). In 2017, 53% of all RECs retired and 51% of Tier 1 non-carve-out RECs retired were generated by facilities operating prior to 2005. The latter resources that received RECs in 2017 from Tier 1 non-carve-out generation operating before 2005 included black liquor (43%), small hydro (24%), and MSW (21%). Also in 2017, 85% of Tier 2 RECs were generated by facilities operating prior to 2005, all of them large hydro.

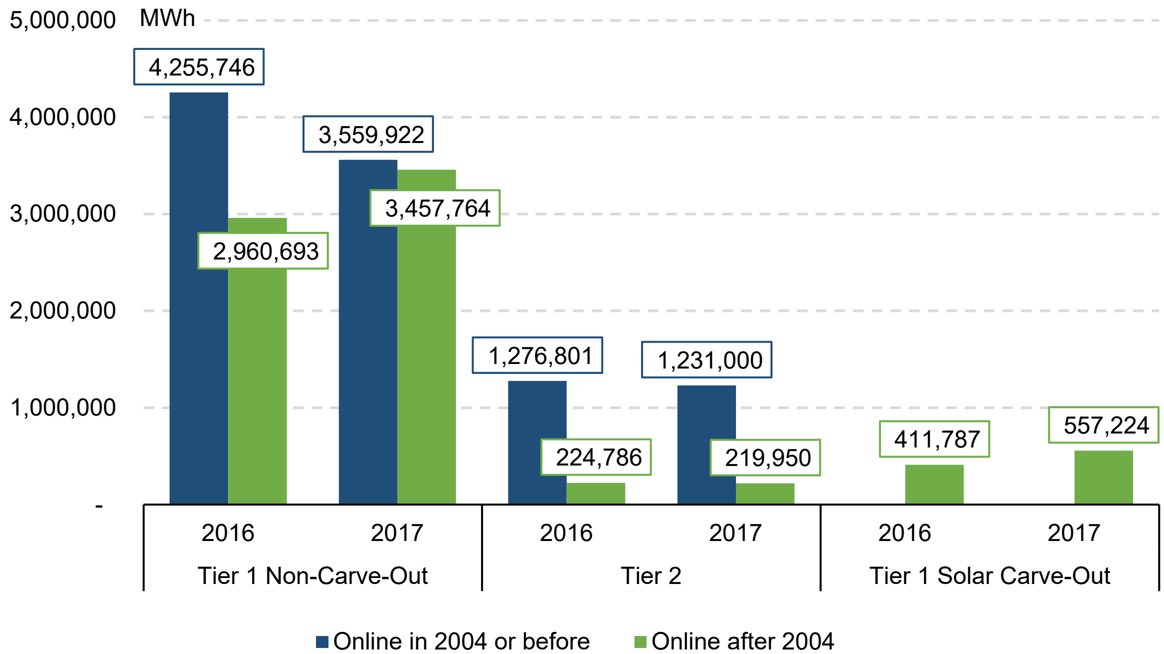

Figure ES-9. RECs Retired for Maryland RPS Compliance, by Plant Age and RPS Category

Sources: Maryland PSC 2018 *Renewable Energy Portfolio Standard Report*; PJM-GATS.

Most RECs retired for the Maryland RPS are from out-of-state sources.

Typically, between 10-25% of RECs retired for compliance with the Maryland RPS come from in-state resources, primarily solar, MSW, and Tier 2 hydro (see Figure ES-10 and Figure ES-11). This share has remained relatively flat since 2011 despite growth in the overall number of RECs retired. This may be due to a combination of limitations in the availability of in-state RECs, the use of RECs produced in Maryland to comply with other state RPS policies, and the availability of RECs at a lower cost from other states.

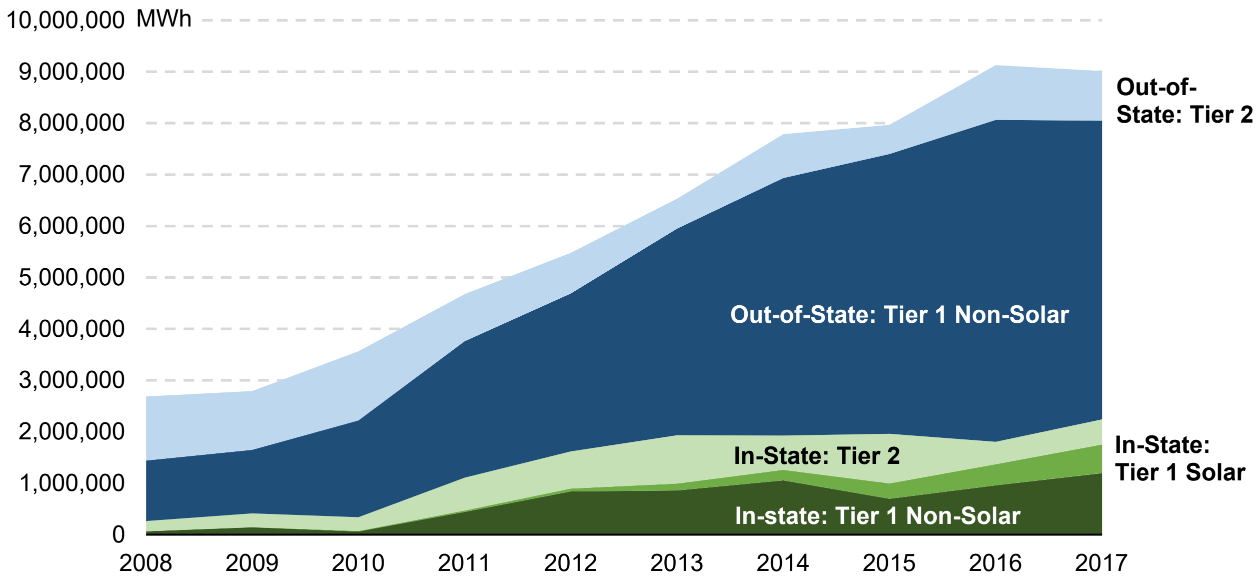

Figure ES-10. Maryland REC Retirement, by Location and RPS Category

Source: Maryland PSC Renewable Energy Portfolio Standard Reports.

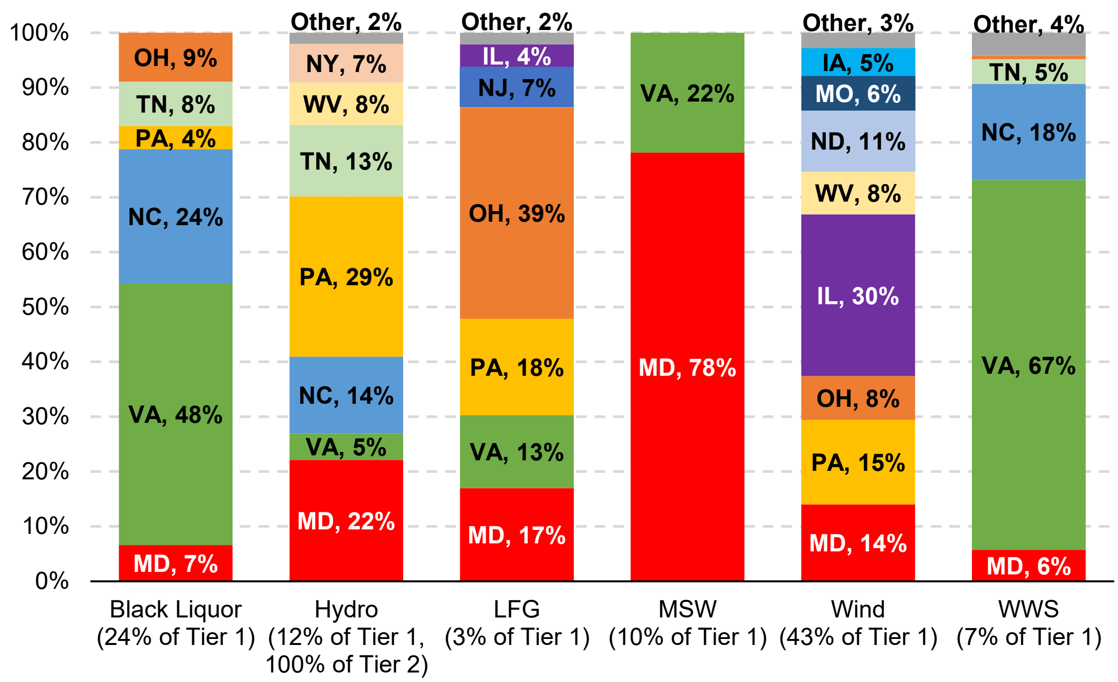

Figure ES-11. Percentage of RECs Generated in Each State Used for Compliance with the Maryland RPS, by Fuel Source (2017)

Source: Maryland PSC 2018 *Renewable Energy Portfolio Standard Report*.

Note*:* The percentages under each fuel category reflect each fuel type's share of Maryland RPS compliance for 2017.

Maryland's reliance on out-of-state RECs for RPS compliance is common in the mid-Atlantic region and reflects, at least in part, enduring differentials in renewable energy production costs and resource availability across PJM. For example, Figure ES-12 and Figure ES-13 compare recent offers for wind and solar power purchase agreements (PPAs), respectively, at various hubs in PJM, as tracked by LevelTen Energy, which runs a marketplace for PPAs.[6] Wind PPA offers in the price hub for Northern Illinois, which has a relatively strong wind resource, were roughly $6/MWh cheaper than wind PPAs in the Western Hub, which includes the western edge of Maryland. The Northern Illinois wind PPA offers ($26.20/MWh) were also more than $7.50/MWh cheaper than solar PPAs in the Eastern Hub ($33.90/MWh), which includes the bulk of Maryland. Though not shown here, wind PPAs in the heart of the Midwest are even lower (e.g., $14.40/MWh in portions of North Dakota), which helps to explain the use of RECs from Iowa, Missouri, and North Dakota for Maryland RPS compliance, despite the cost of transmitting the associated power into PJM.

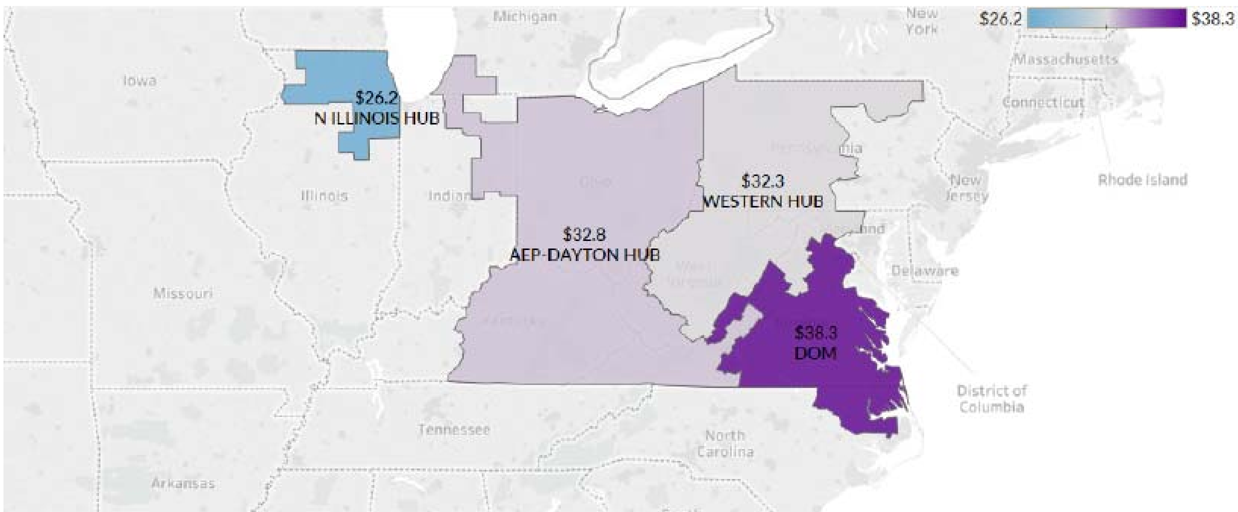

Figure ES-12. PJM Market Overview – Wind PPA Price, by Hub, Q1 2019 ($/MWh)

Source: LevelTen Energy, Q1 PPA Price Index, May 2019.

Note: Price data are aggregated. Prices shown refer to the most competitive 25th percentile offer price.

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[6] While PPA price offers reflect multiple factors, they nevertheless help to illustrate regional differences in renewable energy production costs as well as cost differentials between technologies.

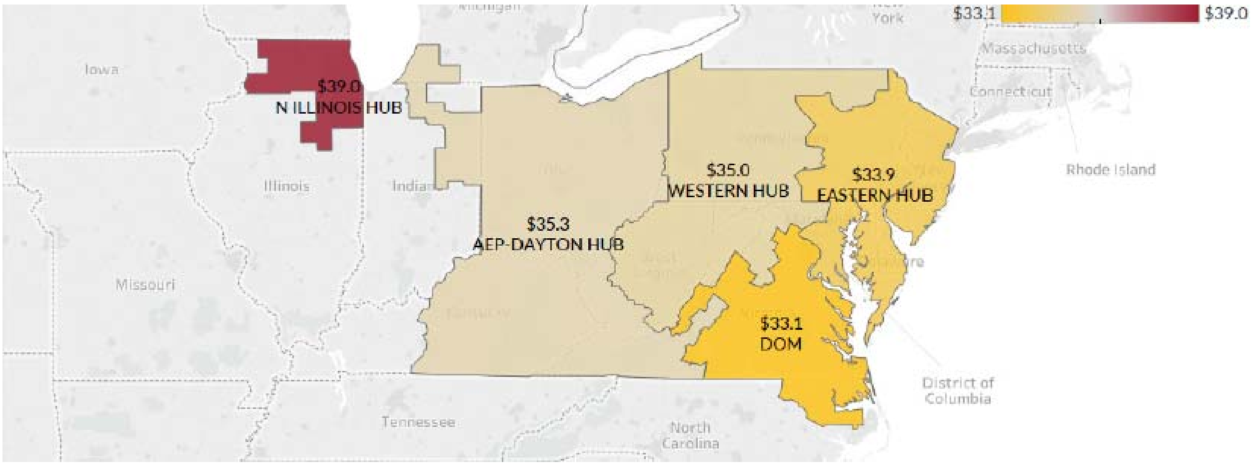

Figure ES-13. PJM Market Overview – Solar PPA Price, by Hub, Q1 2019 ($/MWh)

Source: LevelTen Energy, Q1 PPA Price Index, May 2019.

Note: Price data are aggregated. Prices shown refer to the most competitive 25th percentile offer price.

The Maryland RPS has resulted in modest greenhouse gas reductions but may be working at cross-purposes with the state's efforts to reduce nitrogen oxides (NOx) and sulfur dioxide (SO_2) emissions.

Policies that promote renewable energy resources, including the RPS, can help reduce air emissions by supporting generation from resources that produce little or no air emissions. Estimates by LBNL and NREL of the benefits associated with RPS policies range from $0.033/kilowatt-hour of renewable energy generated (kWh-RE) to $0.165/kWh-RE, inclusive of avoided greenhouse gases (GHGs), climate change damage, and air pollution, in addition to human health and environmental benefits.

Since 2005, carbon dioxide (CO_2) emissions per MWh of electricity generated have dropped throughout PJM, including in Maryland (see Figure ES-14). These reductions largely correspond with the retirement of coal plants and the growth of natural gas generation in PJM. The Maryland RPS has played a small role as well. PJM-wide CO_2 emissions per MWh in 2017, the latest year available, were approximately 0.8% lower than they would have been absent the Maryland RPS, assuming all retired RECs supported resources that would not have operated otherwise.

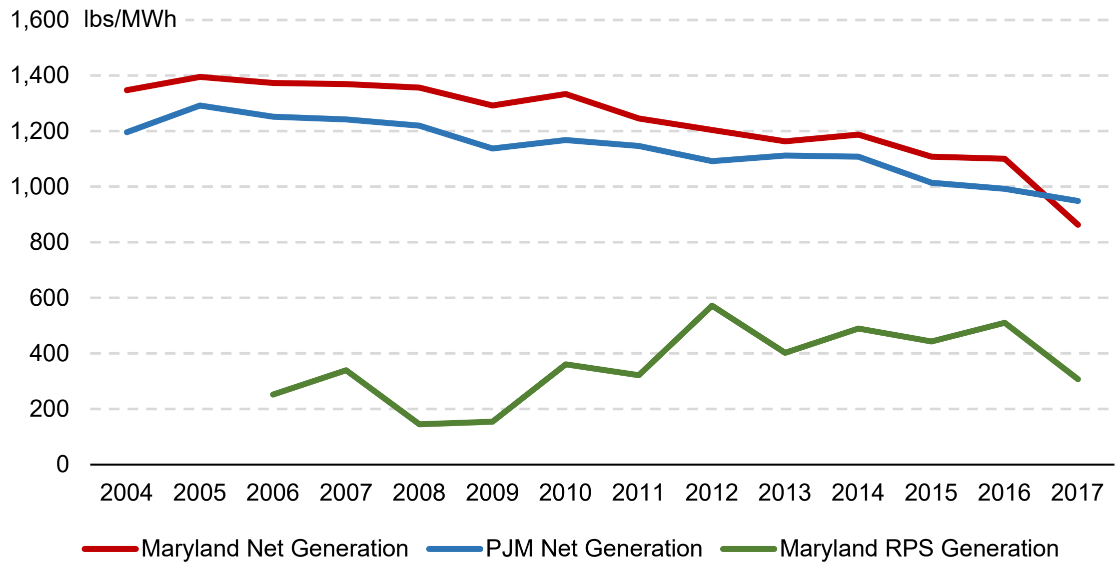

Figure ES-14. Weighted Average of Carbon Emissions in Maryland and PJM, by Electric Generation Category

Sources: PJM-GATS; EIA, "Maryland Electricity Profile 2017."

By contrast, the SO_2 and NOx emissions profiles of Maryland RPS resources, on average, are equal to or slightly higher than net Maryland and net PJM generation since 2010 (see Figure ES-15 and Figure ES-16). This is due to the eligibility of black liquor, LFG, and MSW to meet Maryland RPS requirements and the continued declines in Maryland and PJM emissions due to coal plant retirements.[7] (As shown earlier in Figure ES-7, these resources have represented between 35-75% of the resources used for Tier 1 compliance, depending on the year.)

[7] In producing emissions estimates, the final report uses short-term estimates based on the average emissions levels of comparable resources registered in PJM-GATS, as discussed further in Section 2.2, "Environment." Exeter did not address or account for the carbon neutrality of some resources over the long term, such as biomass. Additionally, Exeter did not address or account for the methane avoidance benefits from combusting some resources, such as MSW and LFG, as compared to landfilling.

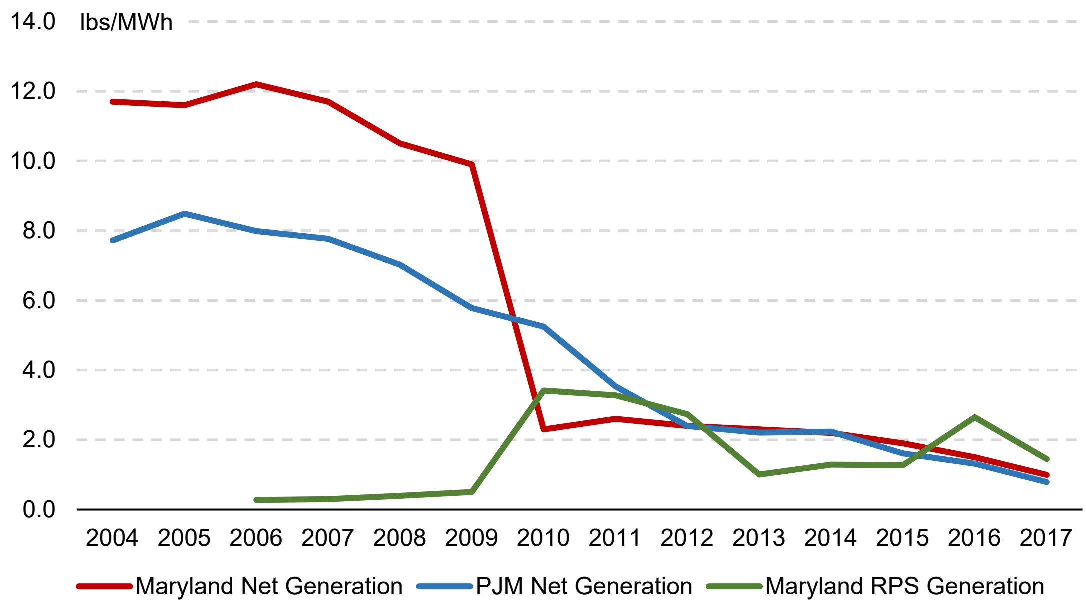

Figure ES-15. Weighted Average of SO_2 Emissions in Maryland and PJM, by Electric Generation Category

Sources: PJM-GATS; EIA, "Maryland Electricity Profile 2017."

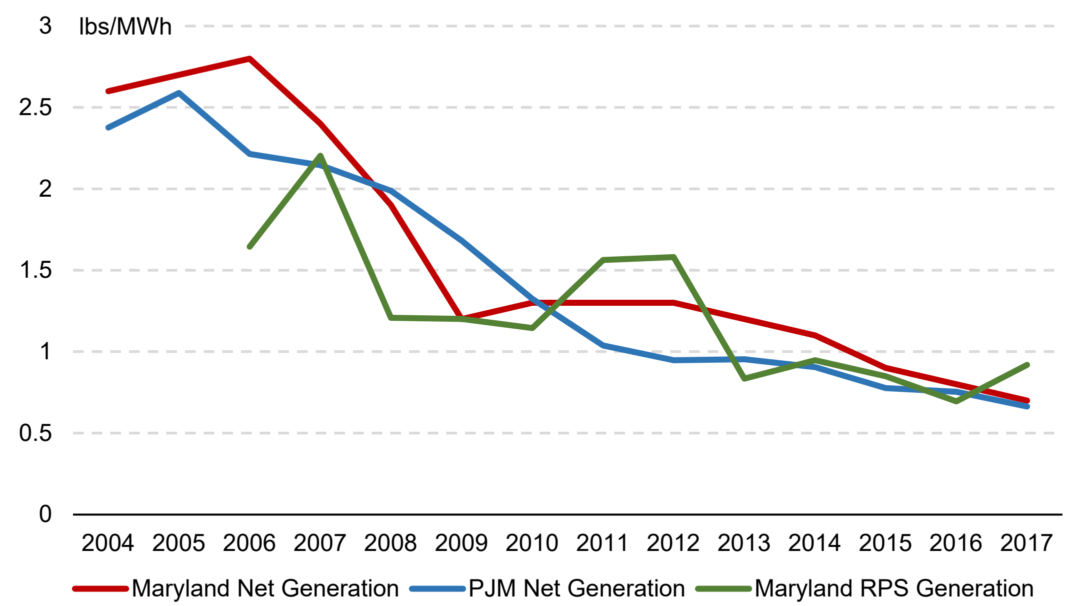

Figure ES-16. Weighted Average of NOx Emissions in Maryland and PJM, by Electric Generation Category

Sources: PJM-GATS; EIA, "Maryland Electricity Profile 2017."

The Maryland RPS has resulted in modest in-state economic development, including jobs with higher-than-average salaries.

The notion that energy policy could act as a driver of economic development has existed for decades. The basic premise is that energy policy can influence how society generates and/or uses energy while at the same time creating jobs and economic wealth. RPS policies are one potential way to spur this sort of development.

According to a U.S. Department of Energy (DOE) report, only 1.1% of employment in Maryland as of 2016 is in traditional energy jobs, including power generation; fuels; or transmission, distribution, and storage, compared to the national average of 2.4%. Energy efficiency is the largest contributor to energy employment in Maryland, representing over 67,000 workers in 2016 and making up 3.1% of all energy efficiency jobs nationwide. Clean energy jobs comprised the majority of energy sector jobs in Maryland from 2016-2018 (see Figure ES-17). According to the same report plus two follow-up studies, there were between approximately 7,800 and 8,100 solar, wind, large hydro, and other non-fossil fuel renewable energy jobs in Maryland during 2016-2018. This is between 6.1-6.5% of all energy sector jobs in the state, and between 0.2-0.4% of total non-farm employment statewide.

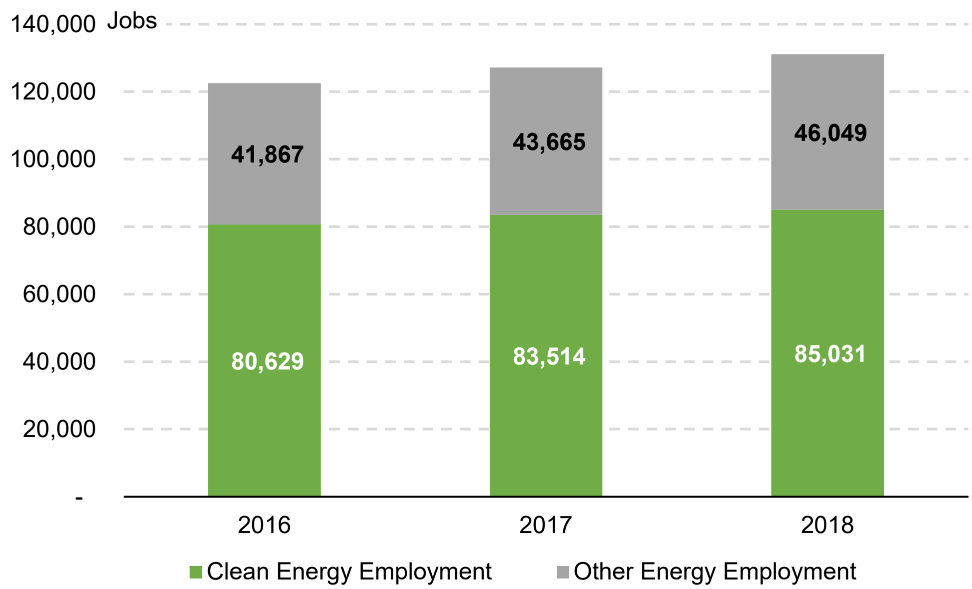

Figure ES-17. Number of Clean Energy Jobs in Maryland as a Share of Total Energy Employment

Sources: DOE, "2017 U.S. Energy and Employment Report State Charts;" EFI/NASEO, *U.S. Energy and Employment Report*, 2018 and 2019.

Note: Clean Energy Employment includes the following sectors: electric power generation; fuels; transmission, distribution, and storage; and energy efficiency.

Jobs related to the Maryland RPS (and other forms of electric power generation) are typically in construction. This is in keeping with national studies, such as one conducted by LBNL and NREL, which found that new renewable energy sources used for RPS compliance in 2013 supported 199,600 U.S.-based jobs, roughly 85% of which were in construction. LBNL and NREL also found average annual earnings per full-time employee of $60,000 for jobs related to renewable energy sources used for RPS compliance. The Maryland Department of Labor, using data from the U.S. Bureau of Labor Statistics (BLS), produced a study of the clean energy industry workforce in Maryland in 2017. This assessment found that weekly wages for jobs in the "Clean Energy Cluster" were, on average, 1.4 times higher than jobs in the private sector as a whole.

Assuming data collection efforts continue, more definitive trends and relationships between Maryland RPS requirements and employment may emerge over time. Growth in solar jobs is likely to have the strongest relationship with the Maryland RPS, due to the in-state provisions of the solar carve-out (see Figure ES-18). Among the select PJM states reviewed, Maryland ranks third in both solar jobs and in renewable energy jobs as a share of total energy employment. (Maryland also ranks third in solar capacity per capita, within the PJM states). However, solar jobs appear to have become decoupled from the solar carve-out in 2016, because of a glut of solar power and lower SREC prices.

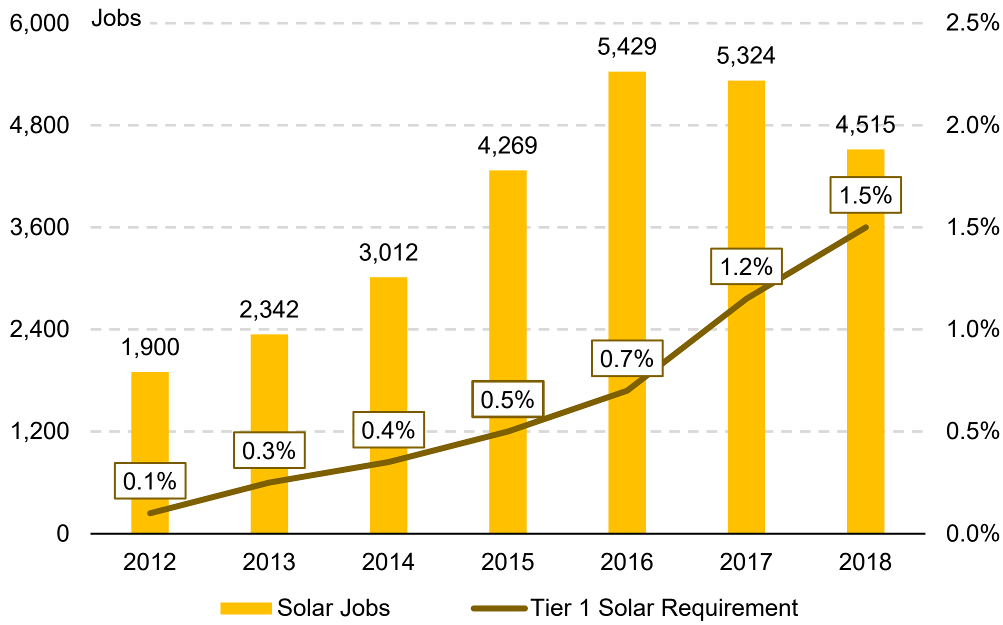

Figure ES-18. Number of Solar Jobs Relative to Maryland's Tier 1 Solar Carve-out Requirement

Source: The Solar Foundation, *National Solar Jobs Census.*

Most states, including Maryland, saw moderate growth in energy sector employment from 2016-2018, increasing jobs by up to 10% over 2016 levels (see Figure ES-19). Despite growth in energy sector jobs from 2016-2018, Maryland has experienced very small declines in renewable energy generation jobs, placing it below all reviewed states in PJM other than Michigan. This decline in Maryland's energy sector employment directly relates to the change in solar employment. Maryland experienced the largest percentage drop in solar jobs among the states in PJM reviewed.

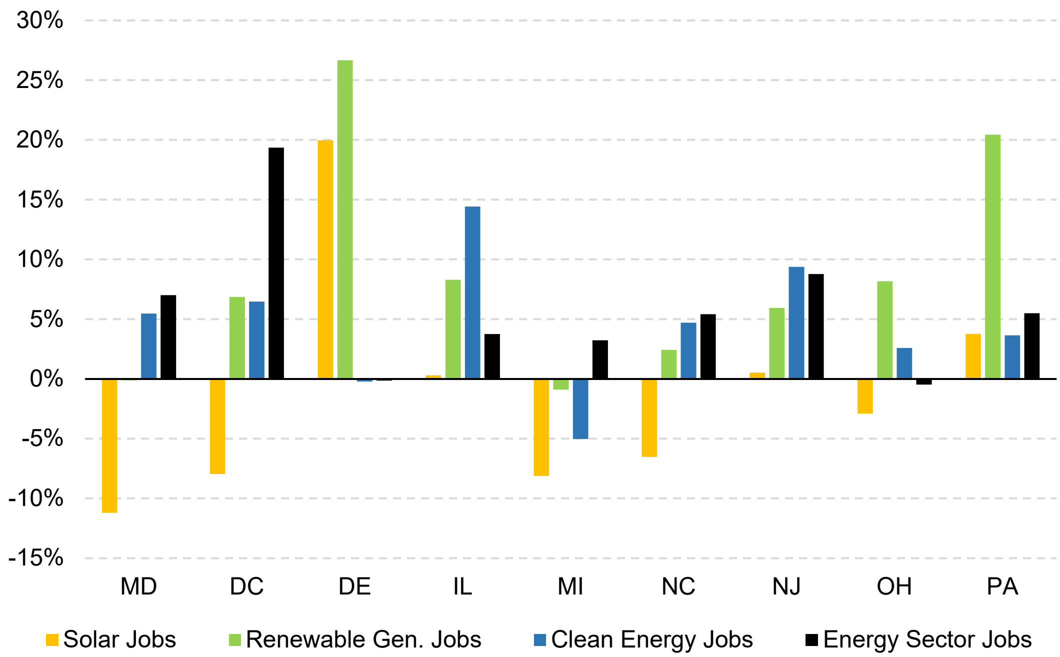

Figure ES-19. Change in Energy Sector Job Categories in Select States in PJM, from 2016 to 2018

Sources: DOE, "2017 U.S. Energy and Employment Report State Charts;" EFI/NASEO, *U.S. Energy and Employment Report*, 2018 and 2019.

Note: Several small changes (between -0.5% and 0.5%) are imperceptible in the figure. For example, Maryland Renewable Generation Jobs slightly declined (-0.1%) from 2016 to 2018. Each subsequent category is inclusive of the preceding categories; that is, Renewable Generation Jobs includes Solar Jobs; Clean Energy Jobs includes Renewable Generation Jobs and Solar Jobs; and Energy Sector Jobs includes Clean Energy Jobs, Renewable Generation Jobs, and Solar Jobs.

Environmental justice communities have received a disproportionately low share of the benefits associated with renewable energy projects in Maryland.

Ch. 393 requires this study to include whether public health and environmental benefits from clean energy are being equitably distributed across environmental justice (EJ) communities.

Since neither Maryland nor the federal government have an official definition for an EJ community, a basic methodology was developed to identify predominantly minority and/or low-income communities in the state, at a census tract level. RPS-certified facilities in Maryland were then overlaid with these census tracts on a map to identify the number and capacity of utility-scale renewable energy facilities in EJ and non-EJ communities. Subsequently, a score was assessed to each RPS facility using a rubric that allocates points based on the facility's environmental, economic, and land use characteristics. Indirect benefits and costs from RPS-certified facilities were not captured in this analysis.

Approximately 26% of utility-scale renewable energy capacity in Maryland is in EJ communities (see Figure ES-20 and Table ES-1). This increases to 40% when excluding the Conowingo Dam. The latter figure is almost equivalent to the 43% of the state's population that resides in an EJ-designated census tract. However, EJ communities realize only 25% of the overall benefits associated with utility-scale renewable energy. This is because more utility-scale projects—and, in particular, solar projects—are located in non-EJ communities than in EJ communities. The disparity may be due in part to topography and development density. Several large areas that meet the EJ criteria are in western Maryland, but its hilly terrain is not conducive to utility-scale solar projects. Meanwhile, very little of the Eastern Shore meets the EJ criteria, but its large, flat terrain has attracted many of the state's largest utility-scale solar projects. It should be noted that altering how different costs and benefits are weighted within the scoring rubric developed for the final report can fundamentally change the estimated EJ impact of different resources, as well as the impact of the Maryland RPS overall on EJ communities. There are also several areas near major metropolitan areas that meet the EJ criteria, but the development density prevents the development of utility-scale solar projects.

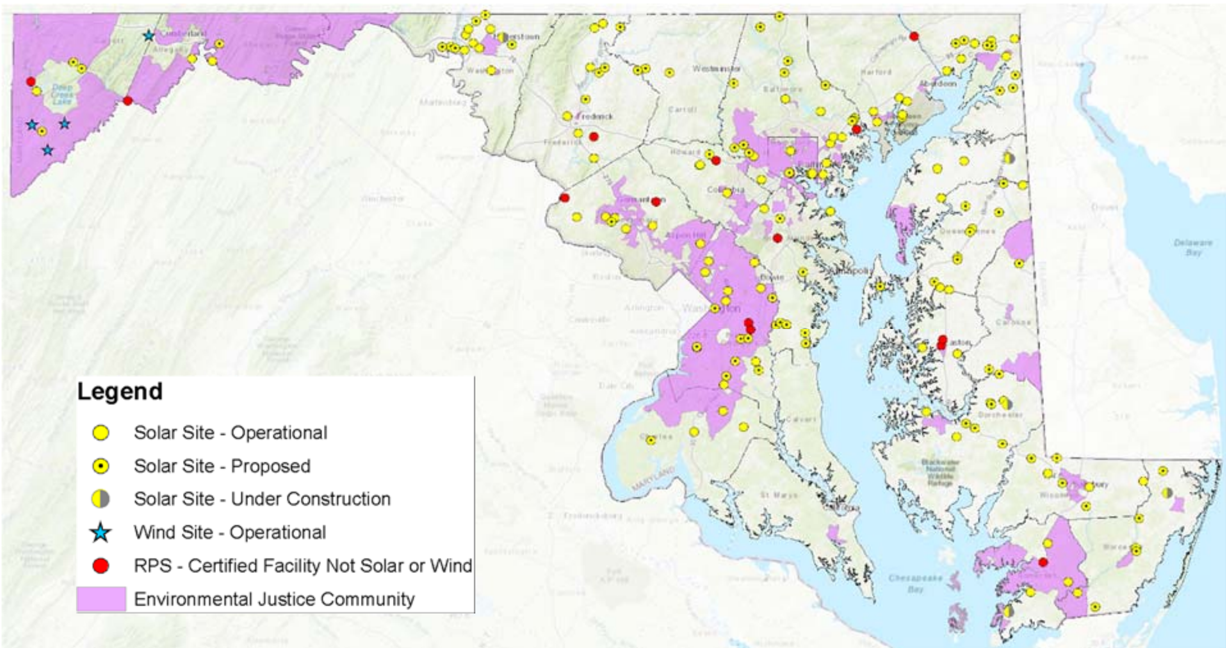

Figure ES-20. Maryland Environmental Justice Communities and RPS-Certified Projects

Source: Adapted from Maryland DNR SmartDG+, dnr.maryland.gov/pprp/Pages/SmartDG.aspx.

Table ES-1. Operating RPS Registered Projects in Maryland >1 MW, by Fuel Source

Fuel Source	No. of Projects >1 MW In-State[1]	Total Project Capacity (MW)[2]	No. of Projects >1 MW in EJ Communities	EJ Community Project Capacity (MW)	Percent of Projects in EJ Communities	Percent Capacity of Projects in EJ Communities
LFG	8	35	1	13	13%	37%
MSW	4	139	1	60	25	43
Solar	118	435	26	84	22	19
Hydro	3	494	2	20	67	4
Wood Waste	1	4	1	4	100	100
Wind	4	190	3	150	75	79
TOTAL	**138**	**1,297**	**34**	**331**	**25%**	**26%**

Source: PJM-GATS.

[1] Excludes the 69-MW Easton Plant, which did not generate electricity in 2017; the Harford Waste-to-Energy Facility, which shuttered in 2016; Luke Mill, which closed in 2019; and counts the four LFG facilities at Brown Station Road as one facility.

[2] Capacity figures reflect EIA data and may not match other data sources.

Based on data provided by the Maryland PSC, distributed solar projects in Maryland are also more likely to be located in non-EJ communities, both by capacity and by number of projects. This is likely due, in part, to the strong correlation between low-income households and renting. Rental units typically have a low adoption rate of distributed solar due to the upfront costs of solar investment, and the misalignment of those who receive the benefits (renters, through lower energy costs) versus those who bear the cost (the landlord).

Many states, including Maryland, use community solar programs to help increase access to solar in EJ communities. For example, the Maryland Energy Administration (MEA) has a Maryland Community Solar Pilot Program that commenced in April 2017, and it supports both commercial community solar and residential community solar. Additionally, MEA has developed the FY Community Solar LMI PPA Incentive Grant Program (LMI-PPA Program) to help extend the benefits of community solar projects to members of the Low and Moderate Income (LMI) community. The program incentivizes community solar subscriber organizations to include terms and conditions in their Subscription Agreements, which maximize cost savings over the contract period for LMI subscribers. Policies that incentivize the reuse of abandoned commercial or industrial properties or facilitate benefit-sharing between landlords and renters can help to attract solar projects to EJ communities.

There appears to be enough renewable energy proposed and projected to meet the end-targets for the Maryland RPS, although not enough to meet all intervening year targets.

Data in the final report come from the *Interim Report Concerning the Maryland Renewable Portfolio Standard* (interim report), which evaluates whether the projected supply of RPS-eligible generation is sufficient for a 25% Maryland RPS (i.e., current law when the interim report was written) or a 50% Maryland RPS scenario based on legislation introduced, but not passed, in 2018.[8]

[8] Maryland Department of Natural Resources, Power Plant Research Program, *Interim Report Concerning the Maryland Renewable Portfolio Standard*, December 2018, dnr.maryland.gov/pprp/Documents/Interim-RPS-Report.pdf.

Under the 25% RPS, no major shortfalls are anticipated. Under a 50% Maryland RPS scenario, the total non-solar-carve-out (i.e., inclusive of offshore wind) Tier 1 requirements of state RPS policies within PJM would be met through 2020, and from 2028-2030, but would not be met from 2021-2027 (see Figure ES-21). Anticipated growth in solar capacity would make it possible to meet the 14.5% solar carve-out requirement for the 50% Maryland RPS scenario in 2030, but not in the years leading up to 2030 (i.e., from 2019-2029) (see Figure ES-22). However, these projections do not account for the possibility of banking excess credits in one year for use during a later compliance period.

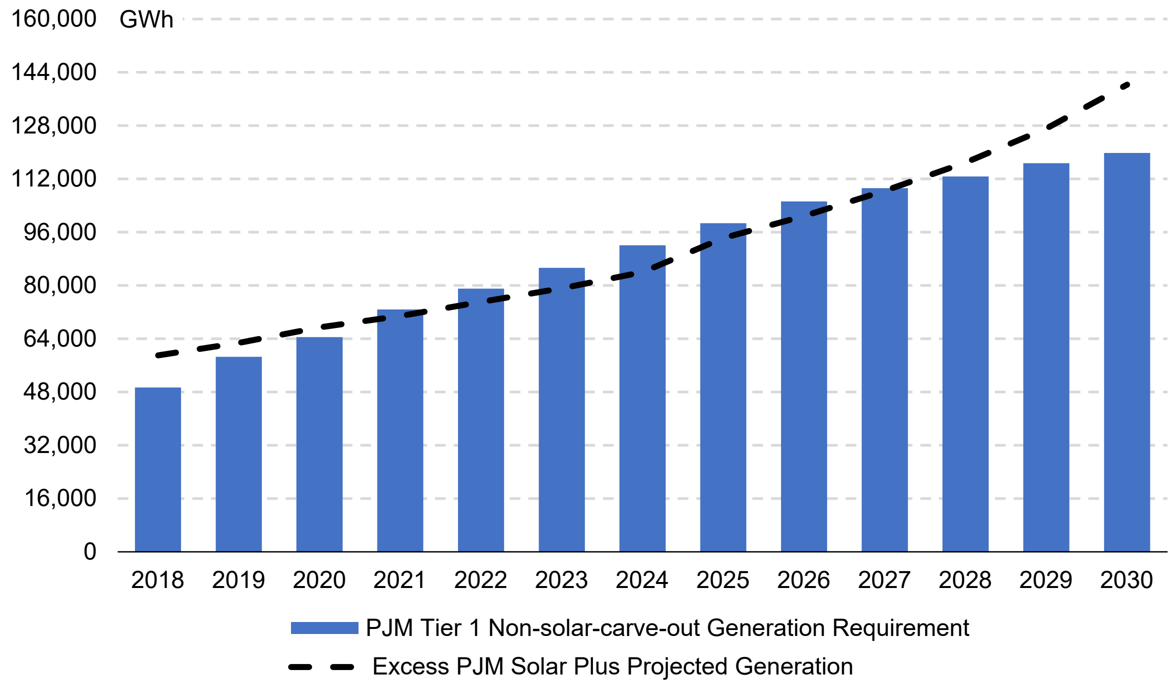

Figure ES-21. Non-Solar-Carve-out Tier 1 RPS Requirements in PJM, 50% RPS Scenario

Source: Interim report.

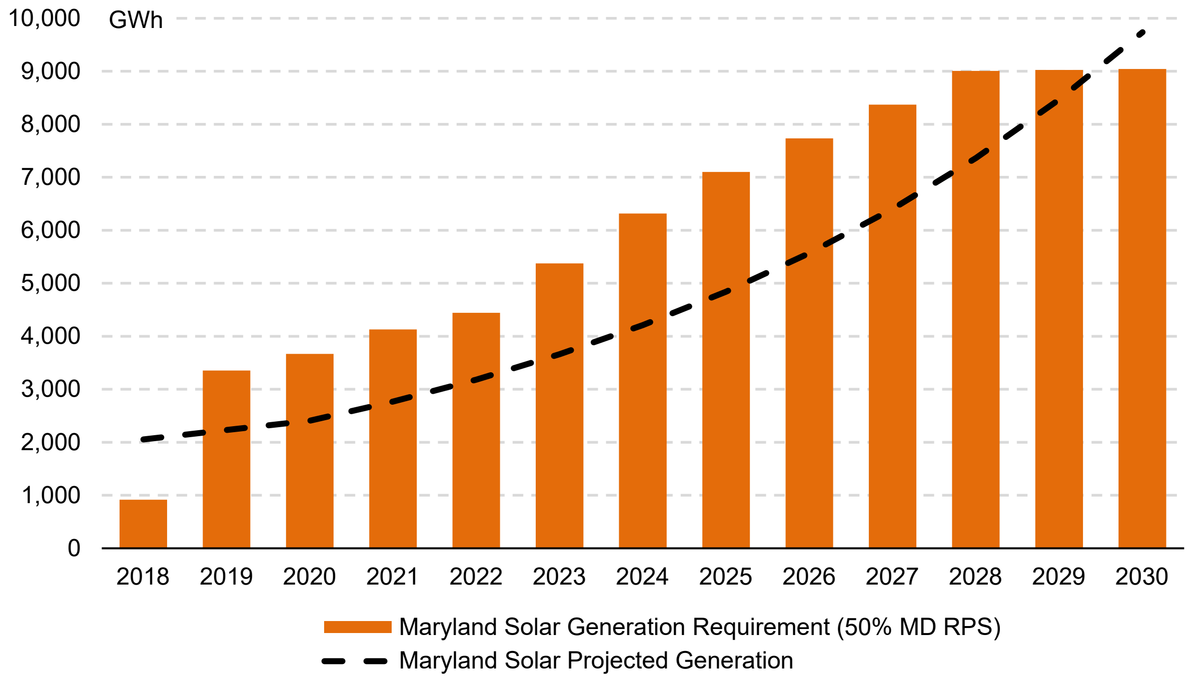

Figure ES-22. 14.5% Solar Carve-out Tier 1 Requirements in Maryland Compared to Projected Maryland Solar Generation, 50% RPS Scenario

Source: Interim report.

Several assumptions in preparing these estimates drive the results, and changes in those assumptions could affect the results in either direction. These assumptions include the following: that states in PJM will not change their existing RPS policies, that states in PJM without RPS policies will remain so, and that projected load growth and projected growth in solar, onshore wind, and offshore wind capacity do not vary from what was assumed. Finally, these projections do not account for reliance on outside-of-PJM renewable generation (for Tier 1 non-carve-out RECs) or the prospects of prices inducing additional development.

Substantial amounts of potential renewable energy in PJM appear to be economically feasible.

Based on analyses conducted by NREL, the states in PJM have the technical potential to sustain 41,499,625 GWh, or 23,808 GW, of annual generation by solar, wind, hydro, and biopower resources. Under a set of assumptions developed by NREL, approximately 235,000 GWh of this potential would be economic in addition to already existing levels of renewable energy as of 2013.[9] This economic potential exceeds the projected 2030 RPS requirement of the 50% Maryland RPS scenario from the interim report for the states in PJM (134,300 GWh) by nearly 75% (see Table ES-2).

[9] A resource is economic if the Levelized Avoided Cost of Energy (LACE) exceeds the Levelized Cost of Energy (LCOE) to the grid. More specifically, NREL compared the expected cost of generating electricity using a new renewable energy project (i.e., its LCOE), with the new project's value to the grid (i.e., its LACE). The LACE is equivalent to the value of utility services that are not necessary (i.e., avoidable) as a result of the new renewable energy project. If LACE is greater than LCOE, a project is considered economic. See Section 3.2 for more details.

According to these same NREL analyses, Maryland has the technical potential to sustain over 920,000 GWh, or 500 GW, of annual generation by solar, wind, hydro, and biopower resources. Approximately 5,400 GWh of this potential would be economic in addition to already existing levels as of 2013. This includes 4,900 GWh of distributed PV potential. The economic resource potential that NREL identified in Maryland also includes 300 GWh of onshore wind and 200 GWh of hydro. (This hydro potential would involve new, small-scale dams or powering existing dams that do not currently generate power.) No new biomass was found to be economic.

Table ES-2. Comparison of NREL Technical and Economic Resource Potential Estimates to 2030 Projections of RPS-Eligible Generation and RPS Requirements in Maryland and PJM, 50% RPS Scenario (GWh)

	PJM[1]				MARYLAND-Specific	
	Tier 1 Solar	Tier 1 Offshore Wind	Tier 1 Non-Carve-out and RPS Compliance	TOTAL	Tier 1 Solar	Tier 1 Offshore Wind
Interim Report						
2030 Projected Supply of RPS-Eligible Generation	78,666	1,369	69,931	**149,966**	9,737	1,369
2030 Projected RPS Requirements	14,508	6,236	113,533	**134,277**	9,042	6,236
NREL						
Technical Potential	38,711,500	1,488,125	1,300,000	**41,499,625**	818,500	96,289
% above 2030 Projected Supply	49,110%	108,602%	1,759%	**27,573%**	8,306%	6,934%
% above 2030 Projected Requirement	266,729%	23,763%	1,045%	**30,806%**	8,952%	1,444%
Economic Potential[2]	110,600	0	124,400	**235,000**	4,900	0
% above 2030 Projected Supply	41%	0%	78%	**57%**	-50%	0%
% above 2030 Projected Requirement	662%	0%	10%	**75%**	-46%	0%

Sources: Offshore wind technical potential: NREL, *2016 Offshore Wind Energy Resource Assessment for the United States*, nrel.gov/docs/fy16osti/66599.pdf (Appendices H and I). All other information: NREL, *Estimating Renewable Energy Economic Potential in the United States: Methodology and Initial Results*, nrel.gov/docs/fy15osti/64503.pdf (Appendices A and F) (see full report for additional descriptions of the data and underlying assumptions).

[1] Note that the interim report adjusts supply and RPS requirement estimates for states with partial PJM participation in accordance to the percent share of the state's load that is served by PJM. NREL estimates are inclusive of the totality of states located partially or fully in PJM, based on the assumption that generators throughout these states can potentially deliver power into PJM.

[2] Economic potential is incremental to 2013 generation levels.

There are several limitations to NREL's estimates. NREL solely evaluated the economic viability of individual projects; it did not evaluate aggregate impacts to grid operations. NREL also did not contemplate costs or benefits related to land use. Some of the technical potential NREL identified is also duplicative, because NREL did not preclude different forms of generation, such as wind and solar, from being developed in the same physical space. On the other hand, NREL's analysis of economic potential is based on 2015 cost projections. As renewable energy generation costs continue to decline, particularly for wind and solar projects, additional renewable energy generation will likely become economic. Based on the above and other assumptions, NREL's estimates of technical potential are best understood as an upper bound, while estimates of economic potential can be understood as a lower bound.

Maryland's carve-out requirements, especially for offshore wind, will likely raise future RPS compliance costs significantly.

The approach used to gauge historical rate impacts—RECs plus ACP costs—is also used in the final report to estimate future rate impacts of the Maryland RPS. Two main sets of estimates were developed. The first set of estimates was made in December 2018, and it assumes that the 25% Maryland RPS (in effect at the time) would remain in place through 2030. A second set of estimates was made in July 2019 to account for the 50% Maryland RPS, implemented following the enactment of Ch. 757 in May 2019.[10]

The 25% RPS estimates include Maryland's original Tier 1 offshore wind carve-out, for which the Maryland PSC approved the issuance of ORECs to two projects: the 248-MW US Wind project, and the 120-MW Skipjack project.[11] These "Round 1" projects will sell ORECs at a pre-approved rate of $131.93/MWh (2012$), levelized over a 20-year contract term, less market revenues (i.e., capacity and energy earnings). Based on the proposed price schedule and estimated market revenues for each project, the ORECs purchased to fulfill the state's original 2.5% offshore wind carve-out are likely to be more costly in nominal terms than the combined cost of all other renewable energy resources used for compliance with the Maryland RPS (see Figure ES-23). In 2019, the 25% Maryland RPS is estimated to add approximately $14 per year to residential customer bills. By 2030, this cost increases to $43 per year. In terms of rate impacts, the 25% Maryland RPS is estimated to peak at 3.4% of retail bills in 2023. This compares to a maximum impact of 1.8% through 2017.

Based on recent project bids along the East Coast, prices for ORECs from future "Round 2" offshore wind projects, as required by the 50% Maryland RPS, are estimated to fall from an average, weighted nominal price of $115.96/MWh to as low as $46.23/MWh. These OREC estimates are unbundled from energy and other market revenues. Despite this drop, the blended cost of ORECs (i.e., the cost of Round 1 and Round 2 projects) will still exceed the combined cost of SRECs and non-carve-out RECs. In 2019, the 50% Maryland RPS is estimated to add approximately $41 per year to residential customer bills. By 2030, this cost increases to $115 per year. The rate impact of the 50% Maryland RPS is estimated to peak at 7.6% of retail bills in 2030. From 2025-2030, solar carve-out requirements are expected to be met by ACPs or SRECs at the capped price.

[10] The 50% RPS estimates are inclusive of costs that would have been incurred under the 25% RPS as well, such as already approved offshore wind projects.

[11] At the time of the PSC Order, the US Wind project was projected to come online in 2020 and the Skipjack Project in late 2022. In conducting the analysis for this report, the online dates for both projects were pushed back one year to account for permitting delays (i.e., US Wind would come online in 2021 while Skipjack would come online in 2023). Skipjack continues to predict that its online date will be 2022 while US Wind has since delayed its projected operating date to 2023.

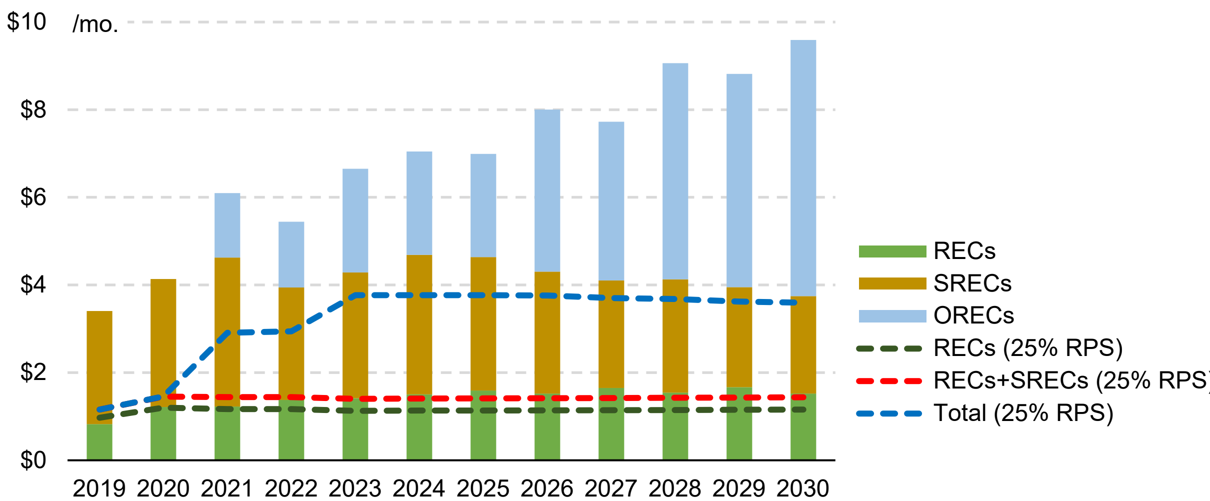

Figure ES-23. Estimated Average Monthly RPS Compliance Costs for Maryland Residential Customers, 25% RPS and 50% RPS

Several simplifying assumptions have been made for the purposes of estimating expected REC costs, including reliance on public spot market REC prices, the assumption that REC and SREC prices grow at the rate of inflation in 2023 and onwards, and the exclusion of potential cost savings due to federal or state offshore wind incentive programs. Should REC, SREC or OREC prices decrease, estimated RPS compliance costs to consumers will also decrease, as assessed in an alternative scenario at the end of Section 3.5, "Future Ratepayer Impacts in Maryland."

Excluding certain technologies from the Maryland RPS has limited impact on the availability or pricing of RECs in PJM.

REC prices depend on a complex array of supply and demand conditions. All else being equal, excluding resources reduces the supply of available RPS-eligible generation and increases RPS compliance costs. However, a relatively broad pool of resources is available to address Maryland's RPS requirement. These resources, which also serve other state RPS policies, collectively generated 37.6 million RECs in 2018 versus a total REC demand in Maryland of 10.9 million. REC availability and pricing roughly equilibrate across all of PJM, reducing the effect of changes to any one state RPS policy. Maryland is the only state in PJM that includes black liquor as an eligible Tier 1 resource besides Pennsylvania, where black liquor facilities must be located in-state to be eligible. Consequently, removing black liquor from the Maryland RPS could decrease the supply of eligible renewable energy generation and therefore could increase REC prices. Black liquor, though, has a relatively small and declining market share (1.5% of all qualified RECs) in PJM and therefore has little impact on Tier 1 REC prices.

Eliminating land-based wind, small hydro, or MSW from the Maryland RPS would have limited impact on REC availability because displaced RECs would be absorbed in other states within PJM and replaced by other eligible resources. Similarly, excluding other resources would have minimal effect.

Based on the 50% Maryland RPS scenario from the interim report, eliminating both MSW and black liquor may create short-term supply deficits due to the simultaneous effect of increased demand and reduced supply. This effect, however, only applies in the short run. By 2030, excluding these resources will have minimal impact on Maryland's ability to meet its RPS requirements, or overall REC availability and costs in PJM. Note that the analysis discussed in this section assumed there would be no changes to state RPS policies in PJM other than in Maryland.

These conclusions are based on Maryland acting alone to modify eligibility requirements. If all the states in PJM were to eliminate the eligibility of a resource that is widely relied upon, such as onshore wind or biomass (see Figure ES-8), the impacts could be more significant.

Modeling suggests that increasing the Maryland RPS to 50% lowers the carbon content associated with electricity consumption in Maryland, although not Maryland-based emissions.

Modeling from the 2016 *Long-Term Electricity Report for Maryland* (LTER) was referenced to estimate the prospective impacts of the Maryland RPS on emissions. In the LTER, it was assumed that future RPS requirements would be fulfilled entirely with actual generation, as opposed to ACPs. Furthermore, it was assumed that new wind capacity would be used to fulfill all new RPS requirements, except for solar carve-outs. It was also assumed that all necessary additional renewable energy capacity would either be built in Maryland or within a PJM transmission zone that contains a portion of Maryland.[12]

Based on these assumptions, raising the Maryland RPS from 25% to 50% lowers the CO_2 emissions associated with electricity consumption in Maryland by an average 3.6 million tons, or 12.5%, per year during the 2015-2035 study period (see Figure ES-24).[13] However, CO_2 emissions from electric power plants located in Maryland are relatively unchanged because coal and natural gas plants in Maryland continue to generate power for sale into PJM's wholesale markets. Though not shown here, NOx and SO_2 emissions from in-state generation are also relatively unchanged, for the same reasons.

[12] As noted earlier, to minimize the costs of the study, PPRP relied on existing work, such as PPRP's LTER. The core assumptions used in the LTER remain sound; ACPs are still rarely used for compliance with the Maryland RPS and wind remains the predominant form of renewable generation used to fulfill incremental RPS requirements. Subsection 3.3.3 discusses other important assumptions that are more time-sensitive (e.g., load forecasts, plant retirements in Maryland, etc.) and the likely impacts of changing certain assumptions.

[13] PJM is an interconnected grid with undifferentiated power flowing through the system. This statistic, therefore, represents Maryland's share of PJM-wide emissions, as adjusted for the use of low- or non-emitting resources for RPS compliance.

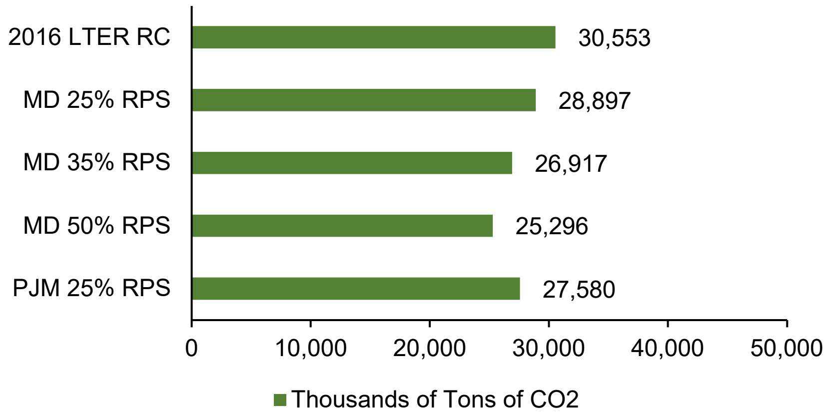

Figure ES-24. Average Annual CO_2 Emissions from Electricity Consumption in Maryland, 2015-2035

Source: 2016 LTER.

Note: The 2016 LTER Reference Case (RC) reflected current law at the time: Maryland RPS rises to 20% by 2022, including 2% solar by 2020. The three Maryland scenarios following the RC represented the Maryland RPS rising to 25%, 30%, or 50% by 2030, with 2.5%, 3%, or 5% solar carve-outs, respectively. The PJM 25% scenario represents every state in PJM adopting a 25% RPS by 2020, including a 2.5% solar carve-out.

The Maryland RPS will generate an estimated 39,300 full-time equivalent jobs and $7.6 billion in in-state sales revenue from 2019-2030.

This study uses the input-out model known as IMPLAN (IMpact analysis for PLANning) to estimate regional job creation and spending associated with the Maryland RPS from 2019-2030. In IMPLAN, an initial change in spending is referred to as a change in "final demand." It is considered a direct effect, which then creates indirect and induced effects.[14] Indirect effects stem from local industries' purchases of inputs (i.e., goods and services) from other local industries. Induced effects reflect the spending of wages from residents involved in providing the goods and services being modeled.

It was assumed that only the carve-out portions of the Maryland RPS would be met by in-state resources. Because of this assumed resource allocation, the study focuses solely on the economic impacts of solar located in Maryland and offshore wind projects located in waters off Maryland's coast. Over the 12-year study period from 2019-2030, the cumulative economic impacts to Maryland of a 50% RPS include: more than 34,000 full-time equivalent (FTE)[15] jobs (or an average of 2,833 FTE jobs per year); nearly $5 billion in sales in Maryland attributable to construction; and an additional 5,300 FTE jobs and $2.6 billion in sales in Maryland attributable to operations and maintenance (O&M) (see Figure ES-25). Forty-two percent of the FTE jobs created as a result of the Maryland RPS are associated with distributed solar, 40% with offshore wind, and 17% with utility-scale solar.

[14] Final demand is the demand for goods that is not used to produce other goods.

[15] FTE represents the hours logged by one employee working on a full-time basis (i.e., 2,080 hours/year = 1 FTE).

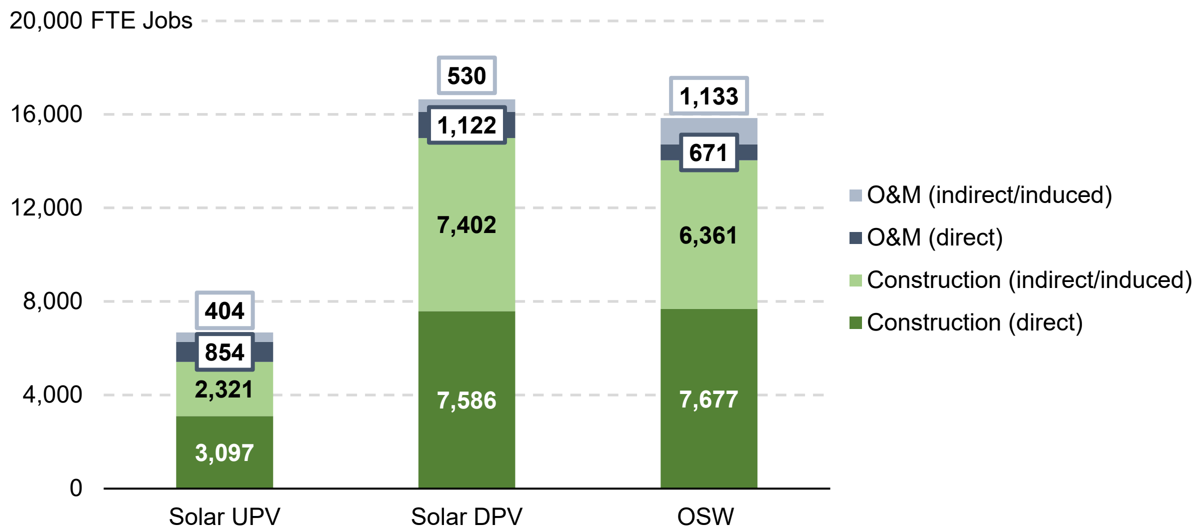

Figure ES-25. Cumulative Full-Time Equivalent Job Creation in Maryland, by Technology, 50% RPS

The identified economic benefits of the Maryland RPS are concentrated in the construction and service industries. For example, Figure ES-26 (below) shows the breakdown of jobs associated with utility-scale solar and distributed solar construction in Maryland. As shown in Figure ES-25 (above), these jobs are primarily associated with periods when new facilities are under development, after which employment is related to O&M for existing projects. Construction, architectural, engineering, and legal services sectors benefit most from direct investment in new facilities.

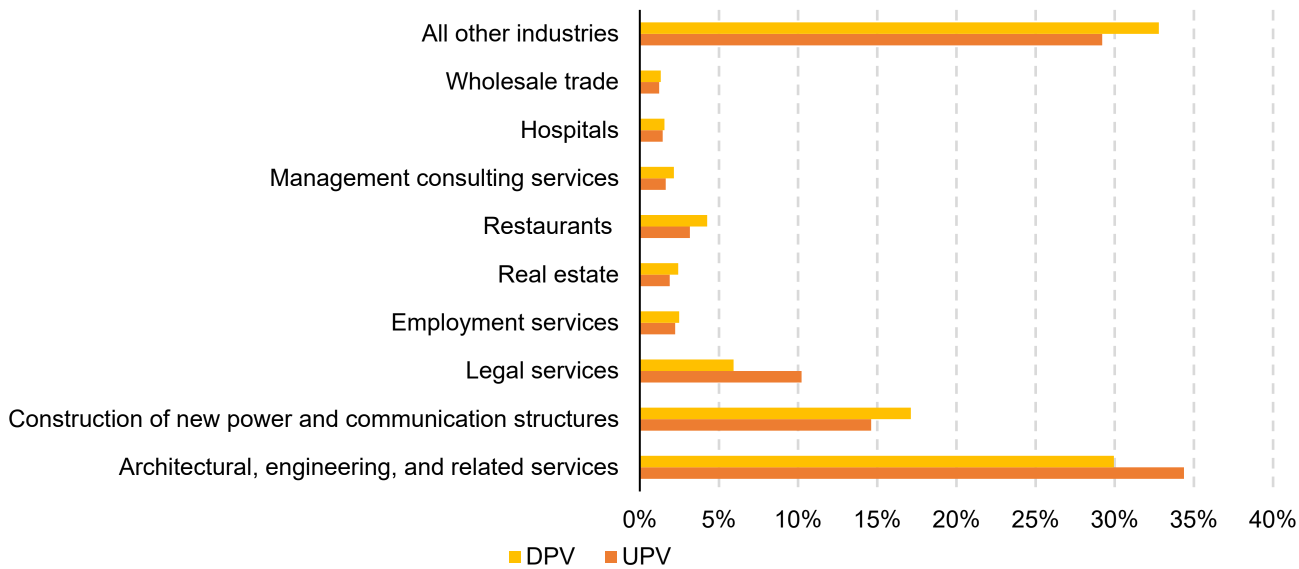

Figure ES-26. Maryland Industries (Percent FTE Jobs) Benefiting from Solar Construction, 50% RPS

Opportunities to expand economic development in Maryland are primarily associated with offshore wind.

The Maryland RPS is currently of little benefit to the state's manufacturing sector because most solar and offshore wind components are manufactured out-of-state or abroad.

Although the majority of onshore wind turbine components (as a fraction of total equipment-related turbine costs) installed in the U.S. are domestically sourced, offshore wind installations require many specialized components that are not currently produced in the United States. Most near-term manufacturing opportunities for offshore wind are limited to upstream materials and subcomponents that can be easily transported, such as scaffolding, coatings, ladders, fastenings, hydraulics, concrete, and electrical components. Table ES-3 identifies some businesses in the mid-Atlantic region that have the potential to support the offshore wind supply chain.

Table ES-3. Existing mid-Atlantic Companies with the Potential to Supply Offshore Wind Components

Industry	MD	DE	NJ	VA	PA
Electronics	**1**	0	3	2	15
Manufacturing & assembly	**17**	0	1	6	17
Installation, construction, materials	**13**	2	1	5	28
Maintenance, logistics, transportation	**16**	0	4	34	6
Services	**6**	2	6	34	4
TOTAL	**53**	**4**	**15**	**81**	**70**

Source: NREL, *Offshore Winds Jobs and Economic Development Impacts in the United States: Technical Report*, 2015.

Many reports predict that future opportunities for suppliers will be greatest in industries responsible for providing foundations and substructures, towers, blade materials, power converters, and transformers. NREL has taken this outlook further by estimating the share of critical offshore wind component manufacturing that could take place in the mid-Atlantic region. These estimates are broken down into three investment scenarios (see Table ES-4). Robust domestic supply chains are unlikely until sufficient demand exists to justify the investment in new, dedicated facilities.

Table ES-4. Regional Investment Paths for the Dynamic Components for Offshore Wind in the mid-Atlantic

	Low Investment		Medium Investment		High Investment	
Year:	**2020**	**2030**	**2020**	**2030**	**2020**	**2030**
Deployed capacity (MW)	366	3,196	1,912	7,832	4,100	16,280
Turbine	32%	68%	35%	95%	65%	100%
Blades & towers	13%	71%	25%	95%	30%	95%
Substructures & foundation	11%	30%	20%	50%	30%	85%

Source: NREL, *Offshore Winds Jobs and Economic Development Impacts in the United States: Technical Report*, 2015.

If offshore wind is developed to projected capacities, U.S. ports will need to be improved to support staging and manufacturing operations. As a condition for Maryland PSC approval of ORECs, both the US Wind and Skipjack projects are required to use a port facility in the greater Baltimore region for marshalling project components, use Ocean City as the O&M port, and invest in upgrades at Tradepoint Atlantic. As such, Tradepoint Atlantic has positioned itself to potentially become an offshore wind hub on the East Coast. This facility has space for offshore wind laydown, manufacturing, and vessel loading. In July 2019, Ørsted, the developer of the Skipjack wind project, announced that it will assemble the wind turbines at Tradepoint Atlantic.

Opportunities for manufacturing growth in Maryland from continuing solar deployment are probably limited to the structural and electrical balance of system (BOS) supply chains. Major solar components, such as modules and inverters, are largely imported. In comparison, structural BOS components (e.g., racking, mounting, and tracking systems) and electrical BOS components (e.g., conductors and monitoring devices) are more often sourced from domestic manufacturing. According to the Solar Energy Industries Association's (SEIA's) National Solar Database, at least two companies selling structural BOS components are located in Maryland. With the increase in Maryland's solar carve-out to 14.5%, the induced demand may attract further BOS manufacturing to Maryland.

PJM could accommodate 30% wind and solar generation, subject to the addition of more regulation and new transmission.

System flexibility refers to the grid's ability to accommodate both predictable and unpredictable imbalances between supply and demand. All power grids are designed to have some degree of flexibility, since electricity demand changes over time, sometimes unpredictably, and conventional generation resources can go offline unexpectedly. Variable generation such as wind and solar can increase grid system supply uncertainty and variability.

PJM takes the lead in balancing supply and demand throughout its entire footprint. This task is divided up into different time frames. For example: (1) regulation resources address moment-to-moment mismatches between supply and demand; (2) primary and supplemental reserves stand "at the ready" to address larger imbalances within 10-30 minutes; (3) ramping resources typically scale up production over a one- to three-hour time frame, for instance, at sundown when demand ramps up swiftly; and (4) seasonal resources, such as hydro dams, help to address seasonal peaks in demand driven by cold or hot weather.

In 2018, wind and solar jointly represented 2.9% of generation in PJM. As such, wind and solar do not pose a major challenge to system operations in PJM today. A study commissioned by PJM determined in 2014 that it could absorb 30% wind and solar generation by increasing regulation reserves and investing in new transmission to limit congestion. The same study found that PJM already employs many best practices in integrating wind and solar generation, such as sub-hourly scheduling, dispatch, and wind and solar forecasting. With the current state RPS policies in place, PJM is projecting that 16.5% of its energy mix will be RPS-eligible generation technologies by 2034.

Maryland can take regulatory and policy steps to increase distribution system flexibility.

Distributed generation (DG) in Maryland does not appear to be taxing the state's distribution system at this time. However, Potomac Electric Power Company (Pepco) and Delmarva Power & Light Company (DPL) currently have several circuits in Maryland that are unable to absorb additional DG or must restrict the size of new projects. One way to address such issues is to co-locate DG with resources that absorb excess generation immediately, rather than having it flow back to the grid. Figure ES-27 shows current and 2030 cost estimates for a variety of load-shifting technologies. Of the technologies that can be used at the distribution level, automated load shifting and electric vehicle (EV) charging are among the most cost-effective. Lithium-ion batteries are expected to become so by 2030.

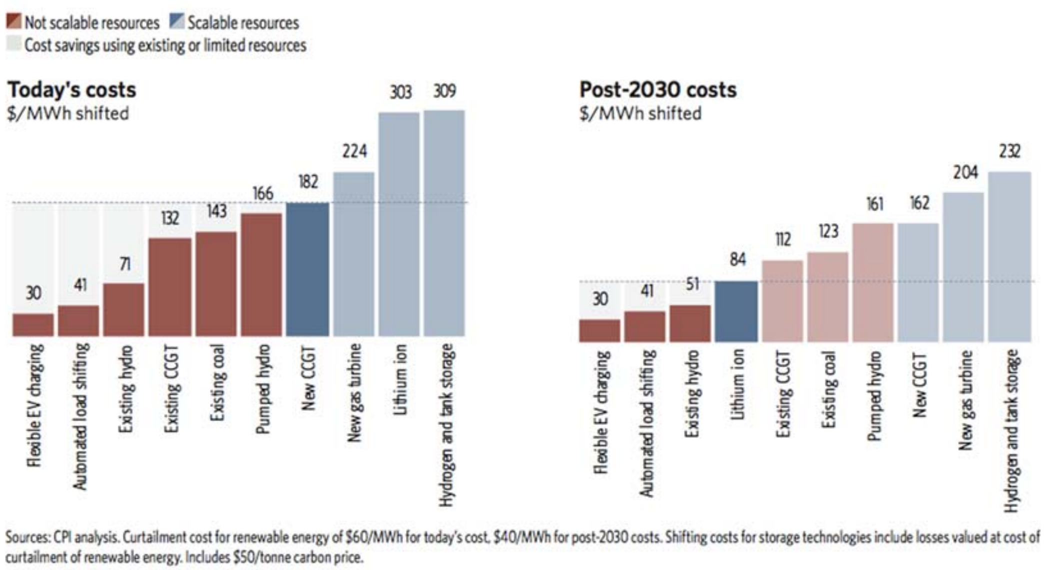

Figure ES-27. Estimated Cost of Daily Load Shifting in 2017 and Post-2030

Source: Brendan Pierpont, *et al.*, *Flexibility: The path to low-carbon, low-cost electricity grids*, Climate Policy Initiative, 2017.

Note: Costs shown are specific to California, but indicative of overall differentials in technology costs.

To the extent that Maryland is interested in laying the groundwork for large-scale deployment of distributed solar (and other distributed energy resources), there are several actions that could be pursued or, in some cases, are already underway. These include: reserving hosting capacity on distribution lines for smaller generators; requiring smart inverters for customer PV systems; increasing long-term planning for distributed resources, such as DG forecasting; and expanding how utilities consider and use flexibility resources. Additionally, since Maryland is working to deploy 300,000 EVs by 2025, it may be possible and economical to enhance the utilization of these resources for system flexibility.

Maryland could also create direct incentives to promote the adoption of flexibility resources on the distribution system. It may be possible to identify and support multi-use storage projects (i.e., projects that serve additional purposes such as customer bill reduction) whose cost is less than the system-wide cost savings they would realize.

Modeling suggests that reliance on long-term contracts for a portion of RPS compliance would result in higher costs than meeting the requirements through sequential short-term contacts.

In restructured states such as Maryland, compliance with state RPS requirements generally takes the form of short-term REC purchases that, by themselves, will generally not drive the development of new renewable energy projects. Partly in response to this issue, at least 11 states require the use of long-term contracts (LTCs) to meet at least a portion of their RPS requirements. In addition to potentially helping more projects get developed, LTCs for renewables may reduce costs to consumers and provide a hedge against future costs. However, there is also an important risk that an LTC will be more costly than other options over the course of the contract's term.

Because many uncertainties surround the future costs and benefits of long-term contracts, several scenarios were developed for the final report based on alternative assumptions about project financing costs, market prices for RECs and SRECs, and portions of the overall RPS to be met through long-term contracts (i.e., 15, 25, or 40%). Additionally, alternative calculations were made based on whether the LTCs would apply to Standard Offer Service (SOS) customers alone or all customers.

Under the range of assumptions considered, reliance on 20-year LTCs for a portion of both Tier 1 non-carve-out and solar carve-out RPS requirements resulted in higher costs than meeting the requirements through sequential short-term contracts over the 20-year period. In some cases, the extra costs associated with LTCs were *de minimis*. In all cases, impacts were below $4.00 per month (net present value, 2021$), based on typical residential usage of 1,000 kWh (i.e., 1 MWh) per month (see Figure ES-28 and Figure ES-29).

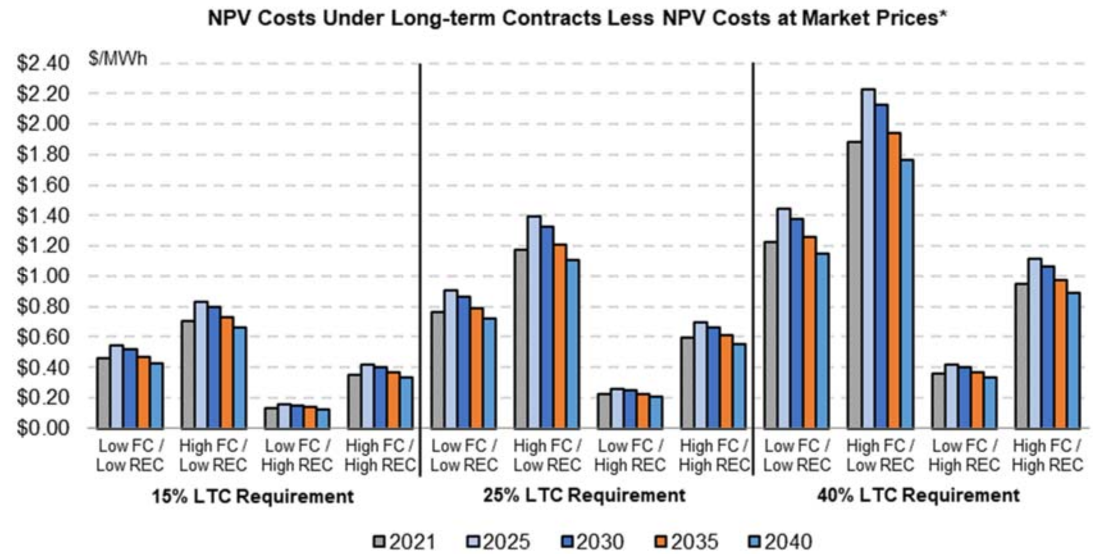

Figure ES-28. Net Present Value Cost Comparison – Tier 1 Non-Carve-out, All Retail Customers, by Average Rate (2021$/MWh)

*"FC" denotes financing costs; "REC" denotes REC prices.

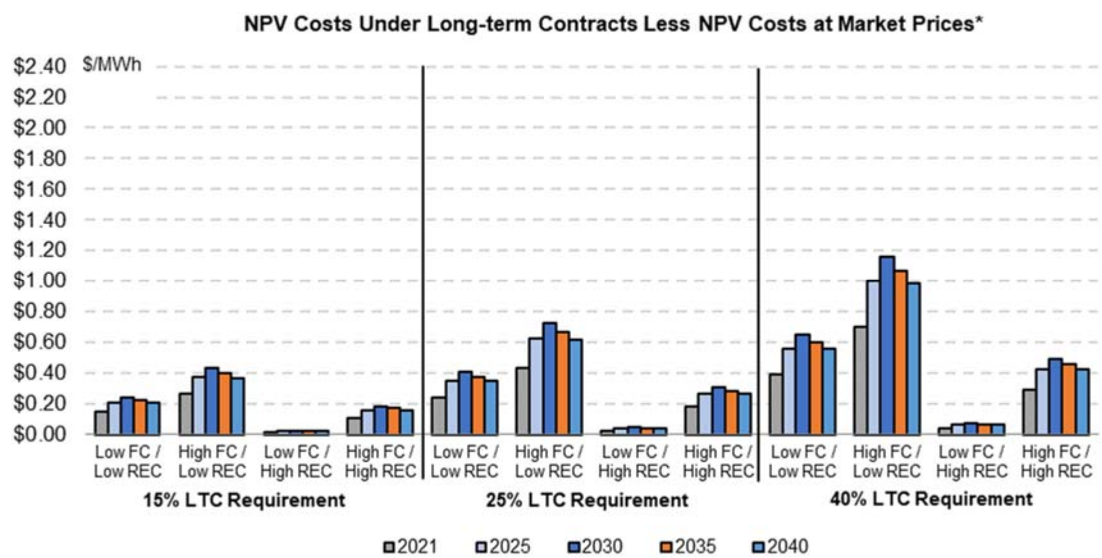

Figure ES-29. Net Present Value Cost Comparison – Tier 1 Solar Carve-out, All Retail Customers, by Average Rate (2021$/MWh)

*"FC" denotes financing costs; "REC" denotes SREC prices.

The scenarios defined in this analysis do not exhaust the spectrum of potential conditions that could emerge and importantly affect the estimated impacts of Maryland relying on LTCs for meeting a portion of its RPS requirements. For example, higher-than-expected increases in the market price of energy would increase the benefits of LTCs since the energy purchased under the fixed-price contracts would be more attractive relative to the market energy prices. The results presented in the final report, therefore, do not define upper and lower bounds of the potential impacts of LTCs, but rather present a set of reasonable outcomes associated with reliance on such contracts.

Non-RPS policies are useful for achieving goals related to the RPS, but are not substitutes for the RPS.

In addition to RPS policies, numerous regulatory and market-based tools can be used to promote renewable energy technologies in the power sector.[16] These policies either provide financial support to individual projects or address barriers to renewable energy by reforming market rules and regulatory processes (see Figure ES-30).

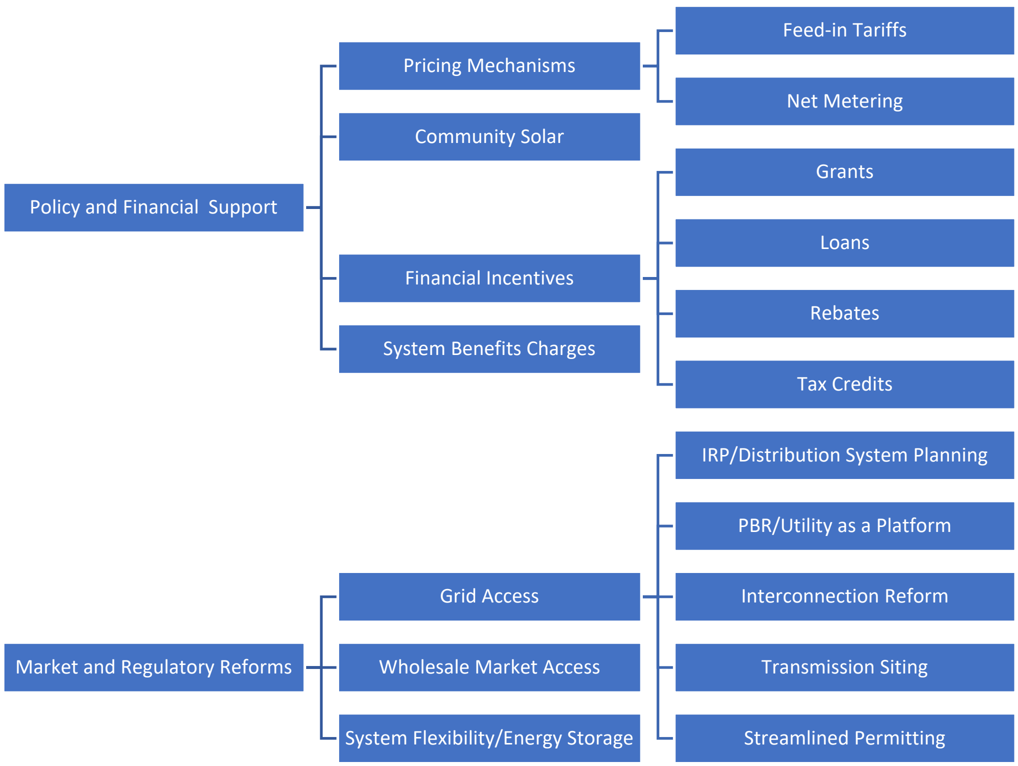

Figure ES-30. Supportive Policies for Renewable Energy in the Power Sector

It is difficult to distinguish the incremental impacts of these initiatives, and other related factors, due to the overlap and interaction among them. Rather, experts who were consulted for the final report said that non-RPS policies are useful complements to the RPS, and they can be used to pursue related objectives, such as: encouraging non-electric renewable energy technologies like solar thermal; promoting DG; or supporting projects in LMI communities.

Chapter 6, "Non-RPS Policies to Promote Renewable Energy," provides primers on all of the policies (and the first two regulatory options) shown in Figure ES-30, summarizing how they work, their use in other states, their chief advantages and disadvantages, and (if applicable) their history in Maryland.

[16] These policies exist within the broader context of policies to promote renewable energy across sectors (i.e., also within the transportation and heating/cooling sectors) and, still more broadly, to curb air and water emissions throughout the economy as a whole.

RPS policies, or related initiatives, are one way to support existing nuclear power plants, which face a variety of economic challenges in PJM.

Existing nuclear power plants face a variety of economic challenges as a result of low energy market and capacity market prices. Several states have recently taken action to support nuclear plants, including the implementation of zero-emission credits (ZECs) in New York, Illinois, and New Jersey; monthly customer surcharges in Ohio; and state-required solicitations of clean energy, including nuclear power in Connecticut. Several states have considered supporting new or existing nuclear through their RPS.

Calvert Cliffs Nuclear Power Plant, located in Calvert County, accounted for 33.1% of Maryland's net electricity generation and 72.3% of its emission-free electricity in 2018. More broadly, Maryland policymakers are considering potential ways to support nuclear power going forward. This topic is the subject of a separate report that was included in the requirements within Ch. 757.

Efforts to support existing and future nuclear energy generation, either through an RPS or through initiatives that borrow elements of the RPS, face legal and regulatory challenges. Lawsuits against the Illinois and New York ZEC initiatives were recently resolved with decisions that are favorable to the continuation of these initiatives. Proposed changes to PJM's Reliability Pricing Model (RPM) that could counteract the actions of states to subsidize generation, whether it be nuclear power or renewable energy generation, are pending Federal Energy Regulatory Commission (FERC) action, creating uncertainty for market participants and state policymakers. See Section 7.3.6 for details on PJM's proposals.

The future of the Maryland RPS depends on what goals are most important to policymakers.

There are many ways to configure an RPS, as reflected by the diversity of existing state RPS policies. Chapter 4, "Assessment of Potential Changes to the Maryland RPS," provides an evaluation of nearly a dozen options for the Maryland RPS: maintaining the 50% Tier 1 requirement; adopting a 100% RPS or Clean Energy Standard (CES), which would add other eligible resources not typically eligible for a RPS such as nuclear power and large hydro; maintaining the 14.5% Tier 1 solar carve-out; removing black liquor; providing state support for energy storage; moving hydro from Tier 2 to Tier 1; requiring long-term contracts; creating a Clean Peak Standard; lowering the ACP level; limiting geographic eligibility to within PJM; and implementing ZECs or procurement support for nuclear power.

In many cases, potential changes or additions to the RPS involve the same trade-offs highlighted throughout the final report. As stated earlier, the Maryland RPS is often expected to be all things to all people. That is, the RPS is not only a driver of renewable energy development, but also serves as a tool for combating climate change and improving local air quality; a source of jobs and economic development; a support for technological innovation; an impetus and sustainer of in-state businesses; etc. The success of the Maryland RPS in serving all these functions simultaneously is mixed. Ultimately, Maryland policymakers may decide to prioritize what they want the Maryland RPS to accomplish, and then they are able to adjust current law to best meet those priorities.

1. Introduction: Understanding the Maryland RPS

The Maryland General Assembly enacted the Maryland RPS in 2004. Since the law first took effect in 2006, the Maryland RPS has been amended 11 times, including as recently as the enactment of the Clean Energy Jobs Act (CEJA) (SB 516) in May 2019, as codified in Chapter 757 of the Acts of the Maryland General Assembly of 2019. As a result of these revisions, the Maryland RPS has changed in significant ways since first enacted. The underlying design and primary purpose of the policy, however, remains the same.

In order to understand the past, present, and future of the Maryland RPS, the final report begins with an introductory overview of the RPS. This chapter begins by defining the RPS and outlining its key characteristics. Next, the chapter reviews the primary purpose of the RPS. Subsequently, an overview is provided of the history of the Maryland RPS and how it evolved into its current form. Finally, the chapter concludes with a brief summary of the current policy, effective as of the enactment of Ch. 757 in May 2019.

1.1. What Is an RPS?

An RPS requires that a designated portion of the electricity sold by LSEs in a given state comes from eligible energy sources, primarily renewable energy. Maryland is one of 29 states (and the District of Columbia) with an RPS requirement, as shown in Figure 1-1.

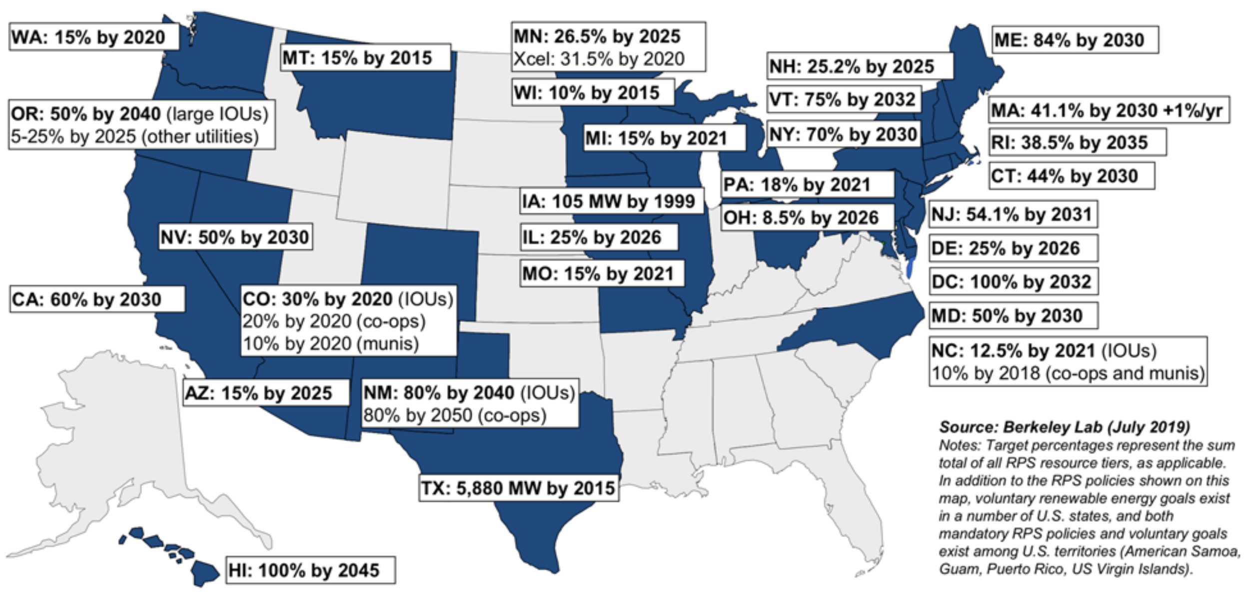

Figure 1-1. RPS Policies in the U.S., as of July 2019

Source: LBNL, *U.S. Renewables Portfolio Standards – 2019 Annual Status Update*.

Although RPS policy design and implementation vary by state, most programs share a handful of similar features. First, the renewable energy requirement is usually defined as a percentage of total retail sales on an annual basis. States typically implement an RPS over time through a gradual ramp-up of the percentage requirement toward a designated target level.

Second, LSEs generally comply with RPS requirements through the retirement of RECs. A REC is a certificate demonstrating 1 MWh of energy output from a certified renewable energy generator that can be used to meet RPS compliance requirements. RECs can be traded, sold, or purchased multiple times until a REC is retired, either to comply with a state RPS policy or as part of a voluntary green power purchase that is separate from RPS policies. States rely on tracking systems covering a single state or region, such as PJM-GATS, to trace RECs and REC retirements.[17] While a REC may be eligible for use in more than one state, a REC that is used to demonstrate RPS compliance may only be used once and in one state, and is retired once used.

Third, many states require LSEs to pay a penalty of some form if they are unable to meet the requirements of the RPS. Alternatively, states may require LSEs to pay an ACP for each REC that it is short of its RPS requirement during a given compliance period. Funds generated from the ACP can be used for a variety of purposes, such as providing grants and loans for the development of renewable energy resources. The ACP operates as a *de facto* ceiling for REC prices. That is, LSEs are willing to purchase or create RECs up to the point that REC costs exceed the ACP.

There is substantial variation in how states implement the above RPS features. Additional RPS features and requirements that are common components of RPS policies but can vary across states include:

- Compliance timelines;
- Locational requirements, such as restrictions that out-of-state resources must be “deliverable” to in-state distribution;
- LSE obligations, such as exemptions for electric cooperatives (co-ops) or municipal utilities (munis);
- Technology eligibility, such as distinct “tiers” and separate requirements for different resource classes;
- Contracting requirements, such as rules designating a minimum contract term for an LSE to procure renewable energy, thereby providing some level of market certainty;
- Flexibility rules, such as banking (i.e., allowing LSEs to use a REC generated in one year to satisfy RPS requirements in future years);
- Cost caps, such as limiting aggregate customer rate impacts or capping the amount of RPS costs that can be financed through a bill surcharge;
- Carve-outs, such as requiring that a portion of a state’s RPS policy be met by designated resources (usually located in-state), often solar; and
- Multipliers, such as increasing the credit value of RECs from designated resources and thereby incentivizing their use for RPS compliance.

These features, as well as other differentiating factors between state RPS policies, are described further throughout the subsequent final report.

1.2. How Does an RPS Work?

An RPS facilitates the growth of renewable energy supply by creating demand for renewable energy. That is, an RPS requires LSEs to demonstrate compliance by submitting a required number of RECs derived from the output of qualified renewable energy generation (or pay

[17] PJM is the RTO serving portions or all of 13 states (and the District of Columbia), including Maryland, located in the mid-Atlantic and Midwest.

ACPs). REC prices increase if there is a shortfall of RECs necessary to meet state RPS requirements, and the increase in REC prices will induce development of new renewable energy capacity, the importing of RECs from outside the state or region, or both. The reverse is true if there are more RECs available than needed to meet state RPS requirements.

Renewable energy generators will enter a market and supply RECs insofar as the prospective generator's potential lifetime value, inclusive of expected REC payments, is above zero. REC payments complement other sources of revenue, such as energy and capacity market payments, and help offset generator expenses, including capital costs and ongoing O&M costs. In effect, REC payments serve as a subsidy for renewable energy generation and are tied directly to output (i.e., kWh of production).

REC and SREC prices are influenced by a variety of supply and demand considerations both in Maryland and elsewhere in PJM. These factors include the percentage of renewable energy required; types of technologies eligible to supply RECs; geographic eligibility requirements of qualifying resources; ACP levels; demand for RECs for non-RPS purposes; the duration for which RECs can be used; the potential to bank RECs; and cost considerations for potential qualifying resources. REC prices are also affected by intangible factors, such as expectations about how a state legislature may modify an RPS over time.

1.3. History of the Maryland RPS

The Maryland General Assembly has made significant alterations to the Maryland RPS since its inception in 2004. These changes include adjustments to the percentage requirements, the addition of new resources, converting resources from Tier 2 to Tier 1 eligibility, creating resource Tier 1 carve-outs for solar and offshore wind, and imposing conditions on the eligibility of resources located outside of PJM.[18]

This section reviews major developments in the history of the Maryland RPS through 2019. Developments from 2004-2019 are also summarized in Figure 1-2. Changes in the percentage requirements of the Maryland RPS prior to 2019 are visualized in Figure 1-3, which tracks the solar carve-out and overall Tier 1 requirement. Changes to the Maryland RPS in 2019 are described at the end of the section.

[18] Note that, for purposes of this report, usage of the term "Tier 1" is inclusive of both the offshore wind and solar carve-outs. Tier 1 solar requirements are described as the solar carve-out, and Tier 1 offshore wind requirements are described as the offshore wind carve-out. The term "Tier 1 non-carve-out requirements" will be used to describe the portion of Tier 1 that is exclusive of the solar and offshore wind carve-outs.

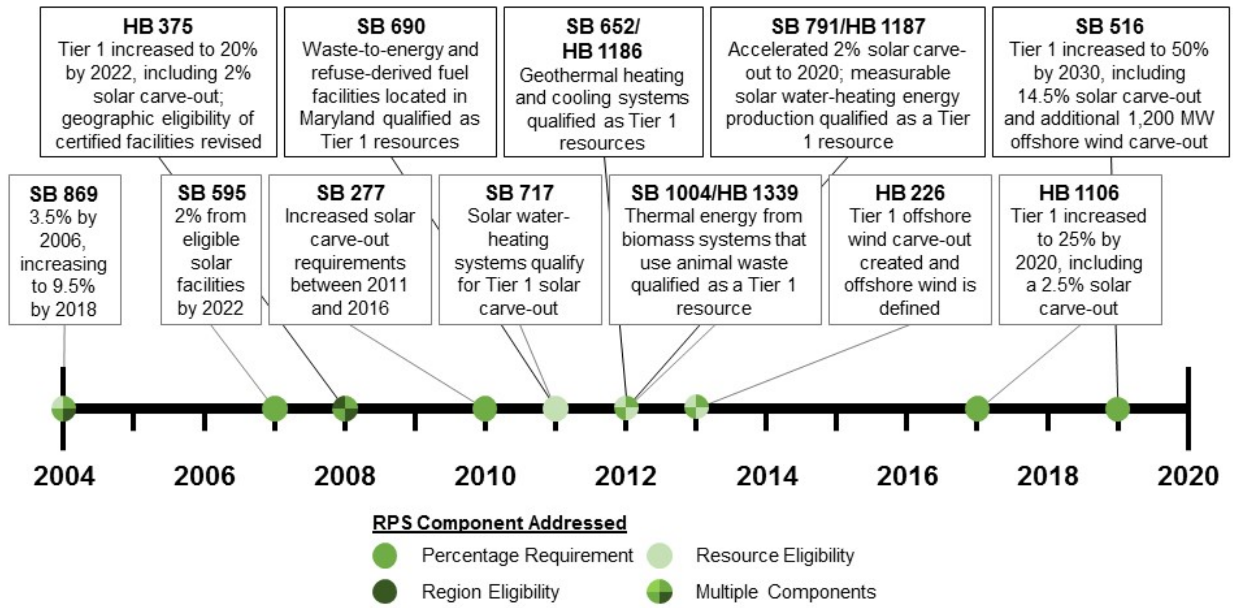

Figure 1-2. Timeline of Changes to the Maryland RPS

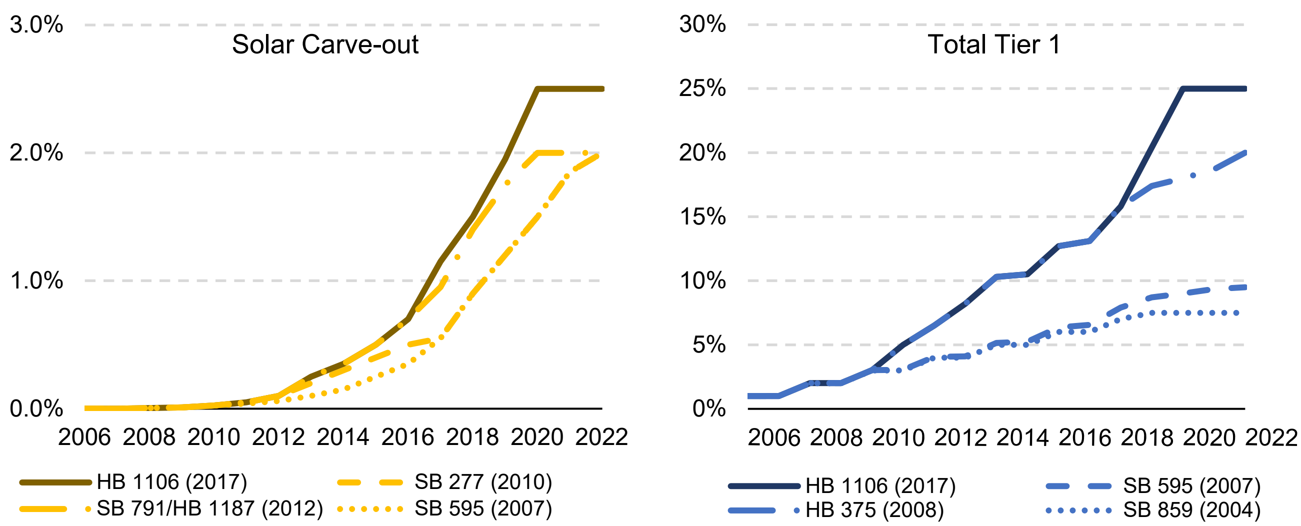

Figure 1-3. History of Maryland RPS Solar Carve-out and Total Tier 1 Requirement, as of 2018

Note: Figure 1-4 below illustrates the changes as a result of enacting the CEJA of 2019.

The Maryland RPS was enacted in 2004 when the Maryland General Assembly passed the Maryland RPS Act. At that time, the law required that 3.5% of retail energy sales come from renewable energy sources by 2006, increasing to 9.5% by 2018, and then decreasing to 7.5% in 2019 and subsequent years.[19] The law distinguished between energy derived from Tier 1 and Tier 2 facilities. Energy derived from Tier 1 resources was to comprise 1% of electricity sales in 2006, and then increase to 7.5% by 2019. Tier 2 resources were to make

[19] Unless otherwise indicated, "renewable energy resources" is inclusive of all resources that may be used to comply with the Maryland RPS.

up 2.5% of electricity sales each year and then sunset by the end of 2018 (i.e., there would be no Tier 2 requirement in 2019 and thereafter).

In 2007, the Maryland General Assembly passed SB 595, Electricity – Net Energy Metering – Renewable Energy Portfolio Standard – Solar Energy. This bill required that 2% of retail electricity sales come from eligible solar facilities by 2022, in addition to the 7.5% sales from Tier 1 facilities.

In 2008, the Maryland General Assembly passed HB 375, Renewable Portfolio Standard Percentage Requirements – Acceleration, which increased the total Tier 1 requirement to 20% by 2022, with 2% solar carve-out and 18% Tier 1. At that time, out-of-state solar could qualify as a solar carve-out resource. The Tier 2 requirements did not change.

HB 375 also changed the geographic eligibility of facilities that qualify under the Maryland RPS. As provided in the original 2004 legislation, renewable energy generation could be located: (1) in the PJM region; (2) in a state that is adjacent to the PJM region; or (3) in a control area (service territory) that is adjacent to the PJM region if the electricity is delivered into the PJM region. As a result of HB 375, effective January 1, 2011, renewable energy generation could be located: (1) in the PJM region; or (2) in a control area that is adjacent to the PJM region if the electricity accompanying the RECs is delivered into the PJM region.[20]

The Maryland General Assembly passed SB 277 in May 2010, which increased the solar carve-out requirements between 2011-2016. In May 2011, the General Assembly approved SB 690 and SB 717. SB 690 allowed Tier 1 eligibility for waste-to-energy and refuse-derived fuel facilities connected to Maryland distribution.[21] Previously, waste-to-energy generation was only eligible for Tier 2. SB 717 allowed RECs from solar water-heating systems not solely used to heat a pool or hot tub to qualify for the Tier 1 solar carve-out.[22] Prior to SB 717, only electric generation from solar power was eligible under the solar carve-out.

In 2012, the Maryland General Assembly passed SB 791/HB 1187. These bills accelerated the Maryland RPS solar carve-out compliance requirements beginning in 2013, moved the 2% solar carve-out requirement from 2022 to 2020, and qualified solar water-heating energy production from certain in-home water heaters for the Tier 1 solar carve-out. Also in 2012, the enactment of SB 652/HB 1186 and SB 1004/HB 1339 qualified eligible geothermal and animal waste power sources, respectively, as Tier 1 resources, effective January 1, 2013.[23,24]

In 2013, Maryland enacted HB 226, which created a carve-out for offshore wind in Tier 1 of the Maryland RPS. Beginning in 2017, this bill allows qualified offshore wind generation to count toward the RPS up to a maximum of 2.5% of retail electricity sales. As a carve-out, this generation counts toward the overall Tier 1 requirement. HB 226 defines qualified

[20] While Tier 1 and Tier 2 facilities in control areas adjacent to PJM regions could still be eligible under the modified RPS following HB 375, the additional transmission and wheeling charges required to deliver this energy into PJM provide a slight competitive disadvantage for facilities located outside of PJM regions. Furthermore, smaller facilities operating behind the meter or serving on-site loads are unable to deliver bundled energy and RECs into PJM regions from an adjacent control area.

[21] Waste incineration facilities must also meet certain requirements with respect to the recycling rate of the jurisdictions where the municipal solid waste is collected.

[22] To qualify, these systems must use Solar Rating & Certification Corporation operating guidelines to certify solar collectors' equipment and have been commissioned on or after June 1, 2011.

[23] Geothermal power sources include geothermal heating and cooling systems commissioned on or after January 1, 2013.

[24] Eligibility of animal waste power sources is based on the thermal energy output of biomass systems that primarily use animal waste.

offshore wind projects as those located on the Outer Continental Shelf, in an area of the ocean designated for leasing by the U.S. Department of the Interior (DOI), and between 10 and 30 miles off the Maryland coast. The projects must also interconnect to the PJM grid at the Delmarva Peninsula and be approved by the Maryland PSC.

The Maryland General Assembly passed HB 1106 in 2017. HB 1106 increased the solar carve-out to 2.5% and overall Tier 1 requirement to 25% by 2020. It also reduced ACPs and increased the cost threshold required for LSEs to delay their solar requirement levels by one year. Most recently, the General Assembly passed SB 516 in April 2019. SB 516 increases the solar carve-out to 14.5% by 2028 and the overall Tier 1 requirement to 50% by 2030. Year-over-year changes in the percentage requirements of the Maryland RPS as a result of SB 516 are visualized in Figure 1-4, which also compares the solar carve-out and overall Tier 1 requirement of SB 516 with levels previously established in HB 1106.

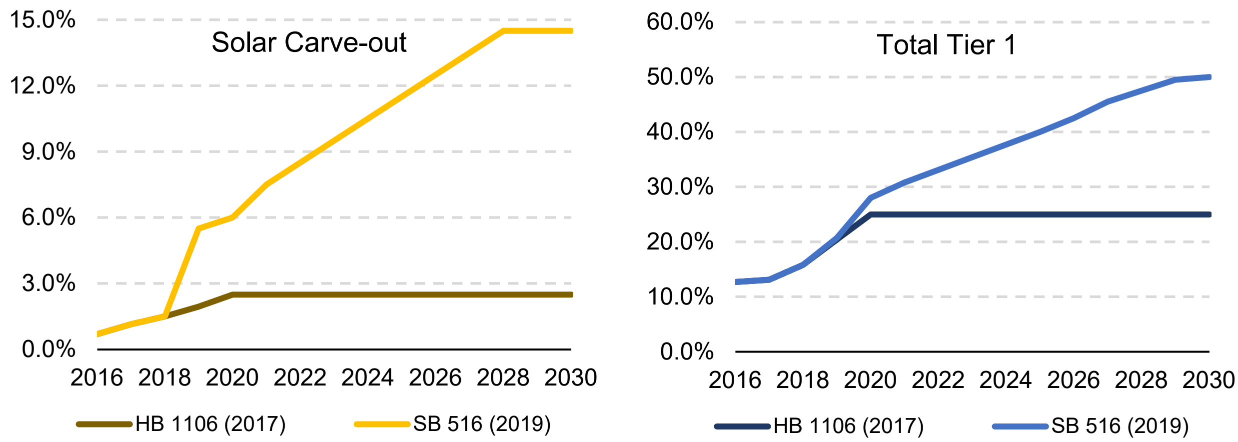

Figure 1-4. Comparison of Maryland RPS Solar Carve-out and Total Tier 1 Requirement in HB 1106 and Ch. 757

Besides increasing the RPS percentage requirements, Ch. 757 also extended the Tier 2 requirement until the end of 2020, further reduced the ACP price levels, increased the threshold to request a one-year delay in solar requirements, and exempted co-ops from solar-carve-out requirements above the levels set in HB 1106, among other changes. Additionally, Ch. 757 made several changes to the offshore wind requirement, including allowing projects in areas up to 80 miles off the Maryland coast; reclassifying projects approved before July 1, 2017 as "Round 1"; creating a new "Round 2" requirement of at least 400 MW of cumulative new projects by 2026, 800 MW by 2028, and 1,200 MW by 2030; removing the 2.5% OREC limit beginning in 2021; and setting a 10% OREC limit that is only applicable in 2025.

1.4. Current Maryland RPS

In Maryland, the PSC approves the eligibility of renewable energy projects for meeting the Maryland RPS consistent with the eligibility requirements spelled out in statute. The resources that currently qualify for the Maryland RPS are listed in Table 1-1. Note that hydro facilities other than pump storage with a capacity of greater than 30 MW are eligible for the Maryland RPS until the sunset of the Tier 2 requirement at the conclusion of 2020.

Table 1-1. Maryland RPS-Eligible Facilities, as of June 2019

TIER 1
Solar PV and solar thermal systems that produce electric power, and solar water-heating systems constructed on or after June 1, 2011 (facilities located within Maryland qualify for the solar carve-out)
Onshore wind
Offshore wind within designated areas near Maryland
Qualifying biomass[1]
Methane from the anaerobic decomposition of organic materials in a landfill or a wastewater treatment plant
Geothermal, including energy generated through geothermal exchange from, or thermal energy avoided by, groundwater or a shallow ground source within Maryland
Ocean, including energy from waves, tides, currents, and thermal differences
Fuel cells powered by a Tier 1 resource
Hydroelectric plants under 30 MW licensed by FERC or exempt from licensing
Poultry litter-to-energy within Maryland
Waste-to-energy (including blast furnace gas and refuse-derived fuels) within Maryland
TIER 2
Hydroelectric power other than pump storage

Source: Annotated Code of Maryland, PUA § 7-703.

[1] Qualifying biomass is: a non-hazardous, organic material that is available on a renewable or recurring basis; waste material that is segregated from inorganic waste material; and is derived from any of the following sources:

1. Excluding old-growth timber, any of the following forest-related resources:
    a. Mill residue, except sawdust and wood shavings;
    b. Pre-commercial soft wood thinning;
    c. Slash, brush, or yard waste; and
    d. Pallets, crates, or dunnage.
2. Agricultural and silvicultural sources, including tree crops, vineyard materials, grains, legumes, sugar, and other crop byproducts or residues.
3. Gas produced from the anaerobic decomposition of animal waste or poultry waste.
4. A plant that is cultivated exclusively for purposes of being used as a Tier 1 or Tier 2 renewable energy resource to produce electricity.

The geographic requirements applicable to these resources are unchanged since HB 375; RECs must come from sources either in PJM or deliverable into PJM. Maryland's solar carve-out requires RECs from qualified resources to be located either within the state or deliverable into Maryland. Likewise, offshore wind must come from a designated coastal area between 10 and 80 miles off the coast of Maryland in order to meet the offshore wind carve-out.

To show compliance with the Maryland RPS, LSEs must retire the appropriate number of RECs in a tracking account in PJM-GATS. LSEs must also submit annual reports to the Maryland PSC, which audits RPS compliance on an annual basis. The percentage requirements of the Maryland RPS, after accounting for legislative changes during the last 15 years, are shown in Table 1-2. Note that the requirements listed in years after 2019 are projected based on existing legislative requirements and recent energy sales forecasts from the PSC. Also note that, according to Ch. 757, electric cooperatives are exempt from the increased solar carve-out. Instead, the required percentage of solar generation for electric cooperatives remains at 2.5% "in 2020 and later." The reduced solar carve-out requirement for electric cooperative customers is replaced with a higher non-solar carve-out requirement.

Table 1-2. Maryland RPS Percentage of Renewable Energy Required, as of September 2019

Year	TIER 1 Non-Carve-out	TIER 1 Solar[1]	TIER 1 Offshore Wind[2]	TIER 1 TOTAL	TIER 2 TOTAL[3]
2006	1%	0%	0%	**1%**	**2.5%**
2007	1	0	0	**1**	**2.5**
2008	2	0.005	0	**2.005**	**2.5**
2009	2	0.01	0	**2.01**	**2.5**
2010	3	0.025	0	**3.025**	**2.5**
2011	4.95	0.05	0	**5**	**2.5**
2012	6.4	0.1	0	**6.5**	**2.5**
2013	7.95	0.25	0	**8.2**	**2.5**
2014	9.95	0.35	0	**10.3**	**2.5**
2015	10	0.5	0	**10.5**	**2.5**
2016	12	0.7	0	**12.7**	**2.5**
2017	11.95	1.15	0	**13.1**	**2.5**
2018	14.3	1.5	0	**15.8**	**2.5**
2019	15.2	5.5	0	**20.7**	**2.5**
2020	22	6	0	**28**	**2.5**
2021	~21.7	7.5	~1.6	**30.8**	**-**
2022	~23	8.5	~1.6	**33.1**	**-**
2023	~23.5	9.5	~2.4	**35.4**	**-**
2024	~24.8	10.5	~2.4	**37.7**	**-**
2025	~26.1	11.5	~2.4	**40**	**-**
2026	~24.7	12.5	~5.3	**42.5**	**-**
2027	~26.6	13.5	~5.4	**45.5**	**-**
2028	~24.7	14.5	~8.3	**47.5**	**-**
2029	~26.6	14.5	~8.4	**49.5**	**-**
2030+	~24.1	14.5	~11.4	**50**	**-**

Source: Annotated Code of Maryland, PUA § 7-703.

[1] Solar requirement began in Compliance Year 2008. Electric cooperatives are required to obtain 2.5% of energy from solar carve-out resources "in 2020 and later" according to Ch. 757. The reduced share of solar is replaced with a higher share of non-carve-out resources (e.g., the 2030 requirement for electric cooperatives is ~36.1% non-carve-out and 2.5% solar carve-out resources).

[2] The percentage of future RECs provided by offshore wind will fluctuate on an annual basis depending on total MWh output and retail energy sales. The estimates presented in this table are based on the expected OREC output of both existing Round 1 projects and prospective Round 2 projects. Round 1 OREC estimates assume only previously approved projects enter service (see Maryland PSC Order No. 88192, Table 2, "Offshore Wind Component of the RPS Obligation for Purchasers of ORECs"). Round 2 OREC estimates assume 400 MW of additional capacity enters service in 2026, 2028, and 2030 as required by Ch. 757, and that all Round 2 facilities have a capacity factor of 45%. Total OREC generation is relative to projected aggregate energy sales, net demand-side management, from the PSC's *Ten-Year Plan (2018-2027) of Electric Companies in Maryland*. The same compound annual growth rate from this period is used to extrapolate to 2030.

[3] The Tier 2 requirement sunsets at the end of Compliance Year 2020.

LSEs may request from the Maryland PSC a one-year delay from complying with the solar carve-out of the Maryland RPS if the cost of purchasing SRECs is equal to or exceeds 6% of the LSE's total annual retail electricity sales revenue in Maryland. ACP levels in Maryland, not including OREC requirements, are currently set as follows:

- Tier 1 (non-carve-out): $30/MWh for non-carve-out shortfalls from 2019-2023; $27.50/MWh in 2024; $25/MWh in 2025; $24.75/MWh in 2026; $24.50/MWh in 2027; $22.50 in 2028-2029; and $22.35/MWh in 2030 and later.
- Tier 1 (solar): $100/MWh for solar shortfalls in 2019-2020; $80/MWh in 2021; $60/MWh in 2022; $45/MWh in 2023; $40/MWh in 2024; $35/MWh in 2025; $30/MWh in 2026; $25/MWh in 2027-2028; $22.50/MWh in 2029; and $22.35/MWh in 2030 and later.
- Tier 1 Industrial Process Load (IPL): $2/MWh for IPL shortfalls in 2017 and beyond in years without an OREC requirement; $1/MWh for IPL shortfalls in any year with an OREC requirement; and $0/MWh for IPL shortfalls in any year when the net impact of Round 1 offshore wind projects exceeds $1.65/MWh (2012$).

Finally, in Maryland, a REC generated in one year may be used to satisfy the RPS requirement in that same year, the following (second) year, or the third year. In other words, Maryland allows REC banking for up to three years.

1.5. Note on Data Sources

The data sources used throughout the final report are specified in each respective section. In several cases, the analysis is based on data from one source when multiple, alternative sources also exist. For example, EIA and PJM-GATS both report data regarding generation from renewable energy resources in Maryland.[25] Despite reporting similar datapoints in many cases, the data from these two sources sometimes differ, and occasionally by a significant magnitude. These distinctions owe to differences between each data source in terms of data collection method (e.g., meter readings, market settlement data, surveys and self-reporting), resource definitions (e.g., minimum size requirements for recorded DG), and boundary definitions (e.g., inclusive of just PJM, or entire states), among other factors. For example, both EIA and PJM-GATS track and record data regarding the characteristics of electric power generators. PJM-GATS includes both data from PJM's market settlement system and, for generators not in PJM's markets, self-reported data from either generators or from states that pre-qualified the generator, such as for state RPS policies. EIA data, meanwhile, is collected via periodic surveys sent to generators, utilities, and other market participants. Participation in these surveys is required by law, as first set forth in the 1974 Federal Energy Administration Act and subsequently amended by over a dozen laws. When deciding what data source to use, the authors applied their best judgement in selecting the source believed to present the most accurate and representative picture of electricity generation in Maryland and surrounding regions.

[25] Note that annual REC retirement data gathered from PJM-GATS mostly match the annual Maryland PSC reports. There are, however, small discrepancies between some states and years resulting in unmatched numbers between PJM-GATS and the PSC. Most of the identified differences stem from later updates to PJM-GATS that are not reflected in the earlier state PSC reports. Given their small size, these differences are not adjusted for in the subsequent text.

2. Effectiveness of the Maryland RPS to Date

Among other things, Ch. 393 calls for an evaluation of the effectiveness of the Maryland RPS to date along several specified dimensions. These include the effect of RPS policies on the health, welfare, environmental, and economic interests of Maryland. This chapter of the final report addresses the effect of the Maryland RPS on:

- Deployment of renewable energy resources;
- Various environmental indicators, including emissions and air pollution;
- Various economic indicators, most notably employment;
- Consumer electricity rates and RPS compliance costs, as viewed through REC prices and ACP costs; and
- Environmental justice.

This chapter synthesizes existing research as well as assesses data from a variety of industry sources, including PJM, EIA, and the Maryland PSC. The findings of each section are summarized at the start, and then discussed in the text. Several sections are broken down into subsections to explore the effect of different design features of the Maryland RPS. RPS design, including resource eligibility, geographical restrictions, cost recovery, etc., can have a significant influence on the outcomes of an RPS. For example, a recent study by Carley, *et al.* (2018) found that a one-point increase in RPS stringency, which measures the amount of renewable energy growth required and over what time period, increases renewable energy generation by 0.2%, solar generation by 1%, and renewable energy capacity by 0.3%.[26] The study also found that the development of in-state wind capacity depends on geographical characteristics and REC trading; the inclusion of energy efficiency in an RPS can crowd out investment in other renewable energy resources; allowing REC purchases from a broader interstate REC market can reduce implementation costs, but it also reduces in-state benefit; and that a technology-neutral RPS supports least-cost renewable energy resources but does not necessarily ensure resource diversity.

Several sections of the chapter are also subdivided to distinguish in-state and out-of-state impacts of the Maryland RPS. This approach addresses one of the major tensions when designing RPS policy: the competing desire to both minimize cost by allowing out-of-state, RPS-eligible resources to be used to meet RPS requirements, and to maximize the RPS policy's in-state environmental and economic benefits by favoring the development of in-state resources, subject to the constraints of the Dormant Commerce Clause of the U.S. Constitution. Maryland is not immune to this challenge; the state participates in PJM and allows out-of-state PJM resources to qualify for the Maryland RPS if located in an adjacent control area and if the power is transmitted into PJM. This complicates assessing the role of the Maryland RPS in providing in-state benefits. Nevertheless, this chapter broadly estimates the contributions of the Maryland RPS and makes key assumptions, detailed below, about the relationship between RPS policies and policy outcomes.

2.1. Deployment of Renewable Energy

Among the most ubiquitous and direct goals of state RPS policies is to increase the amount of renewable energy generation, and therefore renewable energy capacity, available to meet electricity demand. This section of the final report looks specifically at the influence of RPS

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[26] Sanya Carley, Lincoln Davies, David Spence and Nikolaos Zirogiannis, "Empirical evaluation of the stringency and design of renewable portfolio standards," *Nature Energy*, Vol. 3, 2018.

policies on renewable energy development and deployment. First, the section summarizes a recent comprehensive review of RPS policies in the U.S. and their impact, including initial conclusions regarding deployment impacts. Next, it provides statistics on a host of often competing priorities related to renewable energy development and deployment, including promoting in-state renewable energy development, utilizing zero-emission technologies, supporting emerging technologies, and supporting existing renewable energy facilities that might otherwise retire. Ultimately, the "effectiveness" of the Maryland RPS in terms of deployment depends on the relative weight given to these priorities. Below is a summary of the trends and trade-offs detailed in this section:

- Estimates from LBNL suggest, as an upper bound, that RPS policies are associated with, in aggregate, roughly 45% of state-by-state non-hydro renewable energy growth in the U.S. from 2000-2018. In regions like the Northeast and the mid-Atlantic, RPS policies are associated with an even higher share of the growth of non-hydro renewable energy generation.
- The mid-Atlantic region has enough renewable energy under development as of 2018 to already meet its collective 2020 RPS capacity needs, but will require significant expansion of capacity to meet 2030 goals.
- The Maryland RPS has contributed to renewable energy development in the state, especially wind and solar energy. Between 2008-2018, non-hydro, utility-scale renewable energy capacity rose from 155 MW to 697 MW, and generation from these resources more than doubled from 612,485 MWh to 1,531,082 MWh. Within Maryland, wind dominated renewable energy capacity builds in the initial years of the Maryland RPS. Solar has been the primary source of new renewable energy capacity since 2012.
- Half of the renewable energy capacity registered with PJM-GATS that has come online since 2004, totaling 9,095 MW, is eligible to retire RECs for the Maryland RPS. Wind and solar facilities represent 96% of this eligible capacity, although many of these resources will serve other state RPS requirements. These resources are also potentially available to meet current and future RPS requirements in Maryland.
- Most RECs (53%) retired for compliance with the Maryland RPS in 2017 came from facilities that existed prior to the enactment of the Maryland RPS in 2004 (i.e., pre-RPS). These RECs are comprised mostly of black liquor (43%), hydro (24%), and MSW (21%).
- Maryland ranks in the middle of the mid-Atlantic states in PJM with respect to reliance on in-state RECs. Typically, between 10-25% of RECs retired for compliance with the Maryland RPS come from in-state resources, primarily solar, MSW, and Tier 2 hydro. Pennsylvania is the sole mid-Atlantic state to rely on substantially more (i.e., ~50%) in-state RECs.
- Maryland's reliance on carbon-free (i.e., not from combustion-based renewable energy sources such as biomass and MSW) technologies for Tier 1 RPS compliance has risen steadily, reaching over 62% of Tier 1 in 2017. Among the mid-Atlantic states in PJM, this is on a par with Pennsylvania, but below Delaware, New Jersey, and the District of Columbia; 70-100% of RECs retired for Tier 1 compliance in these jurisdictions were from carbon-free resources in 2017.

2.1.1. Overview of RPS Policies and Renewable Energy Development

State RPS policy developments are tracked on an annual basis by LBNL.[27] LBNL's most recent report indicates that state RPS requirements were responsible for, in aggregate, roughly 45% of non-hydro renewable energy generation from 2000-2018 in the U.S., as shown in Figure 2-1.[28] This estimate assumes that all state-level renewable energy growth that coincides with an RPS policy is attributable to the RPS requirement up until the requirement is fulfilled. In reality, some generation used to meet an RPS requirement might have been developed anyway. For instance, if this generation was also economical relative to other types of generation. Additionally, many other factors contributed to the growth of renewable energy over the last two decades, including tax credits, cost declines, and other incentives. Thus, this figure should be interpreted as an upper bound.

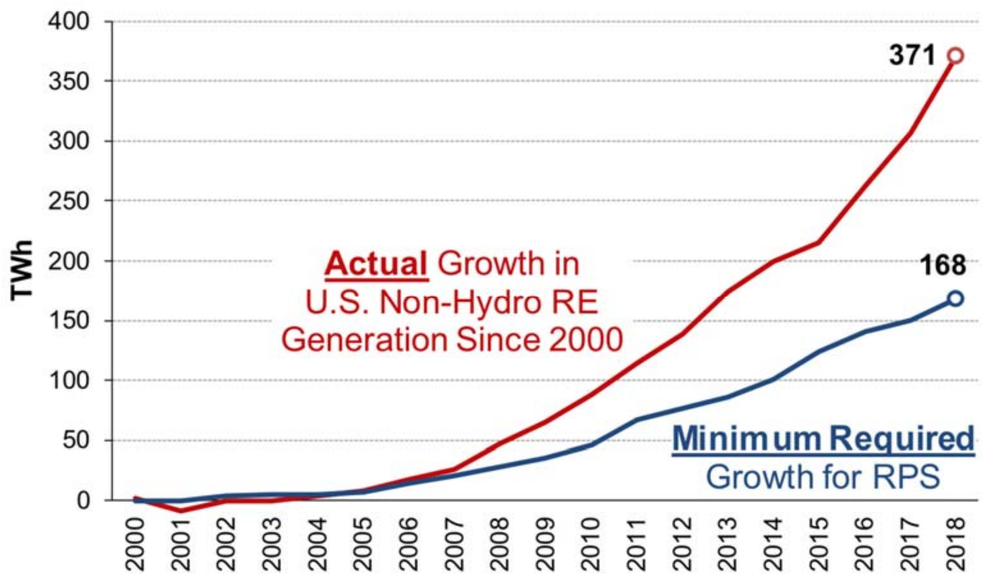

Figure 2-1. Growth in U.S. Non-Hydro Renewable Energy Generation

Source: LBNL, *U.S. Renewables Portfolio Standards – 2019 Annual Status Update*.

Note: According to LBNL, the Minimum Required estimate "excludes contributions to RPS compliance from pre-2000 vintage facilities, and from hydro, municipal solid waste, and non-RE technologies." State-level RPS demand projections are available at: emp.lbl.gov/projects/renewables-portfolio/.

The impact of state RPS policies varies across the country. Figure 2-2 compares RPS requirements and renewable energy generation by region. In the mid-Atlantic, the Northeast, and the West, growth in renewable energy generation tracks relatively closely with RPS requirements. Both the mid-Atlantic and Northeast also rely on RECs from neighboring regions to fulfill RPS requirements.[29] Meanwhile, in Texas and the Midwest, renewable energy generation outpaces RPS requirements, due in large part to the regions'

[27] Galen Barbose, *U.S. Renewables Portfolio Standards – 2019 Annual Status Update*, Lawrence Berkeley National Laboratory, July 2019 presentation, emp.lbl.gov/publications/us-renewables-portfolio-standards-2.

[28] Hydro capacity and generation are omitted from many statistics throughout this subsection. Most large-scale, or conventional, hydro plants predate RPS legislation.

[29] LBNL deems a project in the mid-Atlantic to be RPS-driven if it is registered with PJM-GATS.

rich wind resources and the increasing economic competitiveness of wind power.[30] Finally, in the Southeast, there has been some renewable energy growth, even though only one state has an RPS (North Carolina).

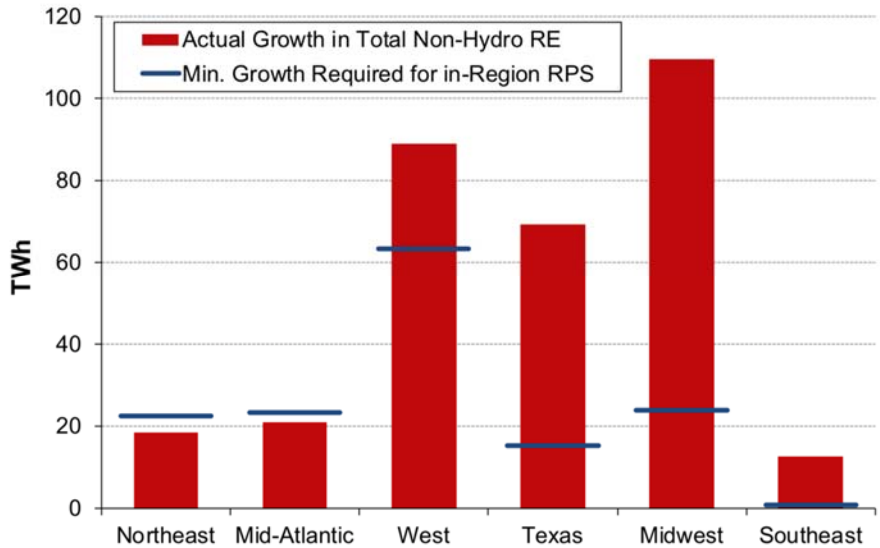

Figure 2-2. Growth in Non-Hydro Renewable Energy Generation, by Region, 2000-2018

Source: LBNL, *U.S. Renewables Portfolio Standards – 2019 Annual Status Update*.

RPS policies have also been closely associated with the growth of renewable energy capacity in the mid-Atlantic, Northeast, and West. Figure 2-3 compares annual renewable energy builds with renewable energy requirements by region. In these three regions, RPS requirements have represented between 60-100% of capacity additions in nearly every year from 2008-2017. For the mid-Atlantic, annual renewable energy capacity additions were almost entirely attributable to state RPS policies for most years, except for 2011 and 2017.

[30] Ryan Wiser and Mark Bolinger, *2017 Wind Technologies Market Report*, U.S. Department of Energy, August 2018, emp.lbl.gov/sites/default/files/2017_wind_technologies_market_report.pdf.

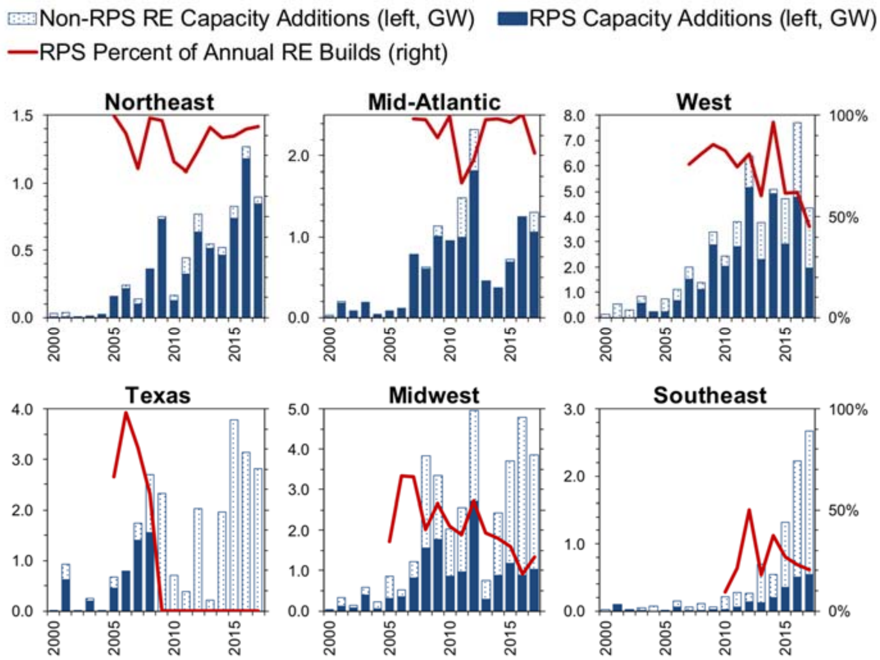

Figure 2-3. Comparison of Annual RPS Requirements and Renewable Energy Builds, by Region, 2000-2017

Source: LBNL, *U.S. Renewables Portfolio Standards – 2019 Annual Status Update*.

Figure 2-4 and Figure 2-5 show annual wind and solar capacity additions in the U.S. Originally, wind dominated RPS annual capacity additions. Since 2013, solar RPS capacity additions have surpassed wind, due to a combination of solar carve-outs and the increased cost-competitiveness of solar power.

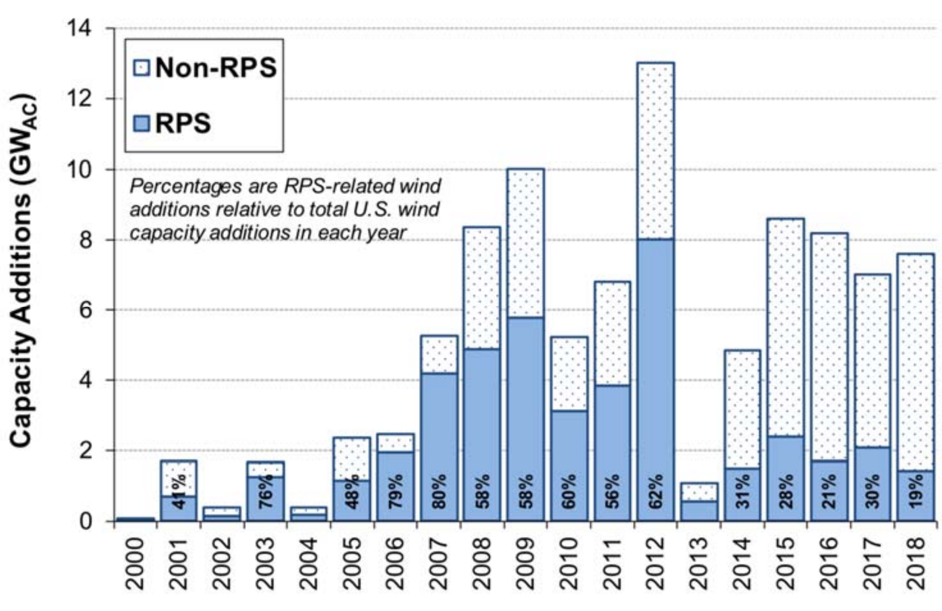

Figure 2-4. Annual RPS Wind Capacity Additions in the U.S.

Source: LBNL, *U.S. Renewables Portfolio Standards – 2019 Annual Status Update*.

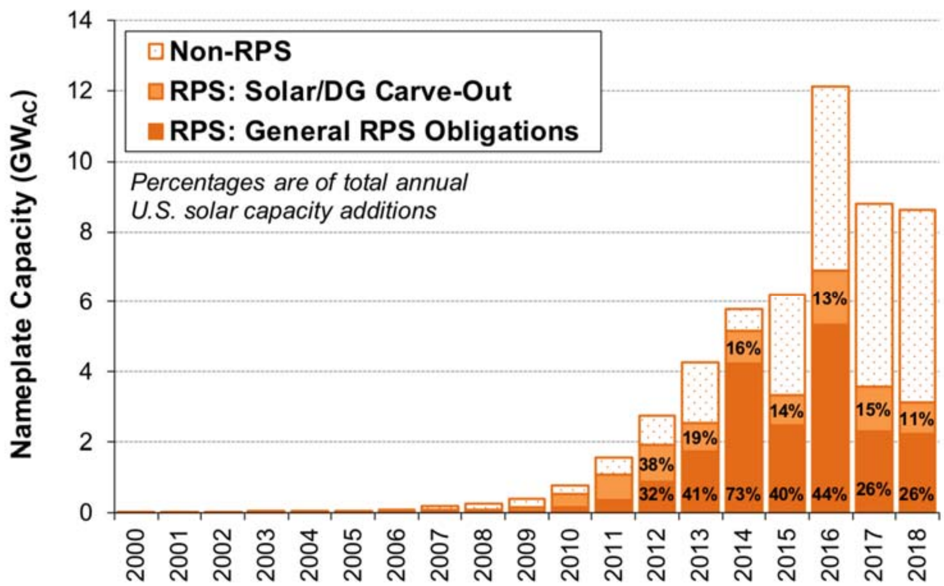

Figure 2-5. Annual RPS Solar Capacity Additions in the U.S.

Source: LBNL, *U.S. Renewables Portfolio Standards – 2019 Annual Status Update*.

As of July 2019, almost half of the states with RPS policies had final targets that will peak by 2026, as included in Figure 2-6. Once these targets are reached, demand for renewable energy generation will grow slowly in these states, due to load growth. However, over the past few years, several states (and the District of Columbia) in addition to Maryland have extended their RPS deadlines and raised their RPS requirement to 50% or higher. In 2015, Hawaii raised its RPS to 100% by 2045, and Vermont enacted an RPS requiring 75% by 2032. In 2016, New York, the District of Columbia, and Oregon raised their RPS requirements to 50% by 2030, 2032, and 2040, respectively. In 2018, New Jersey raised its RPS to 50% by 2030, and California raised its RPS to 60% by 2030, with an additional goal of 100% carbon-free energy, including large hydro by 2045. Also in 2018, the District of Columbia again increased its RPS, this time to 100% by 2032. In the first few months of 2019, New Mexico increased its RPS to 80% by 2040, with a 100% carbon-free energy requirement by 2045; Maine raised its RPS to 80% by 2030, with a goal of 100% by 2050; and New York instituted a 100% carbon-free target by 2040. Note that Figure 2-6 reflects changes in state RPS requirements as of July 2019.

Figure 2-6. Year of Final RPS Requirement, by State

Source: LBNL, *U.S. Renewables Portfolio Standards – 2019 Annual Status Update*.

Note: IOU = investor-owned utility; POU = publicly owned utility. Xcel is the abbreviated name of Northern States Power Company (Minnesota) d/b/a Xcel Energy.

Renewable energy demand nationwide due to state RPS policies is anticipated to nearly double by 2030. Figure 2-7 shows projected RPS demand—relative to available RPS-eligible resources—based on RPS policies in effect in July 2019. The greatest incremental RPS demand is in the mid-Atlantic and Northeast, followed by California and the rest of the West. Incremental RPS needs in the mid-Atlantic are attributed primarily to Maryland, New Jersey, Illinois, and Ohio.

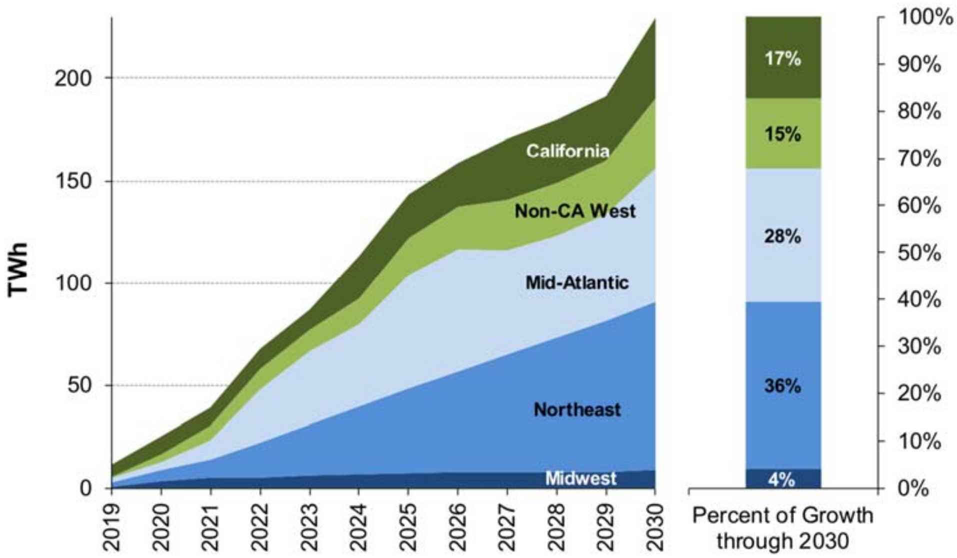

Figure 2-7. Required Increase in RPS Generation, by Region

Source: LBNL, *U.S. Renewables Portfolio Standards – 2019 Annual Status Update*.

Projected growth in renewable energy demand due to state RPS policies will continue driving the development of new renewable energy capacity. To fulfill future RPS requirements in the mid-Atlantic, roughly an additional 20+ GW of renewable energy capacity will be needed by 2030. Figure 2-8 shows anticipated capacity needs by region.

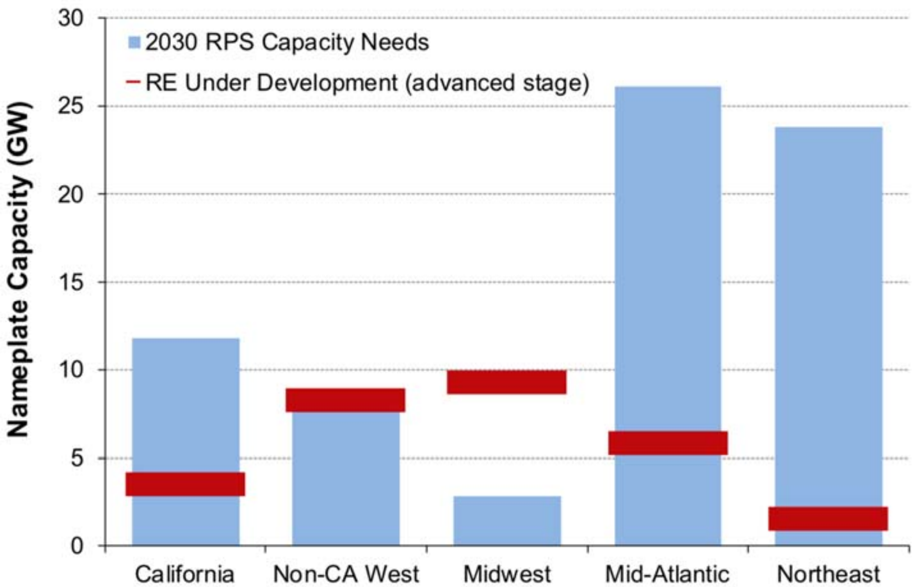

Figure 2-8. Required Increase in RPS Capacity, by Region, 2030

Source: LBNL, *U.S. Renewables Portfolio Standards – 2019 Annual Status Update*.

2.1.2. Renewable Energy Growth in Maryland

Maryland has increased its in-state renewable energy capacity and generation over the last decade. Using EIA data, Table 2-1 summarizes this change over an 11-year period (2008-2018) relative to Maryland's total electric nameplate capacity and generation. According to EIA, nearly 697 MW of non-hydro, utility-scale renewable energy capacity was installed in Maryland as of the end of 2018, up from about 155 MW at the end of 2008.[31,32] Figure 2-9 and Figure 2-10 show the growth of utility-scale renewable energy capacity and generation in Maryland, respectively. This growth was driven by the expansion of in-state wind and utility-scale solar generation, which were a negligible source of capacity in 2008, but they provided 537 MW of in-state nameplate capacity in 2018.[33] Distributed solar added another 714 MW of capacity as of 2018, as discussed in greater detail below. Generation levels follow similar trends. At the same time, large hydro capacity and generation have both remained relatively unchanged; large hydro capacity marginally increased from 527 MW to 551 MW from 2008-2018.

[31] Throughout this chapter, the term "utility-scale" is used to refer to facilities greater than 1 MW in size. Utility-scale totals are inclusive of the total electric power industry, meaning data is inclusive of commercial and industrial, combined-heat and power, independent power producer, and regulated utility facilities (as applicable).

[32] Figures for 2018 are based on preliminary EIA data. *Source:* U.S. Energy Information Administration, "Existing Nameplate and Net Summer Capacity by Energy Source, Producer Type and State (EIA-860)," eia.gov/electricity/data/state/annual_generation_state.xls.

[33] In 2008, EIA did not separately report any Maryland solar PV or wind generation capacity. Of the five operational, utility-scale, land-based wind projects in Maryland, all entered operation after 2009. Tracking from the Interstate Renewable Energy Council (IREC) suggests that there were less than 3 MW of installed solar PV capacity in 2008. *Source:* Larry Sherwood, *U.S. Solar Market Trends 2008*, Interstate Renewable Energy Council, 2009, irecusa.org/wp-content/uploads/2014/09/Solar-Market-Trends-2008.pdf.

Table 2-1. Maryland Electric Generation and Nameplate Capacity

		2008[1]	2014	2018[2]	% Change (2008-2018)	% Change (2014-2018)
NAMEPLATE CAPACITY (MW)[3]	All Sources	13,548.0	13,765.3	17,036.5	25.7%	23.8%
	Large Hydro	527.0	550.8	550.8	4.5	0.0
	% of All Sources	*3.9%*	*4.0%*	*3.2%*	-16.9	-19.2
	Utility-Scale Renewables	155.0	390.4	697.2	349.8	78.6
	% of All Sources	*1.1%*	*2.8%*	*4.1%*	257.7	44.3
	Distributed Solar[4]		183.0	713.5		289.9
	% of All Sources		*1.3%*	*4.2%*		215.1
	All Renewables	**682.0**	**1,124.2**	**1,961.5**	**187.6**	**74.5**
	% of All Sources	***5.0%***	***8.2%***	***11.5%***	**128.7**	**41.0**
GENERATION (MWh)[5]	All Sources	47,360,953	38,086,434	44,777,147	-5.5%	17.6%
	Large Hydro	1,974,078	1,615,523	2,828,853	43.3	75.1
	% of All Sources	*4.2%*	*4.2%*	*6.3%*	51.6	48.9
	Utility-Scale Renewables	612,485	988,874	1,531,082	150.0	54.8
	% of All Sources	*1.3%*	*2.6%*	*3.4%*	164.4	31.7
	Distributed Solar		252,782	850,453		236.4
	% of All Sources		*0.7%*	*1.9%*		186.2
	All Renewables	**2,586,563**	**2,857,179**	**5,210,388**	**101.4**	**82.4**
	% of All Sources	***5.5%***	***7.5%***	***11.6%***	**113.1**	**55.1**

[1] Data prior to 2014 do not include distributed solar PV generation or capacity.

[2] EIA data for 2018 are preliminary (as of May 1, 2019).

[3] EIA, "Existing Nameplate and Net Summer Capacity by Energy Source, Producer Type and State (EIA-860)."

[4] EIA, "Form EIA-861M (formerly EIA-826) detailed data."

[5] EIA, "Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923)."

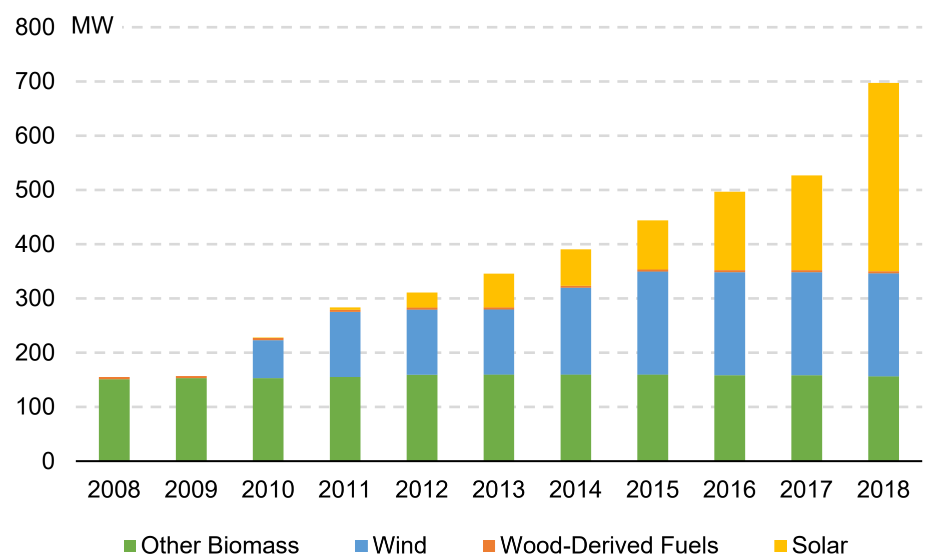

Figure 2-9. Utility-Scale, Non-Hydro Renewable Energy Capacity in Maryland

Source: EIA, "Detailed State Data," 2017. EIA data for 2018 are preliminary (up to date as of May 1, 2019).

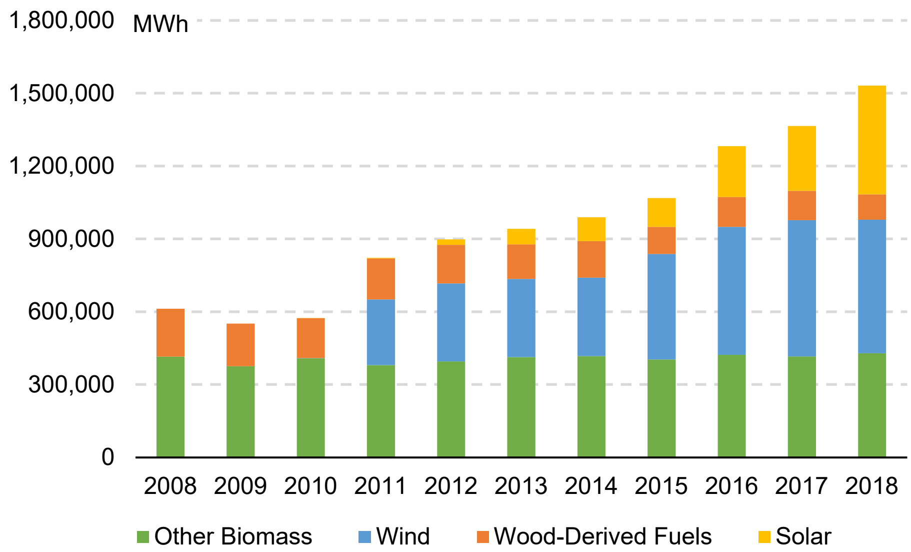

Figure 2-10. Utility Scale, Non-Hydro Renewable Energy Generation in Maryland

Source: EIA, "Detailed State Data," 2017. EIA data for 2018 are preliminary (up to date as of May 1, 2019).

Although EIA only began regularly tracking small-scale, distributed solar in 2014, distributed solar has grown rapidly in the last several years, as tracked in Table 2-1 (above).[34] Between 2014-2018, distributed solar nameplate capacity grew by 290%, rising from 183 MW to 714 MW.[35] Figure 2-11 shows this growth using data from PJM-GATS. According to the latest Maryland PSC report evaluating the Maryland RPS, in 2017, 45,319 facilities—most of them behind-the-meter (BTM)—retired 557,224 SRECs for compliance with Maryland's solar carve-out.[36] To date, over 60% of PV capacity in Maryland is small-scale. However, in 2017, utility-scale capacity grew more quickly (by capacity) than small-scale PV capacity for the first time.

[34] The term "small-scale" refers to facilities less than 1 MW in size.

[35] Figures for 2018 are based on preliminary EIA data. U.S. Energy Information Administration, "Form EIA-861M (formerly EIA-826) detailed data," eia.gov/electricity/data/eia861m/.

[36] Public Service Commission of Maryland, *Renewable Energy Portfolio Standard Report*, November 2018, psc.state.md.us/wp-content/uploads/FINAL-Renewable-Energy-Portfolio-Standard-Report-with-data-for-CY-2017.pdf.

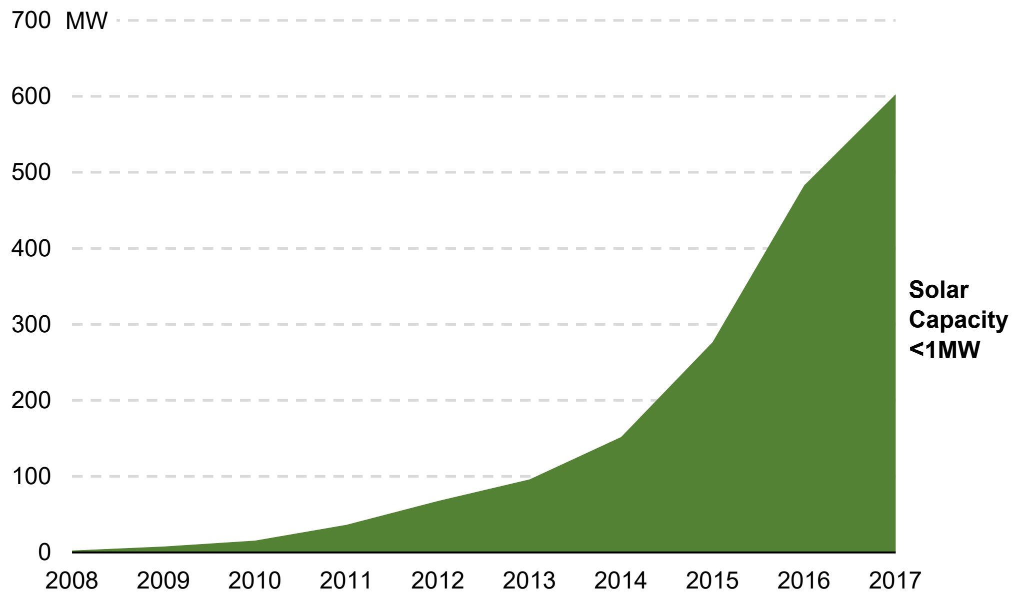

Figure 2-11. Cumulative Distributed PV Capacity Eligible to Retire RECs in Maryland

Source: PJM-GATS.

Note: PJM-GATS records do not match EIA data in recent years due to differences in reporting and tracking. These discrepancies are discussed further in subsequent footnotes throughout the text.

The contribution of renewable energy to Maryland's capacity and energy mix has roughly doubled since 2008. Large hydro, utility-scale, and distributed renewable energy together made up approximately 11.5% of total Maryland capacity in 2018, as calculated in Table 2-1 (above). Likewise, energy generation from the same renewable energy resources comprised 11.6% of total Maryland electric power industry energy generation in 2018. In 2008, large hydro and utility-scale resources comprised approximately 5% and 5.5% of total Maryland capacity and generation, respectively. The trend in Maryland annual renewable energy generation growth is moving counter to the trend for in-state generation overall. Total electricity generation in Maryland declined by 5% from 2008-2018. In comparison, non-hydro, utility-scale renewable energy generation grew by 150% during the same period. More recently, distributed solar generation grew by 236% from 2014-2018.

2.1.3. Comparing Renewable Energy Growth in Maryland with States in PJM

The location of existing and proposed renewable energy resources in PJM is mapped in Figure 2-12. As apparent from this figure, renewable energy generating capacity is located throughout all states in PJM as well as in adjacent areas. Solar resources are most heavily concentrated along the East Coast due to the presence of relatively higher-quality solar resources (as compared to elsewhere in PJM) and, for some of these states, solar carve-out requirements in their RPS policies, such as the solar carve-outs in Delaware, New Jersey and Maryland. Wind resources are primarily located in the Midwest, along the Atlantic coast, and in the Appalachian Mountains, all of which are areas with access to more continuous and higher-speed wind. Hydro resources are adjacent to major waterways in PJM, including the Illinois, Ohio, Susquehanna, Potomac, and Delaware rivers. Biomass resources are located near feedstocks that depend on the type of biomass or biogas used. Landfill methane facilities, for example, are often located near major population hubs where landfills are more common, while wood-based biomass facilities are usually located near forested areas.

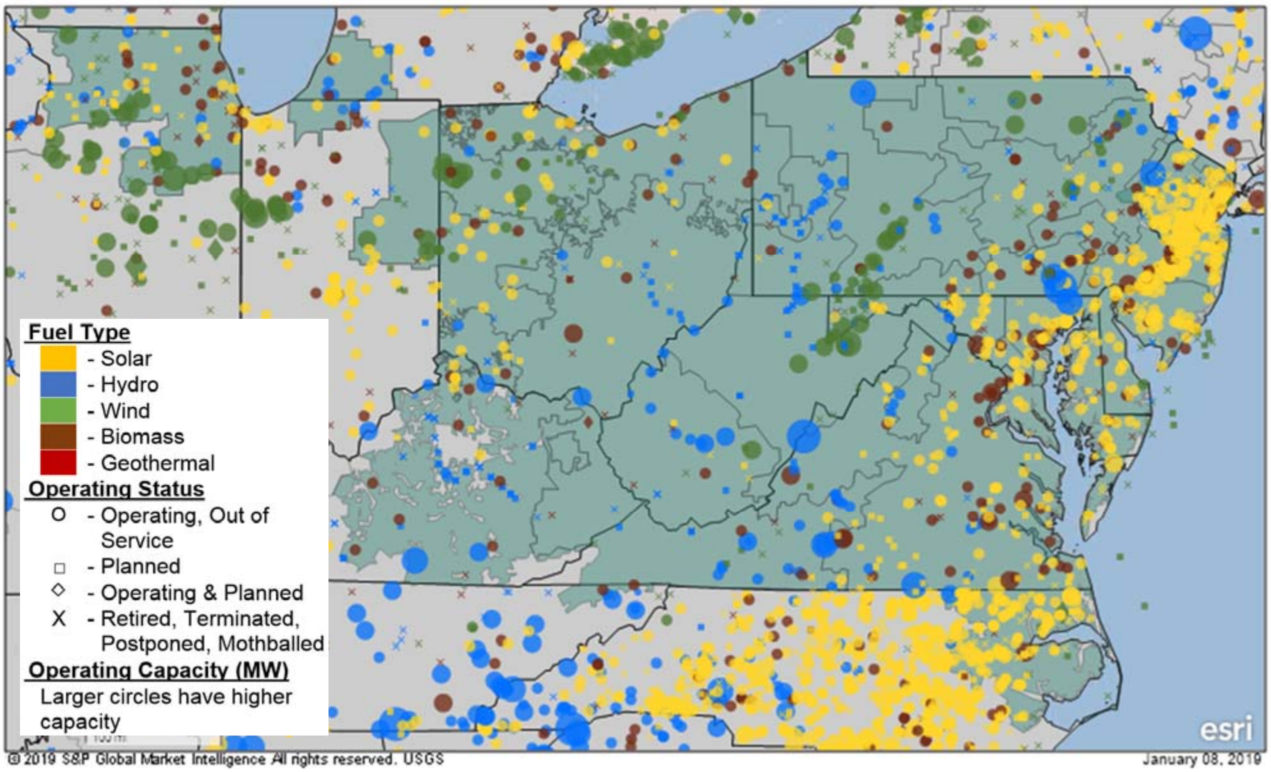

Figure 2-12. Operating, Planned, and Terminated Renewable Energy Projects in PJM, as of January 2019

Source: Adapted from S&P Global Market Intelligence.

Wind development in Maryland has been outpaced by wind development elsewhere in PJM, both on a total and per-capita basis. Figure 2-13 and Figure 2-14 compare 2010-2017 wind development in PJM, by state. Maryland's cumulative wind capacity as of 2017 was approximately 200 MW, which is significantly below five other states in PJM: Illinois, Indiana, Ohio, Pennsylvania, and West Virginia have cumulative capacity that ranges between 504 MW (Ohio) and 2,846 MW (Illinois), only inclusive of jurisdictions in PJM. None of the states with more wind capacity than Maryland maintained a higher RPS than Maryland during this period. (Neither Indiana nor West Virginia has a binding RPS.) In addition, several of these other states have access to better wind resources than those found in most of Maryland, as discussed in Subsection 3.2.2, "Resource-Specific Technical and Economic Potential."

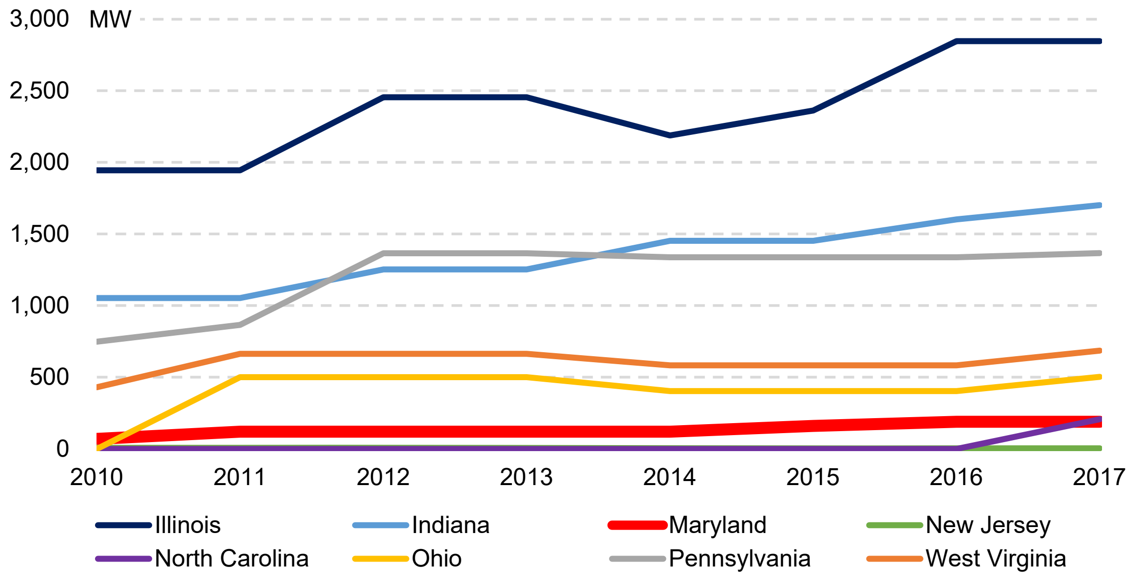

Figure 2-13. Wind Capacity in Select States in PJM

Source: PJM *State of the Market* reports, multiple years.

Note: Only inclusive of capacity that is both located within the PJM portions of the above states and participating in PJM wholesale markets.

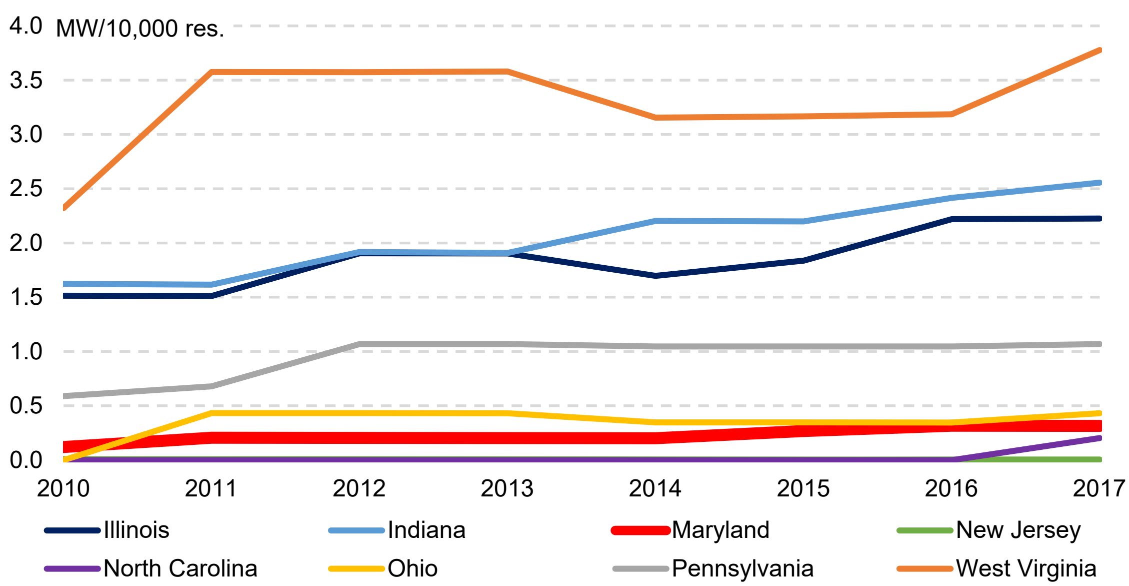

Figure 2-14. Wind Capacity in Select States in PJM, per 10,000 Residents

Source: PJM *State of the Market* reports, multiple years.

Note: Only inclusive of capacity that is both located within the PJM portions of the select states and participating in PJM wholesale markets.

In contrast to wind, Maryland is among the states leading in solar PV development in PJM. Maryland ranks fourth in utility-scale PV development in PJM, after New Jersey, Virginia, and

North Carolina, as shown in Figure 2-15. The state is nearly second in development in PJM after accounting for population, ranking just behind Virginia, as shown in Figure 2-16. It appears that different forces may be driving PV development in these states. Maryland and New Jersey each have in-state solar carve-outs (14.5% by 2028 and 5.1% by 2021, respectively). On the other hand, North Carolina has a small solar carve-out (0.2% by 2018) and Virginia has a voluntary RPS, neither of which is thought to have much of a role in spurring solar development.[37] Both Virginia and North Carolina, however, have superior solar sources as compared to other states in PJM, as discussed in Subsection 3.2.2, "Resource-Specific Technical and Economic Potential." Additionally, both states have facilitated solar growth through other initiatives and benefited from corporate renewable purchasing activity.[38]

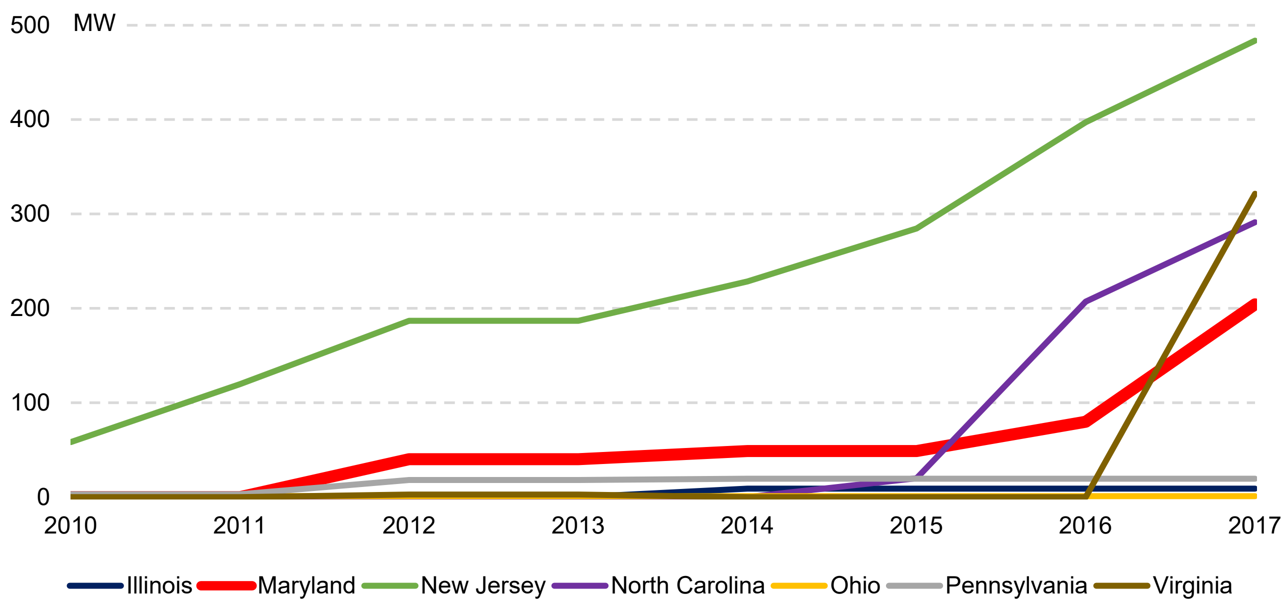

Figure 2-15. Utility-Scale Solar Capacity in Select States in PJM

Source: PJM *State of the Market* reports, multiple years.

Note: West Virginia is excluded due to lack of solar in the state. Only inclusive of capacity that is both located within the PJM portions of the select states and participating in PJM wholesale markets.

[37] In 2017, North Carolina enacted HB 589, which set a solar deployment target of 6,800 MW by 2020.

[38] North Carolina's PV growth has been attributed to four non-carve-out factors: (1) declining PV costs, which have made it the least expensive in-state resource for meeting the North Carolina RPS; (2) a 35% state renewable energy tax credit for projects under construction before December 31, 2015; (3) Public Utility Regulatory Policies Act (PURPA) regulations and rates that, until changed in 2017, made it relatively easy for small PV plants to secure 15-year, fixed-price contracts, which help attract project financing; and (4) growing customer demand for green power, notably by large corporations. Apple, Inc.; Facebook, Inc.; and Google, LLC all have data centers in North Carolina, and advocated successfully for the option to purchase green power directly from utilities. Growth of solar capacity in Virginia is also associated with demand from large corporations. Amazon.com, Inc. data centers were the driving force behind the construction of 260 MW of the 290 MW of utility-scale solar capacity in the state, as of December 2017. This trend is likely to continue; Facebook and Dominion Energy, Inc. reached an agreement in 2017 to construct 300 MW of solar capacity around the state, with 130 MW of this capacity reserved for powering a new Facebook data center. Additionally, Virginia utilities are increasingly developing solar projects because of the state's Grid Transformation & Security Act (SB 966), effective in July 2018, which deemed 5,000 MW of utility-owned and utility-operated wind and solar resources to be in the public interest.

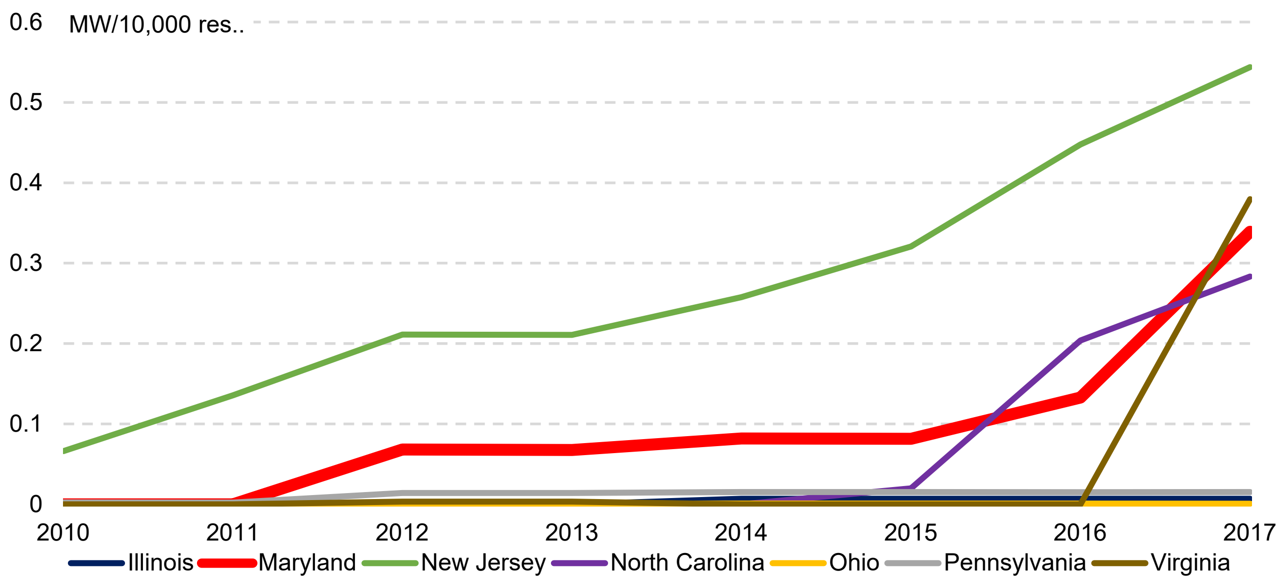

Figure 2-16. Utility-Scale Solar Capacity in Select States in PJM, per 10,000 Residents

Source: PJM *State of the Market* reports, multiple years.

Note: West Virginia is excluded due to lack of solar in the state. Only inclusive of capacity that is both located within the PJM portions of the select states and participating in PJM wholesale markets.

2.1.4. Renewable Energy Used to Meet the Maryland RPS

Figure 2-17 shows the volume of Tier 1, Tier 2, and solar carve-out RECs retired between 2006-2017 in Maryland. During this period, applicable load in the state grew minimally, explaining why Tier 2 REC retirements, which have always been set at 2.5% of applicable retail energy sales, have not grown beyond 1,000,000 RECs. Meanwhile, Tier 1 and solar carve-out retirements have increased as the percentage requirements for each have increased over time. The relationship between specific changes to the Maryland RPS and deployment are discussed further in Section 2.6, “Influence of Past Changes to the Maryland RPS.”

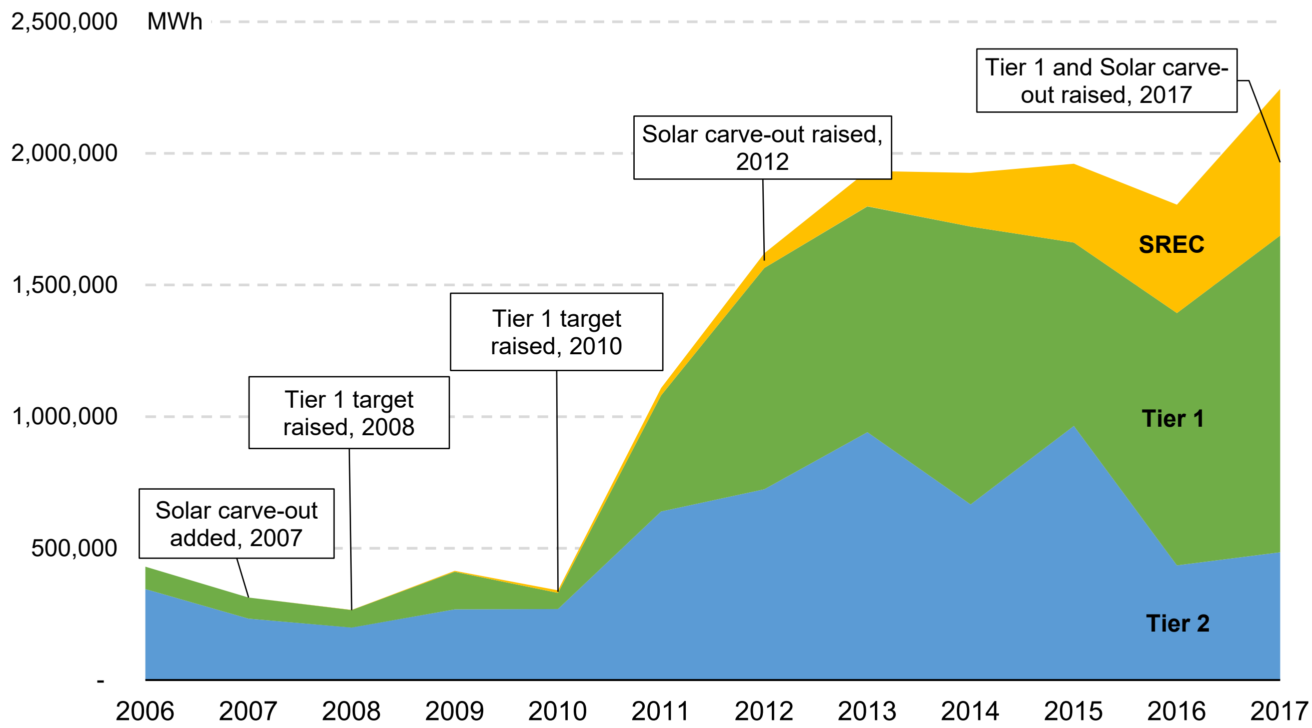

Figure 2-17. RECs Retired in Maryland for Maryland RPS Compliance

Source: PJM-GATS.

Between 2008-2017, Maryland relied on six primary fuel sources—wind, black liquor, hydro, wood/biomass, MSW, and LFG—to meet the Tier 1 non-carve-out portion of its RPS. Wind, black liquor, and MSW, as shown in Figure 2-18 and Table 2-2, have grown the most during this period in terms of number of RECs retired, increasing by 2,996,146; 1,200,983; and 732,424 RECs, respectively. (Note that MSW became Tier 1-eligible in 2011.) However, as a percentage of total Tier 1 REC retirements, only wind experienced a significant increase in its share of RPS compliance. Table 2-2 also compares the percentage of Tier 1 RPS requirements fulfilled by each fuel source in 2008 and 2017. Wind grew from approximately 0% to 42.3% between 2008-2017. Although MSW increased its share from 4% to 10.4% from 2011 (when it became Tier 1-eligible) to 2017, this growth is largely attributable to resources shifting from Tier 2 to Tier 1 non-carve-out in terms of classification.

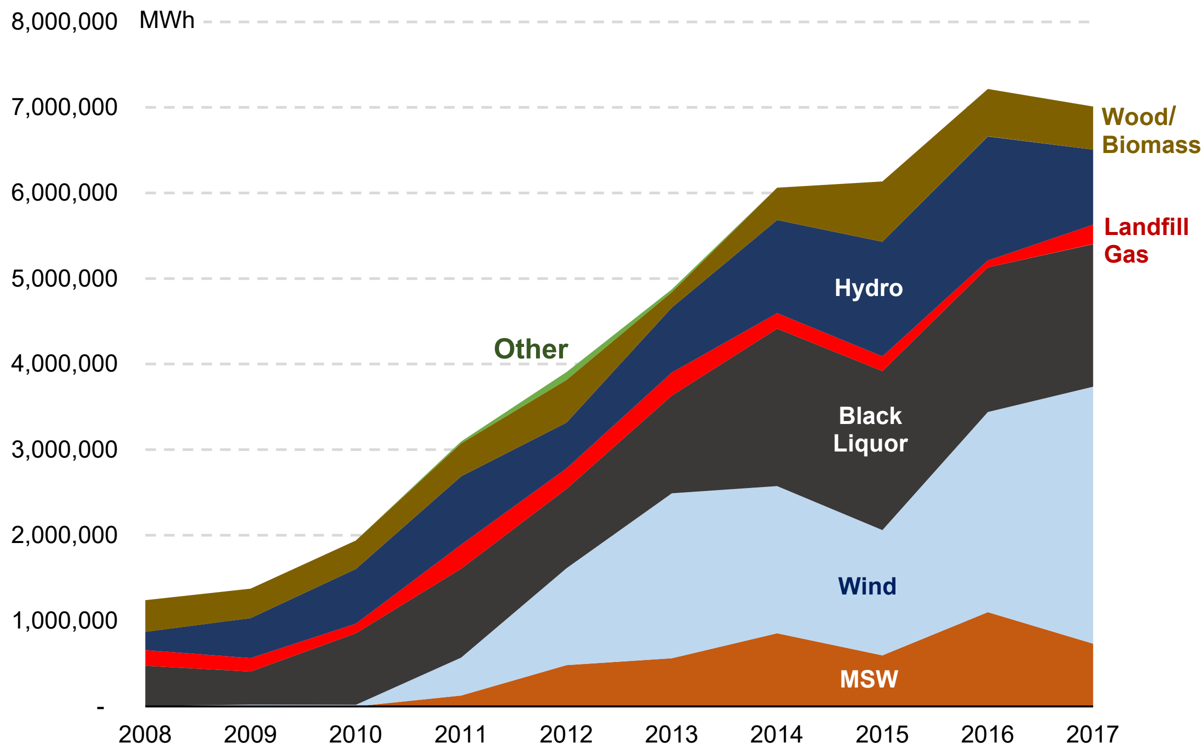

Figure 2-18. RECs Retired for Tier 1 Non-Carve-out Maryland RPS Compliance, by Fuel Source

Source: PJM-GATS.

Table 2-2. RECs Retired for Tier 1 Non-Carve-out Maryland RPS Compliance, by Fuel Source

Fuel Source	Share of Non-Carve-out Tier 1 RECS		Percentage Point Change (2008-2017)	Number of Tier 1 Non-Carve-out RECS		Nominal Change (2008-2017)
	2008	2017		2008	2017	
Black Liquor	37.6%	23.8%	-13.8%	467,248	1,668,231	1,200,983
LFG	14.9	3.2	-11.6	184,416	226,933	42,517
MSW[1]	0.0	10.4	10.4	0	732,424	732,424
Hydro	17.1	12.5	-4.6	211,871	876,022	664,151
Wood Waste	29.9	7.0	-22.9	371,838	502,911	131,073
Wind	0.5	42.8	42.3	6,242	3,002,388	2,996,146
Other	0.0	0.3	0.3	0	2,228	2,228

Source: PJM-GATS.

[1] MSW was only Tier 2-eligible prior to 2011. In 2014, the first year that MSW received only Maryland Tier 1 RECs (and not Tier 2 RECs as well), MSW comprised 14% of Maryland Tier 1 RPS resources. This percentage share has since declined to 10.4% in 2017.

The resource mix used to fulfill Maryland's Tier 1 non-carve-out RPS requirement is on par with Pennsylvania's, and it is more diverse than the other three mid-Atlantic states in PJM that have RPS requirements. This reflects differences in resource eligibility. Figure 2-19 shows the major fuel sources used to fulfill Tier 1 RPS requirements in Maryland, New Jersey, Pennsylvania, and the District of Columbia, as well as all non-solar RPS requirements in Delaware, which has no tiers. Wind has become the primary fuel source relied upon for RECs in all four states and D.C. While carbon-emitting resources are eligible for Tier 1 compliance in Maryland and Pennsylvania, they tend to be considered Tier 2 resources in other states (e.g., MSW in New Jersey), have never been or are no longer accepted for RPS compliance (e.g., black liquor in all three other states), or face higher thresholds for eligibility (e.g., biomass must be greater than 65% efficient in the District of Columbia).

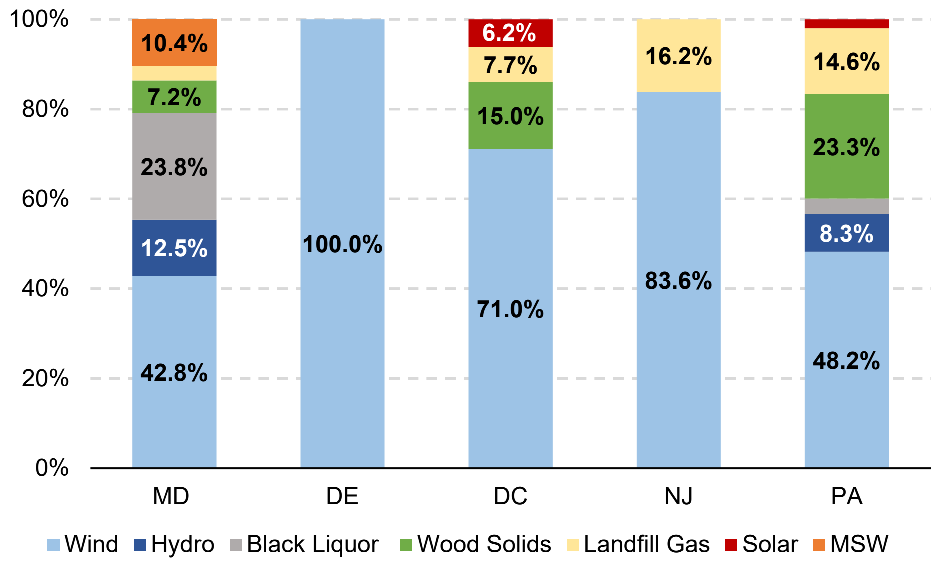

Figure 2-19. RECs Retired for Tier 1 Non-Carve-out RPS Compliance in mid-Atlantic States in PJM, by Fuel Source, 2017

Source: PJM-GATS.

Note: Compliance for PA and MD is from June 2017 – May 2018, rather than CY 2017.

The Maryland RPS does not have a vintage, meaning age, requirement, and both existing and new generation facilities are eligible for the RPS. Figure 2-20 compares the number of RECs retired in 2016-2017 for compliance with the Maryland RPS that were generated by facilities that came online in or before 2004. The data indicate that, in 2017, 53% of all RECs and 51% of Tier 1 non-carve-out RECs retired were generated by facilities operating prior to 2005. The Tier 1 non-carve-out resources operating prior to 2005 that received RECs in 2017 included black liquor (43% of RECs from Tier 1 non-carve-out generation operating before 2005), hydro (24%) and MSW (21%). Also in 2017, 85% of Tier 2 RECs were generated by facilities operating prior to 2005, all of them hydro. Conversely, and not surprisingly, 100% of SRECs in 2017 were generated by facilities that came online after 2004. The share of Tier 1 non-carve-out RECs generated by facilities operating prior to 2005 has declined in the last reported year, falling from 59% in 2016 to 51% in 2017. The Tier 1 solar carve-out and Tier 2 figures did not significantly change between 2016-2017. The reduction in RECs from older sources, such as MSW, black liquor, and hydro, corresponds with an increase in the number of Maryland RECs from sources like wind, as noted earlier.

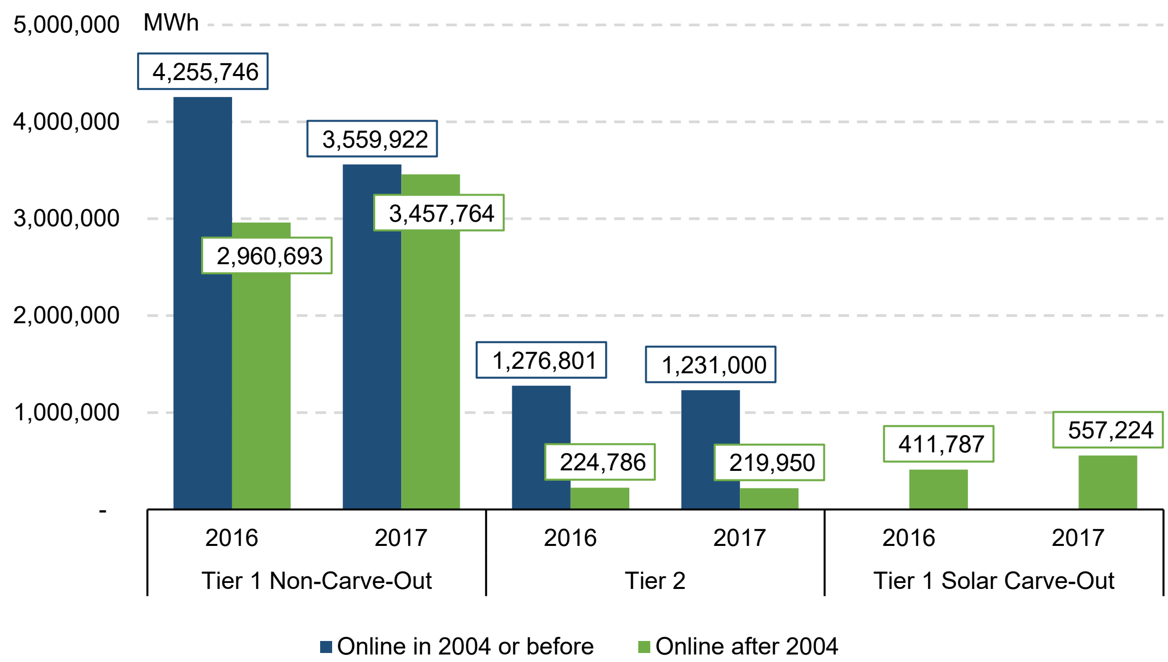

Figure 2-20. RECs Retired for Maryland RPS Compliance, by Plant Age and RPS Category

Sources: Maryland PSC 2018 *Renewable Energy Portfolio Standard Report*; PJM-GATS.

2.1.5. Location of RECs Used to Meet the Maryland RPS

Historically, most of the Maryland RPS has been met by RECs from out-of-state resources, as depicted in Figure 2-21 and Figure 2-22. This share has remained relatively flat since 2011 despite growth in the overall number of RECs retired. According to the Maryland PSC's most recent *Renewable Energy Portfolio Standard Report*, about 75% of the Maryland RPS is met through out-of-state resources as of 2017.[39]

[39] Public Service Commission of Maryland, *Renewable Energy Portfolio Standard Report*, November 2018, psc.state.md.us/wp-content/uploads/FINAL-Renewable-Energy-Portfolio-Standard-Report-with-data-for-CY-2017.pdf.

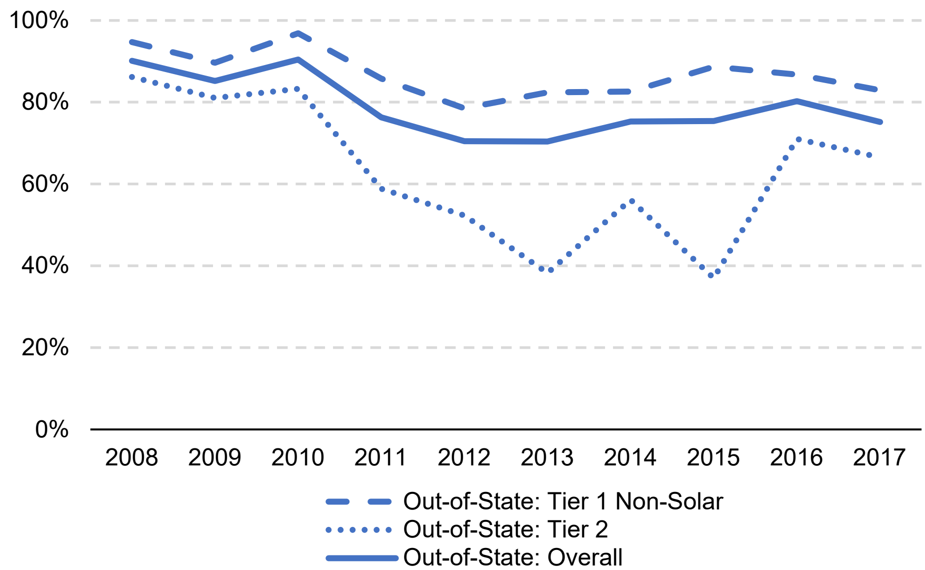

Figure 2-21. Proportion of RECs Retired for the Maryland RPS from Out-of-State Sources, by RPS Category

Source: Maryland PSC *Renewable Energy Portfolio Standard Reports*.

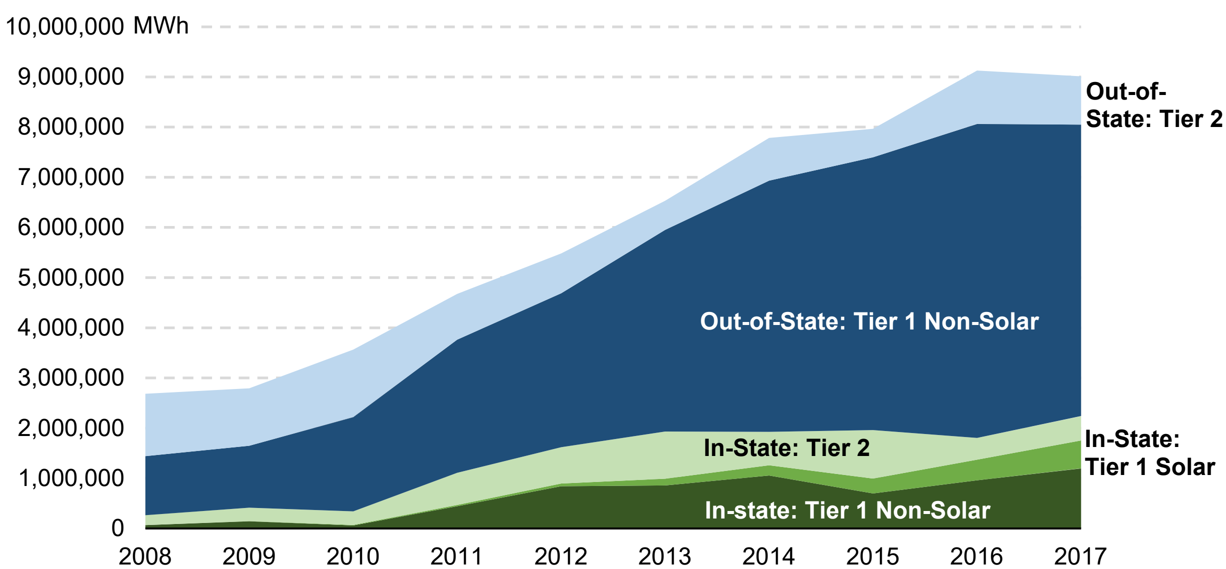

Figure 2-22. Maryland REC Retirement, by Location and RPS Category

Source: Maryland PSC *Renewable Energy Portfolio Standard Reports*.

There are several potential reasons that the total number of in-state RECs retired for the Maryland RPS has remained a constant share of the Maryland RPS requirement, including: limitations in the availability of in-state RECs; the use of RECs produced in Maryland to comply with other state RPS policies; and the availability of RECs, presumably at lower cost, from other states that can be used to comply with the Maryland RPS. Nevertheless, as a result of utilizing out-of-state RECs, the Maryland RPS has contributed to renewable energy development in the rest of PJM and in neighboring regions by providing financial support to out-of-state resources in the form of REC payments.

The Tier 1 and Tier 2 RECs used for complying with the Maryland RPS between 2008-2017 came from 18 states, including Maryland. Table 2-3 tracks the quantity of all RECs retired for compliance with the Maryland RPS by state during this period. In the last six years, Maryland has been first or second on the list of provider states, with Virginia, Pennsylvania, and Illinois consistently rounding out the top four. Figure 2-23 and Figure 2-24 show Maryland's share of all annual REC retirements and Tier 1 REC retirements, respectively. Maryland's share of annual REC retirements is lower in every year when excluding Tier 2 resources. Maryland, however, passed Virginia in 2017 as the largest contributor of Tier 1 REC retirements for Maryland RPS compliance.

Table 2-3. REC Retirements for Maryland RPS Compliance, by State

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	TOTAL
MD	**265,742**	**414,391**	**340,365**	**1,107,828**	**1,619,975**	**1,933,138**	**1,925,924**	**1,960,595**	**1,805,184**	**2,244,783**	**13,617,925**
VA	607,350	766,357	700,345	1,332,544	1,227,114	1,046,243	1,725,125	1,931,202	1,855,133	1,429,866	**12,621,279**
PA	848,711	766,357	989,262	1,054,910	1,158,522	1,454,580	1,499,257	1,113,281	1,017,632	1,247,998	**11,150,510**
IL	32,305	12,372	5,307	173,219	527,400	888,654	969,395	881,907	1,203,431	915,789	**5,609,779**
NY	364,237	459,275	629,839	494,163	281,149	190,642	402,480	438,432	375,825	164,587	**3,800,629**
WV	70,138	156,463	164,459	147,400	104,662	284,859	524,955	578,298	593,535	412,708	**3,037,477**
NC	7,406	4,444	281,614	76,665	19,854	0	94,537	307,302	911,420	821,687	**2,524,929**
OH	167,515	0	9,313	40	92,481	164,676	216,590	245,835	170,096	502,160	**1,568,706**
TN	0	0	0	0	9,651	0	133,826	310,768	487,238	461,006	**1,402,489**
IN	0	353	8,344	9,852	267,543	485,173	239,237	119,778	48,908	83,299	**1,262,487**
MI	243,317	273,883	293,131	6,925	0	0	837	6,879	10,227	5,454	**840,653**
IA	0	4,677	23	147,309	121,351	0	0	34,876	171,230	153,089	**632,555**
ND	0	0	0	0	0	0	0	0	282,055	332,326	**614,381**
MO	0	0	0	0	0	0	0	0	171,742	188,895	**360,637**
NJ	50,001	42,426	90,103	31,726	0	52,767	17,031	11,713	19,883	29,709	**345,359**
DE	29,165	36,882	48,700	66,833	17,647	385	0	4,654	750	3,797	**208,813**
KY	0	0	0	0	0	31,049	36,613	20,471	5,474	20,908	**114,515**
WI	0	0	2,131	26,562	33,192	0	0	0	0	0	**61,885**
DC	0	0	372	0	0	0	0	0	0	0	**372**
TOTAL	**2,685,887**	**2,937,880**	**3,563,308**	**4,675,976**	**5,480,541**	**6,532,166**	**7,785,807**	**7,965,991**	**9,129,763**	**9,018,061**	**59,775,380**

Source: Maryland PSC *Renewable Energy Portfolio Standard Reports*.

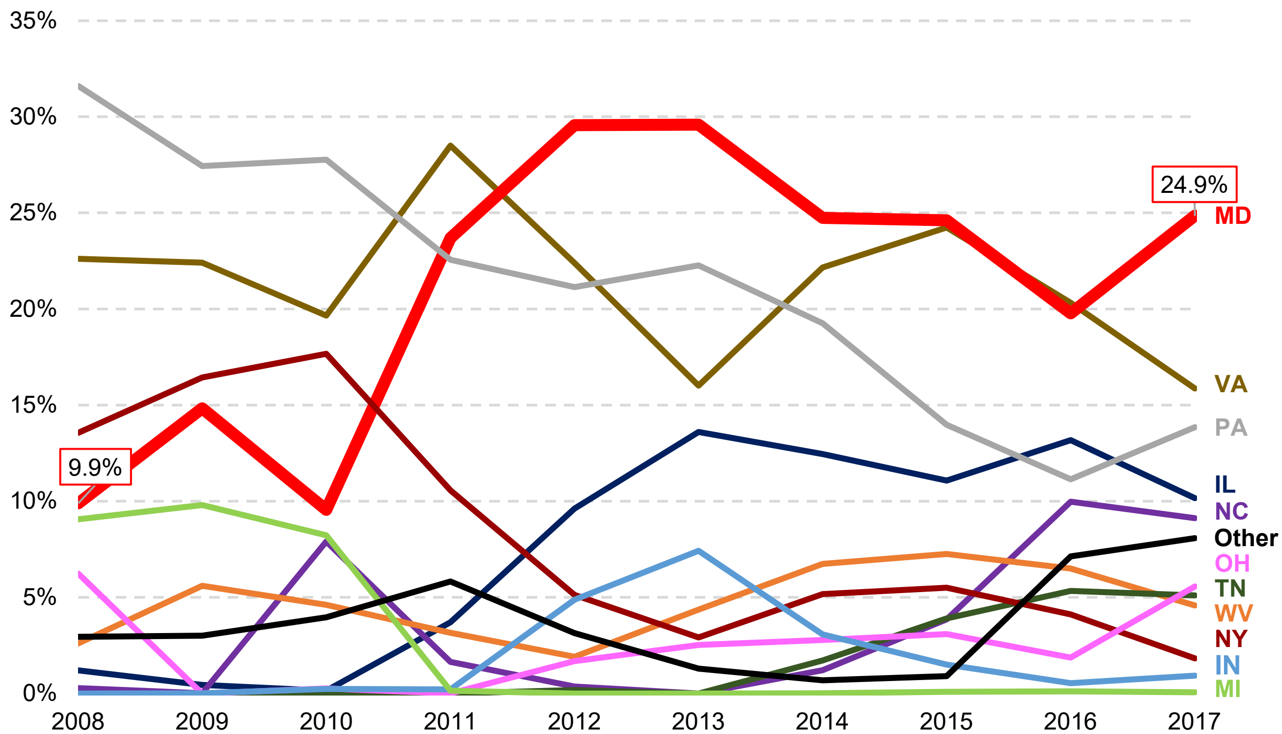

Figure 2-23. Share of Annual REC Retirements for Maryland RPS Compliance, by State (Tier 1 and Tier 2)

Source: Maryland PSC *Renewable Energy Portfolio Standard Reports*.

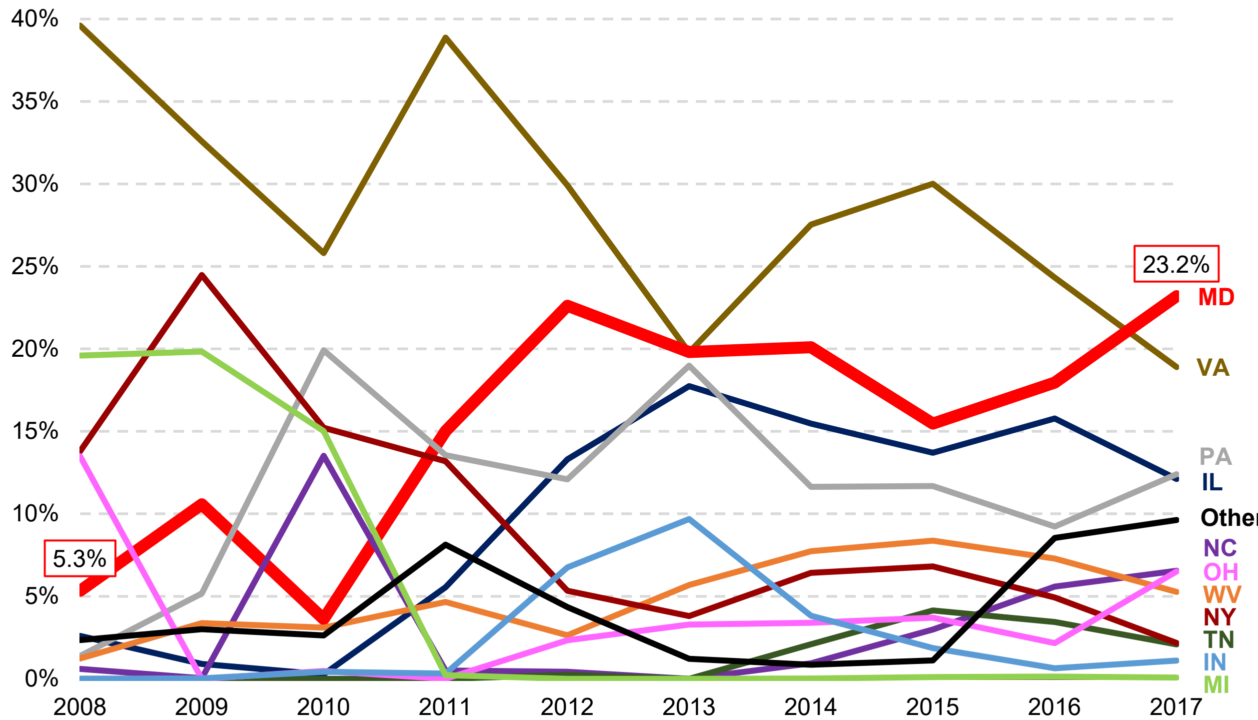

Figure 2-24. Share of Annual REC Retirements for Maryland RPS Compliance by State (Tier 1)

Source: Maryland PSC *Renewable Energy Portfolio Standard Reports*.

For each of the primary, non-solar technologies relied upon to fulfill the Maryland RPS, Figure 2-25 provides a breakdown of the percentage of RECs generated by state in 2017. Illinois was the primary source of wind RECs. Virginia provided nearly half of the black liquor RECs, over two-thirds of the wood waste RECs, and significant amounts of MSW RECs. Pennsylvania provided significant amounts of hydro, LFG, and wind RECs. The only fuel source for which Maryland provided the most RECs was MSW. Maryland was also the number two or three source for hydro, LFG, wind, and wood waste RECs.

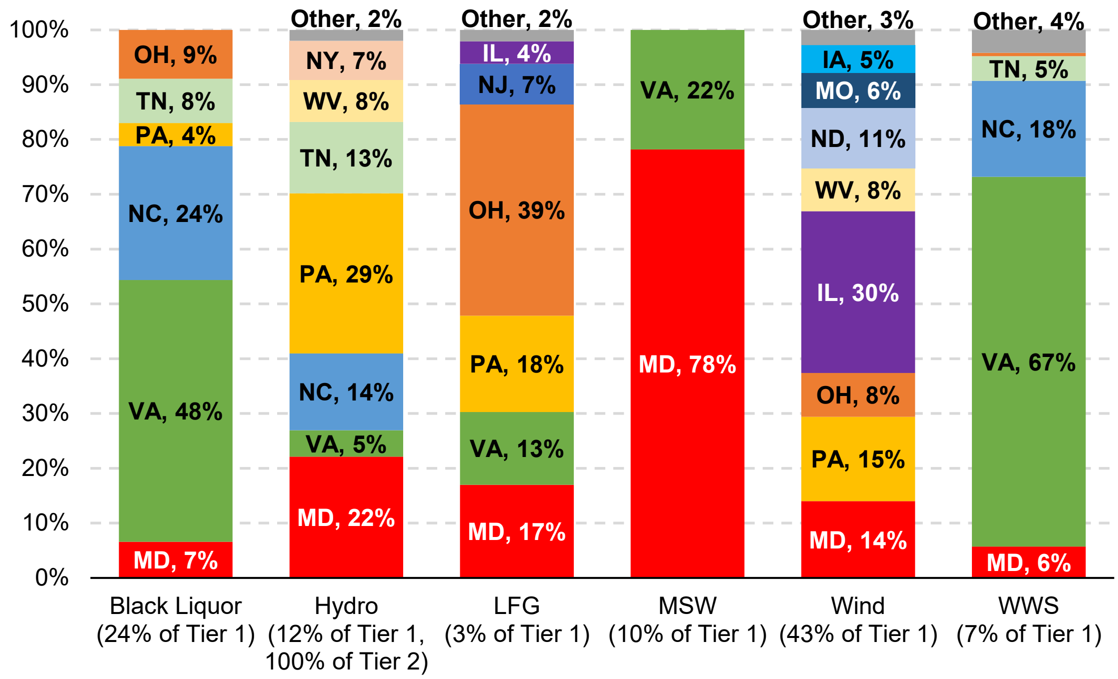

Figure 2-25. Percentage of RECs Generated in Each State, Used for Compliance with the Maryland RPS, by Fuel Source, 2017

Source: Maryland PSC 2018 *Renewable Energy Portfolio Standard Report*.

Note*:* The percentages under each fuel category reflect each fuel type's share of Maryland RPS compliance for 2017.

Table 2-4 expands on Figure 2-25 to track the share of RECs generated in Maryland by fuel source from 2008-2017. The share of MSW RECs from in-state resources that are used for compliance with the Maryland RPS has increased over time, especially after MSW became Tier 1-eligible in 2011; in-state sources comprised 100% of Tier 1 MSW RECs from 2011-2014. This share, however, has fallen in the last several years. The sources of wood and biomass RECs are almost exclusively located out of state, and less than a third of LFG RECs have come from in-state sources in most years during this period. Black liquor RECs from in-state sources have declined since their peak at 24% in 2011. Between 4-7% of total black liquor RECs came from in-state sources from 2014-2017. The location of hydro RECs depends on the Tier of the Maryland RPS. Consistently, less than 10% of Tier 1 hydro RECs are from in-state sources. In-comparison, as much as 64% of Tier 2 hydro RECs are from in-state sources, although this share varies significantly year to year and ranges as low as 11%. Finally, a very small share of wind is from in-state sources, including only 1% during 2014-2016. This percentage, however, increased significantly in 2017.

Table 2-4. Percent of RECs Generated in Maryland Used for Compliance with the Maryland RPS, by Fuel Source

	Fuel Source	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
TIER 1	Blast Furnace Gas	-	-	-	100%	100%	100%	-	-	-	-
	Ag. Biomass	-	-	-	-	-	-	-	0%	0%	0%
	Black Liquor	12%	23%	7%	24%	11%	11%	7%	4%	4%	7%
	Geothermal	-	-	-	-	-	-	100%	100%	100%	100%
	LFG	0%	13%	5%	7%	8%	17%	22%	9%	34%	17%
	MSW	-	-	-	100%	100%	100%	100%	99%	73%	78%
	Wood/Biomass	0%	0%	0%	0%	0%	0%	0%	0%	0%	6%
	Solar Thermal	-	-	-	-	-	-	100%	100%	-	100%
	Hydro	4%	7%	0%	3%	2%	5%	2%	0%	2%	3%
	Wind	0%	0%	0%	0%	11%	3%	1%	1%	1%	14%
TIER 2	Blast Furnace Gas	-	100%	100%	100%	100%	100%	-	-	-	-
	MSW	15%	6%	29%	31%	74%	19%	-	-	-	-
	Hydro	14%	20%	11%	40%	37%	64%	44%	63%	29%	33%

Source: PJM-GATS.

As apparent in the preceding figures and tables, in-state Maryland generation contributed a higher share of Tier 2 RECs as compared to Tier 1 non-carve-out RECs until the Tier 2 requirement lapsed at the end of compliance year 2018. One reason for this is the relatively high amount of hydro and MSW generation in Maryland as compared to other renewable energy resources, as discussed below.[40] Additionally, Maryland is one of a limited number of states in PJM that allows MSW and large hydro (i.e., hydro greater than 30 MW in size) to qualify for its RPS.[41]

Maryland's reliance on out-of-state RECs for RPS compliance is common in the mid-Atlantic region in states with an RPS requirement. Figure 2-26 shows in-state retired RECs as a percentage of all RECs retired in Maryland, Delaware, New Jersey, Pennsylvania, and the District of Columbia between 2008-2017.[42] D.C.'s percentage of in-state RECs hovers near zero due to the small number of RPS-eligible facilities located in the District. Maryland's reliance on in-state RECs has been similar to New Jersey's since 2011 and higher than Delaware's. Pennsylvania's use of in-state RECs has hovered near 50% since 2011. This is primarily due to Pennsylvania's use of in-state RECs for compliance with its Tier 2 requirement. In 2017, Tier 2 RECs represented 52% of the RECs retired for compliance with

[40] MSW was a Tier 2 resource through 2010, after which it became a Tier 1 resource (although some MSW still cleared in the Tier 2 market through 2013).

[41] MSW is accepted as a Tier 1-eligible resource in Ohio and Michigan, as a Tier 2-eligible resource in Pennsylvania and New Jersey, and as part of the voluntary renewable energy goals in Virginia and Indiana. Large hydro is accepted as a Tier 1-eligible resource in Illinois and Michigan, as a Tier 2-eligible resource in the District of Columbia, and as part of the voluntary renewable energy goals in Virginia and Indiana. The hydro facilities must be existing (i.e., not newly constructed or expanded) to qualify for the Illinois, Michigan, and District of Columbia RPS policies. Run-of-the-river hydro systems on the Ohio River greater than 40 MW are also accepted as a Tier 1-eligible resource in Ohio. *Source:* PJM Environmental Information Services, "Comparison of Renewable Portfolio Standards (RPS) Programs in PJM States," June 2018, pjm-eis.com/-/media/pjm-eis/documents/rps-comparison.ashx?la=en.

[42] Note that North Carolina is excluded from subsequent figures that show mid-Atlantic states with RPS policies because only a small portion of the state is served by PJM, and data may not be comparable due to North Carolina's use of the Carolina Renewable Energy Tracking System (NC-RETS) instead of PJM-GATS.

the Pennsylvania RPS (as opposed to 16% in Maryland), and 67% of these Tier 2 RECs were from in-state plants, primarily waste coal and hydro.

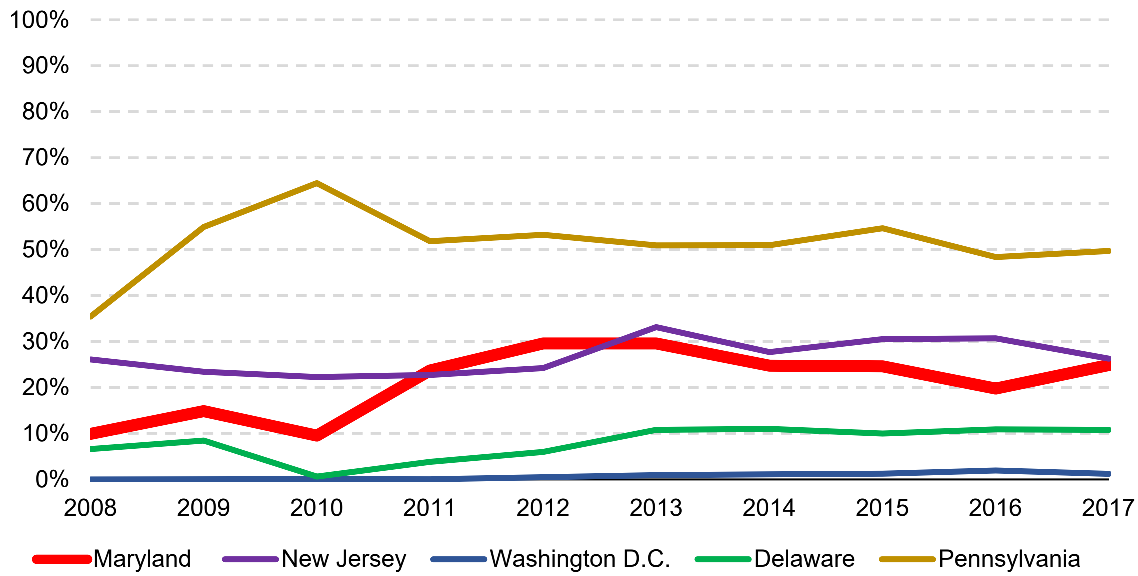

Figure 2-26. In-State Retired RECs as a Percent of Total Retired RECs in mid-Atlantic States with an RPS Requirement

Source: PJM-GATS.

Reliance on out-of-state RECs in mid-Atlantic states with an RPS reflects, at least in part, enduring differentials in renewable energy production costs and resource availability across PJM. For example, Figure 2-27 and Figure 2-28 compare recent offers for wind and solar PPAs, respectively, at various hubs in PJM, as tracked by LevelTen Energy, which runs a marketplace for PPAs.[43] Wind PPA offers in the price hub for Northern Illinois, which has a relatively strong wind resource, were roughly $6/MWh cheaper than wind PPAs in the Western Hub, which includes the western edge of Maryland. The Northern Illinois wind PPA offers were also more than $7.50/MWh cheaper than solar PPAs in the Eastern Hub, which includes the bulk of Maryland. Though not shown here, wind PPAs in the heart of the Midwest are even lower (e.g., $14.40/MWh in portions of North Dakota), which helps to explain the use of RECs from Iowa, Missouri, and North Dakota for Maryland RPS compliance, despite the cost of transmitting the associated power into PJM.[44]

[43] While PPA price offers reflect multiple factors, they nevertheless help to illustrate regional differences in renewable energy production costs as well as cost differentials between technologies.

[44] Ryan Wiser and Mark Bolinger, *2017 Wind Technologies Market Report*, U.S. Department of Energy, August 2018, emp.lbl.gov/sites/default/files/2017_wind_technologies_market_report.pdf.

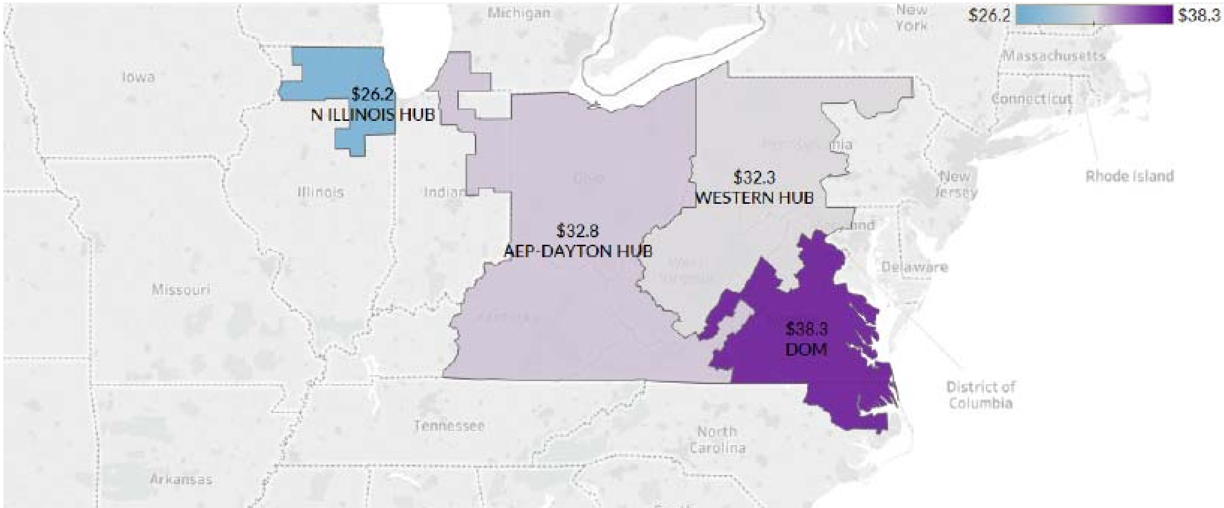

Figure 2-27. PJM Market Overview – Wind PPA Price, by Hub, Q1 2019 ($/MWh)

Source: LevelTen Energy, Q1 PPA Price Index, May 2019.

Note: Price data are aggregated. Prices shown refer to the most competitive 25th percentile offer price.

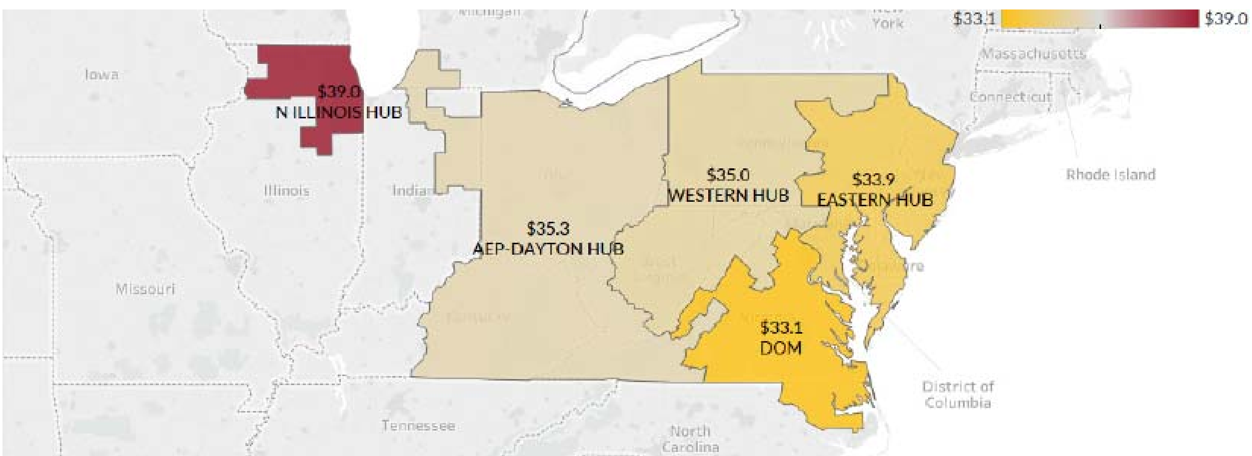

Figure 2-28. PJM Market Overview – Solar PPA Price, by Hub, Q1 2019 ($/MWh)

Source: LevelTen Energy, Q1 PPA Price Index, May 2019.

Note: Price data are aggregated. Prices shown refer to the most competitive 25th percentile offer price.

2.1.6. RECs Available to Meet the Maryland RPS

Figure 2-29 shows the growth (2005-2017) of renewable energy capacity registered with PJM-GATS, as well as the proportion registered to sell RECs with Maryland and the proportion located in Maryland. Overall, 50.8% of the PJM-GATS registered renewable energy capacity that has come online since 2004, totaling 9,095 MW, is eligible for the Maryland RPS, meaning registered to retire RECs for the Maryland RPS.[45] Approximately

[45] A separate registration process is required to become eligible for the Maryland RPS, which requires submitting information to the Maryland PSC as outlined on the PSC's website: psc.state.md.us/electricity/maryland-renewable-energy-portfolio-standard-program-frequently-asked-questions/.

7,600 MW of this new capacity is wind, with the remainder being primarily solar or LFG facilities. Table 2-5 lists the top five resources that began service in 2005 or later and are registered to retire RECs for compliance with the Maryland RPS. Over 60% of the wind, solar, LFG, black liquor, and wood waste capacity in PJM-GATS is registered for the Maryland RPS. Some PJM resources that would otherwise qualify for the Maryland RPS choose not to register in Maryland, but may do so if conditions change (e.g., the market rate for RECs in Maryland increases, making Maryland a more favorable place to retire RECs).

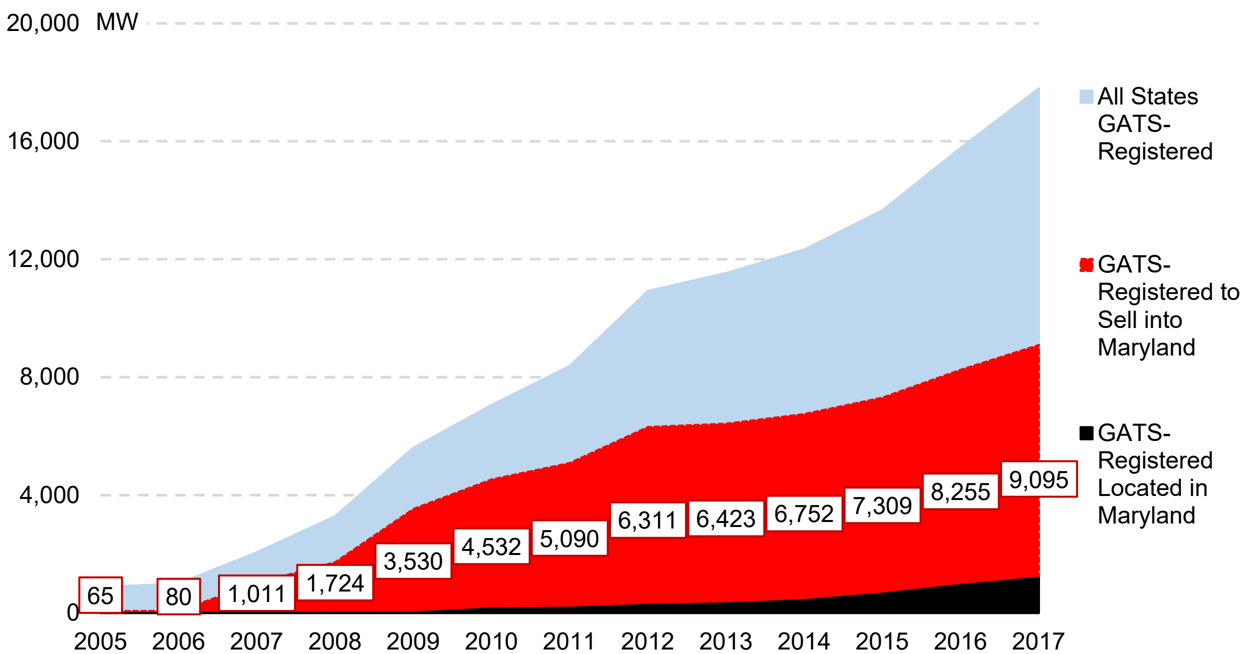

Figure 2-29. Cumulative PJM-GATS Registered Renewable Energy Nameplate Capacity

Source: PJM-GATS.

Note: Inclusive of capacity that has come online after 2004. Each category is inclusive of the category or categories beneath it.

Table 2-5. New Renewable Energy Capacity Registered to Retire RECs for Compliance with the Maryland RPS (2005-2017)

Fuel Source	New Capacity Eligible to Retire Maryland RECs (MW)	Percent of Total New Capacity
Wind	7,782	82%
Solar	982	17
LFG	200	44
Black Liquor[1]	50	100
Wood Waste	50	35

Source: PJM-GATS. Inclusive of capacity that has come online since 2005.

[1] Black liquor capacity corresponds with a plant in Tennessee that came online in 2007.

2.1.7. In-State Renewable Energy Used for PJM-wide RPS Requirements

Figure 2-30 illustrates REC generation in Maryland by the vintage year that the REC was created and by its specific usage.[46] In most years, a large amount of RECs generated in Maryland are banked.[47] In the early years of the Maryland RPS, this was because the supply of RECs in and outside of the state exceeded what was needed to comply with the Maryland RPS. Figure 2-30 also includes the total number of RECs retired for the Maryland RPS over time, which shows that Maryland generated enough RECs to meet a large share of its RPS requirement in the early years of the RPS, especially when the Tier 2 requirement was equal to or in excess of the Tier 1 requirement.

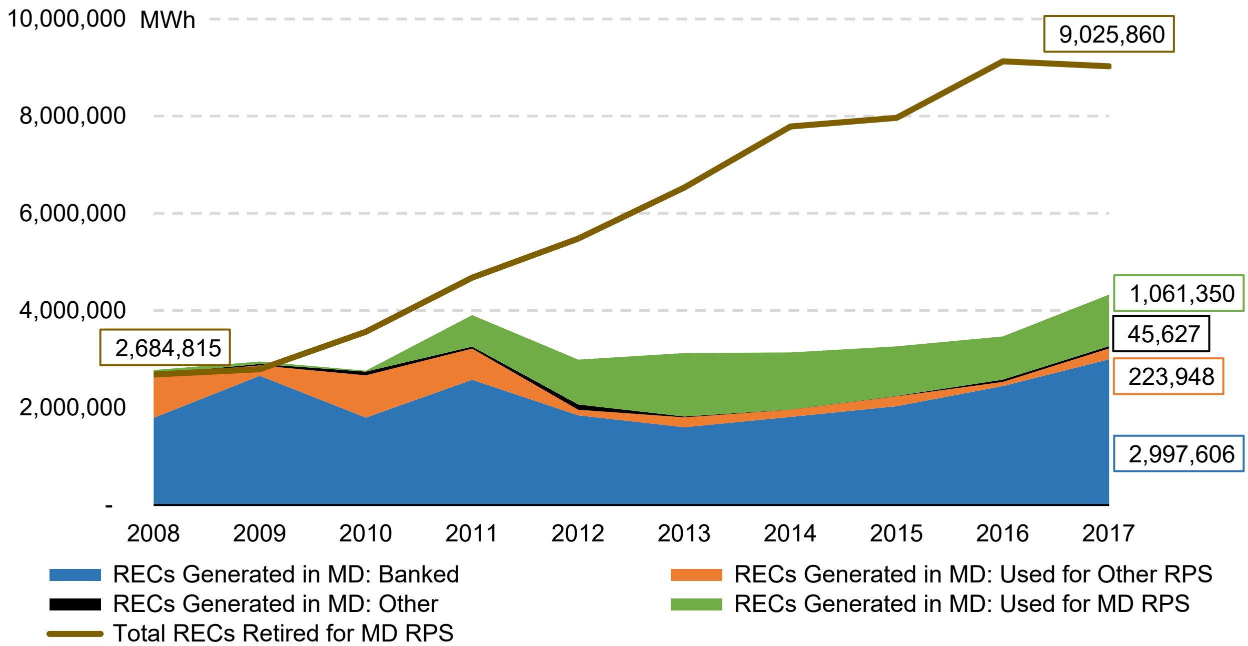

Figure 2-30. Maryland REC Generation and Retirement, by Usage, 2008-2017

Source: Maryland PSC *Renewable Energy Portfolio Standard Reports*.

In the last decade, RECs from in-state renewable energy resources have increased from 2.8 million RECs in 2008 to 4.3 million in 2017.[48] As compared to 2008, the share of RECs from in-state resources that were retired for compliance with other state RPS policies has decreased, while the share used for Maryland RPS compliance has increased. This change corresponds with increases in the number of RECs generated in other states as well as shifts in REC prices within other states in PJM. Although the Tier 1 REC prices for Pennsylvania, New Jersey, Maryland, and Delaware have converged and largely move in tandem as of

[46] The categories displayed in Figure 2-30 are defined as follows: "Used for MD RPS" reflects RECs created in a given year and used for Maryland RPS compliance in that same year. "Used for Other RPS" includes RECs created in a given year and then sold into other state RPS markets that same year, inclusive of voluntary markets. "Banked," which is labeled as "Available" by PJM-GATS beginning in the 2015 reporting year, means that a REC created in a given year was not yet retired in that given year and is still available for usage in subsequent years. (Note that the reported "Banked" category is not cumulative despite RECs being available for multiple years.) "Other" encompasses several categories, including "Bulletin Board," "Pending Transfer," and/or "Active," that are all very small applications of RECs.

[47] Maryland allows resources to bank credits for up to three years.

[48] Public Service Commission of Maryland, *Renewable Energy Portfolio Standard Reports*, psc.state.md.us/commission-reports/.

2018, Pennsylvania's and New Jersey's average Tier 1 REC prices were both greater than equivalent prices for Maryland between 2009-2011.[49] This differentiation provided an incentive for some qualified Maryland resources to supply RECs to these states during these years. Likewise, the average Tier 2 REC prices in New Jersey are consistently greater than in Maryland between 2009-2018, again providing an incentive for qualified resources in Maryland to supply New Jersey Tier 2 RPS requirements.[50]

The largest source of banked RECs in Maryland is hydro. Despite low Tier 2 prices and the initial expiration of Maryland's Tier 2 requirement (since extended by Ch. 757), hydro resources continued to generate RECs in excess of demand up through 2018. This is because: (1) hydro resources can continue operation with very little or no REC support;[51] (2) it is low-cost to create RECs; and (3) banked hydro RECs may become valuable in terms of price if Maryland further extends or expands the Tier 2 requirement, makes hydro a Tier 1 resource, or other states change their eligibility requirements concerning large hydro. Figure 2-31 shows the composition of all in-state RECs by resource type. In-state wind and SREC generation have increased in recent years, which is consistent with the capacity expansion of these resources. Table 2-6 provides the corresponding numbers for Figure 2-31.[52]

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[49] Visuals showing market REC prices in these states from September 2015 – April 2018 are included in Appendix D. Source for historical average price figures: Monitoring Analytics, LLC, *2018 State of the Market Report for PJM*, March 2019, monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-volume2.pdf, Figure 8-3.

[50] Ibid., Figure 8-5.

[51] This is evidenced by the relatively constant share of hydro capacity in Maryland and PJM, as summarized above. This capacity is in excess of RPS demand for hydro RECs, meaning many large hydro resources generate RECs without financial support in the form of REC payments. Additionally, the REC payments available to large hydro are low (both on a per-MWh basis and in aggregate), as detailed in Section 2.4., "Ratepayer Impacts."

[52] Note that the spikes in hydro production in 2011 and 2017 are likely weather-related; hydro generation varies on a year-to-year basis based on water availability, which in turn depends on water withdrawals and precipitation. EIA's "Net Generation for Conventional Hydroelectric" data are supportive of this explanation, as Pennsylvania, an adjacent state with similar weather, experienced similar changes in annual large hydro output in 2011 and 2017. Other states in PJM with large hydro resources, such as Ohio, Kentucky, and West Virginia, experienced dissimilar fluctuations during this same time period. This suggests that PJM-wide market factors are not the sole determinant of change in hydro output.

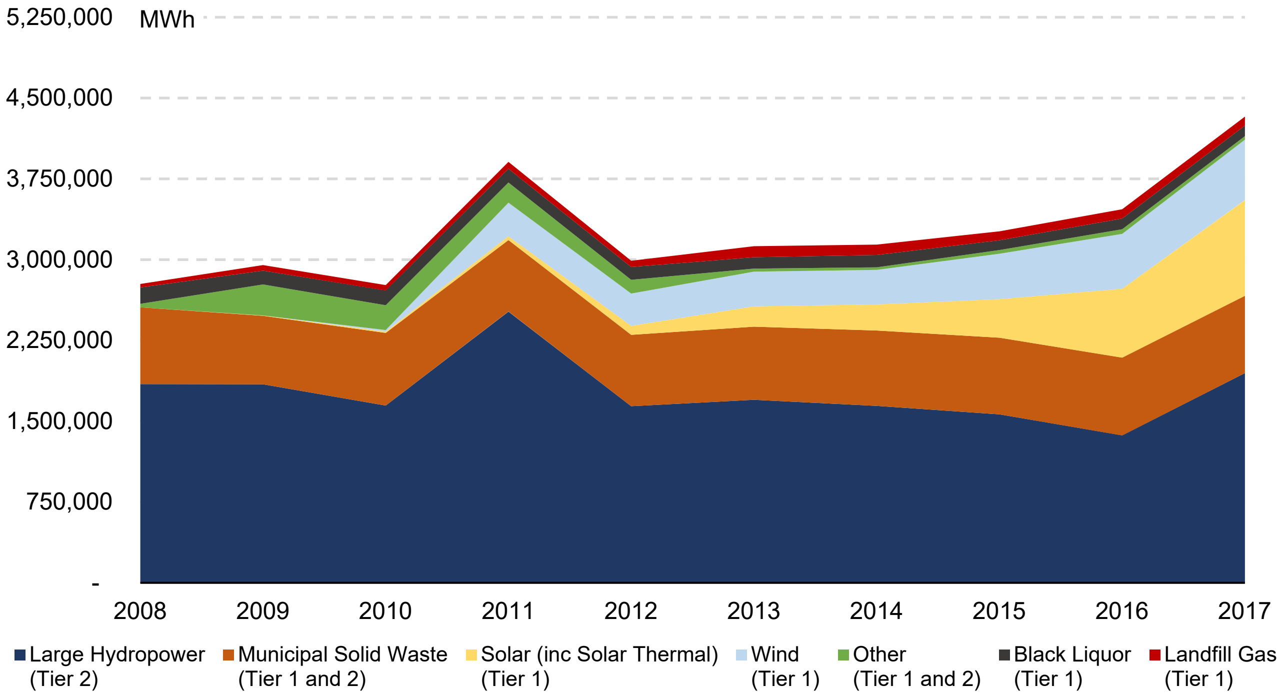

Figure 2-31. Maryland In-State RECs, by Fuel Source, 2008-2017

Source: Maryland PSC *Renewable Energy Portfolio Standard Reports*.

Table 2-6. Maryland RECs, by Fuel Source (MW)

Year/%	TIER 1										TIER 2			TOTAL
	Blast-Furnace Gas	Black Liquor	Geothermal	Hydro (<30 MW)	LFG	MSW	Other Biomass Liquids	Solar (Inc. Solar Thermal)	Wood Waste	Wind	Blast-Furnace Gas	Hydro (>30 MW)	MSW	
2008		151,297		33,015	32,534			276				1,843,962	713,035	**2,774,119**
		6%		*1%*	*1%*			*0%*				*67%*	*26%*	**100%**
2009		128,806		24,860	50,876			3,495			262,005	1,843,455	635,206	**2,948,703**
		4%		*1%*	*2%*			*0%*			*9%*	*63%*	*22%*	**100%**
2010		137,402		22,592	48,618		75	12,337		14,927	207,615	1,645,379	674,401	**2,763,346**
		5%		*1%*	*2%*		*0%*	*0%*		*1%*	*8%*	*60%*	*24%*	**100%**
2011	54,296	128,371		35,051	63,419	166,119	43	34,405		311,774	97,289	2,518,438	497,801	**3,907,006**
	1%	*3%*		*1%*	*2%*	*4%*	*0%*	*1%*		*8%*	*3%*	*65%*	*13%*	**100%**
2012	110,534	119,556		17,803	57,453	662,596	5	83,094		299,525		1,639,132		**2,989,698**
	4%	*4%*		*1%*	*2%*	*22%*	*0%*	*3%*		*10%*		*55%*		**100%**
2013		104,499	44	28,739	102,600	677,530		188,739		322,971		1,699,405		**3,124,527**
		3%	*0%*	*1%*	*3%*	*22%*		*6%*		*10%*		*54%*		**100%**
2014		113,508	283	23,755	96,336	700,539		241,980		320,380		1,642,113		**3,138,894**
		4%	*0%*	*1%*	*3%*	*22%*		*8%*		*10%*		*52%*		**100%**
2015		89,648	1,046	27,492	84,583	711,795		358,040	5,840	421,037		1,563,988		**3,263,469**
		3%	*0%*	*1%*	*3%*	*22%*		*11%*	*0%*	*13%*		*48%*		**100%**
2016		99,937	1,541	24,831	85,440	721,509		639,434	16,176	509,154		1,369,003		**3,467,025**
		3%	*0%*	*1%*	*3%*	*21%*		*18%*	*1%*	*15%*		*40%*		**100%**
2017		98,176	1,886	24,703	83,845	718,474		888,244	6,115	560,667		1,946,421		**4,328,531**
		2%	*0%*	*1%*	*2%*	*17%*		*21%*	*0%*	*13%*		*45%*		**100%**

Source: Maryland PSC 2018 *Renewable Energy Portfolio Standard Report*.

2.2. Environment

This section of the final report reviews the role of the Maryland RPS in reducing air emissions from power plants, including CO_2, NOx, and SO_2. The emissions content of electricity is a measure of the pounds of emissions released per unit of generation, often expressed in terms of CO_2, NOx, or SO_2 per kWh. In an electricity grid, the emission content of power depends on a variety of factors, including the fuel source and heat rate of contributing electric generators, the load factor and capacity of those generators, and the carbon content of the fuels used. All else equal, switching to a fuel source with a lower emission profile (e.g., replacing coal with natural gas), reducing the heat rate, or reducing the load factor or capacity of fossil fuel generators will reduce emission content. Policies that promote renewable energy resources, including an RPS, can help reduce emissions by supporting generation from resources which have low or no emission content.

As discussed in preceding sections, Maryland participates in PJM, a regional transmission organization (RTO) that oversees power dispatch in all or parts of 13 states, including all of Maryland. Power generation throughout the PJM service area is commingled, with power imported and exported based on economic dispatch. While PJM can track how much power is generated by individual power plants, once the electric power is on transmission lines, there is no way of knowing the fuel source, and therefore emissions, of the resources that serve customers in specific areas. In other words, the electricity consumed by Maryland ratepayers is sourced from a broader pool of resources that may or may not be generated from within the state. Consequently, it is unclear what effect the Maryland RPS has had on the emission content of imported electricity. However, it is possible to distinguish broader trends in the emission content of the PJM-wide electricity mix. Maryland imports reflect these trends, and its RPS has contributed to the current mix by supporting low- or zero-emission resources in-state, within PJM, and in outside areas that are deliverable into PJM. Select findings for the subsequent discussion include:

- Estimates for the benefits of renewable energy added as a result of an RPS range from $0.033/kWh of renewable energy (kWh-RE) to $0.165/kWh-RE, inclusive of the estimated benefits from avoided GHGs, climate change damage, and air pollution, in addition to human health and environmental benefits. These estimates are comparable to broader studies of renewable energy, including one that found a marginal benefit of between $0.091-$0.110/kWh for wind, and between $0.099-0.120/kWh for solar in regions near Maryland.
- Since 2005, CO_2 emissions per MWh of electricity generated have dropped throughout PJM, including in Maryland. These reductions largely correspond with the retirement of coal plants and the growth of natural gas generation.
- As a result of allowing resources with an emissions profile, such as biomass and MSW, the Maryland RPS may be, at least in part, working at cross-purposes toward Maryland's desire to reduce emissions.
- The SO_2 and NOx emissions profiles of Maryland RPS-eligible resources are equal to or even higher than net Maryland and net PJM generation, on average.
- In-state generation used for complying with the Maryland RPS produces higher CO_2, NOx, and SO_2 emissions on average than in-state RECs that are banked or used for another state RPS. This is partially because Maryland allows MSW, black liquor, and wood waste to meet its RPS requirements. Relatively few other states in PJM support these resources in their RPS and, if they do, some restrictions are imposed.

- There is evidence that the Maryland RPS is driving down CO_2 emissions throughout PJM. PJM CO_2 levels in 2017, the latest year available, were approximately 0.8% lower than they would have been in the absence of the Maryland RPS, assuming all retired RECs supported resources that would not have operated otherwise. Before 2017, the typical impact on PJM carbon levels from the Maryland RPS was less than 0.6% per year, coinciding with lower Maryland RPS requirements.

2.2.1. NREL and LBNL Research

Several recent studies by LBNL and NREL assume a direct connection between RPS policies and emission reductions, and then calculate the potential benefits of this connection. Wiser, *et al.* (2016), in a national-level assessment of RPS policies, found that compliance with individual state RPS requirements in 2013 reduced SO_2 emissions by 77,400 metric tons (MT), NOx emissions by 43,900 MT, and particulate matter 2.5 (PM2.5) emissions by 4,800 MT.[53,54] The authors also found that nationwide RPS compliance resulted in 59 million fewer MT of carbon dioxide equivalents (CO_2e), including both life cycle-related emissions and displaced combustion at fossil fuel plants. These estimates were primarily developed using the U.S. Environmental Protection Agency's (EPA's) AVoided Emissions and geneRation Tool (AVERT) model.

NREL's modeling suggests that renewable energy generation used for RPS compliance reduced fossil fuel generation by 3.6% in 2013. Just over half of this displaced generation was natural gas, followed by coal. All else equal, renewable energy resources that displace natural gas have less environmental benefit than renewable energy that displaces coal.[55] The largest region in terms of coal displacement and overall fossil fuel displacement in 2013 was the Great Lakes and mid-Atlantic region, as identified by AVERT, inclusive of Maryland and most of PJM. Not surprisingly, both NREL and LBNL found that this region experienced the greatest environmental benefits from the RPS relative to the starting resource composition. Separate research by Callaway, *et al.* (2017), in an evaluation of renewable energy benefits in independent system operators (ISOs) relative to RPS costs from 2010-2012, similarly found the highest marginal benefit of an RPS in the PJM area, largely due to the environmental benefit of displaced coal.[56]

The 2013 emission reductions found by LBNL and NREL were subsequently used to estimate human health benefits stemming from RPS policies.[57] The avoided GHGs and climate change damage benefit of these reductions were converted to a dollar benefit using four Interagency Working Group (IWG) estimates of the social cost of carbon (SCC). The IWG is a body of experts created to help coordinate U.S. government-sponsored international

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[53] Ryan Wiser, Galen Barbose and Jenny Heeter, *et al.*, *A Retrospective Analysis of the Benefits and Impacts of U.S. Renewable Portfolio Standards*, Lawrence Berkeley National Laboratory and National Renewable Energy Laboratory, 2016, nrel.gov/docs/fy16osti/65005.pdf.

[54] Estimates are net of biomass emissions.

[55] This finding is confirmed in several other studies, including most recently: David Young and John Bistline, "The Costs and Value of Renewable Portfolio Standards in Meeting Decarbonization Goals," *Energy Economics*, Vol. 73, 2018; Anthony Oliver and Madhu Khanna, "The spatial distribution of welfare costs of Renewable Portfolio Standards in the United States electricity sector," *Letters in Spatial and Resource Sciences*, Vol. 11(3), 2018.

[56] Duncan Callaway, Meredith Fowlie and Gavin McCormick, "Location, Location, Location: The Variable Value of Renewable Energy and Demand-side Efficiency Resources," *Journal of the Association of Environmental and Resource Economists*, Vol. 5(1), 2015.

[57] Emissions from conventional power plants that use fossil fuels have been linked to lung diseases such as asthma and chronic obstructive pulmonary disorder. Therefore, indirect benefits associated with RPS policies also include associated healthcare benefits, such as reductions in hospital visits or lost workdays associated with ailments caused by pollutants such as particulates, carbon monoxide (CO), and SO_2, and lower morbidity rates, particularly among vulnerable groups.

exchanges, in this case to identify a consensus valuation of the ultimate costs of GHGs. The SCC estimates referenced by NREL included:

- Low SCC: \$12.1/MT CO_2e (0.7 cents/kWh-RE)
- Central SCC: \$37.3/MT CO_2e (2.2 cents/kWh-RE)
- High SCC: \$59.2/MT CO_2e (3.6 cents/kWh-RE)
- Higher-than-expected SCC: \$106.4/MT CO_2e (6.4 cents/kWh-RE)

Together, these estimates suggest a range of potential GHG and climate change benefits. Likewise, the air pollution and human health and environmental benefits were converted to dollars using a mix of EPA's benefit-per-ton methodology, EPA's CO-Benefits Risk Assessment (COBRA) model, and the Air Pollution Emission Experiments and Policy (APEEP) Analysis Model. The resultant benefit estimates for reductions in SO_2, NOx, and PM2.5 range from 2.6-10.1 cents/kWh-RE.[58] The largest source of benefit is reductions in SO_2 (and resultant PM2.5), which accounts for over three-fourths of the pollution and human health benefit in most scenarios. In total, Wiser, *et al.* (2016) estimated that emissions reductions in 2013 as a result of RPS policies produced benefits in the range of \$2.6-\$9.9 billion, depending on the assumed social cost of emissions. The authors note, however, that the morbidity estimates used to calculate these benefits are based on relatively few studies and are therefore uncertain.

The potential benefits identified by Wiser, *et al.* (2016) are consistent with an earlier study looking at state-level assessments. Barbose, *et al.* (2015) found that state studies of RPS impacts generally estimated an air quality benefit in the range of 4-23 cents/kWh-RE.[59] This range stems from how different states value avoided CO_2. Barbose, *et al.* (2015) also found that most state studies used assumptions at the lower end of the SCC levels identified by the IWG.

Several other academic studies have developed other estimates of the environmental benefits of renewable energy. Millstein, *et al.* (2017), in a study evaluating renewable energy production from 2007-2015, estimate air quality benefits from wind and solar in the range of \$29.7-\$112.8 billion, mostly due to avoided mortality, as well as cumulative climate benefits of \$5.3-\$106.8 billion.[60] Their study estimates a marginal benefit of 0.073 cents/kWh for wind and 0.04 cents/kWh for solar. Buonocore, *et al.* (2016) modeled health and climate benefits for representative areas in PJM, and they found benefits in the range of \$14-\$170/MWh (2012\$).[61] Their model simulated the effects of different wind and solar installation types of different sizes while also accounting for performance, location, and time dynamics; fuel source and pollution control; atmospheric conditions; and downwind population distribution. Benefits, in their model, are a function of new renewable energy generation and displaced fossil generation by fuel source.[62] Like Wiser, *et al.* (2016), Buonocore, *et al.* (2016) found that SO_2 displaced from coal was a major driver of

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[58] Biomass is estimated to emit, respectively: 1,800 MT, 6,200 MT, and 900 MT of SO_2, NOx, and PM2.5. As a result, biomass reduced the total emission benefit by 2.3%, 12.3%, and 15.8%, respectively. However, since SO_2 is the biggest driver of benefit and cost, biomass only has a marginal impact on the total benefit.

[59] Galen Barbose, Lori Bird and Jenny Heeter, *et al.*, "Costs and Benefits of Renewables Portfolio Standards in the United States," *Renewable and Sustainable Energy Reviews*, Vol. 52, 2015.

[60] Dev Millstein, Ryan Wiser, Mark Bolinger and Galen Barbose, "The climate and air-quality benefits of wind and solar power in the United States," *Nature Energy*, Vol. 2, 2017.

[61] Jonathan Buonocore, Patrick Luckow and Gregory Norris, *et al.*, "Health and climate benefits of different energy-efficiency and renewable energy choices," *Nature Climate Change*, Vol. 6, 2016.

[62] Alternatively stated, total benefit = capacity factor * fuel types displaced * emissions displaced * impacts displaced.

renewable energy-related environmental benefits. Places with more coal, such as within PJM, stood to benefit more from renewable energy due to its displacement effect. Of the areas assessed, southern New Jersey and Virginia are representative of impacts of renewable energy additions in Maryland. The authors found the following benefit based on the average results of their simulations:

- Virginia – wind: $91/MWh; solar: $120/MWh
- Southern New Jersey – wind: $110/MWh; solar: $99/MWh

Ultimately, the authors conclude that site-specific characteristics have bearing on the potential benefits of different renewable energy projects.

2.2.2. Emissions Levels from Power Plants in PJM and Maryland

As noted earlier, power generation throughout the PJM service area is commingled. The locations of RPS-eligible generating plants and other generators, however, are known. This information can be used to identify an estimated average contribution to emissions of Maryland in-state RPS-eligible resources as compared to the totality of Maryland- or PJM-wide generation. This comparison is made over the subsequent pages. Figure 2-32 shows the resource weighted average emissions of CO_2, NOx, and SO_2 from net Maryland generation and net PJM generation between 2004-2017. The annual emissions figures for Maryland are sourced from EIA's state electricity profile for the state.[63] The annual emissions figures for PJM are provided by PJM-GATS.[64] PJM-GATS derives its emissions data from EPA's Emissions & Generation Resource Integrated Database (eGRID) of plant emission rates, and uses fuel type default emission factors where eGRID data are not available.

In comparison, Figure 2-33 shows the resource weighted average emission profile for Maryland RPS-eligible resources and RECs generated in Maryland during the same period. The emissions figures for Maryland RPS-eligible resources are calculated using annual REC retirement figures from the Maryland PSC (used to determine the weight factor for each contributing renewable energy resource type) and the annual average emission levels from PJM overall for each contributing renewable energy resource. That is, the resources used to comply with the Maryland RPS, which can be located both in- and out-of-state, are assumed to have emissions equal to the average PJM-wide equivalent for those same resources.[65] The emissions figures for RECs generated in-state are calculated in a similar fashion. In this case, the included resources reflect all RECs generated in Maryland regardless of whether they are used to comply with the Maryland RPS, another state RPS, are banked, or are sold or traded with other market participants. The emissions average is again sourced from the PJM overall average. Table 2-7 summarizes the data shown in Figure 2-32 and Figure 2-33. The trends apparent in the charts and table are discussed further in subsequent subsections.

There are several limitations to the data used for the above comparison. First, EPA's eGRID data is only updated periodically, and was last revised in 2016. Second, using system-wide averages for Maryland RPS resources does not account for heterogeneity in the emissions

[63] U.S. Energy Information Administration, "Maryland Electricity Profile 2017," eia.gov/electricity/state/maryland/.

[64] PJM-GATS, "PJM System Mix – System Mix by Fuel," gats.pjm-eis.com/GATS2/PublicReports/PJMSystemMix.

[65] For example, Maryland retired 1,668,231 RECs from black liquor resources in 2017. At that time, the average carbon content of black liquor resources located throughout PJM was 508 lbs/MWh of CO_2. The carbon emissions content of the RECs specifically retired for the Maryland RPS were assumed to be 508 lbs/MWh of CO_2 as well. One limitation of this approach is that it does not account for heterogeneity in the emissions profile of specific resources used for the Maryland RPS versus equivalent resources elsewhere in PJM.

profile of specific resources used for the Maryland RPS versus equivalent resources elsewhere in PJM.

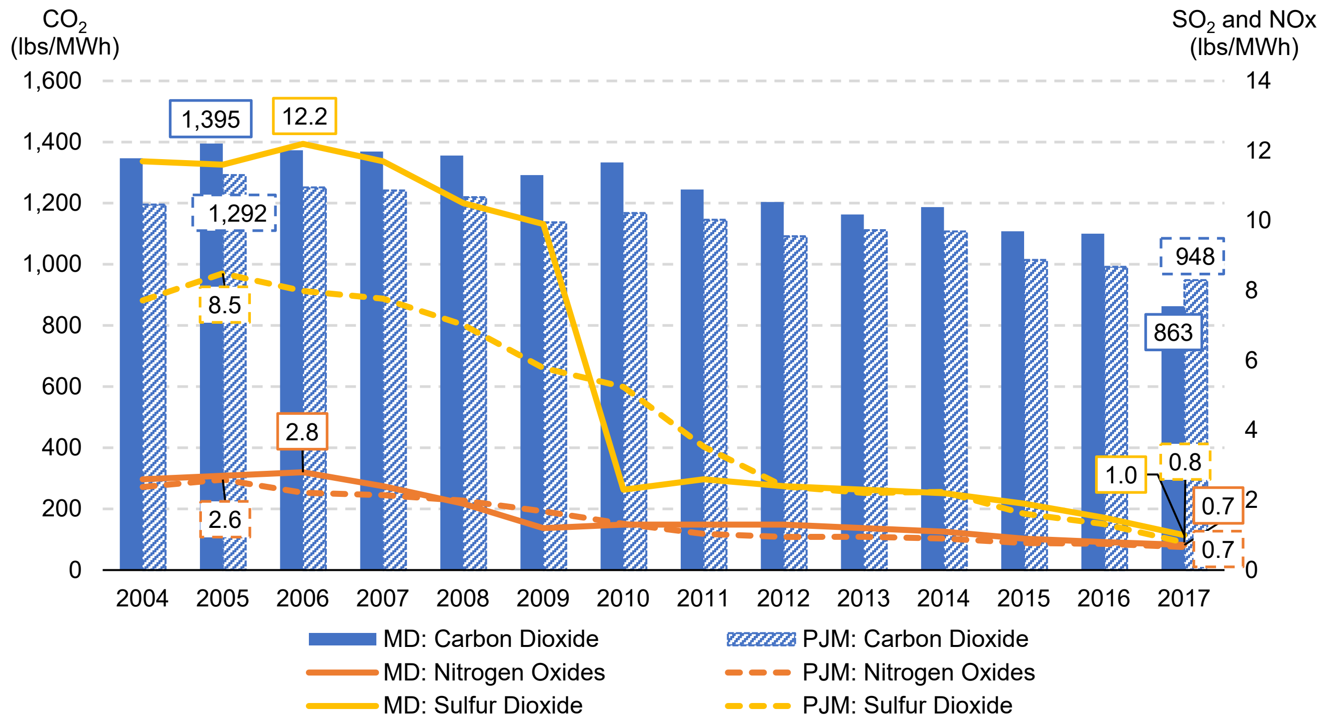

Figure 2-32. Average Emissions of Maryland and PJM Net Generation

Sources: PJM-GATS; Maryland PSC *Renewable Energy Portfolio Standard Reports.*

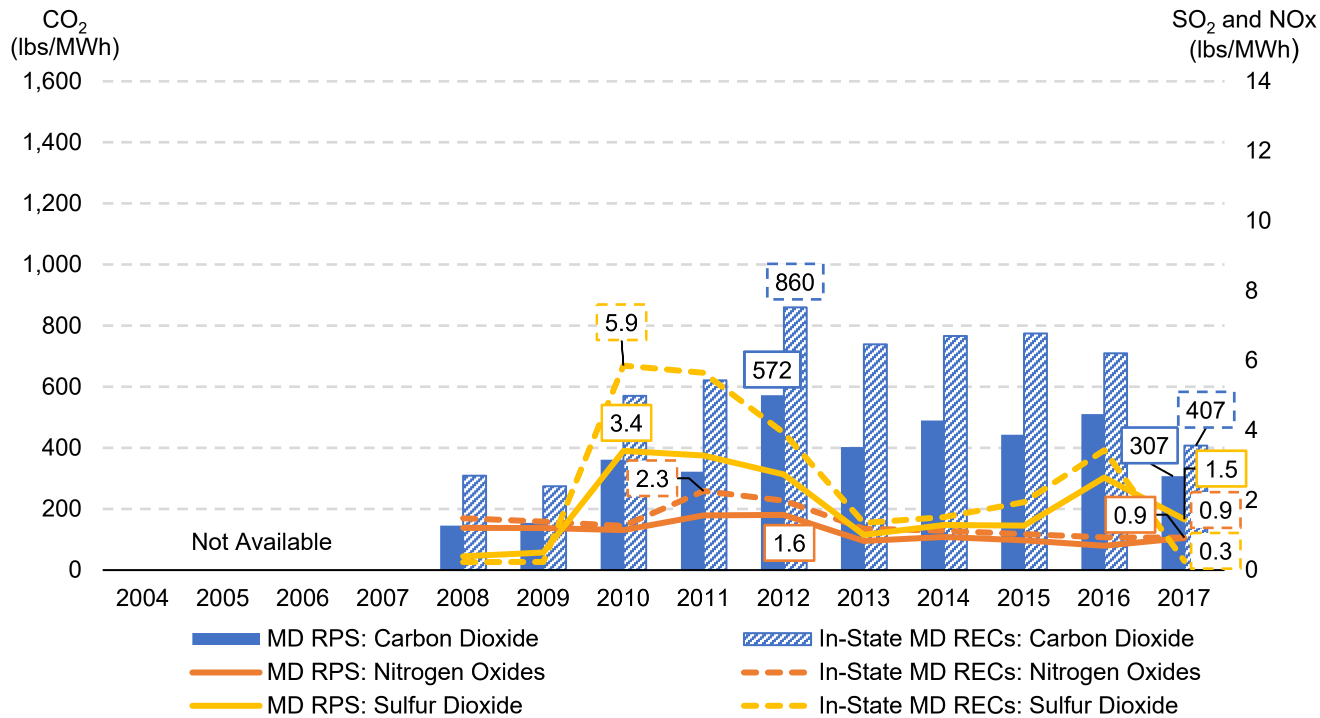

Figure 2-33. Average Emissions of Resources Used for Maryland RPS Compliance and RECs Generated in Maryland

Sources: PJM-GATS; Maryland PSC *Renewable Energy Portfolio Standard Reports*.

Table 2-7. Maryland RPS Emissions Profile

Year	**GENERATION** (GWh)				**EMISSIONS AVERAGES** (lbs/MWh)									**RECs Generated in MD**[6]		
	Net PJM[1]	**Net MD**[2]	**MD RPS**[3]	**RECs Generated in MD**	**PJM Generation**[4]			**MD Generation**[5]			**MD RPS Generation**[6]					
					CO_2	NOx	SO_2	CO_2	NOx	SO_2	CO_2	NOx	SO_2	CO_2	NOx	SO_2
2004	447,958	52,052	0	-	1,196	2.4	7.7	1,347	2.6	11.7	0	0.0	0.0	-	-	-
2005	710,435	52,662	0	-	1,292	2.6	8.5	1,395	2.7	11.6	0	0.0	0.0	-	-	-
2006	724,925	48,957	2,211	-	1,252	2.2	8.0	1,373	2.8	12.2	252	1.6	0.3	-	-	-
2007	752,097	50,198	2,289	-	1,242	2.1	7.8	1,369	2.4	11.7	339	2.2	0.3	-	-	-
2008	735,244	47,361	2,859	2,774	1,220	2.0	7.0	1,356	1.9	10.5	145	1.2	0.4	309	1.5	0.2
2009	693,279	43,775	2,823	2,949	1,137	1.7	5.8	1,292	1.2	9.9	154	1.2	0.5	274	1.4	0.2
2010	745,149	43,607	3,610	2,763	1,168	1.3	5.2	1,333	1.3	2.3	361	1.1	3.4	570	1.3	5.9
2011	762,526	41,818	4,770	3,907	1,146	1.0	3.5	1,245	1.3	2.6	322	1.6	3.3	621	2.3	5.6
2012	790,090	37,810	5,563	2,990	1,092	0.9	2.4	1,204	1.3	2.4	572	1.6	2.7	860	2.0	3.9
2013	799,841	35,850	6,623	3,124	1,112	1.0	2.2	1,163	1.2	2.3	402	0.8	1.0	739	1.2	1.3
2014	807,986	37,834	7,896	3,139	1,108	0.9	2.2	1,187	1.1	2.2	489	0.9	1.3	766	1.1	1.5
2015	786,699	36,366	8,032	3,264	1,014	0.8	1.6	1,108	0.9	1.9	443	0.8	1.3	774	1.0	1.9
2016	812,536	37,167	9,326	3,467	992	0.8	1.3	1,100	0.8	1.5	510	0.7	2.6	709	0.9	3.4
2017	808,230	34,104	9,251	4,329	948	0.7	0.8	1,077	0.7	1.3	307	0.9	1.5	407	0.9	0.3

[1] Note that PJM expanded during the represented period. When available, generation figures are drawn from the following year to reflect updates (e.g., 2010 net generation is sourced from the 2011 *State of the Market Report for PJM*.

[2] Inclusive of independent power producer and combined heat and power (CHP) generation. *Source:* EIA, "Maryland Electricity Profile 2017."

[3] Inclusive of Tier 1 (including solar carve-out) and Tier 2 (which is static at 2.5% from 2006-2018). Calculated by multiplying the RPS requirement by estimated retail energy sales. Retail energy sales are inclusive of both bundled and unbundled provider sales. Does not reflect gross consumption (i.e., not inclusive of transmission and distribution losses). *Source:* EIA, "Maryland Electricity Profile 2017."

[4] 2004 estimated using generation mix from the *2004 State of the Market* report and 2005 emission content for resources. Average emissions weighted based on portfolio composition. *Sources:* PJM, *2004 State of the Market*; PJM, *2013-2017 CO_2, SO_2 and NOx Emission Rates*; PJM-GATS, "PJM System Mix – System Mix by Fuel."

[5] *Source:* EIA, "Maryland Electricity Profile 2017."

[6] Resource composition determined using Maryland PSC *Renewable Energy Portfolio Standard Reports*. Emissions content calculated using weighted average based on comparable PJM emissions; *source:* PJM, *2013-2017 CO_2, SO_2 and NOx Emission Rates.*

2.2.3. PJM and Maryland Power Emission Trends

Since 2005-2006, air emissions from power plants in PJM have dropped across the board; the 2017 average PJM-wide CO_2 emission rate was more than 25% below 2005 levels, while NOx and SO_2 emissions levels were 73% and 91% lower, respectively. Although RPS policies have contributed to this decline, the most direct cause of this change is the ongoing decline of coal's share of generation, as illustrated in Figure 2-34. In 2005, coal contributed approximately 57% of total electricity generation in PJM. In 2017, this share fell to approximately 32%. In contrast, natural gas generation has expanded its share of generation from 5% in 2005 to nearly 27% in 2017. This transformation has, on its own, significantly reduced PJM-wide emissions. The average carbon content for natural gas production from 2005-2017, 1,008 CO_2/MWh, was approximately half the average carbon content for coal during this period, 2,054 CO_2/MWh.[66] Similarly, the average SO_2 and NOx content from PJM natural gas generation was 98% and 83% lower, respectively, than equivalent averages for coal from 2005-2017. In Maryland, the impact of coal retirements is especially apparent. Following the retirement of the coal-fired Chalk Point and Dickerson Generating Stations in May 2017, the annual average CO_2 emission levels in Maryland dropped by over 21%, from 1,100 CO_2/MWh in 2016 to 863 CO_2/MWh in 2017. This was the single greatest year-over-year change between 2004-2017. Several reasons for the decline in coal generation, as well as the rise of natural gas and renewable generation, are outlined below.

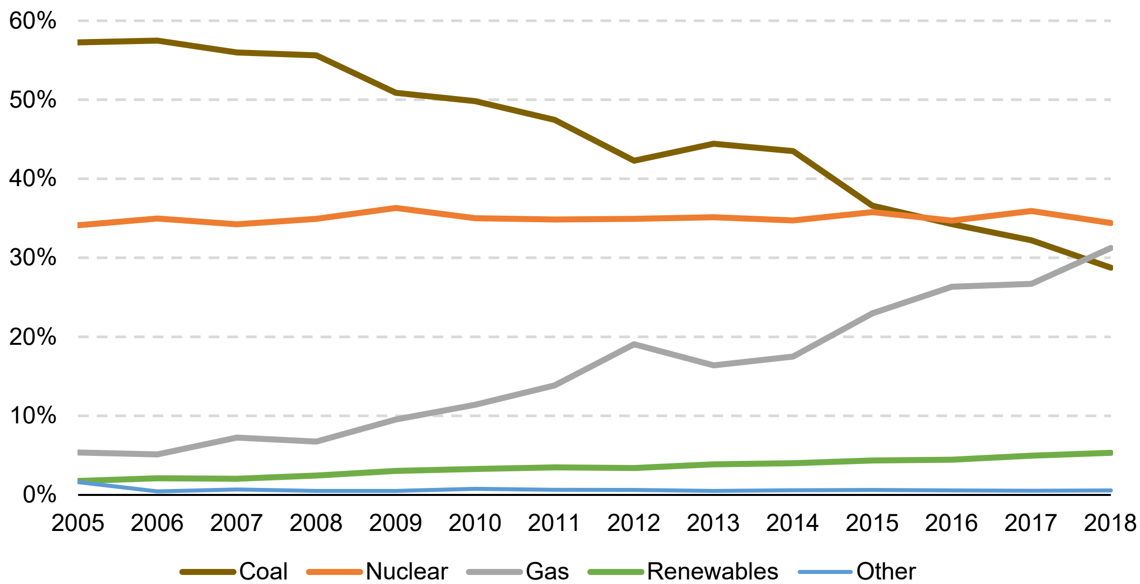

Figure 2-34. Share of PJM Generation, by Fuel Source

Source: PJM-GATS.

One contributing factor to changes in PJM's and Maryland's resource mix is flat or declining demand. Changes in demand affect average emission rates by altering the clearing price of energy and capacity; reduced demand decreases prices and displaces higher-cost supply. In

[66] Emissions figures reflect the weighted carbon content of contributing coal and natural gas sources, including: bituminous and anthracite, coal-based synfuel, sub-bituminous, and waste/other coal; and both regular and "other" forms of natural gas. *Sources:* PJM, *2013-2017 CO_2, SO_2 and NOx Emission Rates*, March 2018, pjm.com/-/media/library/reports-notices/special-reports/20180315-2017-emissions-report.ashx?la=en; PJM-GATS, "PJM System Mix – System Mix by Fuel," gats.pjm-eis.com/GATS2/PublicReports/PJMSystemMix.

this case, flat or declining demand contributed to the retirement of the oldest, least-efficient power plants in PJM, often coal-fired generators. The second-greatest year-over-year reduction in PJM carbon emissions, a 6.8% decrease between 2008-2009, coincided with a precipitous fall in demand during the last recession. SO_2 and NOx levels also fell at this time. This drop in demand, along with tepid growth thereafter, is shown in Figure 2-35, which tracks retail energy sales in states that participate in PJM regardless of when they joined PJM or what proportion of the state participates.[67] Maryland demand follows a similar, albeit flatter, trend, having decreased by over 9,000 GWh in total from a peak requirement of 68,365 GWh in 2005 to the 2017 total retail sale level of 59,304 GWh. The ongoing decline of demand is also due, at least in part, to energy efficiency initiatives.

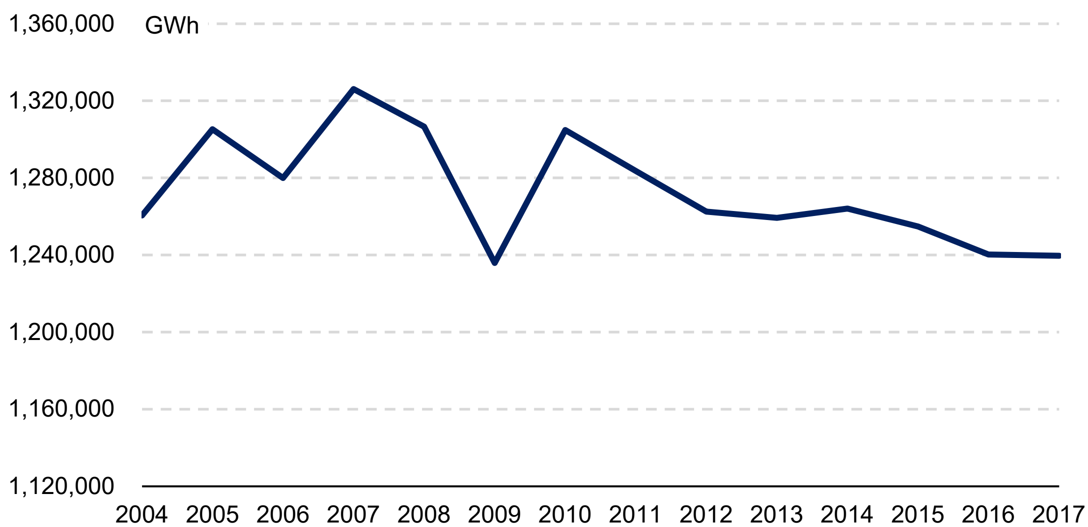

Figure 2-35. Total Retail Energy Sales in States that Participate in PJM

Source: EIA, "Form EIA-861M (formerly EIA-826) detailed data."

Note: The retail energy sales data in this figure include the totality of sales in states that participated in PJM from 2004-2017, regardless of what portion of the state participates in PJM, or when the state joined PJM. These data distinguish broader trends in retail energy sales from changes due to the ongoing growth of the PJM footprint.

Another contributing factor to changes in PJM's and Maryland's resource mix is persistently low natural gas fuel prices. Low natural gas prices reduce the operating costs of natural gas power plants and increase their economic competitiveness, especially as compared to coal plants. Increased economic competitiveness encourages higher capacity factors for existing natural gas generators, fuel-switching (e.g., converting coal plants to use natural gas instead), and the development of new natural gas capacity. The natural gas spot price at Henry Hub, which is a liquid trading point and popular "basis" (i.e., gas price reference point), fell from $12.69 per million British thermal units (MMBtu) in June 2008 to just $2.99/MMBtu in September 2009, the lowest price since July 2002. Prices fell even further several times in the ensuing years, declining to $1.95/MMBtu in April 2012 and then to $1.73/MMBtu in March 2016 after rebounding in the preceding years.[68] These declines in cost coincide with reduced demand and are also factors in the year-over-year emission

[67] Note that PJM-specific retail energy sales continued to grow during this period despite stagnated demand in the states that participate in PJM due to the ongoing expansion of the PJM footprint.

[68] U.S. Energy Information Administration, "Henry Hub Natural Gas Spot Price," eia.gov/dnav/ng/hist/rngwhhdM.htm.

reductions noted above. SO_2 and NOx levels fell between 10% and 33%, respectively, each year from 2008-2011. As natural gas displaces coal generation, average emissions drop.

Similar market pressures are behind the growth of renewable energy's share of net generation from 1.1% in 2005 to 5% of total PJM generation in 2017, as shown earlier in Figure 2-33.[69] The share of non-hydro renewable energy generation has grown from 0.9% in 2005 to 3.8% in 2017.[70] These trends were documented previously in Section 2.1, "Deployment of Renewable Energy."[71] The emission benefits of renewable energy stem from a combination of factors. First, many renewable energy resources have a lower emission profile than fossil-fuel powered thermal energy generation, such as natural gas and coal-powered generators. Second, renewable energy generation, especially wind and solar generators, often has low operating costs and is dispatched over existing fossil-fuel powered thermal energy generation. That is, once renewable energy projects are developed, they reduce the share of hours during which conventional thermal energy generators produce power.

Finally, changes in Maryland and PJM emission levels also coincide with environmental regulations. The implementation of EPA's Mercury and Air Toxics Standard (MATS) in 2012 led some coal plants to retire rather than embark on expensive upgrades to abate various pollutants. Likewise, pollution controls installed to comply with EPA's Acid Rain Program SO_2 caps and other environmental regulations resulted in either coal plant retirements or SO_2 and NOx reductions from the remaining coal fleet. Emission reductions in Maryland are also associated with the Maryland Healthy Air Act (HAA) which, after coming into effect in 2007, implemented stringent emission limits for in-state coal plants.[72]

2.2.4. Maryland Renewable Energy Emission Trends

Although CO_2 emissions are lower, SO_2 and NOx emissions of both Maryland RPS resources and renewable energy generators in Maryland are equal to or even slightly higher than net Maryland and net PJM generation. Additionally, the emissions profile for Maryland RPS-eligible resources and RECs generated in Maryland has remained largely constant over the last decade. Overall emissions may not decline, or may not decline as much as expected, with an RPS policy as compared to without an RPS policy if the RPS-eligible technologies for a state RPS are inclusive of combustion technologies with a non-negligible emission profile. This is the case in Maryland; MSW, biomass, black liquor, and LFG are all eligible for Tier 1 of the RPS and emit GHGs or other air pollutants.[73] Table 2-8 summarizes the emissions profile of these resources in 2017 relative to their share of the Maryland RPS by using PJM-

[69] PJM-GATS, "Number of Certificates by Fuel," gats.pjm-eis.com/GATS2/PublicReports/GATSCertificatesStatistics/Filter.

[70] Ibid.

[71] Of particular note, the weighted-average Levelized Cost Of Energy (LCOE) for renewables, especially utility-solar solar PV and onshore wind, have fallen significantly in recent years. Lazard identified an approximately 80% and 63% drop in the average LCOE of utility-scale solar PV and onshore wind, respectively, in the U.S. from 2010-2017. Simultaneously, a variety of state and federal initiatives are or were in place to support renewable generation besides RPS policies, as discussed further in Chapter 6, "Non-RPS Policies to Promote Renewable Energy."

[72] Annotated Code of Maryland, Environment Title 2 Ambient Air Quality Control Subtitle 10 Health Air Act Sections 2-1001 - 2-1005.

[73] Note that biomass is considered by some to be GHG-neutral on a life-cycle basis because of tree replanting, which captures carbon emissions from activities like wood-burning. For additional information, see NREL's discussion of biomass as a renewable resource at: nrel.gov/research/re-biomass.html. For purposes of this report, the authors focus exclusively on direct air emissions and therefore do not consider the life-cycle emissions impacts of specific renewable resources. Similarly, the authors did not address or account for the methane avoidance benefits from combusting some biomass resources, such as MSW and LFG, as compared to landfilling.

GATS average emissions for each fuel source. As a result of allowing resources with an emissions profile, the Maryland RPS may be, at least in part, working at cross-purposes toward Maryland's goal of reducing emissions, depending on how much of the Maryland RPS is met by RPS-eligible emitting resources and the specific emissions content of these resources.

Table 2-8. Emissions Profile of Resources Used to Meet the Maryland RPS, 2017

	Fuel Source	RECs[1] (MWh)	Share	CO_2/ MWh[2]	NOx/ MWh[2]	SO_2/ MWh[2]
TIER 1	Agr. Biomass	345	0.0%	0.000	0.000	0.000
	Black Liquor	1,668,231	18.5	506.736	1.295	7.513
	Geothermal	1,880	0.0	0.000	0.000	0.000
	Hydro	882,114	9.8	0.000	0.000	0.000
	LFG	227,393	2.5	111.173	10.910	0.394
	MSW	732,424	8.1	2,368.188	4.135	0.493
	Biogas	11,284	0.1	55.556	0.000	0.000
	Solar (incl. Solar Thermal)	557,224	6.2	0.000	0.000	0.000
	Wood Waste	491,627	5.4	339.075	1.266	0.220
	Wind	3,002,388	33.3	0.000	0.000	0.000
TIER 2	Hydro	1,450,950	16.1%	0.000	0.000	0.000
	TOTAL	**9,025,860**				
	Weighted Average (Tier 1)			**366.008**	**1.095**	**1.728**
	Weighted Average (Tiers 1 & 2)			**307.170**	**0.919**	**1.451**

[1] *Source:* Maryland PSC 2018 *Renewable Energy Portfolio Standard Report*.

[2] *Source:* PJM-GATS.

The emissions profiles of the RPS-eligible renewable energy resources that are located in Maryland vary depending on how the RECs from these resources are used, as shown in Figure 2-36 through Figure 2-38. RECs generated in Maryland can be used for the Maryland RPS, used for another state's RPS, or banked. Maryland-generated RECs that are retired for compliance with the Maryland RPS produce higher CO_2, NOx, and SO_2 emissions, on average, than RECs that are banked or used for compliance with another state RPS policy. This finding is partially due to, as noted earlier, Maryland allowing MSW, black liquor, and wood waste to meet its RPS requirements. As relatively few other states support these resources in the RPS (and Maryland REC prices are comparatively higher than the states that do), these resources are directly incentivized by Maryland to produce renewable energy generation for Maryland LSEs.

One implication of these findings, combined with the trends observed earlier in Figure 2-34 and Figure 2-35, is that the Maryland RPS benefits in terms of its emission profile from the presence of large hydro. Removing Tier 2 hydro resources from the Maryland RPS mix in 2017 would have increased emissions by 19%, including raising CO_2 from 307 to 366 lbs/MWh, SO_2 from 0.9 to 1.1 lbs/MWh, and NOx from 1.5 to 1.7 lbs/MWh.[74] Trends in

[74] The 19% increase in these emissions assumes that Tier 2 hydro is replaced with the average Tier 1 resource. Overall emissions levels may not significantly change if Tier 2 hydro is replaced with no-emission alternatives (e.g., wind or solar). Additionally, emissions levels may decline if Tier 2 hydro is replaced with no-emissions alternatives and the previously supported Tier 2 hydro continues to operate (despite the absence of REC support).

REC retirement and banking, however, also suggest that hydro resources can and do operate without REC support, and therefore are minimally incentivized by the RPS. Another implication of these findings is that Maryland's continued support of black liquor, MSW, and wood waste displaces zero-emission alternatives from receiving Maryland RECs. This is evidenced by the higher emissions levels of RECs generated in Maryland that are used for the Maryland RPS versus those that are banked or used elsewhere (i.e., in compliance with other state RPS policies).

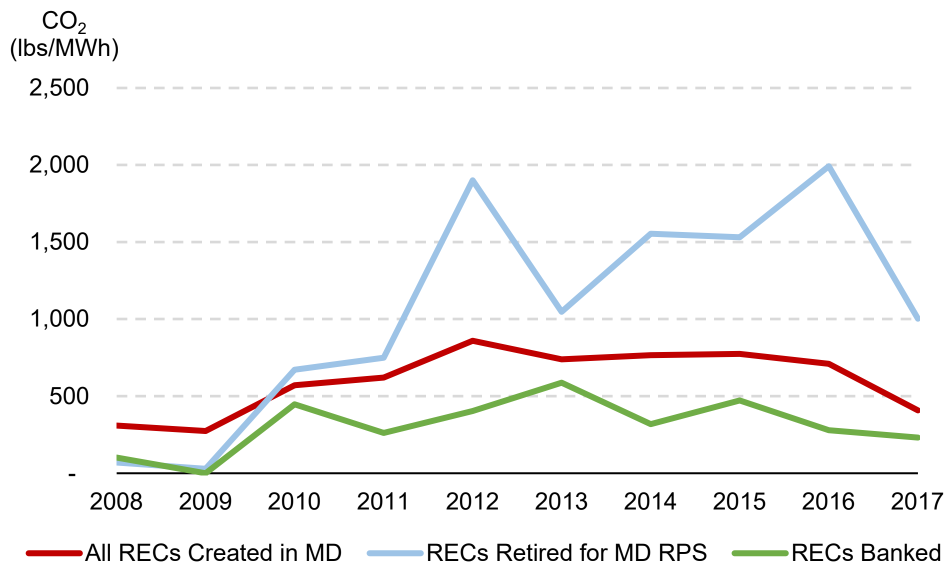

Figure 2-36. RECs Generated in Maryland – Average CO_2 Emissions

Sources: PJM-GATS; Maryland PSC *Renewable Energy Portfolio Standard Reports*.

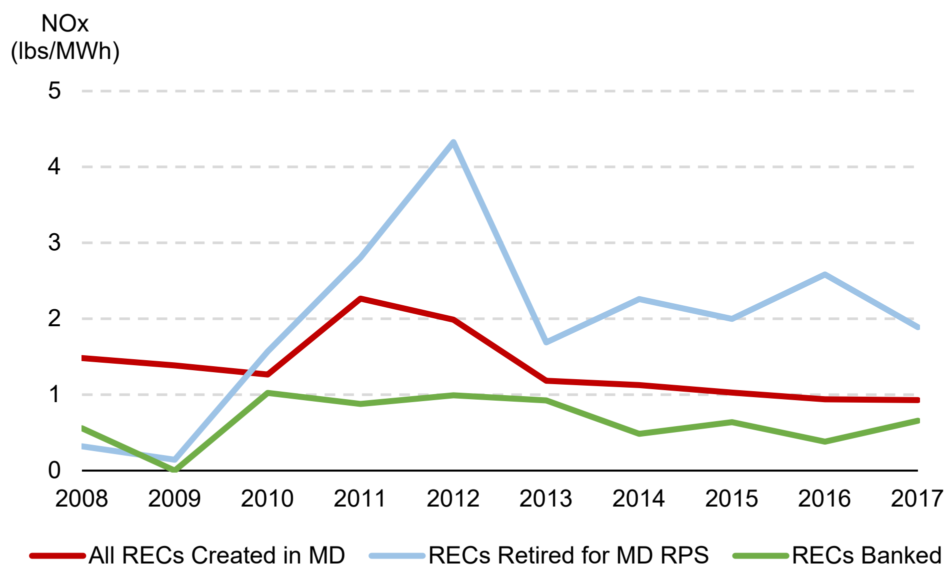

Figure 2-37. RECs Generated in Maryland – Average NOx Emissions

Sources: PJM-GATS; Maryland PSC *Renewable Energy Portfolio Standard Reports*.

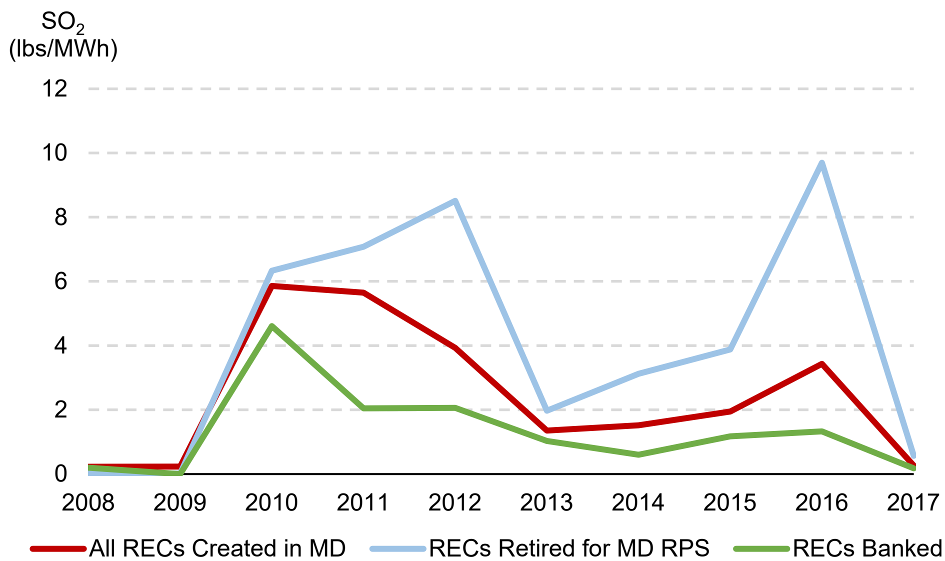

Figure 2-38. RECs Generated in Maryland – Average SO_2 Emissions

Source: PJM-GATS; Maryland PSC *Renewable Energy Portfolio Standard Reports*.

2.2.5. Carbon Content of Maryland Energy Imports

Over 42% of total retail energy sales in Maryland were met by power imports from PJM in 2017, up from preceding years, as calculated using data in Table 2-9.[75] As a result of Maryland's reliance on imports, the GHG emission profile of PJM is of significance to the overall carbon content of Maryland power consumption. The Maryland RPS indirectly influences the mix of generation contributing to Maryland's power imports, and therefore also affects the carbon content of imports.

Although it is not possible to distinguish the exact share of Maryland's power imports that are supplied by resources supported by the Maryland RPS, a high-level review of the carbon content of both Maryland generation and the generation used to meet the Maryland RPS can help identify the effectiveness of the Maryland RPS in reducing the carbon content of PJM power. What follows is a brief review of this influence, which is also reviewed in Table 2-9. Listed for reference in Table 2-9 are net Maryland generation [*Column 1*] and net PJM generation [*Column 6*]. Table 2-9 also identifies the weighted average carbon emissions of Maryland [*Column 2*] and PJM generation [*Column 8*]. Maryland's share of PJM generation [*Column 7*] has declined over time, coincident with the growth of the PJM footprint and the ongoing retirement of Maryland generation capacity. Table 2-9 further identifies the size of the Maryland RPS and its relative share of all PJM generation [*Column 14*] on an annual basis. The share of generation supported by the Maryland RPS is very small but growing as the Maryland RPS requirements [*Column 12*] increase.

[75] The amount of imports is roughly equal to the difference between net Maryland generation [*Table 2-9*, *Column 1*] and total Maryland retail sales [*Column 4*], which is calculated in [*Column 5*]. All data sourced from: U.S. Energy Information Administration, "Maryland Electricity Profile 2017," eia.gov/electricity/state/maryland/.

Table 2-9. Maryland and PJM Emissions Profile

	MARYLAND					PJM						MARYLAND RPS				
	Net MD Generation[1] (GWh)	Avg. MD CO_2 Emitted[2] (lbs/MWh)		Total MD Retail Energy Sales[3] (GWh)	MD Energy Imports (GWh)	Net PJM Generation[4] (GWh)	MD Share	Avg. PJM CO_2 Emitted[5] (lbs/MWh)		Total PJM Retail Energy Sales[6] (GWh)	PJM Energy Imports (GWh)	Renewable Energy Required[7]	Approx. Obligation (GWh)	Share of PJM Generation (GWh)	Avg. CO_2 Emitted[8] (lbs/MWh)	
Column:	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**
Formula:	**A**	**B**	**YOY Δ**	**C**	**C – A**	**D**	**A/D**	**E**	**YOY Δ**	**F**	**F – D**	**G**	**C*G**	**(C*G) /D**	**H**	**YOY Δ**
2004	52,052	1,347	-	66,891	14,839	447,957	11.6%	1,196	-	411,434	-36,523	0.00%	0	0.0%	0	-
2005	52,667	1,395	3.6%	68,365	15,704	710,435	7.4	1,292	8.0%	617,668	-92,767	0.00	0	0.0	0	-
2006	48,957	1,373	-1.6	63,173	14,217	724,926	6.8	1,252	-3.1	629,940	-94,985	3.50	2,211	0.3	252	-
2007	50,198	1,369	-0.3	65,391	15,193	752,097	6.7	1,242	-0.8	653,715	-98,382	3.50	2,289	0.3	339	34.5%
2008	47,361	1,356	-0.9	63,326	15,965	735,244	6.4	1,220	-1.8	644,947	-90,297	4.51	2,853	0.4	145	-57.2
2009	43,775	1,292	-4.7	62,589	18,814	693,279	6.3	1,137	-6.8	615,076	-78,203	4.51	2,823	0.4	154	6.2
2010	43,607	1,333	3.2	65,336	21,728	745,149	5.9	1,168	2.7	643,284	-101,865	5.53	3,610	0.5	361	134.4
2011	41,818	1,245	-6.6	63,600	21,787	762,526	5.5	1,146	-1.9	687,836	-74,690	7.50	4,770	0.6	322	-10.8
2012	37,810	1,204	-3.3	61,814	24,004	790,090	4.8	1,092	-4.7	717,001	-73,089	9.00	5,563	0.7	572	77.6
2013	35,851	1,163	-3.4	61,900	26,049	799,842	4.5	1,112	1.8	723,969	-75,873	10.70	6,623	0.8	402	-29.7
2014	37,834	1,187	2.1	61,684	23,850	807,987	4.7	1,108	-0.4	729,447	-78,539	12.80	7,896	1.0	489	21.6
2015	36,366	1,108	-6.7	61,782	25,416	786,699	4.6	1,014	-8.5	727,952	-58,747	13.00	8,032	1.0	443	-9.4
2016	37,167	1,100	-0.7	61,354	24,187	812,536	4.6	992	-2.2	724,332	-88,204	15.20	9,326	1.1	510	15.1
2017	34,104	863	-21.5	59,304	25,200	808,230	4.2	948	-4.4	716,060	-92,170	15.60	9,251	1.1	307	-39.8

YOY Δ = year-over-year change.

[1] Inclusive of independent power producer and combined heat and power (CHP) generation. *Source:* EIA, "Maryland Electricity Profile 2017."

[2] *Source:* EIA, "Maryland Electricity Profile 2017."

[3] Retail energy sales inclusive of both bundled and unbundled provider sales. Does not reflect gross consumption (i.e., not inclusive of transmission and distribution losses). *Source:* EIA, "Maryland Electricity Profile 2017."

[4] Note that PJM expanded during the represented period. When available, generation figures are drawn from the following year to reflect updates (e.g., 2010 net generation is sourced from the *2011 State of the Market Report for PJM*.

[5] 2004 estimated using the generation mix from the 2004 *State of the Market Report for PJM* and the 2005 carbon content for resources. *Sources: 2004 State of the Market for PJM*; PJM, *"CO_2, SO_2 and NOx Emission Rates*;" PJM-GATS, "PJM System Mix – System Mix by Fuel."

[6] Estimated by adjusting total statewide retail energy sales to reflect the portion of each state estimated to be supplied by PJM. Shares are adjusted to reflect changes in the composition of PJM after a utility joins PJM in proportion to the number of months of PJM participation. For example, the share of Illinois served by PJM was set at 41.8% in 2004, instead of Commonwealth Edison's (ComEd's) actual retail energy sales share of 62.7%, to reflect eight months of ComEd participation in PJM after it joined in May 2004. Small co-ops and munis are presumed to participate in PJM indirectly unless EIA data indicate otherwise. Net metered sales excluded. Retail energy sales data sourced from EIA "Annual Electric Power Industry Report, Form EIA-861 detailed data files."

[7] Percentage inclusive of Tier 1 (including solar carve-out) and Tier 2 (which is static at 2.5% from 2006-2018).

[8] See *Table 2-10* for additional information regarding the sources used to calculate average carbon emissions for Maryland RPS-eligible resources. Data inclusive of Tier 1 and Tier 2 resources.

The average carbon content of the resources used to comply with the Maryland RPS [*Table 2-9, Column 15*] is significantly lower than the carbon content of the broader PJM resource mix. Figure 2-39 visualizes the weighted average carbon content of Maryland, PJM, and Maryland RPS generation from 2004-2017. Table 2-10 tracks the fuel type of resources contributing to the Maryland RPS over time and breaks down the average carbon content of the Maryland RPS by resource.

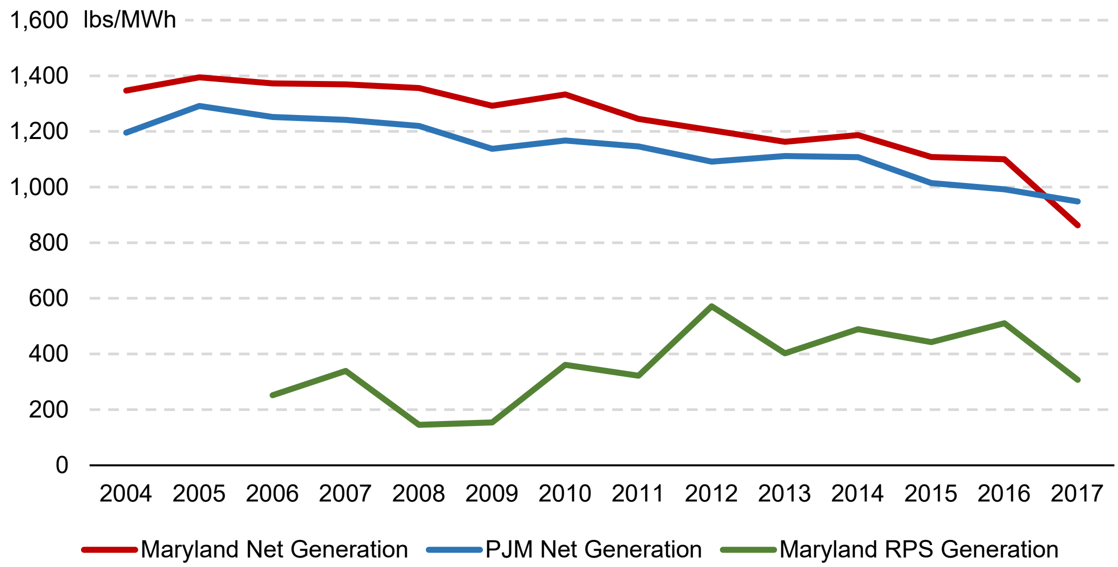

Figure 2-39. Weighted Average of Carbon Emissions in Maryland and PJM, by Electric Generation Category

Source: PJM-GATS; EIA, "Maryland Electricity Profile 2017."

Table 2-10. Carbon Content of RECs Retired to Fulfill Maryland RPS Requirements

		2006			2007			2008			2009			2010			2011		
	Fuel Source	RECs (GWh)	Share	lbs/ MWh	RECs (GWh)	Share	lbs/ MWh	RECs (GWh)	Share	lbs/ MWh	RECs (GWh)	Share	lbs/ MWh	RECs (GWh)	Share	lbs/ MWh	RECs (GWh)	Share	lbs/ MWh
TIER 1	Agr. Biomass																		
	BFG																22.4	0%	1,059
	Black Liquor	240.3	13%	281	348.3	18%	140	445.7	17%	211	390.7	14%	198	836.1	23%	187	1,038.4	22%	252
	Geothermal																		
	Hydro	163.3	9%	0	54.4	3%	0	202.1	8%	0	467.2	17%	0	638.5	18%	0	797.7	17%	0
	LFG	189.8	10%	215	197.7	10%	369	175.9	7%	217	157.3	6%	123	112.3	3%	298	280.0	6%	219
	MSW	366.4	20%	988													125.3	3%	3,341
	Biogas																		
	Other Biomass Liquids													0.1	0%	500	0.0	0%	1,800
	Solar							0.2	0%	0	3.3	0%	0	15.5	0%	0	27.9	1%	0
	Wood Waste	132.6	7%	15	322.7	17%	22	354.6	13%	16	342.0	12%	7	332.2	9%	528	386.3	8%	1
	Wind							5.9	0%	0	20.0	1%	0	18.2	1%	0	445.0	10%	0
TIER 2	BFG													24.3	1%	0	61.0	1%	1,059
	Hydro	783.6	42%	0	505.3	26%	0	1,279.9	48%	0	1,141.5	41%	0	1,181.7	33%	0	1,290.1	28%	0
	MSW				499.0	26%	1,052	220.6	8%	1,146	271.4	10%	1,221	404.5	11%	2,276	201.8	4%	3,341
	TOTAL[1]	**1,876.0**			**1,927.4**			**2,684.8**			**2,793.5**			**3,563.3**			**4,676.0**		
	Weighted Avg. (Tier 1):			**432**			**139**			**116**			**72**			**187**			**245**
	Weighted Avg. (Tiers 1 & 2):			**252**			**339**			**145**			**154**			**361**			**322**

Table 2-10. (cont.)

		2012			2013			2014			2015			2016			2017		
	Fuel Source	RECs (GWh)	Share	lbs/ MWh	RECs (GWh)	Share	lbs/ MWh	RECs (GWh)	Share	lbs/ MWh	RECs (GWh)	Share	lbs/ MWh	RECs (GWh)	Share	lbs/ MWh	RECs (GWh)	Share	lbs/ MWh
TIER 1	Agr. Biomass										3	0%	0	1	0%	0	3	0%	0
	BFG	96	2%	2,491	33	0%	2,659												
	Black Liquor	927.3	17%	268	1,143.2	18%	146	1,848	24%	254	1,858.2	23%	216	1,691	19%	207	1,668.2	18%	507
	Geothermal							1	0%	0	1	0%	0	7	0%	0	1.9	0%	0
	Hydro	534.7	10%	0	759.0	12%	0	1,088.5	14%	0	1,339.6	17%	0	1,453	16%	0	876.0	10%	0
	LFG	246	4%	192	268.7	4%	196	185	2%	211	172.7	2%	113	84	1%	107	226.9	3%	111
	MSW	481.9	9%	3,399	562.4	9%	3,354	854.3	11%	3,362	595.5	7%	3,497	1,101.1	12%	3,341	732.4	8%	2,368
	Biogas				9.5	0%	0	13.6	0%	0	6.5	0%	0	17.1	0%	050	11.3	0%	056
	Other Biomass Liquids																		
	Solar	56.2	1%	0	134.3	2%	0	203.9	3%	0	299.5	4%	0	411.8	5%	0	557.2	6%	0
	Wood Waste	500	9%	018	172.9	3%	290	365.1	5%	1,180	698.1	9%	1,469	537.1	6%	1,158	491.6	5%	339
	Wind	1,132.1	21%	0	1,927.5	30%	0	1,719.3	22%	0	1,464.1	18%	0	2,339.6	26%	0	3,002.4	33%	0
TIER 2	BFG	171	3%	2,491	24.6	0%	2,659												
	Hydro	1,187.0	22%	0	1,401.9	21%	0	1,519.7	20%	0	1,531.3	19%	0	1,501.6	16%	0	1,449.7	16%	0
	MSW	161	3%	3,399	97.0	1%	3,354												
	TOTAL[1]	**5,480.5**			**6,531.4**			**7,785.8**			**7,966.0**			**9,129.8**			**9,018.1**		
	Weighted Avg. (Tier 1)			**547**			**447**			**608**			**548**			**611**			
	Weighted Avg. (Tiers 1 & 2)			**572**			**402**			**489**			**443**			**510**			

Notes: Retired REC totals derived from Maryland PSC *Renewable Energy Portfolio Standard Reports*. Fuel source categories and the division between Tier 1 and Tier 2 are copied from this source. Note that the resources listed separately for Tier 1 and Tier 2 (e.g., Tier 1 hydro and Tier 2 hydro) are distinct as defined in the Maryland RPS. Also note that resource eligibility for each Tier changes over time (e.g., MSW shifts from Tier 2 to Tier 1). Changes in RPS composition over time are discussed further in Section 1.3, "History of the Maryland RPS." Carbon content set equal to PJM-wide carbon content by resource for each respective year, as derived from PJM-GATS. In some cases, the listed lbs/MWh of CO_2 may vary from the actual carbon content of resources supported by the Maryland RPS.

[1] The total RECs may not equal Maryland's compliance requirement due to: (1) payment of ACPs; (2) RECs not clearly accounted for in PJM-GATS and therefore excluded from this analysis; or (3) rounding or related estimation error.

The carbon content of Maryland RPS-eligible resources is generally very low, between 72-611 lbs/MWh of CO_2 for just Tier 1 resources, and between 145-572 lbs/MWh of CO_2 for all RPS-eligible resources on an annualized, weighted basis, as identified above in Table 2-10. Three particular resources with CO_2 emissions—LFG, black liquor, and MSW—comprise between 29-54% of the resources used for complying with the Maryland RPS, and between 35-73% of the resources used for Tier 1 compliance. Changes in the share of RECs from these resources can cause considerable variability in the weighted average carbon content of RPS generation, as shown above in Figure 2-39 and tracked year-to-year in Table 2-9 [*Column 16*]. Over time, however, the share of RPS-eligible resources with a non-zero carbon content is declining, as wind and solar take on a more prominent role in Maryland RPS compliance. Figure 2-40 tracks the share of zero-carbon, RPS-eligible resources over time for both overall RPS REC retirements and Tier 1 retirements. The percentage of Tier 1 and Tier 2 zero-carbon resources is higher than Tier 1 alone due to the presence of large hydro as a Tier 2 resource.

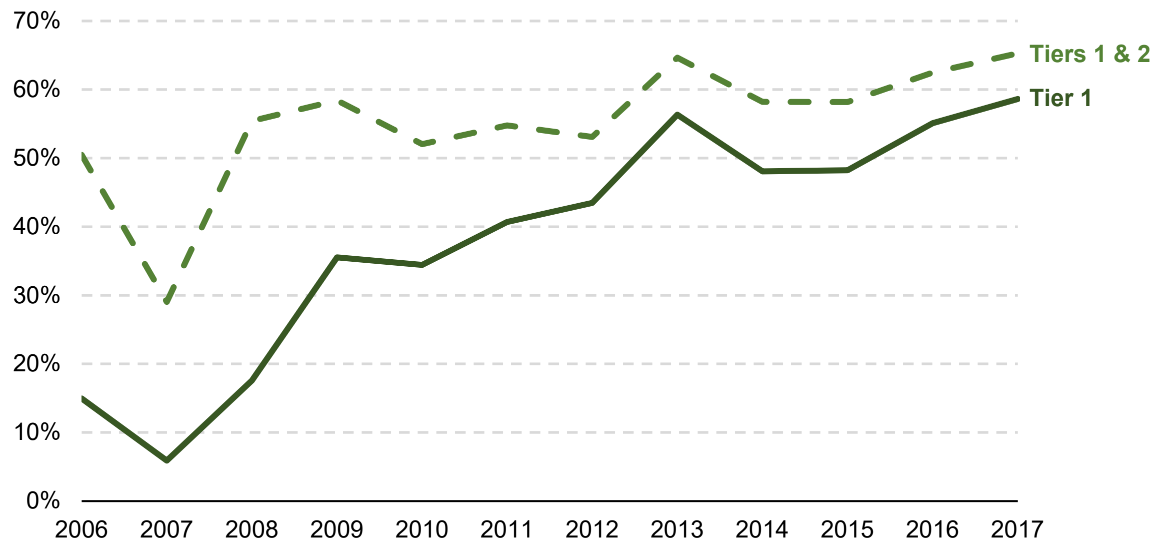

Figure 2-40. Share of REC Retirements from Zero-Carbon Renewable Energy Resources, by Maryland RPS Category

Source: Table 2-10.

Out-of-state resources supported by the Maryland RPS contribute to reductions in the carbon content of the PJM system mix and therefore the power that Maryland imports. However, whereas Maryland's in-state generation accounts for about 4.5% of total PJM generation for the last five years [*Table 2-9, Column 7*], the renewable energy generation supported by Maryland RECs is only 1.1% of total PJM generation as of 2017 and lower in preceding years [*Table 2-9, Column 14*]. If it is assumed that all resources receiving Maryland RECs are contributing to the PJM generation mix in part because of the Maryland RPS, the net effect of the Maryland RPS is a reduction in PJM-wide carbon levels per MWh. Table 2-11 represents the outcome of removing all generation supported by Maryland RECs from the PJM mix as a separate scenario [*Table 2-11, Column 17*]. Under these conditions, PJM-wide weighted average carbon levels per MWh increase (assuming no Maryland RPS) to 956 lbs/MWh of CO_2 from 948 lbs/MWh of CO_2 in 2017, or a 0.8% increase. This is roughly proportional with the Maryland RPS policy's share of all PJM generation, which equals approximately 1.1%. In other words, the latest year (i.e., 2017) of PJM carbon levels was approximately 0.8% lower because of the Maryland RPS, assuming all retired RECs supported resources that would not have operated otherwise. Before 2017, the typical impact on PJM carbon levels was less than 0.6% per year, coinciding with lower Maryland RPS requirements.

Table 2-11. Impact of Removing Maryland RPS Resources on PJM Emissions Profile

	Scenario: Average PJM CO_2 Emitted, Excluding MD RPS Resources (lbs/MWh)[1]		
Column:[2]	**17**	**18**	**19**
Formula:[3]	**(E–H*((C*G)/D))/ (1-(C*G)/D)**	**YOY Δ**	**Difference from PJM**[4]
2004	1,196	-	0.0%
2005	1,292	8.0%	0.0
2006	1,255	-2.9	0.2
2007	1,245	-0.8	0.2
2008	1,224	-1.7	0.3
2009	1,141	-6.8	0.4
2010	1,172	2.7	0.3
2011	1,151	-1.8	0.5
2012	1,096	-4.8	0.3
2013	1,118	2.0	0.5
2014	1,114	-0.3	0.6
2015	1,020	-8.5	0.6
2016	998	-2.2	0.6
2017	956	-4.2	0.8

[1] This scenario depicts the effect of removing the PJM generation used to meet Maryland RPS requirements, represented as the approximate RPS obligation [*Table 2-9, Column 13*] from the pool of PJM generation [*Table 2-9, Column 6*].

[2] Columns 17-19 are continued from *Table 2-9*.

[3] Formula references the labeled columns (i.e., A through H) in *Table 2-9.*

[4] These percentages represent the difference between the average scenario carbon content [*Column 17*] and the PJM average carbon content [*Table 2-9, Column 8*]. Positive percentages suggest increases in the PJM average carbon content.

2.2.6. SO_2 and NOx Emission Changes as a Result of the Maryland RPS

The analysis adopted above to assess the effectiveness of the Maryland RPS in reducing the carbon content of PJM-wide generation, including imported electricity, can also be applied to SO_2 and NOx using the same data sources as the previous subsection. The impact of the Maryland RPS on SO_2 and NOx levels, however, is less consistently positive. As discussed above, several renewable energy resources eligible for the Maryland RPS emit non-trivial amounts of SO_2 and NOx. (As shown earlier, these resources have represented between 35-75% of the resources used for Tier 1 compliance, depending on the year.) Additionally, SO_2 and NOx emission rates throughout PJM continue to decline as coal plants retire and generators install additional scrubbing equipment to meet environmental requirements. Figure 2-41 and Figure 2-42 compare Maryland RPS generation with Maryland net generation and PJM net generation from 2004-2017 for SO_2 and NOx, respectively.

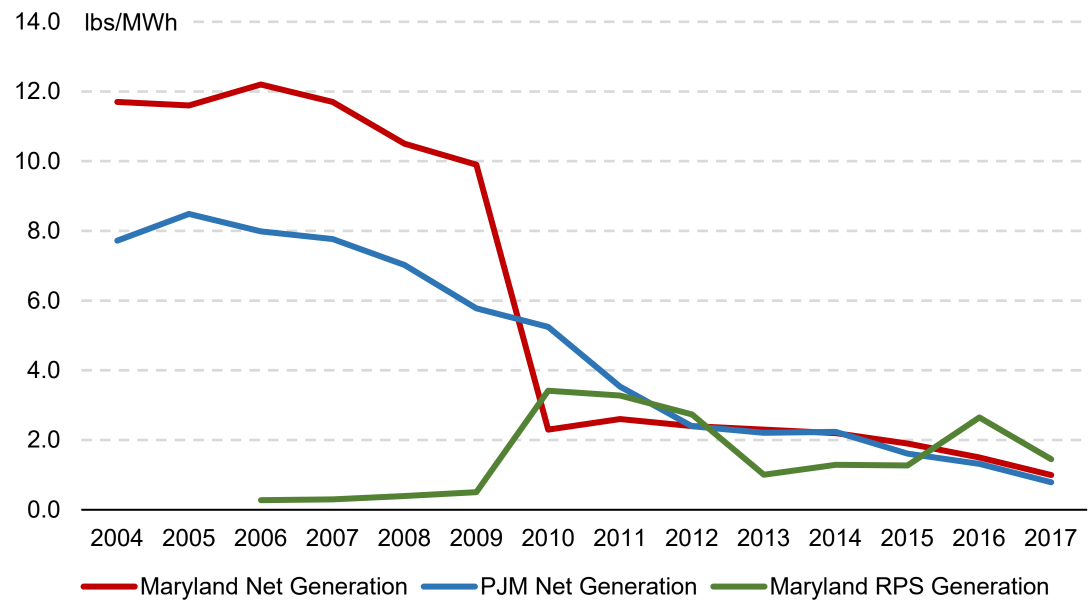

Figure 2-41. Weighted Average of SO_2 Emissions in Maryland and PJM, by Electric Generation Category

Sources: PJM-GATS; EIA, "Maryland Electricity Profile 2017."

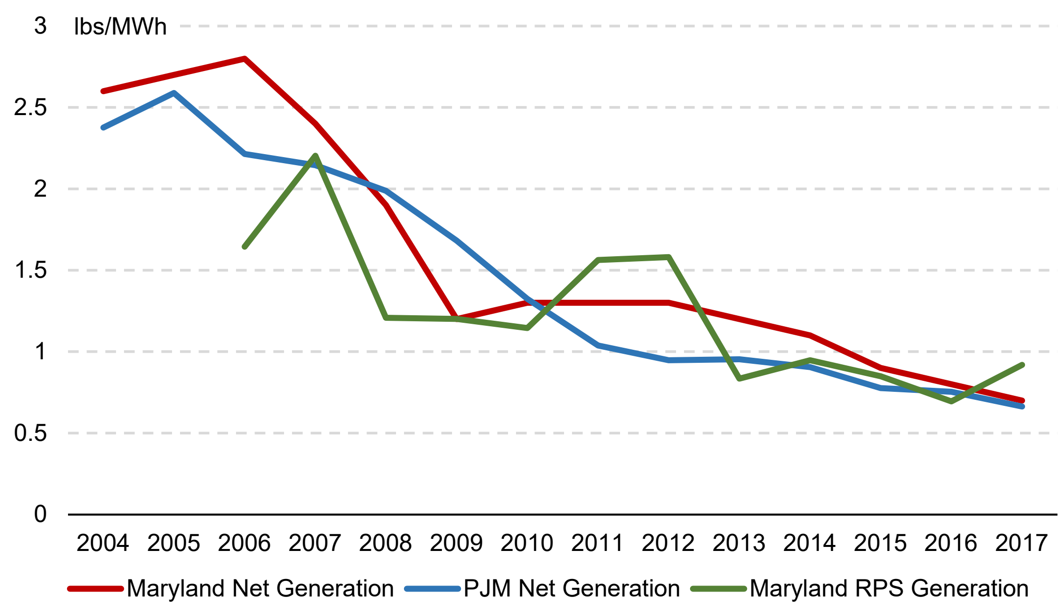

Figure 2-42. Weighted Average of NOx Emissions in Maryland and PJM, by Electric Generation Category

Sources: PJM-GATS; EIA, "Maryland Electricity Profile 2017."

Table 2-12, following the same methodology used for the scenario in Table 2-11 above, represents the outcome of removing all generation supported by Maryland RECs from the PJM mix in terms of CO_2, SO_2, and NOx levels. Under these conditions, PJM-wide weighted average SO_2 and NOx levels per MWh actually decrease in 2017, by 1% and 0.4%, respectively, when excluding Maryland RPS generation. In other words, PJM-wide SO_2 and NOx emissions are higher in 2017 as a result of the Maryland RPS. In most preceding years, the impact is more positive, although at a low level. The effect of the Maryland RPS ranges between a 1.2% decrease and a 0.5% increase in SO_2 and NOx emissions. The percent impact of the Maryland RPS on SO_2 and NOx emissions is generally smaller than its impact on carbon content.

Table 2-12. PJM Emissions After Removing Maryland RPS Resources

Year	CO_2 (lbs/MWh)	% Change	SO_2 (lbs/MWh)	% Change	NOx (lbs/MWh)	% Change
2006	1,255	0.2%	8.0	0.3%	2.2	0.1%
2007	1,244	0.2	7.8	0.3	2.1	0.0
2008	1,224	0.3	7.0	0.4	2.0	0.2
2009	1,141	0.4	5.8	0.4	1.7	0.1
2010	1,171	0.3	5.3	0.2	1.3	0.1
2011	1,151	0.5	3.5	0.0	1.0	-0.3
2012	1,095	0.3	2.4	-0.1	0.9	-0.5
2013	1,118	0.5	2.2	0.5	1.0	0.1
2014	1,114	0.6	2.2	0.4	0.9	0.0
2015	1,020	0.6	1.6	0.2	0.8	-0.1
2016	998	0.6	1.3	-1.2	0.8	0.1
2017	956	0.8	0.8	-1.0	0.7	-0.4

Notes: These scenarios depict the effect of removing the PJM generation used to meet Maryland RPS requirements from the pool of PJM generation. The percentages represent the difference between the revised PJM average emissions and the actual average emissions listed in *Table 2-7*. Positive percentages suggest increases in the PJM average emissions (i.e., Maryland RPS resources have a favorable effect on overall emissions).

2.2.7. Water Use Impacts of RPS Requirements

Although water consumption is difficult to value, it is generally preferential to reduce water usage in the power sector because it preserves water for other valuable uses, such as residential or agricultural applications. Water used in power systems can also be harmful to the environment to the extent that discharged water includes pollutants. NREL's evaluation of the nationwide impacts of renewable energy added as a result of RPS policies found net water usage reductions of approximately 8,420 gallons of withdrawal per megawatt-hour of renewable energy (MWh-RE) and 270 gallons of consumption per MWh-RE.[76] These gains primarily stem from the retirement of older generators that use once-through cooling systems, many of which are located in the PJM region. The downstream benefit of these reductions is greatest in drought-stricken regions insofar as it frees water for other uses and reduces related vulnerability. Reduced water use can also benefit fish, wildlife, and other aquatic ecosystems.

[76] Ryan Wiser, Galen Barbose and Jenny Heeter, *et al.*, *A Retrospective Analysis of the Benefits and Impacts of U.S. Renewable Portfolio Standards*, Lawrence Berkeley National Laboratory and National Renewable Energy Laboratory, 2016, nrel.gov/docs/fy16osti/65005.pdf.

2.3. Economic Development

The notion that energy policy could act as a driver of economic development has existed for decades, but it came into its own as a discipline in the 2000s.[77] The basic premise of green economic development is that policymakers, utilities, businesses, governments, and other stakeholders could undertake activities that transform the provision and use of energy while at the same time creating jobs and economic wealth. RPS policies are one potential way to spur this sort of development. This section of the final report explores the economic impacts of the Maryland RPS along one major dimension: the creation or sustainment of jobs. The first subsection reviews existing LBNL and NREL studies examining the relationship between RPS policies and economic outcomes, principally job creation. The following subsection reviews existing estimates of "green" or "clean" jobs in Maryland. The next subsection describes the relationship between the Maryland RPS and energy sector job growth in the state to date. Finally, the section concludes with a review of recent trends in energy employment in other states in PJM and how these trends relate to state RPS policies. Findings from this section include:

- Existing estimates of clean energy or green jobs in Maryland vary in accordance to the stringency of job classification and what fuels are included. Recent estimates suggest that Maryland has a low concentration of energy jobs relative to other states.
- Energy efficiency is the largest contributor to overall Maryland energy employment. The fastest growing portions of Maryland's energy economy in terms of employment are the fuels sector, including mining, extraction, and other fuel management jobs, and the transmission, distribution, and storage sector.
- Most electric power generation jobs are in construction. Solar is the largest electric power generation employer.
- To the extent that it is assumed that all non-hydro renewable energy generation jobs in Maryland are as a result of the RPS, the total number of existing jobs is relatively small. DOE, Energy Futures Initiative (EFI), and National Association of State Energy Officials (NASEO) estimate that there were between approximately 7,800 and 8,100 total solar, wind, large hydro, and other non-fossil fuel renewable energy jobs in Maryland during 2016-2018. This is between 6.1-6.5% of all energy sector jobs in the state, and between 0.2-0.4% of total nonfarm employment statewide.
- The relationship between the Maryland RPS and job changes in the electric generation sector is mixed. Wind and other non-solar and non-hydro renewable energy generation jobs appear to increase as the Tier 1 non-carve-out RPS requirement increases. Solar jobs appear to have become decoupled from the solar carve-out in 2016, potentially because of a glut of supply relative to the Tier 1 solar carve-out RPS percentage requirement.
- All states in PJM with an RPS policy saw gains in non-solar renewable energy generation employment from 2016-2018. States in PJM with a higher share of solar jobs, including Maryland, saw the largest drops in solar employment during this period.
- All states that increased their RPS from 2016-2018 saw increases in renewable energy generation employment, except for Maryland. Maryland increased its solar

[77] Sanya Carley, Sara Lawrence and Adrienne Brown, *et al.*, "Energy-Based Economic Development," *Renewable and Sustainable Energy Reviews*, Vol. 15, 2011.

carve-out the most from 2016-2018, but it also experienced the largest solar job losses of the states in PJM with an RPS.

- Among the select PJM states reviewed, Maryland is the third-highest in terms of solar jobs and renewable energy generation employment as a share of total energy employment. States with higher RPS requirements or carve-outs tend to have a greater share of renewable energy jobs as a proportion of all energy sector jobs in the state.

2.3.1. NREL and LBNL Research

As part of a national-level assessment of RPS policies, LBNL and NREL examined the impact of RPS policies on employment. Wiser, *et al.* (2016), using NREL's Jobs and Economic Development Impacts (JEDI) suite of models, found that new renewable energy sources used for RPS compliance in 2013 supported 199,600 gross U.S.-based jobs, with average annual earnings per full-time employee of $60,000. Their estimates assume that renewable energy growth is attributable to RPS policies up to the specified RPS policy requirement. As much as 85% of these jobs are related to construction, with the remaining dedicated to ongoing O&M of new renewable energy facilities. Solar PV is the source of most construction jobs, while wind makes up the majority of O&M jobs. According to the study authors, it is unclear whether this job creation, as well as corresponding multiplier effects throughout the local economy, surpass any job losses that occur as a result of displaced power plants or due to rate increases. (See the call-out box at right and Appendix C for a discussion of academic literature on the broader economic impacts of RPS policies.) It is also unclear to what degree job gains occur at a regional versus state level. In the Barbose, *et al.* (2015) survey of state RPS assessments also identified economic benefits, finding that the estimated benefit found in the assessed state studies generally ranged from $5-$27/MWh-RE added as a result of the RPS. These studies, however, were prospective estimates of RPS impacts and may not reflect the true benefit or cost of RPS policies for the local economy.

Economic Development Literature

Exeter reviewed the academic literature for research related to the economic impacts of RPS policies. Appendix C summarizes relevant articles and their findings. Key takeaways from this literature include:

- Existing studies of the economic impact of RPS policies are limited by: variation in how they account for labor intensity, job losses, job quality, job skills, and cost increases as a result of the RPS; failure to address emerging efficiencies and changes in cost; and an emphasis on gross, rather than net, impacts.
- RPS policies can help sustain and grow the number of green businesses in a state, as distinct from the ambiguous effect of RPS policies on net jobs.
- According to several studies, job losses as a result of increased power prices in Maryland are estimated to be a 0.044% decrease in statewide employment for each 1% increase in electricity prices, on average.

2.3.2. Estimates of Clean Energy Employment in Maryland

The range of existing clean energy job estimates for Maryland serves as a useful boundary when assessing change in the clean energy economy over time. Table 2-13 summarizes these estimates and provides brief characterization of what each estimate represents. The estimates vary in accordance to the job classification criteria and in relationship to what fuels are included (e.g., whether nuclear jobs count as clean employment). Most of these estimates were developed using large-scale surveys and/or public data, often from the BLS. BLS also conducted its own state-level study of employment related to green goods and services (GGS) in 2010, and again in 2011. Based on BLS' assessment, GGS employment comprised as much as 3.2% of total employment in Maryland in 2010 and 3.7% in 2011. Table 2-14 provides a breakdown of private sector GGS jobs in Maryland for 2011 using BLS data. GGS employment was an especially prominent contributor to Maryland construction jobs, where it comprised approximately 13.4% of the sector's total employment. BLS' GGS assessment was discontinued after 2011.

Table 2-13. Estimates of Renewable Energy, Energy Efficiency, and Nuclear Energy Jobs in Maryland (2006-2018)

Study	Year	Jobs	Scope	Method	Additional Notes
Mayors Climate Protection Center, U.S. Conference of Mayors (Global Insight, 2008)[1]	2006	44,799	Green jobs in Maryland metro areas	Assessment of BLS data	Inclusive of power sector (nuclear and renewable energy), biofuel, energy efficiency, and pollution control employment, as well as related upstream (e.g., manufacturing, wholesalers, construction, installation, etc.) and downstream (e.g., public administration, engineering, legal, consulting, etc.) jobs.
Pew Charitable Trust (2009)[2]	1998	13,225	Maryland clean energy jobs either actively engaged in the clean energy economy or supplying products and services to it	Assessment of National Establishment Time Series (Dun & Bradstreet), BLS, and industry data. Businesses screened for clean energy focus.	Inclusive of jobs that help: expand clean energy production or energy efficiency (including nuclear); reduce GHG emissions, waste and pollution; and/or conserve natural resources.
	2007	12,908			
Brookings Institute (Muro, *et al.*, 2011)[3]	2003	34,837	Maryland clean energy jobs either actively engaged in the clean energy economy or supplying products and services to it	Assessment of National Establishment Time Series (Dun & Bradstreet) and BLS data.	Job categories include: agricultural and natural resource conservation; education and compliance; energy and resource efficiency; GHG reduction, environmental management, and recycling; and renewable energy (excluding nuclear).
	2010	43,207			
U.S. Bureau of Labor Statistics (2010, 2011)[4]	2010	77,346 (50,880 private sector)	Green goods and services employment in Maryland	Survey of 120,000 business establishments	Jobs in "businesses that produce goods and provide services that benefit the environment or conserve natural resources" (BLS, 2013), including businesses involved in: renewable energy generation (excluding nuclear), energy efficiency, pollution or GHG reduction, recycling, natural resources conservation, and environmental compliance or education.
	2011	91,489 (63,638 private sector)			
Maryland Department of Labor, Licensing and Regulation (2017)[5]	2011	47,654	Energy production sub-cluster of clean energy industry jobs in Maryland	BLS Quarterly Census of Employment and Wages	Inclusive of jobs related to: nuclear, hydro, solar, wind, or geothermal generation; the electric bulk power system; roofing; heating equipment; electrical equipment; lighting fixtures manufacturing; aircraft engine manufacturing; electronic parts; and utility regulation and administration, among other industries.
	2012	48,054			
	2013	47,425			
	2014	49,204			
	2015	54,233			
	2016	54,215			

Table 2-13 (cont.)

Study	Year	Jobs	Scope	Method	Additional Notes
U.S. Department of Energy (2017)[6]	2016	80,629 (67,061 energy efficiency)	Energy employment in Maryland, reduced just to include clean and advanced energy jobs	BLS Quarterly Census of Employment and Wages, Multiple Worksite Report, and Annual Refiling Survey.	Total energy sector employment reduced to just include: electric power generation jobs working with solar, wind, large hydro, nuclear, or other generation; fuel jobs working with corn ethanol, other ethanol / biomass, wood waste, or other fuels; jobs in storage, smart grid, and microgrid and other; and energy efficiency.
Energy Futures Initiative, National Association of State Energy Officials (2018, 2019)[7]	2017	83,534 (68,981 energy efficiency)			
	2018	85,031 (70,530 energy efficiency)			
The Solar Foundation (2013, 2014, 2015, 2016, 2017, 2018)[8]	2012	1,900	Solar workers in Maryland	Phone and email survey	Defined as employees spending at least half of their time on solar-related work. Inclusive of installation, manufacturing, sales and distribution, project development, and other related jobs.
	2013	2,342			
	2014	3,012			
	2015	4,269			
	2016	5,429			
	2017	5,324			
	2018	4,515			

[1] Global Insight, *U.S. Metro Economies: Current and Potential Green Jobs in the U.S. Economy*, U.S. Conference of Mayors and the Mayors Climate Protection Center, 2008.

[2] The Pew Charitable Trusts, *The Clean Energy Economy: Repowering Jobs, Businesses and Investments Across America*, 2009.

[3] Mark Muro, Jonathan Rothwell and Devashree Saha, "Sizing the Clean Economy: A National and Regional Green Jobs Assessment," Brookings Institution, 2011.

[4] U.S. Bureau of Labor Statistics News Release: "Employment in Green Goods and Services – 2011."

[5] Maryland Department of Labor, Licensing and Regulation, *Report on the Study of Workforce Development Training Needs for the Clean Energy Industry*, 2017.

[6] DOE, "2017 U.S. Energy and Employment Report State Charts."

[7] EFI/NASEO, *U.S. Energy and Employment Report*, 2018 and 2019.

[8] The Solar Foundation, *National Solar Jobs Census*, Maryland Fact Sheets for 2016, 2017, and 2018.

Table 2-14. Number of Green Goods and Services (GGS) Private Sector Jobs in Maryland, 2011 Annual Averages

	Constr-uction	Manu-fact-uring	Trade	Trans-portation & Ware-housing	Profes-sional/ Scientific/ Technical Services	Admin-istrative & Waste services	Other Services Except Public Admin-istration	TOTAL
GGS Private Sector Employment	19,243	7,081	4,243	5,672	15,573	7,718	989	**63,638**
Share of Total State Employment in Each Sector	13.4%	6.3%	1.2%	9.0%	6.8%	5.3%	1.1%	**3.2%**

Source: U.S. Bureau of Labor Statistics News Release: "Employment in Green Goods and Services – 2011," Tables 5 and 6.

Note: Percentages are calculated by category. The sum of sector-specific employment figures (e.g., construction, manufacturing, trade, etc.) does not match the "Total" due to additional, non-represented sectors that are not listed.

The Maryland Department of Labor, using BLS data, produced a study of the Clean Energy Industry workforce of Maryland in 2017.[78] This assessment identified a "strong trend of growth in the Clean Energy Cluster," inclusive of jobs defined as supporting the creation of Tier 1 renewable energy sources.[79] The study found that average weekly wages for jobs in this cluster were, on average, 1.4 times higher than jobs in the private sector as a whole.[80] The study also identified a 64% increase in "green job" postings from 2011-2016, which is more broadly defined and inclusive of jobs related to agriculture, science, transportation, engineering, construction, industry, wildlife, and more.[81]

More recently, the DOE developed the *U.S. Energy and Employment Report* (2017).[82] The report found that Maryland has a low concentration of energy jobs as compared to the rest of the nation. Only 1.1% of employment in Maryland is in traditional energy jobs (including power generation; fuels; or transmission, distribution, and storage) compared to the national average of 2.4%. Energy efficiency is the largest contributor to energy employment in Maryland, representing over 67,000 workers in 2016, and it makes up 3.1% of all energy efficiency jobs nationwide.[83] Within the Maryland electric power sector, including generation, transmission, and distribution, most jobs are in construction (39.7%). Over 70% of electric power jobs in Maryland serve renewable energy or non-carbon generation types. Solar generation is by far the largest driver of electric power sector employment, making up over half of jobs. These results match BLS' findings and The Solar Foundation's *National Solar Jobs Census*, which found that installation and construction are the largest source of GGS and solar jobs, respectively.

In 2018 and 2019, EFI/NASEO released assessments of energy employment by state that followed the same methodology as DOE's study.[84] The results correspond with DOE's initial study, including the finding that energy jobs are a lower share of total Maryland jobs as compared to other states. EFI/NASEO also found low overall growth in electric power sector jobs and a decline in the number of solar jobs between 2016-2018. This finding coincides with declining solar installations in Maryland as well as the continued shift away from instate power generation toward increased imports. The Solar Foundation also shows a decline in Maryland solar employment over the last three years (2016-2018).[85] Although solar project development jobs have increased, installation, manufacturing, and sales/distribution jobs all fell between 2016-2018.

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[78] Maryland Department of Labor, *Report on the Study of Workforce Development Training Needs for the Clean Energy Industry*, 2017, dlslibrary.state.md.us/publications/Exec/DLLR/SB921HB1106(2016)Ch1(2)_2017.pdf.

[79] Ibid. See *Table 2-13* of the final report for further description.

[80] Ibid.

[81] Ibid.

[82] U.S. Department of Energy, "2017 U.S. Energy and Employment Report State Charts," 2017, energy.gov/sites/prod/files/2017/01/f34/2017%20US%20Energy%20and%20Jobs%20Report%20State%20Charts%202_0.pdf (states listed alphabetically).

[83] Energy Efficiency jobs include construction, manufacturing, trade, and professional services related to Energy Star and Efficient Lighting, Traditional HVAC, High Efficiency and Renewable Heating and Cooling, Advanced Materials and Insulation, and several other related fields.

[84] Energy Futures Initiative and National Association of State Energy Officials, *U.S. Energy and Employment Report: Energy Employment by State*.
2018: usenergyjobs.org/s/USEER2018_States.pdf;
2019: usenergyjobs.org/s/USEER-Energy-Employment-by-State.pdf.

[85] The Solar Foundation, *National Solar Jobs Census*, Maryland Fact Sheet.
2016: thesolarfoundation.org/solar-jobs-census/factsheet-2016-md/.
2017: thesolarfoundation.org/solar-jobs-census-factsheet-2017-md/.
2018: thesolarfoundation.org/solar-jobs-census/factsheet-2018-md/.

2.3.3. RPS Impacts on Jobs in Maryland

The DOE and EFI/NASEO estimates of total clean energy employment in Maryland, as defined above in Table 2-13, provide a useful gauge of the potential impact of the Maryland RPS on in-state jobs. Although Maryland has relatively few overall energy sector jobs as compared to other states, clean energy jobs make up a high proportion of the energy sector jobs that do exist in Maryland. This share is increasing in the last three years, as tracked in Figure 2-43. Energy efficiency is by far the biggest contributor, making up approximately 83% of clean energy jobs. Of the approximately 8,584 net new energy jobs added in Maryland in the last three years, energy efficiency jobs comprised approximately 40% of the increase. In terms of same-sector employment, however, the fastest-growing portions of Maryland's energy economy are the fuels sector and the transmission, distribution, and storage sector. Although there are relatively fewer jobs in these two sectors, they grew by 17% and 15%, respectively, between 2016-2018. In comparison, the electric power generation sector grew by only 2%. The estimated number of jobs by sector from 2016-2018 are included in Table 2-15.

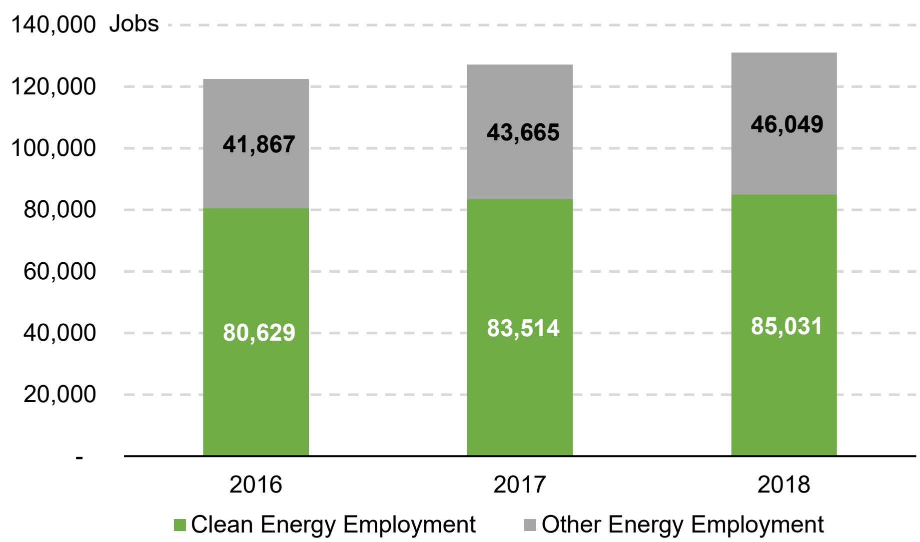

Figure 2-43. Number of Clean Energy Jobs in Maryland as a Share of Total Energy Employment

Sources: DOE, "2017 U.S. Energy and Employment Report State Charts;" EFI/NASEO, *U.S. Energy and Employment Report*, 2018 and 2019.

Note: Clean Energy Employment includes the following sectors: electric power generation; fuels; transmission, distribution, and storage; and energy efficiency.

Table 2-15. Number of Maryland Energy Jobs, by Sector

Sector	2016	2017	2018	Total Job Gains	% Change
Electric Power Generation	13,053	13,377	13,254	201	2%
Fuels	2,449	2,460	2,861	412	17
Trans., Distr., and Storage	13,426	14,752	15,455	2,029	15
Energy Efficiency	67,061	68,981	70,530	3,469	5
Motor Vehicles	26,507	27,609	28,980	2,473	9
TOTAL	**122,496**	**127,179**	**131,080**	**8,584**	**7%**

Sources: DOE, "2017 U.S. Energy and Employment Report State Charts;" EFI/NASEO, *U.S. Energy and Employment Report*, 2018 and 2019.

Table 2-16 tracks electric power generation job changes in Maryland in the last three years by resource type.[86] Electric power sector job growth from 2016-2018 was minimal. The results in the table should be viewed with some caution, especially with regard to the potential impact of the Maryland RPS. First, the time period for which the best data exist (2016-2018) is not necessarily representative of the total job impacts of the RPS. For example, the solar and wind industries in Maryland were virtually non-existent prior to 2004 when the Maryland RPS was enacted. Since that time, the Maryland RPS was an impetus to develop these industries. In the case of solar, which has an in-state carve-out requirement, almost all existing solar jobs are at least partially attributable to the Maryland RPS.

[86] Note that DOE's and EFI/NASEO's job estimates are based on survey techniques and are therefore subject to some degree of error. Subdividing the data magnifies this potential error and, as a result, small changes are likely to be at least partially due to random variation in the estimates rather than systemic change. Emphasis should be placed on trends in the data over time rather than the absolute numbers.

Table 2-16. Number of Maryland Electric Power Generation Jobs, by Fuel Source

Fuel Source	2016	2017	2018	% Change
Other Non-Fossil[1]	73	321	524	618%
Nuclear	1,234	1,234	1,197	-3
Oil & Other Fossil Fuels	51	55	62	22
Coal	2,415	2,301	2,131	-12
Natural Gas	1,369	1,762	1,890	38
Large Hydro[2]	3	52	98	3,167
Wind	630	771	890	41
Solar	7,279	6,881	6,463	-11
TOTAL	**13,054**	**13,377**	**13,255**	**2%**

Sources: DOE, "2017 U.S. Energy and Employment Report State Charts;" EFI/NASEO, *U.S. Energy and Employment Report*, 2018 and 2019.

Note: Estimates reflect the fuel source type that occupies the majority of time for each job except for solar, which also includes all part-time employment as well.

[1] Adjusted in 2016 to split out nuclear jobs based on the 2017 estimated employment level for nuclear.

[2] There is little evidence to indicate that large hydro employment has significantly changed in Maryland during the last three years. Thus, the increase in large hydro jobs is likely spurious or otherwise an artifact of measurement error.

Second, there are broader economic forces at work in Maryland and PJM power markets that also influence in-state power generation employment. The decline of coal and nuclear jobs, for instance, also stems in part from unrelated declines in natural gas costs that have made natural gas generation more competitive in PJM, displacing other large baseload power sources as a result. Most of this change is unrelated to RPS policies. Third, changes in electric power generation jobs do not tell the whole story of how policies like an RPS may impact employment in the state. There are also employment benefits in other portions of Maryland's energy economy. For example, the rapid growth in distributed solar PV has spurred additional interconnection work. Job gains from this activity are reflected in the transmission, distribution, and storage sector estimates; traditional transmission and distribution jobs grew by 11.5% from 2016-2018, adding over 1,000 jobs. A portion may relate to RPS-induced renewable energy.

Despite the above qualifications, the electric power generation sector breakdown by fuel source provides some indication of how the Maryland RPS has influenced employment in the state. To the extent that it is assumed that all renewable energy generation jobs in the state are as a result of the RPS, the total number of existing jobs is relatively small; DOE and EFI/NASEO estimate between approximately 7,800-8,100 solar, wind, large hydro, and other non-fossil fuel jobs in Maryland's electric power generation sector.[87] This is between

[87] Non-fossil fuel jobs include other renewable energy jobs besides large hydro, wind, and solar, such as biomass, MSW, LFG, and small hydro.

0.2-0.4% of total nonfarm employment in Maryland between 2016-2018, according to BLS data.[88]

The allocation of electric power generation jobs by industry sector is consistent with expectations set by the prior literature and BLS 2010 and 2011 estimates. Figure 2-44 tracks job changes by job type. Most electric power generation jobs are in construction. The number of construction jobs has remained relatively flat between 2016-2018 despite increases in the Maryland RPS percentage requirement.

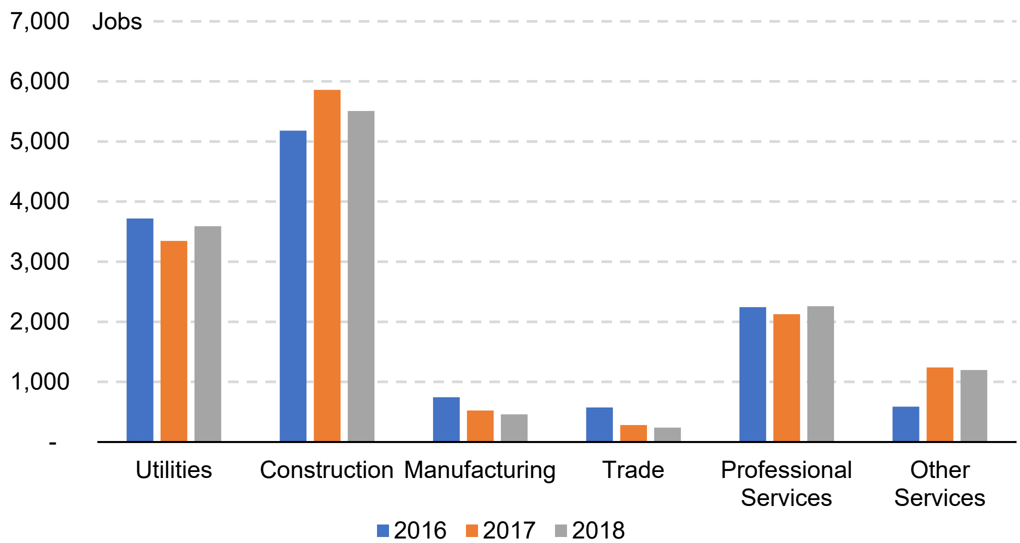

Figure 2-44. Number of Maryland Electric Power Generation Jobs, by Industry Sector

Sources: DOE, "2017 U.S. Energy and Employment Report State Charts;" EFI/NASEO, *U.S. Energy and Employment Report*, 2018 and 2019.

The relationship between the Maryland RPS and job changes by fuel source is unclear although, again, three years is a relatively short period of time in which to discern any relationship. Assuming this data collection effort continues, more definitive trends and relationships may emerge over time. Figure 2-45 shows the recent trend in wind and other non-fossil fuel jobs relative to the Tier 1 non-carve-out RPS percentage requirement. As the percentage has increased, so have jobs in these electric power generation sectors.

[88] Based on seasonally adjusted data. *Source:* U.S. Bureau of Labor Statistics, "Databases, Tables & Calculators by Subject – Employment," bls.gov/data/#employment.

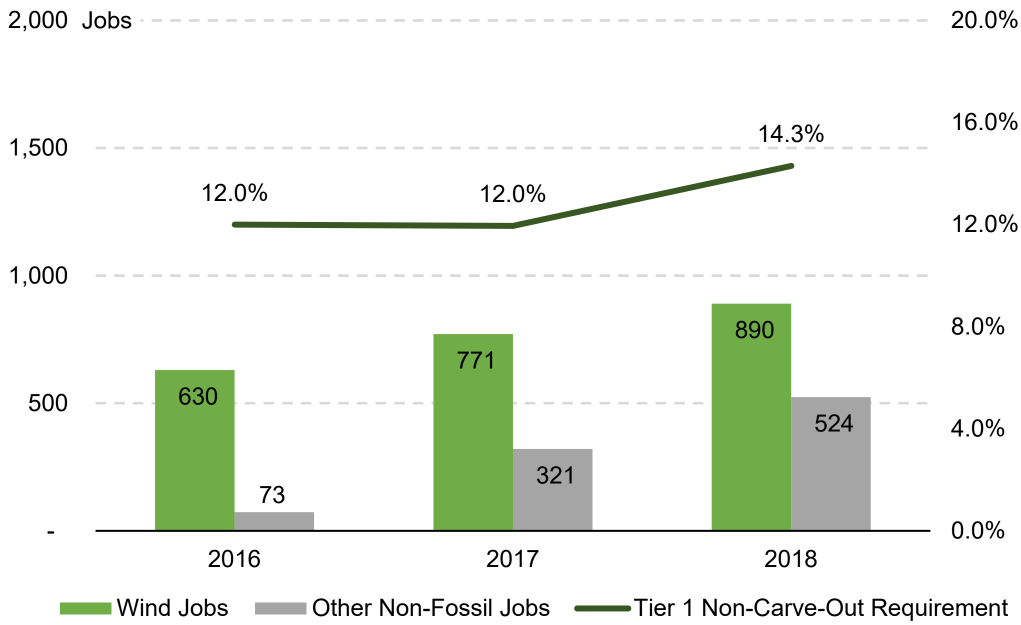

Figure 2-45. Number of Wind and Other Non-Fossil Fuel Jobs Relative to Maryland's Tier 1 Non-Carve-out RPS Requirement

Sources: DOE, "2017 U.S. Energy and Employment Report State Charts;" EFI/NASEO, *U.S. Energy and Employment Report*, 2018 and 2019.

In comparison, Figure 2-46 and Figure 2-47 show changes in solar sector employment relative to the Tier 1 solar carve-out using DOE and EFI/NASEO data, and The Solar Foundation data, respectively. The two sources show similar trends.[89] In general, the number of solar jobs in Maryland increased as the carve-out grew until peaking in 2016. Since that time, job growth appears to be decoupled from the Maryland RPS. That is, solar jobs have declined despite the solar carve-out both increasing and doing so at a faster rate.

One explanation for this change in relationship put forth by industry participants is that the initial RPS requirement levels, coupled with federal and other state incentives, created significant demand that the industry met and exceeded.[90] A resultant glut in solar has resulted in early compliance with the solar carve-out of the Maryland RPS and put downward pressure on SREC prices, making it less economic for continued development of new solar projects. As a result, the solar industry has cut construction jobs, reducing the total employment figures.[91] Of the different changes in employment over time seen in the previous figures, growth in solar jobs is likely to have the strongest relationship with the Maryland RPS due to the carve-out's in-state provisions.

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[89] Note that DOE and EFI/NASEO show solar jobs regardless of what portion of employment time is dedicated to solar work. A further breakdown provided in the latest EFI/NASEO report shows that, in 2018, the estimated 6,463 total solar jobs included approximately 4,515 jobs where more than 50% of the employee time was working on solar. This subdivided estimate is identical to the estimates provided by The Solar Foundation for total 2018 solar employment in Maryland.

[90] Maryland-District of Columbia-Delaware-Virginia Solar Energy Industries Association Press Release, "Maryland Lost 800 Solar Jobs in 2018. More Losses Coming in 2019 Without General Assembly Action. Pass the Clean Energy Jobs Act (SB 516)," ccanactionfund.org/media/MD-Solar-Jobs-Losses-Press-Release.pdf.

[91] Ibid.

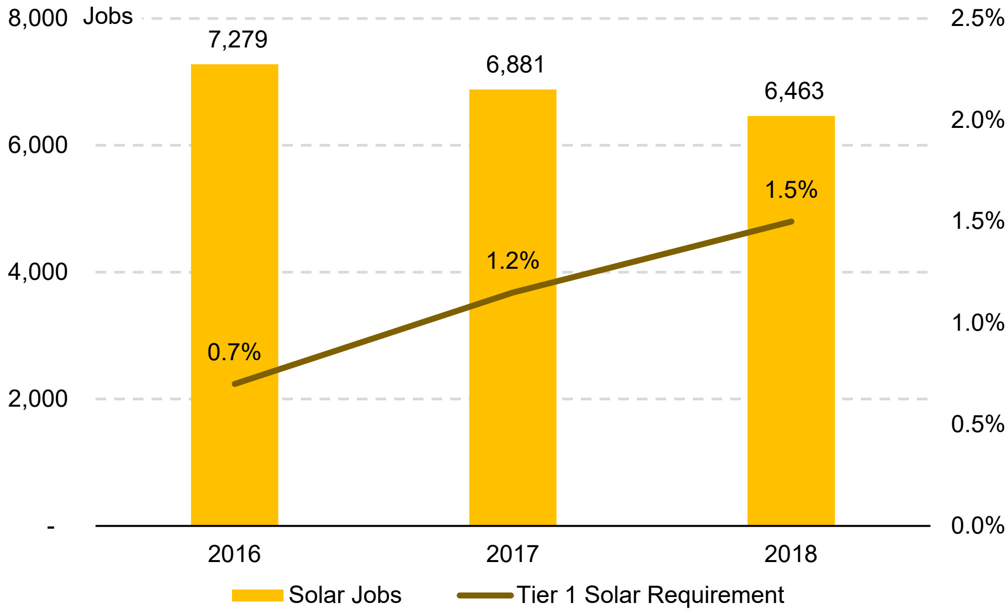

Figure 2-46. Number of Solar Jobs Relative to Maryland's Tier 1 Solar Carve-out Requirement (DOE & EFI/NASEO)

Sources: DOE, "2017 U.S. Energy and Employment Report State Charts;" EFI/NASEO, *U.S. Energy and Employment Report*, 2018 and 2019.

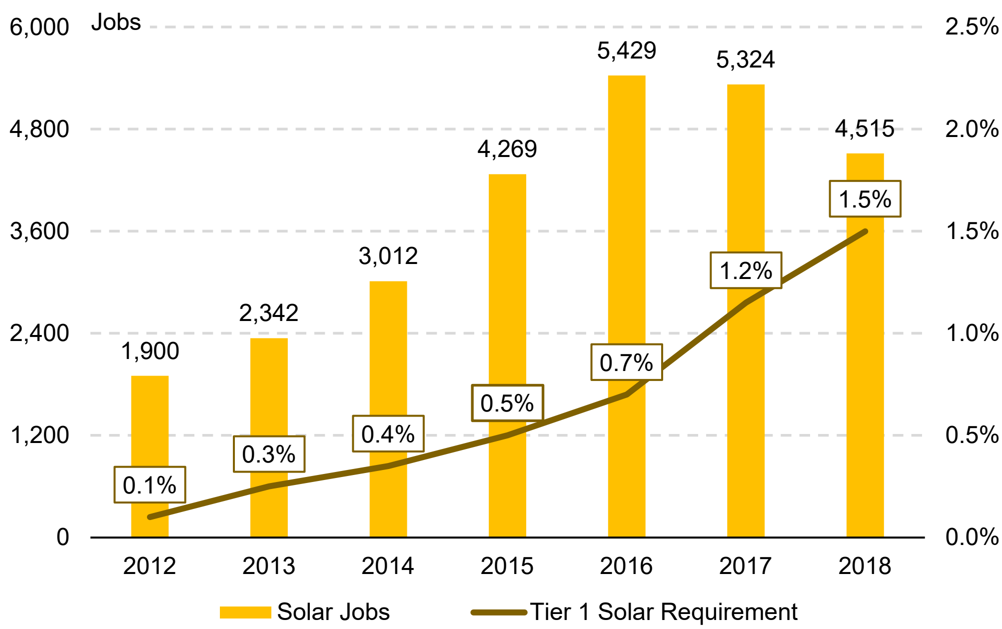

Figure 2-47. Number of Solar Jobs Relative to Maryland's Tier 1 Solar Carve-out Requirement (The Solar Foundation)

Source: The Solar Foundation, *National Solar Jobs Census*.

2.3.4. RPS Impacts on Jobs in Other States in PJM

The lack of long-term energy employment data for Maryland precludes drawing conclusions about the precise relationship between RPS policies and employment in the state. Assessing similar-level data in other states, however, can provide external validity for some of the initial observations presented above. It can also provide a point of comparison to evaluate the relative impact of RPS policies in Maryland versus other states in PJM. Figure 2-48 shows the percent change in employment by category within select PJM states from 2016-2018. Most states, including Maryland, saw moderate growth in overall energy sector employment, increasing jobs by up to 10% over 2016 levels. The chief exception was Ohio, in which the energy sector shrank as conventional generation resources retired. The percent change for the District of Columbia and Delaware may not reflect broad employment trends due to the small employment base from which the change is calculated.

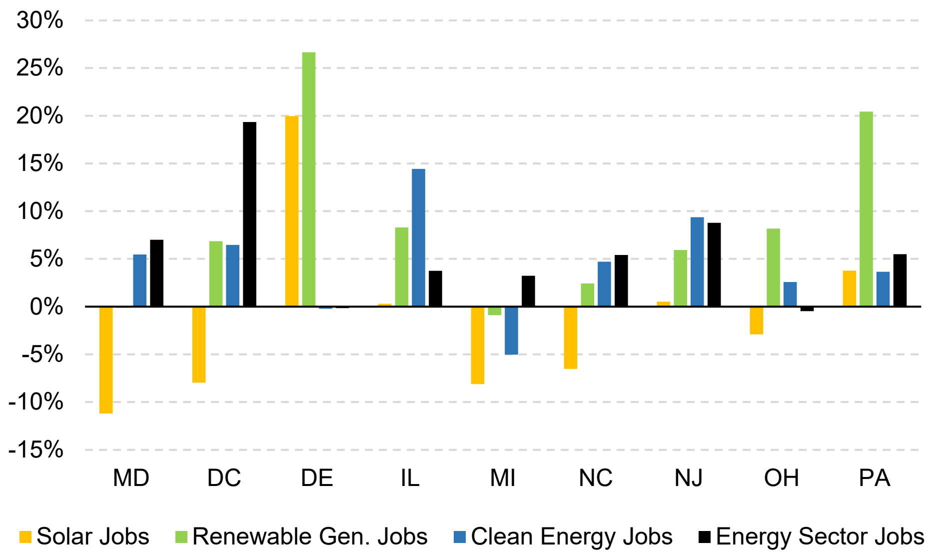

Figure 2-48. Change in Energy Sector Job Categories in Select States in PJM, from 2016 to 2018

Sources: DOE, "2017 U.S. Energy and Employment Report State Charts;" EFI/NASEO, *U.S. Energy and Employment Report*, 2018 and 2019.

Note: Several small changes (between -0.5% and 0.5%) are imperceptible in the figure. For example, Maryland Renewable Generation Jobs slightly declined (-0.1%) from 2016-2018. Each subsequent category is inclusive of the preceding categories; that is, Renewable Generation Jobs includes Solar Jobs; Clean Energy Jobs includes Renewable Generation Jobs and Solar Jobs; and Energy Sector Jobs includes Clean Energy Jobs, Renewable Generation Jobs, and Solar Jobs.

One driver of overall job growth in PJM states is the expansion of both renewable energy generation and clean energy jobs, the latter of which includes renewable fuels, storage, and energy efficiency jobs, among other related clean energy industries. Clean energy jobs grew in all reviewed states in PJM except Michigan and Delaware. Michigan, which has a relatively small clean energy sector as compared to other states in PJM, has also seen declines in renewable energy generation jobs. Maryland has experienced small declines in renewable energy generation jobs as well, placing it below all reviewed states in PJM other than Michigan. This decline in Maryland directly relates to the change in a subset of renewable energy generation jobs: solar employment. Maryland has experienced the largest percentage drop in solar jobs, followed by the District of Columbia, Michigan, and North

Carolina. Figure 2-49 tracks the nominal number of solar jobs gained or lost in select states in PJM from 2016 to 2018.

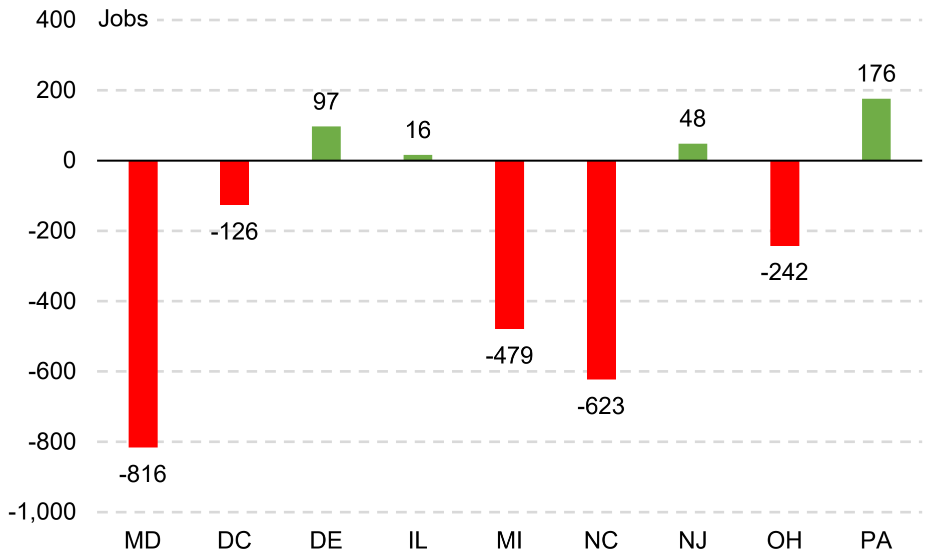

Figure 2-49. Change in the Number of Solar Jobs in Select States in PJM, from 2016 to 2018

Sources: DOE, "2017 U.S. Energy and Employment Report State Charts;" EFI/NASEO, *U.S. Energy and Employment Report*, 2018 and 2019.

Figure 2-50 shows the percentage distribution of renewable energy generation jobs by renewable energy technology for select states in PJM as of 2018. Except for Michigan and Delaware, states with a higher share of solar jobs also saw large drops in solar employment in the last several years. As noted earlier, some solar industry representatives attribute this change to market a glut in solar generation supply relative to demand.

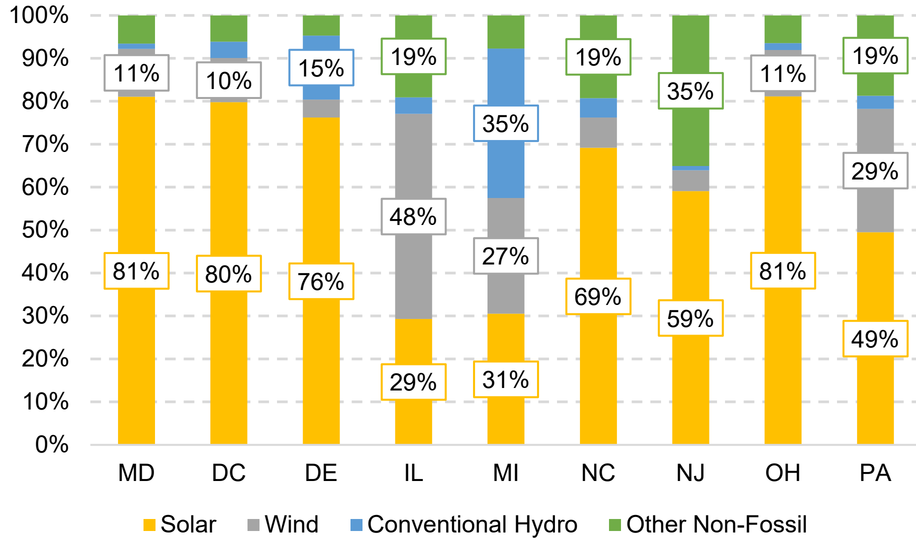

Figure 2-50. Allocation of Renewable Energy Generation Jobs in Select States in PJM, 2018

Sources: DOE, "2017 U.S. Energy and Employment Report State Charts;" EFI/NASEO, *U.S. Energy and Employment Report*, 2018 and 2019.

In comparison to Figure 2-50, Figure 2-51 shows the overall change in nominal non-solar renewable energy generation jobs in select states in PJM from 2016-2018. All of these states saw gains in non-solar renewable energy generation employment from 2016-2018. Several of the states with higher renewable energy generation job growth, including Pennsylvania, Illinois, and North Carolina, have a more diverse employment mix than Maryland in terms of renewable energy generation jobs by fuel source. As shown above in Figure 2-50, nearly half of Illinois renewable energy jobs and nearly a third of Pennsylvania and Michigan renewable energy jobs serve wind, while New Jersey and North Carolina have notable levels of employment serving other non-fossil fuel renewable energy generation technologies.

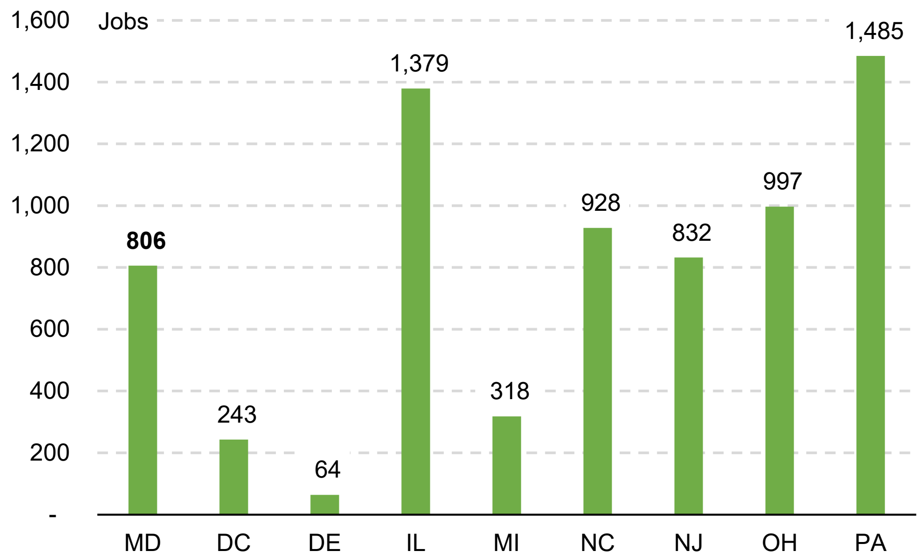

Figure 2-51. Change in Non-Solar Jobs in Select PJM States, 2016-2018

Sources: DOE, "2017 U.S. Energy and Employment Report State Charts;" EFI/NASEO, *U.S. Energy and Employment Report*, 2018 and 2019.

The relationship between RPS policies and change in energy sector employment is not entirely clear using the available survey data. Figure 2-52 tracks overall RPS percentage requirements in select states in PJM in 2016-2018, and Figure 2-53 tracks solar or DG carve-out percentage requirements by state during the same period. The only state with no change in its RPS, Michigan, saw the lowest renewable energy generation job growth. Relative to their geographic size, Ohio and North Carolina also have a low RPS and experienced lower renewable energy generation employment growth. All states that increased their RPS saw increases in renewable energy generation employment except for Maryland. The change in nominal RPS percentage during the review period does not appear to have strong bearing on change in employment. Rather, the percentage point change is moderated by the size of the state and its retail load. For example, Pennsylvania, the fifth-largest state in terms of population, only increased its RPS by 1% from 2016-2018 but gained over 1,500 renewable energy generation jobs. The District of Columbia meanwhile, increased its RPS by 3.4% and saw only minor growth in renewable energy generation employment, totaling just over 100 new jobs.

Of these states, Maryland increased its solar carve-out the most from 2016-2018 but also experienced the largest solar job losses. This is in part because solar development had outpaced the carve-out in Maryland. Some states with a very low solar carve-out in terms of nominal percentage, such as Illinois and Pennsylvania, saw solar job increases. As noted, this likely relates to the relatively large size of these states; even small percentage increases in carve-out requirements can create many jobs. New Jersey, the state with the largest solar carve-out, saw only a minor increase in solar jobs.

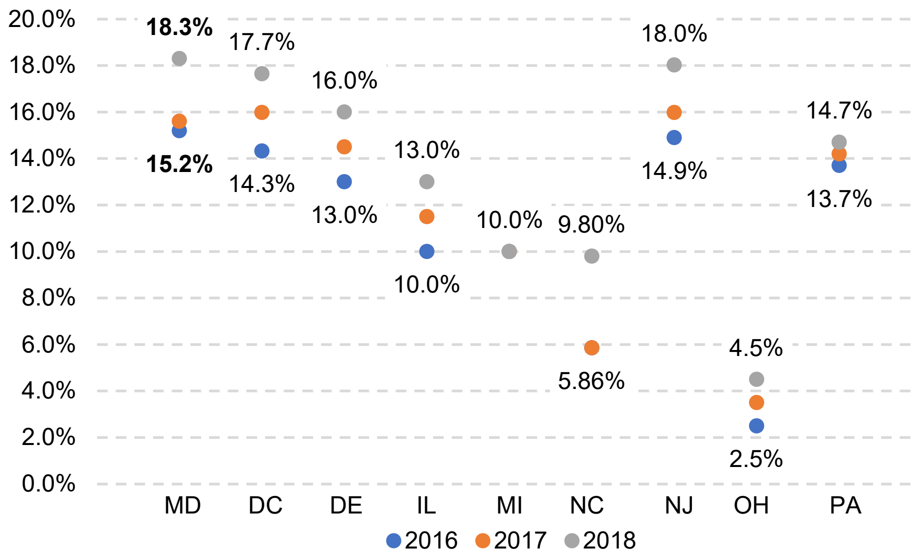

Figure 2-52. Overall RPS Requirements in Select States in PJM

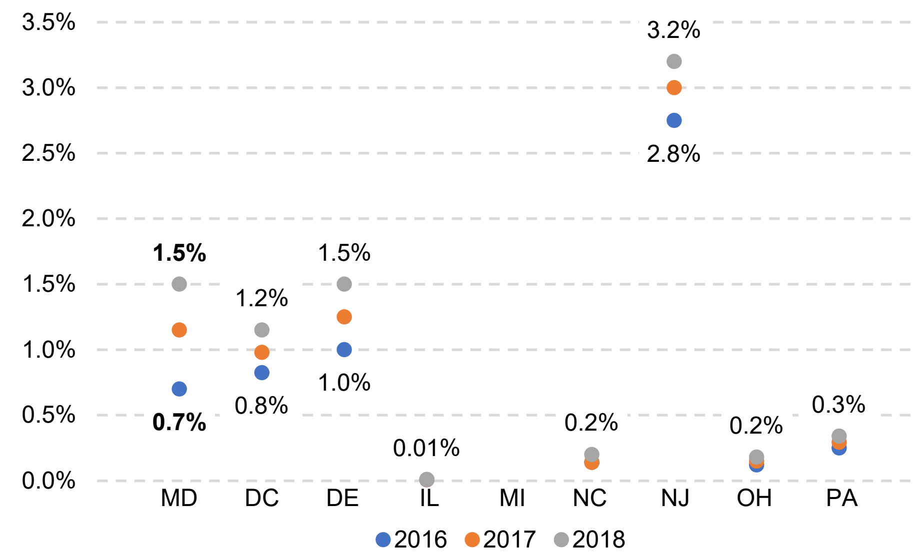

Figure 2-53. RPS Solar or Distributed Generation Carve-out Requirements in Select States in PJM

Figure 2-54 and Figure 2-55 show solar generation and renewable energy generation employment, respectively, as a percent of all energy sector jobs in select states in PJM. In all states except Delaware, solar generation employment decreased as a share of total state energy sector employment from 2016-2018. The largest relative drop was in the District of Columbia, where solar comprises the highest share of all jobs among the evaluated states.

Maryland is the third-highest state in terms of solar jobs as a share of all energy employment. Maryland is also third highest in terms of overall renewable energy generation employment as a share of total energy sector jobs. Renewable energy generation contributes over 6% of energy jobs in Maryland, behind only the District of Columbia and New Jersey. New Jersey has the largest renewable energy generation employment base, comprising over 10% of energy sector jobs. States with a historically greater share of conventional power sources, such as Pennsylvania, Ohio, and Michigan, tend to have lower percentages of renewable energy jobs as a share of their energy economy. States with higher RPS requirements, such as Maryland, New Jersey, and the District of Columbia, tend to have a greater share of renewable energy jobs.

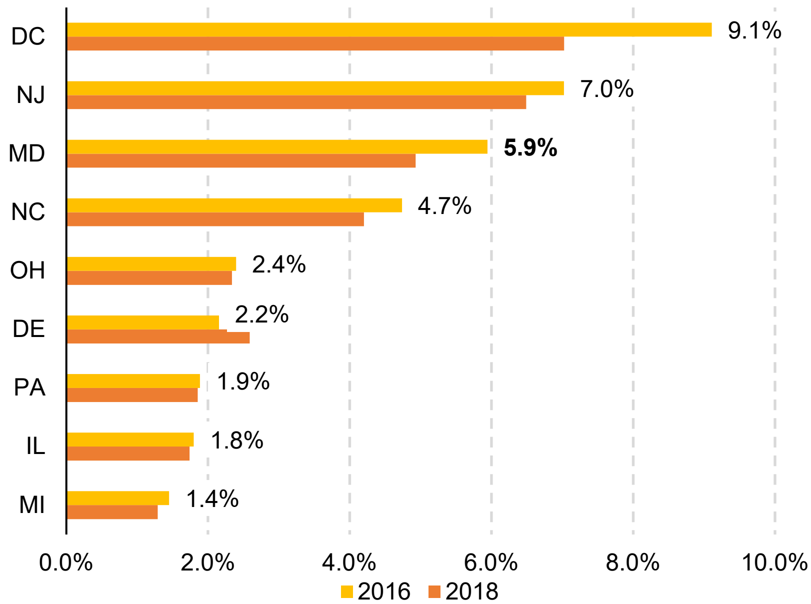

Figure 2-54. Solar Energy Generation's Share of Energy Sector Jobs in Select States in PJM

Sources: DOE, "2017 U.S. Energy and Employment Report State Charts;" EFI/NASEO, *U.S. Energy and Employment Report*, 2018 and 2019.

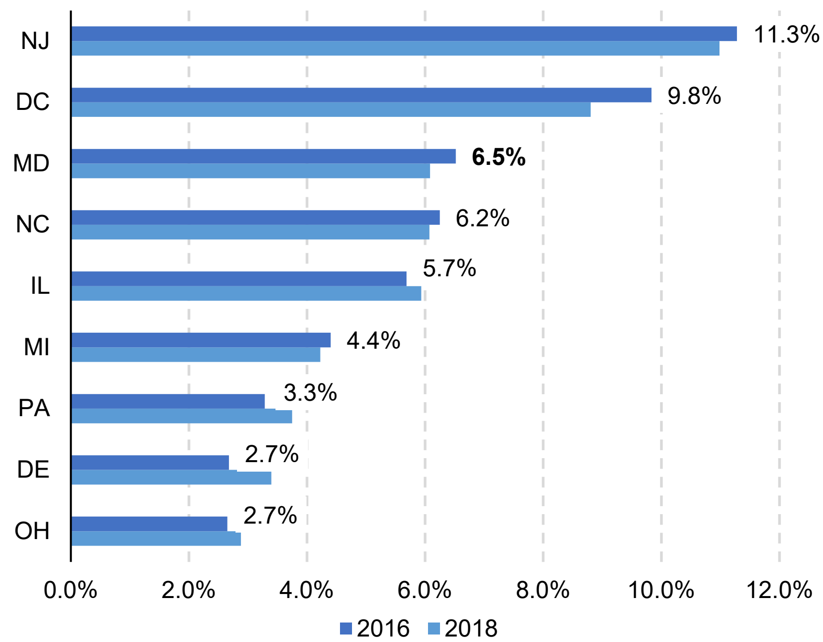

Figure 2-55. Renewable Energy Generation's Share of Energy Sector Jobs in Select States in PJM

Sources: DOE, "2017 U.S. Energy and Employment Report State Charts;" EFI/NASEO, *U.S. Energy and Employment Report*, 2018 and 2019.

2.4. Ratepayer Impacts

This section of the final report estimates the ratepayer impacts of RPS policies in Maryland and other PJM states.[92] It does so using an approach previously applied by LBNL: RPS compliance costs in deregulated (also referred to as "restructured") states are assumed to equal the costs of procuring RECs and the payment of ACPs.[93] These costs can be further divided by total annual retail electricity costs, which itself is the product of annual retail electricity sales multiplied by average retail electricity price, to derive a percentage rate impact on retail ratepayers.

It is important to note that this is a simple approach that excludes positive or negative externalities associated with state RPS policies, such as any price suppression impacts of renewable energy displacing other sources of generation, or transmission or system integration costs. Nevertheless, RECs and ACPs are assumed to represent the incremental cost of an RPS because they can be purchased separately from electricity and would not have been purchased absent an RPS. That is, REC and ACP costs are generally independent of all other power costs and therefore easily distinguished. Regulated utilities or energy commissions in most PJM states provide detailed annual compliance reports that identify REC and ACP costs as separate cost centers.

[92] Note that the first offshore wind projects to receive Maryland PSC approval (Order No. 88192) are not expected to come online until 2021. Consequently, ORECs are omitted from subsequent discussion.

[93] Ryan Wiser, Galen Barbose and Mark Bolinger, *Retail Rate Impacts of Renewable Electricity: Some First Thoughts*, Lawrence Berkeley National Laboratory, 2017. The LBNL study also lists two other methods to estimate the effects of RPS policies on retail electricity rates: econometric analysis and electric sector modeling using the Regional Energy Deployment System (ReEDS).

This section approaches the question of ratepayer costs in six subsections, the first of which provides an overview of the characteristics necessary to have "reasonable" and "affordable" Maryland REC rates, followed by initial evidence that this is the case. The second subsection reviews recent DOE studies on the topic of RPS rate impacts. Maryland REC and SREC costs in recent history are discussed next, along with some of the changes over time. The following two subsections apply LBNL's methodology and develops comparable RPS cost estimates for Maryland and other states in PJM. Finally, the section concludes with a brief review of additional considerations for evaluating rate impacts. Key findings from this section include:

- Maryland REC costs are determined through a functionally competitive market and use of ACPs is minimal.
- NREL and LBNL research found that, nationwide, RPS costs are historically less than 2% of retail electric rates, and that Maryland compliance costs were on par or lower than restructured states in PJM and ISO New England (ISO-NE) markets.
- REC prices peaked in 2015, and then they declined and remained low through April 2019. SREC prices have gradually declined since 2008, and they are increasingly on par with REC price levels, notwithstanding a spike in SREC prices in early 2019 corresponding with the passage of SB 516, which increased the maximum solar carve-out to 14.5%.
- Total RPS compliance costs in Maryland increased from $14.7 million in 2011 to $135.2 million in 2016, then fell to $72.9 million in 2017. As a percent of total retail bills, the Maryland RPS peaked at 1.8% of retail bills in 2016 before falling to approximately 1% in 2017. Despite increasing RPS compliance costs from 2010-2016, average retail electric rates in Maryland have remained relatively flat or have slightly fallen for all customer classes.
- Ratepayer costs from RPS policies reflect the diversity in state RPS policies across PJM; lower standards or more expansive resource eligibility requirements tend to reduce ratepayer impacts, while the opposite applies to more stringent RPS requirements. Maryland RPS compliance costs range in the middle as compared to other states in PJM.

2.4.1. Availability of Renewable Energy at Affordable and Reasonable Rates

Maryland applies a "just and reasonable" standard when the Maryland PSC assesses regulated utility rates.[94] No equivalent standard applies to the costs to procure renewable energy resources in compliance with the Maryland RPS. This is because the provision of electric generation is considered "competitive" in Maryland, and it is not regulated by the PSC.[95] However, the procurement of RECs can be said to result in "reasonable" rates for

[94] This standard, identified in Annotated Code of Maryland, PUA § 4-101, requires that utility service be "consistent with the public good" and "result in an operating income to the public service company that yields, after reasonable deduction for depreciation and other necessary and proper expenses and reserves, a reasonable return on the fair value of the public service company's property used and useful in providing service to the public." The costs of utility service that meet these criteria can be considered just and reasonable. *Source:* Annotated Code of Maryland, PUA § 4-101. Just and reasonable rate defined, govt.westlaw.com/mdc/Document/N02714E009CE711DB9BCF9DAC28345A2A?viewType=FullText&originationContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default).

[95] That is, Maryland is one of as many as 20 states that allows some or all customers to procure unbundled electric service. In most cases, this takes the form of retail supply, meaning the generation and retail sales components of

renewable energy generation to the extent that it is the result of a competitive market process. This view is consistent with the Energy Policy Act of 1992 and 2005 as well as several key FERC findings, including FERC Orders 888 and 2000.[96]

In general, a market is competitive so long as there are many buyers and sellers, a high degree of price transparency, an undifferentiable product, minimal transaction costs to buy or sell the product, clear market boundaries, and limited barriers for suppliers or buyers to enter or exit the market. Maryland RECs are tracked through PJM-GATS and, per Maryland law, are also reported to the Maryland PSC Staff for auditing and reporting purposes. PJM's market monitor, Monitoring Analytics, tracks and reports on PJM-wide REC trading on a quarterly basis, and the Maryland PSC releases an annual RPS report.

Several aspects of Maryland's REC market support its characterization as functionally "competitive" and therefore reasonable:

- Renewable energy resources located throughout PJM and areas that serve power into PJM can contribute RECs that are used to meet the Maryland RPS requirements. This broad market area provides access to a high number of eligible renewable energy resources from unique developers (i.e., many sellers). For example, nearly 66,000 unique plants were registered as eligible to provide Maryland RECs as of October 14, 2019, within PJM-GATS. Because Maryland is a retail supply state, there are also multiple LSEs that are responsible for procuring RECs (i.e., many buyers). The Maryland PSC's Shop-and-Compare website, for instance, lists over 135 active LSEs, including competitive electric suppliers and brokers, providing retail electric service to residential customers in Baltimore Gas and Electric Company's (BGE's) service territory as of January 2019. Although prices can be determined on a bilateral basis, a market for RECs exists.
- The ultimate product purchased, RECs, are undifferentiable except for the renewable energy resource type (e.g., Tier 1 non-carve-out and solar carve-out) and location (e.g., geographic requirements for the solar carve-out), both of which are important for resource eligibility purposes.
- Renewable energy attributes and aggregate REC sales are tracked in a transparent manner by PJM.
- Although some transaction costs and participation hurdles exist (i.e., the amount of time required to site a new resource), the costs imposed by these market barriers have not pushed REC prices above the ACP level, as tracked and reported by the Maryland PSC.

Monitoring Analytics has not identified any concerns about the competitiveness of REC markets except for the lack of transparency of REC pricing. That is, because some REC prices are determined in private, bilateral agreements, the pricing, terms, and conditions of these arrangements are not publicly available when assessing REC costs. This has the potential to hinder efficient market settlement at the marginal price. Maryland partially addresses this issue by requiring LSEs to submit REC cost information to the PSC, where it is subsequently published on an annual basis.

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electric service are separated from transmission and distribution components. Unbundled customers can procure energy supply from a market rather than receiving service from a regulated monopoly provider. *See:* nrel.gov/docs/fy17osti/67106.pdf for a primer on competitive electricity markets.

[96] *See:* ferc.gov/industries/electric/indus-act/competition.asp for a brief overview of major FERC findings with regards to electric competition.

Whether RECs are "affordable" can be determined by comparing REC prices to the ACP level. Maryland allows LSEs to pay an ACP in lieu of submitting RECs. The ACP effectively functions as a cost cap on the price of RECs; if the cost of a REC exceeds the ACP, LSEs will opt to pay the ACP instead of acquiring the REC. So long as REC costs remain below the ACP, RECs can be considered "affordable." In other words, the ACP is set at the level beyond which RECs are no longer considered affordable.

To date, Maryland has met its renewable energy requirements in every year since the inception of the RPS, and LSEs have done so with minimal ACPs. This indicates that renewable energy resources are both sufficiently available and obtainable at affordable rates. Table 2-17 tracks the percent of RPS obligation met by ACPs over time. As shown, ACP usage rates are low throughout most of the history of the Maryland RPS. LSEs have successfully procured RECs to meet over 99% of Tier 1 non-carve-out and Tier 2 RPS obligations in all years. LSEs initially made a significant number of ACPs to meet Tier 1 solar requirements following the implementation of the solar carve-out in 2008. By 2010, however, the use of ACPs for Tier 1 solar fell to levels on par with Tier 1 non-carve-out and Tier 2. Total ACPs across all major resource categories by all LSEs have not exceeded $100,000 since 2011.[97] ACPs in recent years are primarily made to satisfy IPL sales, which contribute approximately 0.3% of Maryland's total RPS obligation and are subject to more lenient RPS requirements.[98]

[97] Public Service Commission of Maryland, *Renewable Energy Portfolio Standard Report*, November 2018, psc.state.md.us/wp-content/uploads/FINAL-Renewable-Energy-Portfolio-Standard-Report-with-data-for-CY-2017.pdf.

[98] The IPL category is inclusive of consumption by manufacturing process. Retail sales to customers who fall under this category, as classified under the North American Industry Classification System, are subject to a reduced ACP for all Tier 1 obligations (including both non-carve-out and carve-out categories) and no ACP for Tier 2 requirements. The ACP for IPL customers was only $2.00/MWh as of 2018. Because the IPL category comprises such a small share of the Maryland RPS, the ACP requirements are not evaluated within the scope of this report.

Table 2-17. Percent of Maryland RPS Obligation Met by Alternative Compliance Payments

Year	TIER 1 Non-Carve-out	TIER 1 Solar Carve-out	TIER 2
2006	0.13%	-	0.13%
2007	0.11	-	0.11
2008	0.04	92.31%	0.04
2009	0.00	46.84	0.00
2010	0.00	3.40	0.00
2011	0.04	0.37	0.04
2012	0.00	0.02	0.00
2013	0.00	0.00	0.00
2014	0.02	0.02	0.02
2015	0.01	0.01	0.01
2016	0.00	0.00	0.00
2017	0.00	0.00	0.00

Note: ACP share derived from the Maryland PSC 2018 *Renewable Energy Portfolio Standard Report*. Number of ACPs is calculated by dividing the ACP expenditure for each given year by the ACP rate in that year.

There are several potential alternative approaches to assess whether REC costs are reasonable and affordable. For example, renewable energy costs can be compared to non-renewable energy alternatives in terms of Levelized Cost of Energy (LCOE) or Levelized Avoided Cost of Energy (LACE). Another approach is to assess the electricity supply curve, also known as the dispatch curve, and measure the cost impact of shifting the supply curve to the right (and thereby lowering energy costs, all else equal) by including renewable energy resources. The overall supply benefit can then be compared to the procurement costs of RECs. A related approach is to evaluate the average or marginal cost of power in the presence or absence of RECs. Each of these alternatives helps characterize the reasonableness and affordability of REC rates but faces significant limitations. They do not, for instance, account for macroeconomic benefits and costs. They also involve normative decision-making about what to use as appropriate comparisons, what benefits and costs to include, what time horizon and discount rate to apply, how to assess relative differences in cost or benefit across customer classes or locations, how to address other policy-driven subsidies, and so forth. Given these complications, for assessment purposes, the final report assumes that REC rates are reasonable and affordable so long as they are determined by competitive markets and remain below the legislatively determined ACP. Both conditions have been met to date.

2.4.2. NREL and LBNL Research

NREL and LBNL have conducted several studies of the rate impacts of RPS policies. Barbose, *et al.* (2015) developed a survey of published state data, including estimates of costs and benefits, related to RPS policies. They found that, between 2010-2013, RPS compliance costs were less than 2% of statewide retail electric rates on average, with incremental costs (i.e., compliance costs that include avoided generation costs) ranging from -0.4 to 4.8 cents/kWh-RE.[99] The authors also found that RPS compliance costs are lower in restructured states, lower in states with secondary tier targets, and higher in states with large solar set-asides. These estimates rely primarily on publicly available REC and ACP costs, and do not account for positive or negative externalities of state RPS policies such as price suppression impacts or system integration costs.

Barbose, *et al.* (2015) also evaluated the wholesale market price effect of an RPS. The authors found, based on an assessment of several other studies, that each MWh-RE reduces wholesale electric prices by $1.00/MWh.[100] The authors are careful to note, however, that wholesale prices are primarily impacted by renewable energy in the short term, with some effects disappearing over time.[101] Additionally, the authors note that price reductions are transfer payments; although some consumers and renewable energy producers may benefit from the RPS, they do so at the expense of other generators.

Another study, in this case by Wiser, *et al.* (2016), looked at all RPS policies in effect in 2013, and they estimated cumulative U.S. wholesale market and natural gas price impacts. They found, unsurprisingly, that low marginal cost renewable energy generation displaced higher marginal cost generation.[102] Like Barbose, *et al.* (2015), however, they note that there is no net welfare gain as a result of this process. Rather, the impact of the RPS is to initiate a transfer between different LSEs, consumers, and producers. Additionally, the estimated impact is thought to be short term and dependent on whether cost savings are passed through to ratepayers. How long the impact persists depends on how quickly price reductions induce displaced generators to retire, therefore shifting the supply curve back to its earlier equilibrium.[103] The authors found that 30-80% of historical reductions in wholesale price are passed through to consumers. This effect, after adjustment, amounts to price reductions that range from 0.0-1.2 cents/kWh-RE as a result of an RPS.[104]

Wiser, *et al.* (2016) also reviewed natural gas price reductions, which can reduce consumer costs from both gas-powered generation and gas heating. An RPS can reduce power sector demand for gas by displacing gas-fired generators. This, in turn, can drive down gas fuel costs. RPS compliance is estimated to have reduced electric sector gas demand by 5%, and overall gas demand by 1.6%, which reduced gas prices by $0.05-$0.14/MMBtu and produced consumer savings in the range of 1.3-3.7 cents/kWh-RE. The authors again note that this result should be interpreted as a transfer.

LBNL's (2019) comprehensive national evaluation of RPS policies includes an updated assessment of compliance costs. LBNL found that RPS compliance costs totaled $4.7 billion

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[99] Galen Barbose, Lori Bird and Jenny Heeter, *et al.*, "Costs and Benefits of Renewables Portfolio Standards in the United States," *Renewable and Sustainable Energy Reviews*, Vol. 52, 2015.

[100] Ibid.

[101] That is, in the short run, lower wholesale prices reduce the incentive for existing generators to continue operating and new generators to enter the market. These two market forces will shift the supply curve back toward its original position over time.

[102] Ryan Wiser, Galen Barbose and Jenny Heeter, *et al.*, *A Retrospective Analysis of the Benefits and Impacts of U.S. Renewable Portfolio Standards*, Lawrence Berkeley National Laboratory and National Renewable Energy Laboratory, 2016, nrel.gov/docs/fy16osti/65005.pdf.

[103] That is, the supply curve first shifts right (i.e., more supply is available), causing supply and demand to intersect at a lower price. This, in turn, causes resource retirements, shifting the supply curve left again and causing supply and demand to intersect at a higher price. However, increased availability of zero-marginal cost resources can dampen the second shift, leading to a new equilibrium at a lower prevailing wholesale price.

[104] Ryan Wiser, Galen Barbose and Jenny Heeter, *et al.*, *A Retrospective Analysis of the Benefits and Impacts of U.S. Renewable Portfolio Standards*, Lawrence Berkeley National Laboratory and National Renewable Energy Laboratory, 2016, nrel.gov/docs/fy16osti/65005.pdf.

in 2018, equating to 2.6% of retail electricity expenditure, on average, in the 29 RPS states and the District of Columbia.[105] These costs as a percentage of retail bills have risen over time, from 0.7% in 2012 to 2.6% in 2018, as a result of rising RPS requirements. Figure 2-56 shows the underlying compliance cost trends.[106]

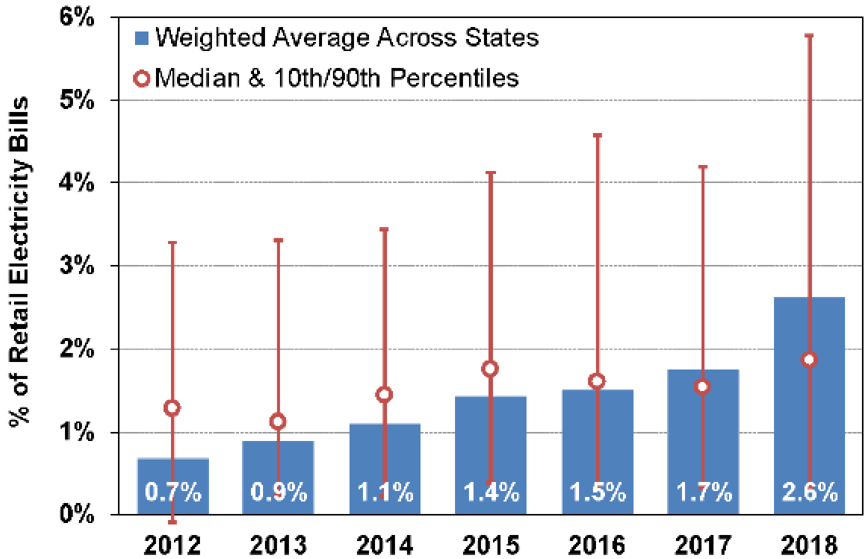

Figure 2-56. RPS Compliance Costs – Percentage of Average Retail Electricity Bill

Source: LBNL, *U.S. Renewables Portfolio Standards – 2019 Annual Status Update*.

Note: Annual averages are weighted based on each state's total revenues from retail electricity sales. 2017-2018 compliance cost data are provisional, as several states have yet to finalize compliance results for those years.

The LBNL study also estimates ratepayer impacts from state RPS policies within the mid-Atlantic and PJM regions. Recent impact estimates vary from less than 1% of retail electricity costs, as is the case in Ohio and Pennsylvania, to more than 6% in New Jersey. The LBNL study also shows that the 2018 cost impacts of the Maryland RPS were less than 1% of average retail electricity bills—on par with or less than the ratepayer impacts of RPS policies in other restructured states with retail deregulation, as shown in Figure 2-57. This cross-state variation corresponds with differences in RPS targets, resource mix, REC prices, wholesale power prices, reliance on pre-existing resources, and other state-specific RPS characteristics, according to LBNL. For example, Pennsylvania allows a wide array of eligible resources and has a small solar carve-out, both factors that correspond with lower compliance costs. New Jersey, on the other hand, has a high solar carve-out, stricter geographic eligibility requirements and corresponding high compliance costs. Further breakdown by resource tier shows cost disparities in the expected direction; Tier 2 compliance costs are generally a lower share of retail bills, while solar or DG carve-out compliance costs are higher.

[105] Galen Barbose, *U.S. Renewables Portfolio Standards – 2019 Annual Status Update*, Lawrence Berkeley National Laboratory, July 2019 presentation, emp.lbl.gov/publications/us-renewables-portfolio-standards-2.

[106] Ibid.

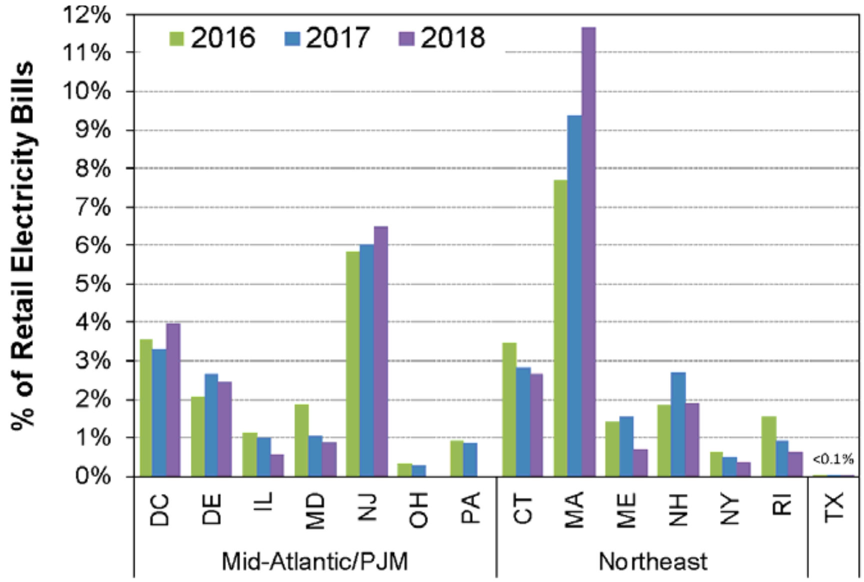

Figure 2-57. RPS Compliance Costs – Percentage of Average Retail Electricity Bill, in Restructured States

Source: LBNL, *U.S. Renewables Portfolio Standards – 2019 Annual Status Update*.

Note: RPS compliance cost estimates for restructured states are based, whenever possible, on the average cost of all RECs retired for compliance, including both spot market purchases and long-term contracts. For states with compliance years that begin in the middle of each calendar year (DE, IL, NJ, PA), compliance years are mapped to the figure based on the end date of each compliance year.

There is limited research evaluating rate impacts of state RPS policies, especially as compared to evaluations of RPS impacts on renewable energy deployment, or on economic or environmental impacts. Nevertheless, the limited academic research that does exist is broadly consistent with that of NREL and LBNL and, in some cases, provides further insight into how RPS costs affect different customer classes. Morey and Kirsch, in an analysis of the rate impacts of various state and federal policies, found that RPS policies corresponded with higher average rates.[107] The magnitude of this effect, however, differed by customer class and state retail access policy. Residential customers faced the largest nominal cost increases, followed by commercial and industrial customers. Larger cost impacts applied in restructured states. Morey and Kirsch ultimately estimated, based on data from 1990-2011, average increases in rates of $72/MWh (6.2%), $44.1/MWh (4.3%), and $31.9/MWh (6.0%) for residential, commercial, and industrial customers, respectively, in restructured states. Using data from the same time period, Wang (2015) also found that RPS policies increased residential prices, in this case between 5-7% depending on the model specification.

Consistent with earlier studies, Tra found that utilities facing an RPS impose higher electric rates on residential and commercial customers.[108] Tra further identified that, on average, electricity rates are approximately 3% higher for utilities required to meet an RPS as compared to those not facing an RPS requirement. Upton and Snyder used a synthetic

[107] Mitch Morey and L.D. Kirsch, "Retail Rate Impacts of State and Federal Electric Utility Policies," *The Electricity Journal*, 26(3), 2013.

[108] Constant Tra, "Have renewable portfolio standards raised electricity rates? Evidence from U.S. electric utilities," *Contemporary Economic Policy*, 34(1), 2015.

control approach to assess the impact of RPS policies.[109] In their study, non-RPS states are weighted along political, economic, and natural resource dimensions so that they directly mirror RPS states. The two are then compared over time in order to discern the impact of the RPS. The authors, using data from between 1990-2013, concluded that RPS policies are associated with increases in electricity prices ranging as high as 10.9-11.4%.

2.4.3. Tracking Maryland REC and SREC Prices

Additional REC and SREC Price History

In order to fulfill special requirement 11 of Ch. 393, which requested information about changes in SREC prices over the immediate 24 months preceding submission of the Interim Report, Exeter compiled additional REC and SREC data from Marex Spectrometer. Marex Spectrometer summarizes spot market prices for REC and SREC trading, by state, on a monthly basis. Although spot market prices do not reflect the true average of REC costs, trends in spot market prices are indicative of changes in the market price for RECs and SRECs. An updated version of Exeter's discussion of REC and SREC prices from the Interim Report is included in Appendix D.

Maryland REC and SREC prices have changed considerably in the last decade, as shown in Table 2-18. From 2011-2015, Tier 1 non-carve-out REC prices in Maryland were increasing rapidly, climbing from an average cost of $2.02/MWh in 2011 to $13.87/MWh in 2015, as demand for RECs grew quickly throughout PJM due to increasing state RPS requirements, both in Maryland and elsewhere.[110] Tier 2 RECs exhibited a similar trend, albeit at lower price levels. SREC prices during this period, meanwhile, were declining steadily, falling from an average cost of $278.26/MWh in 2011 to $130.39/MWh in 2015, but remained an order of magnitude higher than Tier 1 non-carve-out REC costs.[111] The Tier 1 non-carve-out and Tier 2 price trends reversed in 2016 as prices began declining. Additionally, SREC prices continued their decline, but at a faster rate. Although costs for SRECs and non-carve-out Tier 1 RECs increased somewhat from September 2017 – June 2018 (see Appendix D), prices again dropped by the end of 2018, and they remained low compared to past levels. These trends in Maryland are largely consistent with price changes in other states within PJM, indicating that REC and SREC cost drivers stem from broader supply and demand factors within the region.[112]

Tier 1 non-carve-out REC prices have not significantly changed in the first half of 2019. SREC prices increased beginning in late December 2018 and spiked upward in April 2019 (see Appendix D), corresponding with passage of SB 516 in May 2019, which increased the Maryland solar carve-out to 14.5% by 2028. Prior to the passage of SB 516, speculation related to increased future demand for SRECs pushed SREC prices upward.

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[109] Gregory Upton Jr. and Brian Snyder, "Funding renewable energy: An analysis of renewable portfolio standards," *Energy Economics*, Vol. 66, 2017.

[110] Public Service Commission of Maryland, *Renewable Energy Portfolio Standard Report*, November 2018, psc.state.md.us/wp-content/uploads/FINAL-Renewable-Energy-Portfolio-Standard-Report-with-data-for-CY-2017.pdf.

[111] Ibid.

[112] Monitoring Analytics, LLC, *2018 State of the Market Report for PJM*, March 2019, monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-volume2.pdf.

Table 2-18. Average Maryland REC Prices ($/MWh)

Year	TIER 1 Non-Carve-out	TIER 1 Solar Carve-out	TIER 2
2008	$0.94	$345.45	$0.56
2009	0.96	345.28	0.43
2010	0.99	328.57	0.38
2011	2.02	278.26	0.45
2012	3.19	201.92	0.44
2013	7.70	159.71	1.81
2014	11.64	144.06	1.81
2015	13.87	130.39	1.71
2016	12.53	110.51	1.25
2017	7.14	38.18	0.47
2018	5.00 – 7.75	6.50 – 14.00	0.38 – 0.75

Source: 2008-2017 REC prices sourced from the Maryland PSC 2016 *Renewable Energy Portfolio Standard Report*.

Note: 2018 prices sourced from Marex Spectrometer and represent the range of REC prices through CY 2018.

2.4.4. RPS Cost Impacts in Maryland

According to the most recent Maryland PSC RPS report, 102 LSEs submitted RPS compliance reports in 2017, including 76 competitive retail suppliers, 15 brokers, and 11 electric companies, of which four are investor-owned utilities (IOUs).[113] Maryland LSEs retired over 9 million RECs in 2017, slightly less than the 9.1 million RECs retired in 2016. The total cost of RECs retired in 2017 was $72.0 million, down from $135.2 million in 2016. This approximately 47% decrease in costs occurred despite increasing RPS requirements and a greater demand for RECs within the PJM region. Most REC costs in 2017 came from the purchase of Tier 1 non-carve-out RECs (69%), followed by SRECs (30%) and Tier 2 RECs (1%). As noted earlier within Subsection 2.4.1, "Availability of Renewable Energy at Affordable and Reasonable Rates," ACPs only accounted for less than 0.1% of total Maryland RPS compliance costs in 2017, with the majority of ACPs made to satisfy IPL obligations.[114]

Total, annual Maryland RPS compliance costs increased from $14.7 million in 2011 to $135.2 million in 2016. This growth in costs corresponds with increasing Maryland RPS requirements, higher demand for RECs in and outside of Maryland, and static or increased REC prices in most years during this time frame. In comparison, the recent drop in REC costs follows a significant decline in Tier 1 REC and SREC prices, as detailed in the preceding subsection. The average cost of SRECs decreased from $110.63 in 2016 to $38.18 in 2017, and the average cost of Tier 1 non-carve-out RECs fell from $12.22 in 2016 to $7.14 in

[113] *See:* Public Service Commission of Maryland, *Renewable Energy Portfolio Standard Report*, November 2018, psc.state.md.us/wp-content/uploads/FINAL-Renewable-Energy-Portfolio-Standard-Report-with-data-for-CY-2017.pdf.

[114] Ibid.

2017.[115] Figure 2-58 provides annual compliance costs for the Maryland RPS since 2010, broken out by Tier 1 non-carve-out, solar carve-out, and Tier 2, as compared to the Maryland RPS requirements for each category. See Appendix E for a breakdown of Maryland's compliance costs from 2010-2017, by Tier.

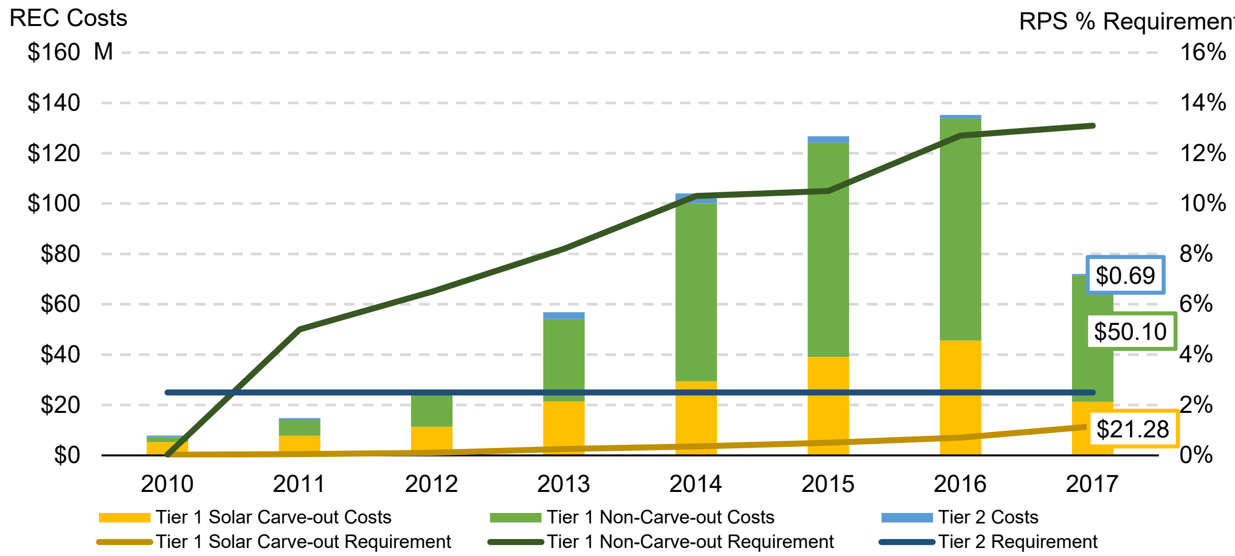

Figure 2-58. Maryland's Annual Total RPS Compliance Costs (RECs) Compared to Requirements

Source: Maryland PSC 2018 *Renewable Energy Portfolio Standard Report*.

Note: Call-out boxes for 2017 show total RPS compliance costs ($millions), by Tier.

When put in the context of retail costs, the impact of the Maryland RPS as a percentage of total retail bills followed similar trends as the nominal compliance costs. The rate impact of the Maryland RPS amounted to about 1% of total retail bills in 2017. This compares to around 1.8% in 2016. Figure 2-59 shows these changes. The solar carve-out has been a significant portion of RPS compliance costs. In 2017, the 1.15% solar carve-out represented 30% of RPS compliance costs in Maryland. Over the prior six years, the solar carve-out represented between 28-53% of RPS compliance costs in Maryland.

[115] Ibid.

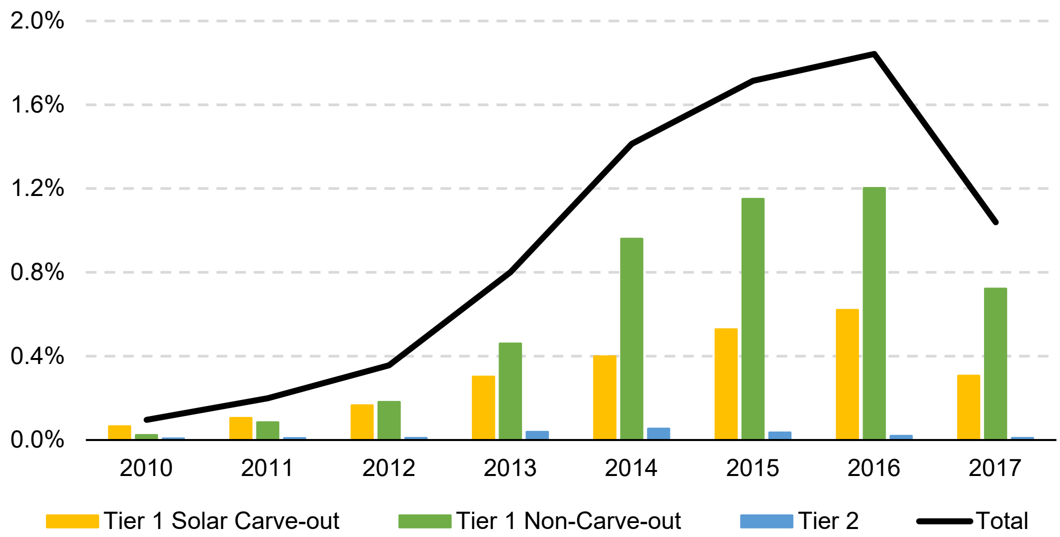

Figure 2-59. Maryland RPS Ratepayer Impact as a Percent of Total Retail Bills

Figure 2-60 tracks the average cost of the Maryland RPS on a cents/kWh basis and compares it to changes in retail rates for each customer class. From 2010-2017, retail electric rates in Maryland have remained relatively flat or have slightly fallen for all customer classes. Trends, up or down, in RPS compliance costs appear to have little impact on retail electric rates. This may be the case because RPS compliance costs are a proportionally small share of total retail electric rates.

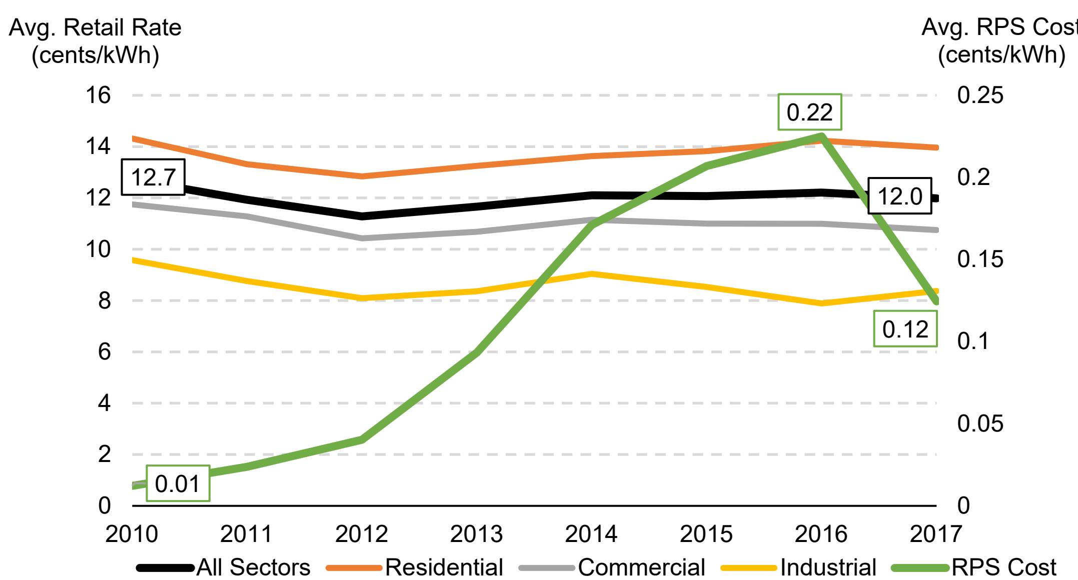

Figure 2-60. Comparing Average RPS Costs to Average Retail Rates, by Customer Class

Source: Retail rates from EIA.

Note: Average RPS cost equals total cost divided by total usage for each respective year.

2.4.5. RPS Cost Impacts in Other States in PJM

Figure 2-61 shows the range in ratepayer impact across most of the states in PJM with an RPS and for which data was available. The Maryland RPS compliance costs, as a share of retail bills, place it in the middle of PJM states. Additional breakdown of compliance costs by state and Tier is included in Appendix E based on data from state RPS compliance reports or LBNL. In general, ratepayer impacts appear to increase over time, likely in relation to increasing RPS percentage requirements. Maryland appears to have experienced the largest decline in costs in the last year, from 2016 to 2017. Only Ohio has seen year-to-year declines in most years. Ohio has the lowest ratepayer impact, estimated to be less than half a percent, while New Jersey ratepayers have paid almost 6% of their total retail bill to support renewable energy development. This wide range in ratepayer costs reflects the diversity in state RPS policies across PJM.

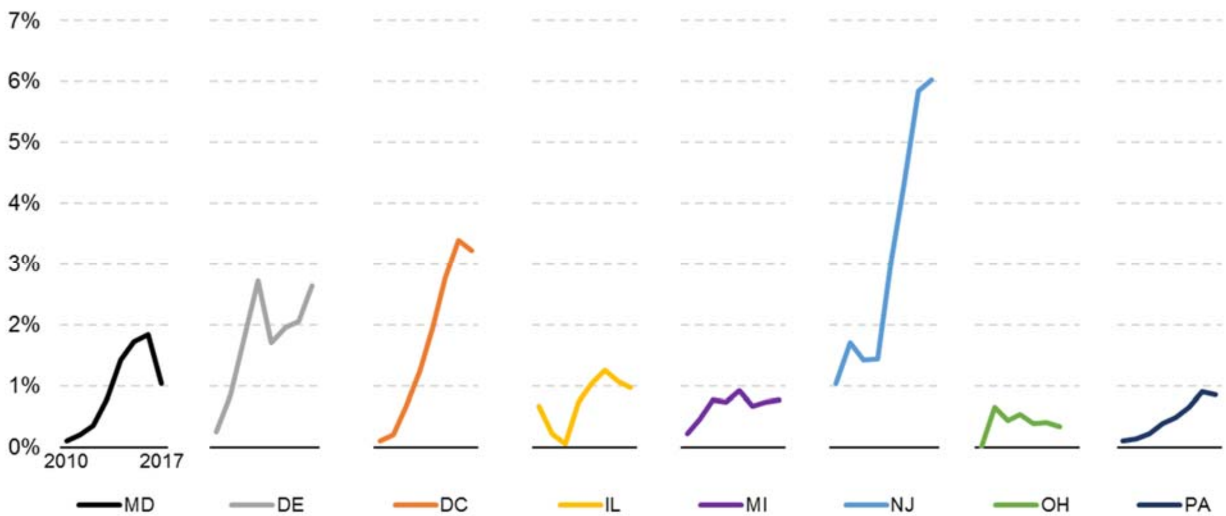

Figure 2-61. RPS Ratepayer Impact as a Percent of Total Retail Bills Across PJM, 2010-2017

Ohio has a relatively modest RPS requirement as compared to other states in PJM and previously suspended the growth of its RPS. The Ohio RPS is set at 5.5% with a 0.22% solar carve-out as of 2019, after having previously been frozen at 2.5% with a 0.15% solar carve-out for two years (2015 and 2016). A variety of technologies are eligible for the Ohio RPS, including MSW, LFG, and biomass. Pennsylvania has lower compliance costs in part because it allows a wider array of eligible resources and maintains a relatively low Tier 1 requirement. Among the resources allowed in the state are waste coal, demand-side management (DSM), and large-scale hydro, alongside other uncommon eligible resources. The Tier 2 requirement in the state was 8.2% in 2018 and 2019, as compared to 6.5% for Tier 1. Michigan and Illinois costs are lower than Maryland because of, at least historically, lower RPS requirements as a percentage of load (10% for both Michigan and Illinois in 2016, for instance).

The District of Columbia, by comparison, has an RPS of 19.85% in 2019, including the solar carve-out of 1.85%. Delaware and New Jersey also have significant RPS requirements. As of 2019, the New Jersey RPS was 20.975% (14.175% Tier 1, 2.5% Tier 2 with a 4.3% solar carve-out). New Jersey's solar carve-out peaks at 5.1% for 2020, 2021, and 2022. Maryland and Delaware maintained solar carve-outs of approximately 1.5% in 2018. Higher RPS requirements and larger solar carve-outs partially explain the higher cost of RPS policies in states with these policies.

Wide variations in ratepayer impacts are also evident in RPS compliance costs for solar requirements, as depicted in Figure 2-62. The magnitude of the ratepayer impact is almost directly proportional to the size of the solar carve-out in each state. New Jersey, the District of Columbia, Delaware, and Maryland's solar carve-outs are all above 1.2% for 2018. Ohio, Illinois, and Pennsylvania, in comparison, have minimal solar requirements, all set below 0.3% in 2018. Solar carve-out compliance costs in Maryland are slightly lower than D.C. and Delaware.

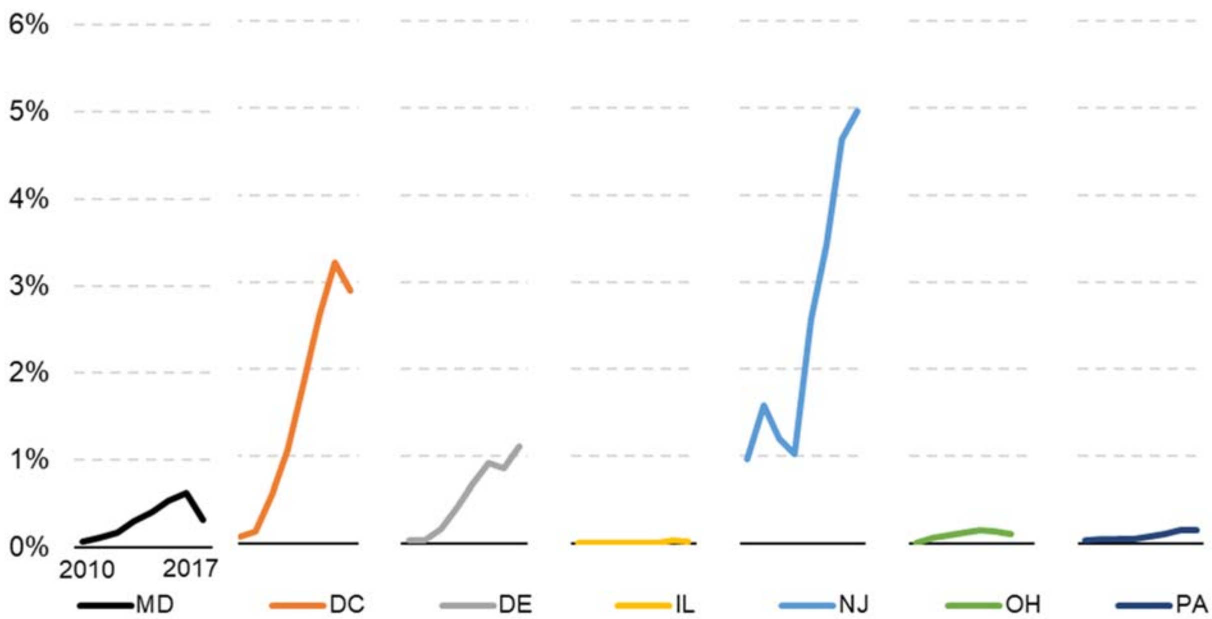

Figure 2-62. Solar Carve-out Ratepayer Impact as a Percent of Total Retail Bills Across PJM, 2010-2017

Note: Michigan is not represented on the graph because it does not have a solar carve-out and therefore does not incur a separate ratepayer impact from solar.

2.4.6. Limitations and Other Rate Impacts

It is important to note the drawbacks of relying on REC and ACP cost data in estimating ratepayer costs. First, as identified earlier, some LSEs enter into multi-year, bilateral contracts for RECs to meet RPS requirements and do not disclose the full terms. This reduces the transparency of costs. Second, compliance cost data that is reported by state agencies may not reflect actual costs to consumers, such as customer refunds or costs not recovered through the rate-making process. As evidence of this, ACPs may be credited to ratepayers or recycled through incentive programs. For example, utilities are forbidden from passing on ACP costs in Ohio and Pennsylvania, cost recovery is automatic in Illinois, and cost recovery is allowed but not guaranteed in Delaware, Maryland, and the District of Columbia. In New Jersey, SREC ACPs are refunded to the consumer, while other ACPs are recoverable.[116]

Third, relying on REC and ACP costs to estimate compliance costs omits system costs and benefits. For instance, RECs and ACPs do not capture transmission capacity expansion costs

[116] Jenny Heeter, Galen Barbose and Lori Bird, *et al.*, *Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards*, National Renewable Energy Laboratory, 2014.

incurred because of renewable energy concentration in a given area.[117] They also exclude system benefits and costs associated with in-state new renewable energy investments spurred by an RPS, including integration costs or lower transmission and distribution costs. These system benefits and costs tend to be modest and may even balance out.[118] A final limitation is the failure to account for price suppression effects. Increased renewable energy development is, in the short run, expected to reduce electricity prices due to its price suppression effects.[119] For example, PJM's Market Monitor reported that, in 2017, 71.9% of the marginal wind units had negative offer prices and 25.8% had zero offer prices.[120] The most recent Maryland LTER, however, found minimal wholesale price impacts from added renewable energy based on production cost.

2.5. Environmental Justice

The Maryland General Assembly directed PPRP to assess "whether the public health and environmental benefits of the growing clean energy industries supported by the RPS are being equitably distributed across overburdened and underserved environmental justice communities." To perform this assessment, this section of the final report begins by describing the history of environmental justice (EJ) both in the U.S. and in Maryland, as well as defining the term "environmental justice community." Next, the section details the methodology developed for identifying EJ communities in Maryland at a census tract level. RPS-certified facilities and EJ communities were then overlaid on the same map to identify the number and capacity of utility-scale renewable energy facilities in EJ and non-EJ communities. Subsequently, a score was assessed to each RPS facility using a rubric that allocates points based on the facility's environmental, economic, and land use characteristics. This provided a basis for comparison of RPS projects to determine whether the scored benefits of those projects were equitably distributed between EJ and non-EJ communities. Finally, this section concludes with an analysis of initial attempts to directly incorporate EJ into RPS policies. Key findings from this evaluation include:

- Technologies that emit low or no emissions, such as hydro, solar, and wind, tend to provide the greatest overall EJ benefit under the utilized scoring rubric. Technologies that emit higher levels of pollutants, on the other hand, provide a decreased EJ benefit. In some cases, there is a trade-off between the economic and environmental benefits of renewable facilities in EJ communities.
- Approximately 26% of utility-scale renewable energy capacity in Maryland is in EJ communities. This increases to 40% when excluding the Conowingo Dam. The latter figure is almost equivalent to the 43% of the state's population that resides in an EJ-designated census tract.
- When comparing the distribution of RPS benefits between EJ and non-EJ communities, EJ communities realize 25% of the overall benefits associated with utility-scale renewable energy. This is because more utility-scale projects—and, in particular, solar projects—are located in non-EJ communities than in EJ communities. However, on an individual project basis (i.e., benefits score per renewable energy

[117] Ibid.

[118] Warren Leon, *Evaluating the Benefits and Costs of a Renewable Portfolio Standard – A Guide for State RPS Programs*, Clean Energy States Alliance, 2012, cesa.org/assets/2012-Files/RPS/CESA-RPS-evaluation-report-final-5-22-12.pdf.

[119] Frank Felder, *Examining Electricity Price Suppression Due to Renewable Resources and Other Grid Investments*, *The Electricity Journal*, 24(4), 2011.

[120] Monitoring Analytics, LLC, *2018 State of the Market Report for PJM*, March 2019, monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-volume2.pdf.

project), EJ communities have a slightly higher level of benefits, on average, than non-EJ communities due to a lower number of emitting utility-scale projects.

- Based on data provided by the Maryland PSC, distributed solar projects in Maryland are more likely to be located in non-EJ communities than EJ communities, both by capacity and by number of projects.
- Altering how different costs and benefits are weighted within the scoring can fundamentally alter the estimated EJ impact of different resources, as well as the impact of the Maryland RPS overall on EJ communities.

2.5.1. History of Environmental Justice

EJ began in 1982 as a grassroots movement spurred by the State of North Carolina's decision to move hazardous waste soil to a landfill located in one of the few counties in the state with a majority black population.[121] Protests over this decision galvanized national attention and recognition that vulnerable communities, particularly low-income minorities, were often disproportionately burdened by environmental pollution, contamination, and other adverse impacts of energy or environmental siting.

EJ gained federal recognition in the 1990s, beginning with the EPA establishing the Environmental Equity Workgroup to address concerns that "racial, minority, and low-income populations bear a higher environmental risk burden than the general population."[122] In 1992, the Workgroup produced a list of recommendations to further the EPA's efforts to address environmental equity concerns.[123] EPA defines EJ as "the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation and enforcement of environmental laws, regulations and policies." Fair treatment indicates that "no group of people should bear a disproportionate share of the negative environmental consequences resulting from industrial, governmental and commercial operations or policies."

In 1994, President Clinton signed Executive Order (EO) 12898, "Federal Actions to Address Justice in Minority Populations and Low-Income Populations," that focused on identifying and addressing the disproportionately high human health and environmental effects of pollution on specified populations. EO 12898 required federal agencies to integrate EJ considerations into the federal processes for establishing environmental standards and permitting federal facilities, among other areas. The EPA has led the charge for EJ through its Office of Environmental Justice.

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[121] Brian Palmer, "The History of Environmental Justice in Five Minutes," Natural Resources Defense Council, 2016, nrdc.org/stories/history-environmental-justice-five-minutes.

[122] U.S. Environmental Protection Agency, "How Did the Environmental Justice Movement Arise?," epa.gov/environmentaljustice.

[123] The list of recommendations can be found in: *Environmental Equity: Reducing Risk for all Communities*, U.S. Environmental Protection Agency, EPA-230-R-92-008, 1992, nepis.epa.gov/Exe/ZyNET.exe/40000JLA.txt?ZyActionD=ZyDocument&Client=EPA&Index=1991%20Thru%201994&Docs=&Query=&Time=&EndTime=&SearchMethod=1&TocRestrict=n&Toc=&TocEntry=&QField=&QFieldYear=&QFieldMonth=&QFieldDay=&UseQField=&IntQFieldOp=0&ExtQFieldOp=0&XmlQuery=&File=D%3A%5CZYFILES%5CINDEX%20DATA%5C91THRU94%5CTXT%5C00000005%5C40000JLA.txt&User=ANONYMOUS&Password=anonymous&SortMethod=h%7C-&MaximumDocuments=1&FuzzyDegree=0&ImageQuality=r75g8/r75g8/x150y150g16/i425&Display=hpfr&DefSeekPage=x&SearchBack=ZyActionL&Back=ZyActionS&BackDesc=Results%20page&MaximumPages=1&ZyEntry=1.

2.5.2. Environmental Justice in Maryland

In 1999, the Maryland Advisory Council on Environmental Justice (MACEJ) published a report regarding EJ issues in the state.[124] The report included a recommendation to establish the Commission on Environmental Justice and Sustainable Communities (CEJSC). The CEJSC is a 20-person body within the Maryland Department of the Environment (MDE) and has the following responsibilities according to its website:[125]

- *Advise State government agencies on EJ.*
- *Analyze the effectiveness of State and local government laws and policies to address issues of EJ and sustainable communities.*
- *Coordinate with CEHPAC [Children's Environmental Health and Protection Advisory Council] on the issues of EJ and sustainable communities.*
- *Develop criteria to assess what communities in MD may be experiencing EJ issues.*
- *Recommend options for addressing EJ issues to the Governor and the General Assembly; include prioritized areas of the State that need immediate attention.*

MDE's definition of EJ is that "all people—regardless of their race, color, national origin or income—are able to enjoy equally high levels of environmental protection."

Several studies have examined the relationships between income, race, and air pollution (including pollution from power plants) or air pollution-based health outcomes.[126] Of particular relevance, one national study found that, even after accounting for income, majority black or Hispanic communities have fewer distributed solar facilities than predominantly white communities.[127] Maryland is working to rectify this through the PSC's pre-application process, which will require an EJ screen for qualifying generation stations as identified in Code of Maryland Regulations (COMAR) 20.79.01. This pre-application will be developed through a formal PSC rulemaking process.

Maryland also has as a pilot program, and associated incentive programs, to encourage community solar, as discussed at the end of this section as well as in Section 6.3 "Community Solar" and Section 6.4 "Grants."

[124] Maryland Advisory Council on Environmental Justice, *Environmental Justice in the State of Maryland*, 1999, mde.state.md.us/programs/Crossmedia/EnvironmentalJustice/Pages/ej_reports.aspx.

[125] Maryland Department of Planning, "Infrastructure and Development," planning.maryland.gov/Pages/OurWork/CommissionEnvJustice.aspx.

[126] See, for example: health.maryland.gov/mhhd/Documents/Maryland%20Chartbook%20of%20Minority%20Health%20and%20Minority%20Health%20Disparities%20Data,%20Third%20Edition%20(December%202012).pdf; ehp.niehs.nih.gov/doi/full/10.1289/ehp.7609; pnas.org/content/116/13/6001.

[127] Deborah Sunter, Sergio Castellanos and Daniel Kammen, "Disparities in Rooftop Photovoltaics Deployment in the United States by Race and Ethnicity," *Nature Sustainability*, Vol. 2, January 2019, rael.berkeley.edu/wp-content/uploads/2019/01/Sunter-Castellanos-Kammen-Nature-SustainablityDisparitiesPVDeploymentRaceEthnicity.pdf.

2.5.3. Methodology to Define an Environmental Justice Community

As there is no set definition in Maryland, a definition for "EJ community" was developed for the final report utilizing tools provided by EPA and PPRP as well as in consultation with EJ experts within Maryland. The primary tool used was EPA's environmental justice screening and mapping tool, known as the EJSCREEN Tool.[128] The tool can be used to identify the following: minority and/or low-income populations, potential environmental quality issues, and a combination of environmental and demographic indicators. More specifically, the EJSCREEN Tool can map 11 environmental indicators, such as air quality, lead paint, and proximity to hazardous waste facilities; six demographic indicators, such as low-income, minority, education level, and age; and 11 EJ indexes, which are a combination of environmental and demographic indicators, such as air toxics and cancer risk. The demographic and environmental data in the tool are nationally available at the census tract or census block group level.[129]

In addition to reviewing the capabilities of the EJSCREEN Tool, the authors researched what other states and agencies have used to define an EJ community. Table 2-19 provides a summary of how other East Coast and mid-Atlantic states have defined EJ areas.

[128] U.S. Environmental Protection Agency, "EJSCREEN: Environmental Justice Screening and Mapping Tool," epa.gov/ejscreen.

[129] Census blocks, the small geographic unit of the U.S. Census, generally include between 600 and 3,000 people, while census tracts generally include between 1,200 and 8,000 people and can comprise multiple census blocks.

Table 2-19. Environmental Justice Definitions

District of Columbia[1]	EJ areas include communities occupied by "District citizens who are low-income, minority, or have limited English proficiency." EJ policies are intended to ensure these citizens "receive equal protection under environmental laws and have meaningful opportunities to participate in environmental decision making undertaken by the D.C. Department of Energy and Environment."
Massachusetts[2]	EJ areas include: ▪ Census block groups with an annual household median income equal to or less than 65% of the statewide median income; or ▪ Areas where 25% or more of residents identify as a minority; or ▪ Areas where 25% or more of households have no one over the age of 14 who speaks English only or very well.
New York[3]	Potential EJ areas are census blocks that meet at least one of the following thresholds: ▪ At least 51.1% of the population in an urban area reported themselves to be members of a minority group; or ▪ At least 33.8% of the population in a rural area reported themselves to be members of a minority group; or ▪ At least 23.59% of the population in an urban or rural area had household incomes below the federal poverty level.
Pennsylvania[4]	An EJ area is any census track where 20% or more of the population live in poverty and/or 30% or more of the population are minorities.
Rhode Island[5]	EJ areas are determined based on 0.5-mile rings with minority and low-income population within the top 15% in the state (on a statewide basis, not a regional basis).

[1] DC.gov Office of Enforcement and Environmental Justice, *DC Comprehensive Plan*, Chapter 10 "Transportation, Public Works and Environmental Services," planning.dc.gov/sites/default/files/dc/sites/op/publication/attachments/Chapter%252010.pdf, p. 372.

[2] Mass.gov, *Massachusetts State Health Assessment*, 2017, mass.gov/files/documents/2017/11/03/Chapter%203.pdf.

[3] Federal Emergency Management System (FEMA), *Environmental Assessment Peckham Reservoir Dam Flood Damage Village of Sidney, Delaware County, New York*, 2017, fema.gov/media-library-data/1499886994419-8c15244c76abbe73999cd90268cabe41/SidneyVPeckhamDamFEMAEA.pdf.

[4] Pennsylvania Department Environmental Protection, "PA Environmental Justice Areas," dep.pa.gov/PublicParticipation/OfficeofEnvironmentalJustice/Pages/PA-Environmental-Justice-Areas.aspx.

[5] Rhode Island Department of Environmental Management, "Policy for Considering Environmental Justice in the Review of Investigation and Remediation of Contaminated Properties," dem.ri.gov/envequity/pdf/ejfinal.pdf.

For the final report, a sensitivity analysis was performed utilizing the EJSCREEN Tool to evaluate the presence of EJ communities in Maryland at census block, census tract, and zip code levels. This analysis evaluated several different assumptions about per capita income, minority population, and household income levels to use when identifying EJ communities. The different levels addressed include:

- Percent minority population:
    - 20%
    - 30%
    - 40%
    - 50%
- Per capita income:
    - Below 200% of the Federal Poverty Level (per capita income below $24,120)

    - Below 65% of the state’s median household income (per capita income below $51,314)
- Median household income:
    - Below 200% of the Federal Poverty Level (per capita income below $24,120)
    - Below 65% of the state’s median household income (per capita income below $51,314)
    - Below 50% of the state’s median household income (per capita income below $39,473)

Ultimately, the following EJ community definition was adopted: an EJ community is a census tract with 50% or more of the population identifying as a minority or a census tract with 50% or more of the population with a median household income equal to or below 65% of the state’s median income ($51,314). Any census tract that meets at least one of the criteria is recognized as an EJ community for the purposes of this assessment. Approximately 45% of census tracts in Maryland can be classified as EJ communities. These tracts include approximately 43% of Maryland’s population, based on 2010 U.S. Census figures.

2.5.4. Identifying RPS Facilities Within Environmental Justice Communities

For the final report, the areas that fit the above EJ definition were identified and mapped using PPRP’s SmartDG+ tool. SmartDG+ is a screening tool that shows the location of operational and planned solar and wind projects in Maryland that are between 1-10 MW in size. The tool also provides geographic information as a way to help developers find locations for potential wind, solar, and combined heat and power (CHP) projects. For this assessment, Exeter added an EJ community layer to indicate which census tracts meet the definition of an EJ community. A second layer was also developed to map all RPS-certified projects above 1 MW, including biomass, LFG, blast furnace gas (BFG), MSW, hydro, and wood waste. The resulting map of Maryland’s EJ communities and RPS-certified facilities is provided in Figure 2-63. The areas highlighted in pink are the census tracts that meet this study’s definition of an EJ community.

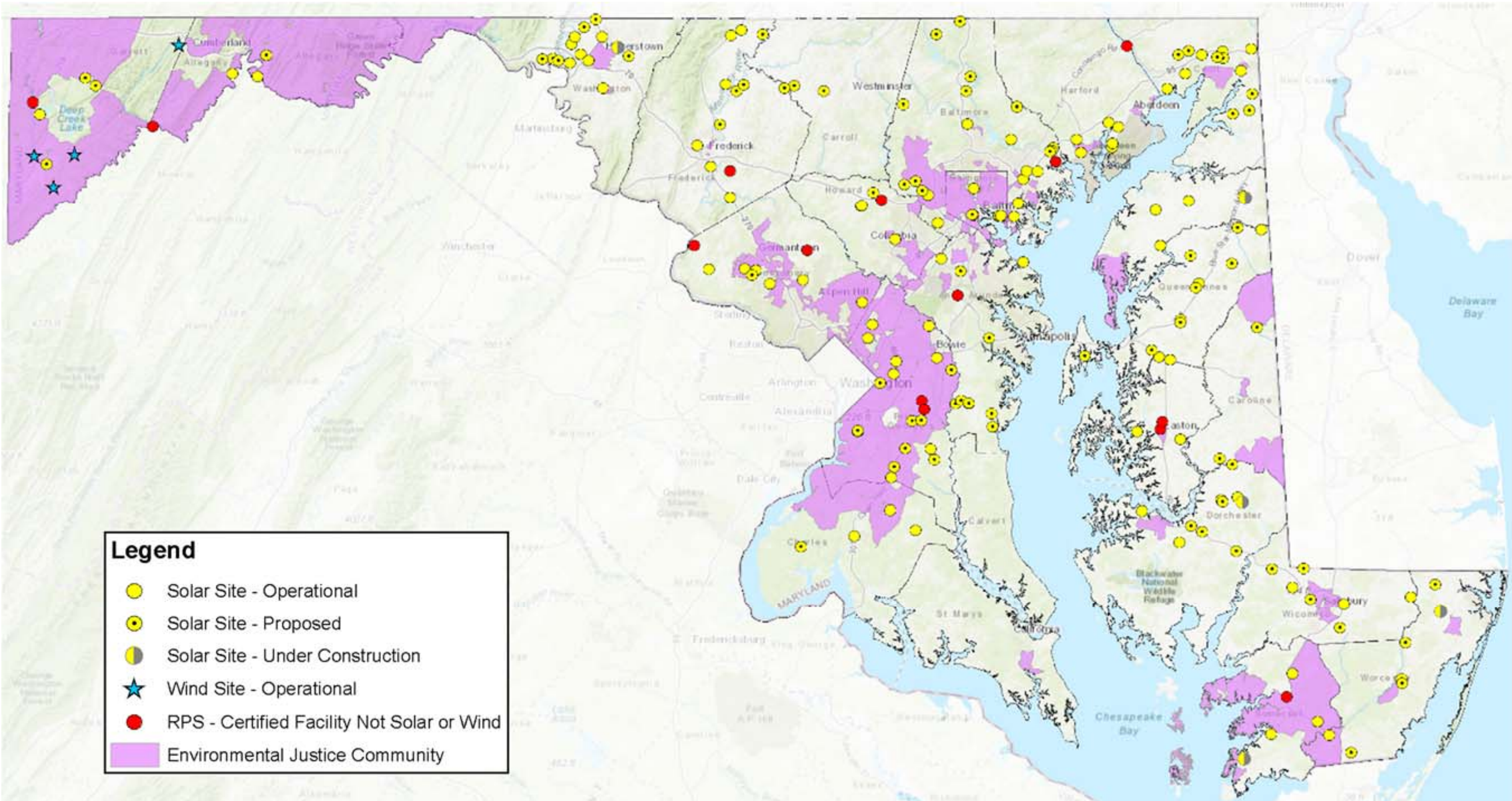

Figure 2-63. Maryland Environmental Justice Communities and RPS-Certified Projects

Source: Adapted from Maryland DNR SmartDG+, dnr.maryland.gov/pprp/Pages/SmartDG.aspx.

In total, 34 operating RPS-certified projects greater than 1 MW are located within a defined EJ community, which is approximately 25% of the number of operational RPS-certified projects in Maryland. In terms of capacity, approximately 26%, or 331 MW, of renewable energy capacity is located within Maryland EJ communities. These capacity figures are based on data from the EIA. Excluding the Conowingo Dam hydro facility, which has a capacity of 474 MW, approximately 40% of the renewable energy capacity in Maryland is located in EJ communities. The level of capacity is almost equivalent to the population within the census tracts identified as EJ communities. Table 2-20 compares the number of operating RPS-certified projects greater than 1 MW in Maryland or EJ communities.

Table 2-20. Operating RPS Registered Projects in Maryland >1 MW, by Fuel Source

Fuel Source	No. of Projects >1 MW In-State[1]	Total Project Capacity (MW)[2]	No. of Projects >1 MW in EJ Communities	EJ Community Project Capacity (MW)	Percent of Projects in EJ Communities	Percent of Capacity of Projects in EJ Communities
LFG	8	35	1	13	13%	37%
MSW	4	139	1	60	25	43
Solar	118	435	26	84	22	19
Hydro	3	494	2	20	67	4
Wood Waste	1	4	1	4	100	100
Wind	4	190	3	150	75	79
TOTAL	**138**	**1,297**	**34**	**331**	**25%**	**26%**

Source: PJM-GATS.

[1] Excludes the 69-MW Easton Plant, which did not generate electricity in 2017; the Harford Waste-to-Energy Facility, which shuttered in 2016; Luke Mill, which closed in 2019; and counts the four LFG facilities at Brown Station Road as one facility.

[2] Capacity figures reflect EIA data and may not match other data sources.

As seen in Table 2-20, many more utility-scale projects—and, in particular, solar projects—are located in non-EJ communities than in EJ communities. The disparity may be due in part to topography. Several large areas that meet the EJ criteria are in western Maryland, but its hilly terrain is not conducive to utility-scale solar projects. Meanwhile, very little of the Eastern Shore meets the EJ criteria, but its large, flat terrain has attracted many of the state's largest utility-scale solar projects. Other differences between the areas, such as solar quality, access to interconnection, and local rules and regulations, among other things, may also contribute to the observed resource allocation.

2.5.5. Assessing the Benefits of RPS Facilities Within Environmental Justice Communities

To assess how the benefits of RPS-certified facilities are distributed among EJ communities, Exeter developed a scoring system. Three criteria were evaluated as proxies for each facilities' economic, environmental, and health benefits: CO_2e emissions, land usage, and number of jobs during operation of the facility. CO_2e converts any given quantity of a GHG into the equivalent amount of CO_2 by multiplying the GHG quantity by its global warming potential (GWP). GWP is an index for the amount of warming a gas causes over a given period of time. That is, the CO_2e indexed GWP for any GHG is the order of magnitude of warming caused relative to CO_2. For example, methane (CH_4) has a GWP of 25, which implies that one kilogram of CH_4 causes 25 times the amount of warming relative to CO_2 over a 100-year period. Using CO_2e as a stand-in for other emissions, such as NOx and sulfur oxides (SOx), facilitates comparison between different resource types. Higher emission levels have negative environmental and health impacts on surrounding communities. RPS-certified facilities that emit low or no emissions, therefore, are scored as being more beneficial to a community than those with higher emissions levels.

Land use can have environmental impacts insofar as it affects air, water, watershed, wildlife habitat, and human health.[130] It can also have economic impacts when land used for energy production displaces other uses of the land. The consequences of land use for renewable energy facilities, however, are mixed. On one hand, renewable energy facilities can sometimes co-exist with other land uses, such as farming or pollinator-friendly habitats.[131] Land development, however, can also create impervious surfaces which can lead to increased storm runoff and flooding.[132] With respect to flooding, this EJ analysis assumes that facilities that require less land provide higher benefits to the surrounding community.

Finally, renewable energy projects can have a positive economic impact on a community insofar as they support local employment. Employment that is stimulated by renewable energy facilities can be estimated based upon the facility's capacity and fuel source. Since employment during the construction of a renewable energy facility is generally temporary, this assessment only considers the employment impacts of facilities in terms of ongoing FTE O&M jobs. Higher levels of employment will likely result in higher economic benefits for the surrounding community and are scored accordingly.

Each facility was ranked on a scale from one to five for each of the above benefit categories. Higher category-specific or overall scores indicate greater benefits. For example, zero GHG emissions would receive a score of five, whereas a plant that emits 300,000 tons of CO_2 would receive a score of one. The scoring rubric is provided in Table 2-21.

Table 2-21. Environmental Justice Benefit Scoring Rubric Used to Assess Renewable Energy Projects in Maryland

Benefits	Score				
	1	2	3	4	5
CO_2e (tons)	30,001 +	15,001 - 30,000	5,001 - 15,000	1,001 - 5,000	0 - 1,000
Land Use (acres)	100 +	75 - 99	50 - 74	25 - 49	0 - 25
No. of O&M Jobs	0 - 10	11 - 50	51 - 100	101 - 150	151+

Several assumptions were made to determine the level of benefits for each facility. The CO_2e was based upon 2017 data provided to the EPA's Facility Level Information on GreenHouse gases Tool (FLIGHT) for facilities not powered by hydro, solar, or wind energy. Hydro, solar, and wind energy were assumed to have no emission output.[133] The calculation of a facility's land use was based upon one of two methodologies, depending on the energy source. NREL provides an average land use by technology type for biomass, solar, and wind on an acre-per-MW of capacity basis. Biomass is projected to use 0.3 acres/MW, solar uses about 6.1 acres/MW, and wind uses approximately 44.7 acres/MW.[134] (Note that wind

[130] U.S. Environmental Protection Agency, "Land Use: What are the trends in land use and their effects on human health and the environment?," epa.gov/report-environment/land-use.

[131] "Partnership to assess pollinator-friendly solar farms," *Cornell Chronicle*, July 9, 2018, news.cornell.edu/stories/2018/07/partnership-assess-pollinator-friendly-solar-farms.

[132] Ibid.

[133] U.S. Environmental Protection Agency, "2017 Greenhouse Gas Emissions from Large Facilities," Facility Level Information on GreenHouse gases Tool (FLIGHT), ghgdata.epa.gov/ghgp/main.do#.

[134] National Renewable Energy Laboratory, "Land Use by System Technology," nrel.gov/analysis/tech-size.html.

projects often have additional uses, such as agriculture and livestock grazing. For the purposes of scoring wind projects, 3.5 acres/MW is used. This is based on the finding in a separate NREL study that, on average, less than 3.5 acres/MW is disturbed during wind project construction.[135]) For the remaining facilities, land use was estimated using mapping software that estimates the acreage depending upon aerial maps. The total number of jobs during the operational period of a facility varied by fuel source. Solar and wind facilities are assumed to provide 0.4 O&M jobs for every MW of capacity.[136] Jobs for biomass, LFG, MSW, hydro, and wood waste facilities were projected based upon a 2010 study that summarized a variety of sources to determine the average number of jobs per MW during the O&M phase of a facility's lifetime.[137,138]

Benefits Scores for Each Facility Within an Environmental Justice Community

The highest total benefits score that a facility may receive is 15. The higher the score, the greater the benefits to the EJ community through reduced emissions, decreased land usage, increased employment, or some combination thereof. The individual and overall benefit scores of the 34 utility-scale renewable facilities in EJ communities are summarized by facility in Table 2-22. Brown Station Road, an LFG facility, ranked the lowest in terms of EJ benefits, with an overall score of four. Although this facility has higher employment than many of the other technology types, its emissions output and land requirements drive down the overall score. The overall highest benefit score was 11, which the majority of solar facilities received. Due to higher land usage, wind facilities received a slightly lower total benefits score than solar. The Wheelabrator Baltimore refuse facility, a municipal waste plant, had an overall benefits score of 11. Although Wheelabrator has relatively high emissions, its large estimated employment impacts and relatively small footprint help increase its score. This particular outcome is sensitive to the assumptions used during scoring; weighting land use benefits lower (i.e., less of a positive impact) or emissions benefits higher (i.e., more of a harmful impact) would reduce Wheelabrator's apparent benefit to its EJ community.

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[135] Paul Denholm, Maureen Hand, Maddalena Jackson and Sean Ong, *Land-Use Requirements of Modern Wind Power Plants in the United States*, National Renewable Energy Laboratory, 2009, nrel.gov/docs/fy09osti/45834.pdf.

[136] Daniel Steinberg, Gian Porro and Marshall Goldberg, *Preliminary Analysis of the Jobs and Economic Impacts of Renewable Energy Projects Supported by the § 1603 Treasury Grant Program*, National Renewable Energy Laboratory and MRG & Associates, 2012, nrel.gov/docs/fy12osti/52739.pdf.

[137] The number of jobs per MW are as follows: biomass: 3.22 jobs/MW; LFG: 2.68 jobs/MW; MSW: 0.72 jobs/MW; hydro: 2.07 jobs/MW; and wood waste: 3.22 jobs/MW.

[138] Max Wei, Shana Patadia and Daniel Kammen, "Putting Renewables and Energy Efficiency to Work: How Many Jobs Can the Clean Energy Industry Generate in the US?," *Energy Policy*, Vol. 38, 2010, rael.berkeley.edu/old_drupal/sites/default/files/WeiPatadiaKammen_CleanEnergyJobs_EPolicy2010.pdf.

Table 2-22. Benefit Scores of Renewable Energy Facilities in Maryland Environmental Justice Communities

Plant Name	Fuel Source	Nameplate Capacity (MW)	CO_2e	Land Usage	Jobs	TOTAL Score
Allegany County Public Safety Building	Solar	1.07	5	5	1	**11**
Amazon Solar	Solar	1.04	5	5	1	**11**
Amazon Solar	Solar	1.04	5	5	1	**11**
Amazon Solar	Solar	1.61	5	5	1	**11**
Autumn Glory Community Solar	Solar	2.00	5	5	1	**11**
Bowie State Solar System	Solar	1.62	5	5	1	**11**
Brown Station Road	LFG	13.40	1	1	2	**4**
CCBC Solar	Solar	1.16	5	5	1	**11**
Centers for Medicare and Medicaid Services	Solar	1.12	5	5	1	**11**
Criterion Wind Project	Wind	70.00	5	3	2	**10**
Darrow's Lane Pumping Station	Solar	1.07	5	5	1	**11**
Deep Creek	Hydro	10.00	5	5	1	**11**
Deep Creek	Hydro	10.00	5	5	1	**11**
Eastern Correctional Institution	Wood Waste	3.80	1	5	2	**8**
Elkton WWTP	Solar	2.22	5	5	1	**11**
Fair Wind Generating Facility	Wind	30.00	5	4	2	**11**
FedEx Field Solar Facility	Solar	1.96	5	5	1	**11**
First Baptist Solar Project	Solar	2.06	5	5	1	**11**
Kohl's Solar	Solar	2.39	5	5	1	**11**
Macy's Solar	Solar	1.07	5	5	1	**11**
Maryland Solar Farm 1	Solar	29.06	5	1	2	**8**
MTC Logistics Cold Storage PV Solar	Solar	1.61	5	5	1	**11**
Pocomoke City Wastewater Solar	Solar	2.09	5	5	1	**11**
PREIT Solar Project	Solar	2.10	5	5	1	**11**
PSREG Waldorf Solar Energy Center	Solar	13.09	5	2	1	**8**
Regency Furniture	Solar	1.34	5	5	1	**11**
Roth Rock Wind Power Facility	Wind	50.00	5	3	2	**10**
South Germantown Recreational Park	Solar	1.45	5	5	1	**11**
UMES Solar Project	Solar	2.22	5	5	1	**11**
UMMS At Pocomoke Solar	Solar	3.66	5	5	1	**11**
University of Maryland Solar Project	Solar	1.09	5	5	1	**11**
Verizon	Solar	2.08	5	5	1	**11**
Wheelabrator Baltimore Refuse	MSW	60.22	1	5	5	**11**
WSSC Solar	Solar	2.49	5	5	1	**11**

As is evident from the score distribution, there are trade-offs between the types of technology in terms of benefit. Utility-scale renewable energy facilities with an emission profile generally offer a higher number of ongoing O&M jobs on a per-unit basis and have lower land use requirements than utility-size wind and solar projects. Hydro, solar, and wind renewable energy projects, however, offer the highest overall benefits to EJ communities in most cases.

Exeter notes that the allocation of benefits can differ significantly if the above point allocations are altered or reweighted. For example, if emissions impacts were weighted more than land impacts, a solar project would likely rank higher in terms of benefits. If, however, job impacts were weighted more than emission impacts, then the LFG facility would rank higher. Exeter tested several variations of the utilized scoring rubric, including separate categories for major emission types, different allocations between each benefit score level, and increases or reductions in the amount of points assigned to each category. In many cases, the outcomes were similar; non-emitting projects scored higher in terms of benefit to EJ communities.

2.5.6. Comparison of Facility Scores Within Environmental Justice and Non-Environmental Justice Communities

To determine how the benefits were distributed between EJ and non-EJ communities, each facility located in a non-EJ community was scored using the same rubric. The results of this assessment are compared in Table 2-23. In terms of the level of benefits, the total benefit score for the 138 facilities located in non-EJ communities was 1,046, and for the 34 facilities in EJ communities was significantly lower, with 349 points. Based upon the total score, the level of RPS benefits appear to be disproportionately distributed among non-EJ communities. The higher level of benefits recognized in non-EJ communities is related to the higher number of renewable energy projects in these communities, especially solar projects. However, when the total benefits are averaged over the number of projects, EJ communities recognize an average benefit of 10.26 per project as compared to 9.97 for non-EJ communities. The slightly better benefit per project for EJ communities likely stems from a higher number of LFG and MSW facilities being located in non-EJ communities.

Table 2-23. Comparison of Benefits Score of Utility-Scale Renewable Energy in EJ and Non-EJ Communities

	Non-EJ Communities	EJ Communities	EJ Share
No. of Projects >1 MW[1]	104	34	25%
Overall Benefits Score	1,046	349	25%
Average Score per Project	9.97	10.26	

[1] Excludes the 69-MW Easton Plant, which did not generate electricity in 2017; the Harford Waste-to-Energy Facility, which shuttered in 2016; Luke Mill, which closed in 2019; and counts the four LFG facilities at Brown Station Road as one facility.

2.5.7. Analysis of Rooftop Solar and Environmental Justice Communities

A recent study published in the *Nature Sustainability* journal found that there is a significantly lower adoption rate of distributed solar among minorities and low-income populations.[139,140] More specifically, the study determined the following:

- When considering household income:
  - Census tracts with a majority of black, Hispanic, and Asian populations, on average, installed "significantly less" distributed solar than census tracts with no black or Hispanic majority, at 69%, 20%, and 2% less, respectively.
  - Census tracts with a white majority installed approximately 21% more distributed solar systems on average than census tracts with no majority.
- When considering home ownership:
  - Census tracts with a majority of black or Hispanic populations installed distributed solar at a rate of 61 and 45% lower rates, respectively, than census tracts with no majority of any particular race.
  - Census tracts with a white majority installed distributed solar at a rate of 37% more than census tracts with no majority of any particular race.[141]

To determine whether a similar phenomenon existed among EJ communities in Maryland, a dataset was obtained from the Maryland PSC with the zip code and capacity of 11,783 unique solar DG projects located in Maryland as of May 2019.[142] Utilizing this data, it was determined that approximately 31% of solar DG projects and 30% of solar DG capacity in Maryland are located in EJ communities.[143] This is disproportionate to the share of Maryland's population that EJ communities comprise.

Diving into the data further, there are approximately 149 Maryland zip codes out of just over 600 that include both an EJ and non-EJ census tract. In aggregate, approximately 50% of the population in these split zip codes are in EJ communities. However, the allocation of

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[139] Deborah Sunter, Sergio Castellanos and Daniel Kammen, "Disparities in Rooftop Photovoltaics Deployment in the United States by Race and Ethnicity," *Nature Sustainability*, Vol. 2, January 2019, rael.berkeley.edu/wp-content/uploads/2019/01/Sunter-Castellanos-Kammen-Nature-SustainablityDisparitiesPVDeploymentRaceEthnicity.pdf.

[140] The study used data from Google's Project Sunroof and merged it with the 2009-2013 American Community Survey.

[141] Deborah Sunter, Sergio Castellanos and Daniel Kammen, "Disparities in Rooftop Photovoltaics Deployment in the United States by Race and Ethnicity," *Nature Sustainability*, Vol. 2, January 2019, rael.berkeley.edu/wp-content/uploads/2019/01/Sunter-Castellanos-Kammen-Nature-SustainablityDisparitiesPVDeploymentRaceEthnicity.pdf.

[142] Note that, as of year-end 2018, there were 61,726 Maryland-certified solar DG facilities located within the state that were below 1 MW, according to data from PJM-GATS. Of those, 41,154 are 0.10 MW or below, which is the size range for residential distributed solar. Exeter is working with the Maryland PSC to verify the accuracy of the provided data and, if possible, obtain a more complete data set. *Sources:* PJM-GATS, "Renewable Generators Registered in GATS," gats.pjm-eis.com/gats2/PublicReports/RenewableGeneratorsRegisteredinGATS; Ran Fu, David Feldman and Robert Margolis, *et al.*, *U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017*, National Renewable Energy Laboratory, 2017, nrel.gov/docs/fy17osti/68925.pdf.

[143] Although zip codes and census tracts are not contiguous, it is possible to interpret the two relative to each other using "HUD-USPS Zip Code Crosswalk" files. These files provide the share of residential addresses, business addresses, "other" addresses, and total addresses from each zip code that intersect with specific census tracts. When a census tract comprises a portion of a zip code, the percent overlap can be used as a weight. This form of weighting was used to roughly identify the allocation of solar DG projects, in this case using the "total addresses" percentages.

solar projects is again skewed; 42.6% of solar DG capacity and 43.4% of solar DG projects are in EJ communities within split zip codes.

One of the factors that may explain the lower penetration of distributed solar in EJ communities is the strong correlation between low-income households and renting. Rental units typically have a low adoption rate of distributed solar due to the upfront costs of solar investment, and the misalignment of those who receive the benefits (renters, through lower energy costs) versus those who bear the costs (the landlord). Additionally, since distributed solar is functionally a fixed asset, its benefits are nontransferable and therefore of less value to populations that are more likely to relocate.

Community solar is one way to allow low-income and minority populations to participate in solar. Community solar is a business model that allows for solar power installations to be funded by subscribers, such as ratepayers, individuals, and/or businesses, who buy or lease a portion of a solar project. The Maryland PSC, under Rulemaking 56, revised the COMAR to require the state's distribution utilities to implement community solar pilots. The pilots have a statewide cap of 193 MW, of which 60 MW must be set aside for low- and moderate-income ratepayers. As of November 2019, 17 MW of community solar projects located in LMI communities have been given a "reserved" or "accepted" status under the pilot program. This means that the projects have been accepted by one of the participating utilities, but they are not yet in service. Many presumably are still seeking subscribers.[144] See Section 6.3 for information on the progress of Maryland's pilot program. In addition to the utility-level efforts, MEA is providing financial grants to qualified low-income participants who purchase a community solar allocation.[145] Similar programs in Oregon and Colorado, both passed as part of state RPS bills, require that a portion of shared solar arrays be owned by low-income residents. On the federal level, the U.S. Department of Housing and Urban Development (HUD) runs the Renew300 initiative, which aims to install 300 MW of on-site or community renewable energy generation on federally assisted housing.[146]

The Maryland RPS does allow the use of the Strategic Energy Investment Fund (SEIF) for grants to small, minority, and women-owned businesses. In 2019, the Maryland General Assembly passed CEJA, which directs MEA to allocate $7 million from SEIF between 2021-2028 to the above groups, plus veteran-owned small businesses that are in the clean energy industry.

2.5.8. Environmental Justice and U.S. State RPS Policies

Some states have recently attempted to incorporate EJ concerns into their respective RPS policies. The District of Columbia, as part of legislation concerning increasing its RPS that was passed in December 2018, added requirements that funds generated from the RPS, utility fees, and usage taxes be used to: benefit low-income residents, including energy bill

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[144] Values based on the interconnection queues posted by the four participating utilities:

BGE: bge.com/SmartEnergy/MyGreenPowerConnection/Documents/BGE_CSEGS_QUEUE_PilotApplicationList.pdf.

DPL: delmarva.com/MyAccount/MyService/Documents/21119Copy%20of%20CSEGS%20Pilot%20Queue%20Status%20-%20Delmarva%20Year%202%2011%2026%20%202018%20(version%201).pdf.

Pepco: pepco.com/MyAccount/MyService/Documents/32519CSEGS%20Pilot%20Queue%20Status%20-%20Pepco%20Year%201%2008%2010%202017.pdf.

FirstEnergy: firstenergycorp.com/content/dam/feconnect/files/retail/md/community-solar/pe-pilot-queue.pdf.

[145] Further details on MEA community solar grants are provided in Subsection 6.3.3, "Maryland's Use of Community Solar."

[146] HUD Exchange, "Renew300: Advancing Renewable Energy in Affordable Housing," hudexchange.info/programs/renewable-energy/.

assistance; establish workforce development for residents in energy efficiency fields; and support energy-saving improvements to buildings that primarily serve low-income persons.[147] These efforts complement the District's Solar for All program, enacted as part of updates made to the District of Columbia RPS in 2016. The Solar for All program supports the installation of solar PV at low-income and senior households as well as at small businesses and nonprofits.[148]

New Mexico added requirements for workforce training and transition assistance when it updated its RPS in March 2019. These include up to $20 million in severance and job training assistance to employees who lose their jobs at generators that are retired from service.[149] Washington's updated RPS, enacted in April 2019, is among the first to comprehensively address equity concerns. The bill requires utilities to provide energy assistance to low-income communities not only in the form of bill reductions, but also in support of customer procurement of distributed energy. Washington also required that utilities consider "vulnerable communities" during a newly created Cumulative Impact Analysis process for future generation siting. Additionally, the state created tax incentives for renewable energy projects that include procurement from or contract with women-, minority-, or veteran-owned businesses, or that compensate workers at collectively bargained rates.[150]

Maryland addresses many of the topics discussed here, including workforce training and bill assistance, but they are outside the context of the state's RPS.

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[147] Council of the District of Columbia, D.C. Bill 22-0904, *CleanEnergy DC Omnibus Amendment Act of 2018*, lims.dccouncil.us/Legislation/B22-0904?FromSearchResults=true.

[148] Council of the District of Columbia, D.C. Act 21-466, *Renewable Portfolio Standard Expansion Amendment Act of 2016*, lims.dccouncil.us/Download/35409/B21-0650-SignedAct.pdf.

[149] State of New Mexico, SB 489, *Energy Transition Act*, 2019, nmlegis.gov/Sessions/19%20Regular/bills/senate/SB0489.html.

[150] For an overview, *See:* vox.com/energy-and-environment/2019/4/18/18363292/washington-clean-energy-bill. The full legislation is available at: lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bills/Senate%20Passed%20Legislature/5116-S2.PL.pdf.

2.6. Influence of Past Changes to the Maryland RPS

Like most states with an RPS, Maryland has changed its renewable energy requirements multiple times. These changes are summarized chronologically in the introduction to the final report. The purpose of this section of the final report is to provide a closer look at these changes, including discussion of their relation to trends in renewable energy development, deployment, and other metrics such as REC prices. This section covers: raising Tier 1 requirements, creating or accelerating solar and offshore wind carve-outs, changing Tier 1 resource eligibility, and lowering ACP levels. Not surprisingly, the impacts of changes made to the Maryland RPS overlap. Nevertheless, certain correlations between past changes and variables of interest bear discussion. Among the findings of this section are the following:

- Increasing the Tier 1 non-carve-out requirement corresponds with continued new renewable energy development and deployment in PJM.
- The creation of a solar carve-out has led to the development of over 1 GW of distributed and utility-scale solar in Maryland. Continued development of solar in Maryland appears closely tied to the level of the solar carve-out.
- The offshore wind carve-out in the Maryland RPS has led to two approved offshore wind projects totaling 368 MW of capacity, estimated to produce 1,369 GWh of power on an annual basis once both are online.
- More RECs from MSW have been retired since MSW was converted to Tier 1 status than when MSW was a Tier 2 resource. Additionally, the requirement that these resources must be connected to the distribution grid serving Maryland greatly increased the share of MSW RECs from in-state sources.
- Geothermal energy and solar hot water and cooling remain relatively small contributors to the Tier 1 requirements of the Maryland RPS, in part because of the small size of the individual systems.
- Adding a requirement that RECs from control areas adjacent to PJM must be associated with electricity that is delivered into PJM has only modestly reduced imports from outside of PJM.
- Reliance upon ACPs has been minimal other than in 2008 and 2009 when the solar carve-out was established.

Note that this section does not attempt to identify causal relationships between changes in the Maryland RPS and outcomes of interest. Identifying causality requires econometric and other technical analysis. These forms of analysis face many challenges, including endogeneity and exogeneity concerns (i.e., bias stemming from the causality assumptions). Given these challenges, this section instead focuses on reviewing select relationships using trends. Also note that this section does not address more recent changes brought about following the passage of CEJA. Finally, this discussion assesses the impact of past changes to the Maryland RPS in isolation and does not consider the overarching impact of frequently changing the Maryland RPS.

2.6.1. Raising Total Tier 1 Percentage Requirements

Back-to-back state legislative bills (in 2007 and 2008) more than doubled Maryland's total Tier 1 RPS requirement. In the aftermath, Tier 1 non-carve-out REC prices rose sharply through 2015. This corresponded with six years of relatively rapid development of projects in PJM that are eligible to retire Tier 1 non-carve-out RECs in Maryland. From 2007-2012, an average of 1,235 MW of projects eligible for Tier 1 of the Maryland RPS came online in PJM each year. This rate began to slow between 2013-2015, with additions averaging 382 MW of Tier 1-eligible projects per year. Beginning in 2016, Tier 1 non-carve-out REC prices also began to fall, including a steep drop in prices in 2017. That same year, HB 1106 was enacted, which raised total Tier 1 requirements from 2017 onwards. Nevertheless, Tier 1 non-carve-out REC prices have continued to fall, albeit more gradually. The rate of Tier 1-eligible project deployments in PJM increased somewhat beginning in 2016, albeit at levels below the 2007-2012 rate; an average of 727 MW of Tier 1-eligible projects came online in PJM each year from 2016-2018. Tier 1 non-carve-out REC prices and capacity additions (online post-2004) are compared to the overall Maryland RPS Tier 1 requirement in Figure 2-64 and Figure 2-65, respectively.

These trends underscore the complex combination of factors that impact Tier 1 non-carve-out REC supply and demand, including the creation of carve-outs and Tier 1 eligibility changes in Maryland and in other states with RPS policies, as well as other market factors, such as declining cost of many renewable energy technologies and low load growth. Additionally, the gradual phase-down of the federal investment tax credit (ITC) and production tax credit (PTC) also affects renewable energy development, and therefore availability of Tier 1 RECs.

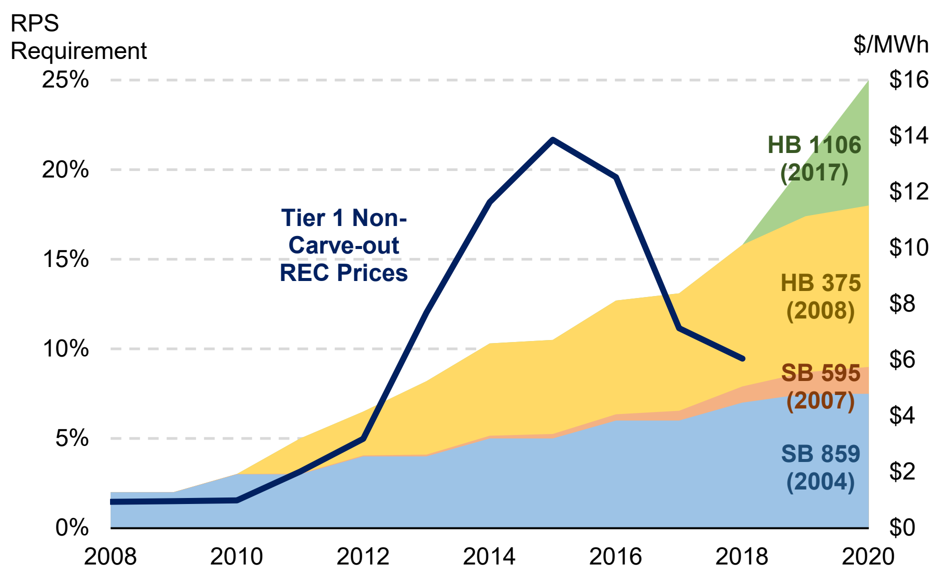

Figure 2-64. Maryland RPS Tier 1 Requirement and Tier 1 Non-Carve-out REC Prices

Source: REC prices from 2008-2017 sourced from the Maryland PSC 2018 *Renewable Energy Portfolio Standard Report*. 2018 REC price estimated using Marex Spectrometer spot-market prices for Maryland RECs.

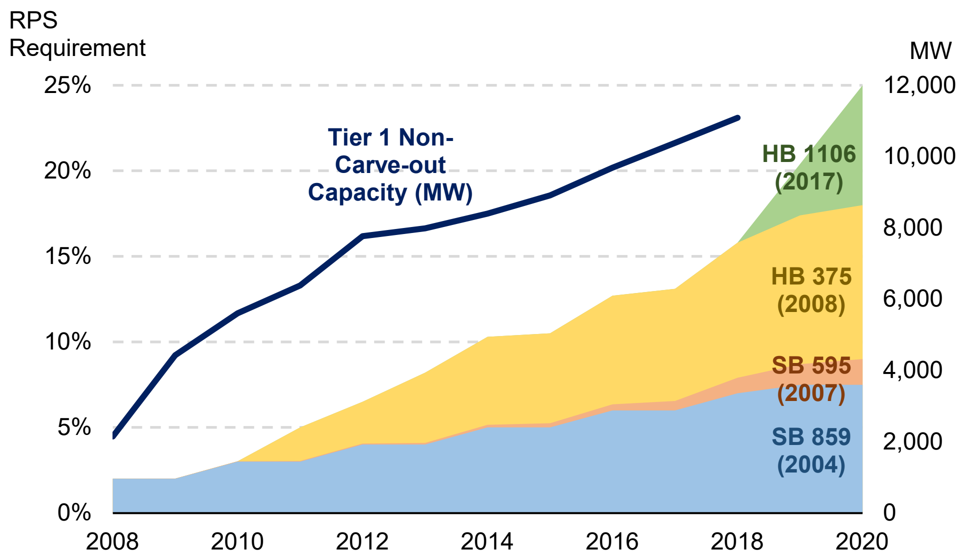

Figure 2-65. Maryland RPS Tier 1 Requirement and Tier 1 Non-Carve-out Capacity Additions in PJM, online post-2004

Source: Tier 1 non-carve-out cumulative capacity from PJM-GATS.

2.6.2. Creating and Accelerating the Solar Carve-out

Maryland is one of 15 (plus the District of Columbia), to establish a solar or DG carve-out. SB 595 established Maryland's solar carve-out in 2007. It required that an increasing percentage of Tier 1 RECs be fulfilled using solar PV generation, beginning with 0.0005% in 2008, reaching 2% in 2022, and then continuing at 2% in perpetuity. Originally, out-of-state PV facilities were eligible to provide SRECs if there were not enough RECs from in-state PV facilities. By 2010, solar development in Maryland had begun outpacing the carve-out requirement. In response, SB 277 accelerated the compliance schedule between 2011-2016. In February 2012, the Maryland PSC determined that there were enough in-state SRECs to fulfill the solar carve-out moving forward, which terminated the eligibility of out-of-state solar facilities. Also in 2012, SB 791 once again accelerated the compliance schedule, this time from 2013-2020. Then, in 2016, HB 1106 raised the final solar carve-out target to 2.5% in 2020 and subsequent years.

Prior to the passage of the Maryland RPS and the creation of the solar carve-out, solar was a negligible part of Maryland's energy mix. Since that time, solar capacity has expanded significantly; Maryland added approximately 347.2 MW of utility-scale and 713.5 MW of distributed solar between 2004-2018. This growth is documented above in Section 2.1, "Deployment of Renewable Energy."

Figure 2-66 compares PV generation in Maryland as a share of total sales alongside the state's evolving solar carve-out requirements. Tier 1 solar carve-out-eligible generation in Maryland surpassed the carve-out level for the first time in 2010. Despite acting twice (in 2010 and 2012) to accelerate the carve-out requirement, PV generation has maintained a comfortable margin above the carve-out in terms of share of sales ever since. This may be due, at least in part, to PV companies taking advantage of the federal ITC, which begins stepping down in 2020, and it expires altogether for residential customers in 2022 but stays at 10% for business customers. In 2016, the share of eligible solar generation exceeded the Maryland RPS requirement by over 50%. After the carve-out was raised (2016), the level of excess solar generation fell to 32% in 2017 and 14% in 2018. Excess solar is banked or used for compliance with RPS requirements in other states in PJM. For example, in 2017, Maryland resources produced nearly 884,328 RECs, of which 291,362 (33%) were retired in 2017 to meet the Maryland Tier 1 solar carve-out; 592,509 (67%) were banked; and 3,781 (less than 1%) were used to meet the RPS requirements of the District of Columbia and Pennsylvania.[151]

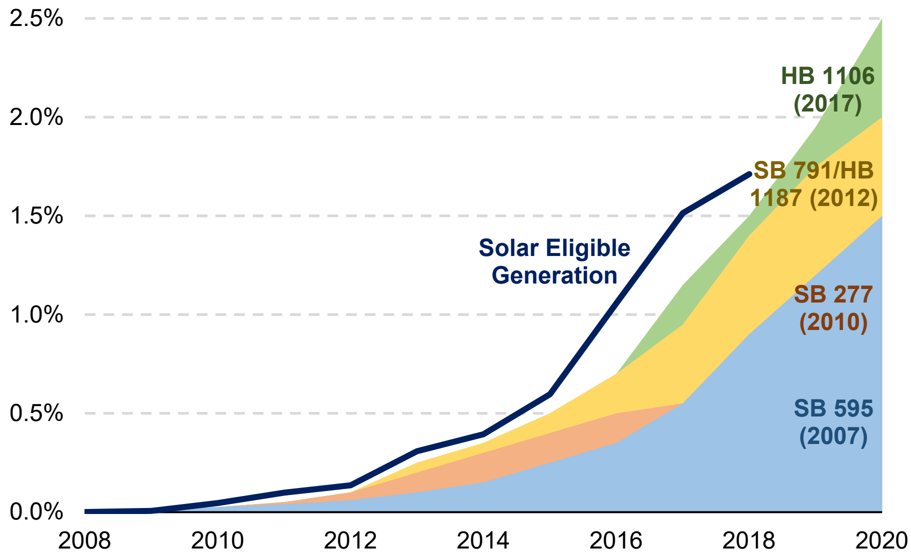

Figure 2-66. Maryland RPS Solar Carve-out Requirement and Estimated PV Generation in Maryland as a Share of Total Sales

Sources: All PV generation data for Maryland from PJM-GATS.

2.6.3. Creating the Offshore Wind Carve-out

In 2013, HB 226 created an offshore wind carve-out that allows up to 2.5% of the Tier 1 requirement to come from offshore wind. The offshore wind tier is different from the rest of the Maryland RPS in that the Maryland PSC must approve the issuance of ORECs. The PSC can only approve the issuance of ORECs under several conditions: if the net rate impact is less than $1.50 per month for residential ratepayers; if projected rate impacts on non-residential customers would not exceed 1.5% of their annual electric costs; and if OREC prices would not be greater than $190/MWh (2012$).

In 2017, the Maryland PSC approved the issuance of ORECs for two offshore wind projects for a total of 368 MW: 248 MW for US Wind, part of a larger, 750-MW project; and 120 MW for Skipjack, a subsidiary of Deepwater Wind Holdings, LLC. Ørsted, a Danish energy company, acquired Deepwater Wind in 2018. Each company will receive ORECs valued at $131.93/MWh for 20 years. These ORECs are more expensive than Tier 1 RECs by an order of magnitude and, should these projects come online, they will add over $180 million in gross annual MD RPS compliance costs once online.[152] This is roughly 2.5 times the $72 million that was expended to comply with the Maryland RPS in 2017. At the customer level, net ratepayer impacts were found to be below $1.40 per month for residential

[151] Public Service Commission of Maryland, *Renewable Energy Portfolio Standard Report*, Appendix C, November 2018.

[152] This estimate assumes 1,369 GWh of annual production, as identified in the interim report and calculated using the assumed capacity factors for the two projects provided in Maryland PSC Order No. 88192.

customers and less than a 1.4% impact on the annual bills of commercial and industrial customers as of the time the PSC approved the projects.[153]

2.6.4. Expanding Tier 1 Resource Eligibility

Over the years, Maryland has expanded the technologies that are eligible for Tier 1 of the RPS (including the solar carve-out) and transitioned some Tier 2 resources to Tier 1. SB 690, passed in 2011, added waste-to-energy (i.e., MSW) and refuse-derived fuel facilities located in Maryland as Tier 1 resources. (MSW was previously a Tier 2 resource.) SB 690 also made a new resource eligible for the carve-out: solar heaters that are not solely used to heat a pool or hot tub. In 2012, SB 652 / HB 1186 added qualified geothermal heating and cooling systems commissioned on or after January 1, 2013. The same year, SB 1004/HB 1339 added qualified thermal energy associated with biomass systems that primarily use animal waste, also effective on or after January 1, 2013. All the above technologies are only eligible for RECs if the generator connects with the distribution grid serving Maryland. Table 2-24 shows the number of RECs retired annually by each technology following its addition/transition to Tier 1 of the Maryland RPS. Technology-specific observations follow the table.

Table 2-24. RECs/SRECs Retired by Technologies Newly Eligible for Tier 1 or Solar Carve-out of the Maryland RPS

	MSW					
Year	Tier 1	Tier 2	Total	Geothermal	Agr. Biomass	Solar Thermal
2008	-	211,746	211,746	-	-	-
2009	-	248,256	248,256	-	-	-
2010	-	404,490	404,490	-	-	-
2011	125,278	201,821	327,099	-	-	-
2012	481,864	160,080	641,944	-	-	368
2013	562,394	97,030	659,424	-	-	1,386
2014	854,276	-	854,276	126	-	3,050
2015	595,527	-	595,527	122	317	3,801
2016	1,101,078	-	1,101,078	692	95	2,980
2017	732,424	-	732,424	1,880	345	3,478
2018	978,517	-	978,517	2,738	40	3,298

Source: PJM-GATS.

Municipal Solid Waste

MSW has benefited significantly from becoming Tier 1-eligible. In the years when MSW was a Tier 2 resource, it competed against hydro to provide RECs up to the Tier 2 limit of 2.5% of retail energy sales. At most, MSW facilities retired just under 405,000 RECs in a single year during this period. The vast majority of MSW RECs came from out-of-state providers, primarily Virginia, but also from Pennsylvania and New Jersey; under 15% of MSW RECs came from Maryland generators in 2008 and 2009, and under 30% in 2010.[154]

[153] Maryland Public Service Commission, "Maryland PSC Awards ORECS to Two Offshore Wind Developers," 2017, psc.state.md.us/wp-content/uploads/PSC-Awards-ORECs-to-US-Wind-Skipjack.pdf.

[154] Maryland PSC *Renewable Energy Portfolio Standard Reports*.

Since becoming Tier 1-eligible in 2011, MSW facilities have retired up to 1.1 million RECs in a single year. Additionally, the majority of Tier 1 MSW RECs came from Maryland sources, reaching 100% from 2011-2014 before declining in the last several years to the 2017 level of 78.13%.[155] The growth in MSW REC retirements is shown in Figure 2-67. MSW's shift to Tier 1 temporarily diminished the supply of Tier 2 RECs, causing their price to more than quadruple between 2012-2013, rising from $0.44 to $1.81/MWh. Since then, Tier 2 REC prices have returned to $0.47/MWh.

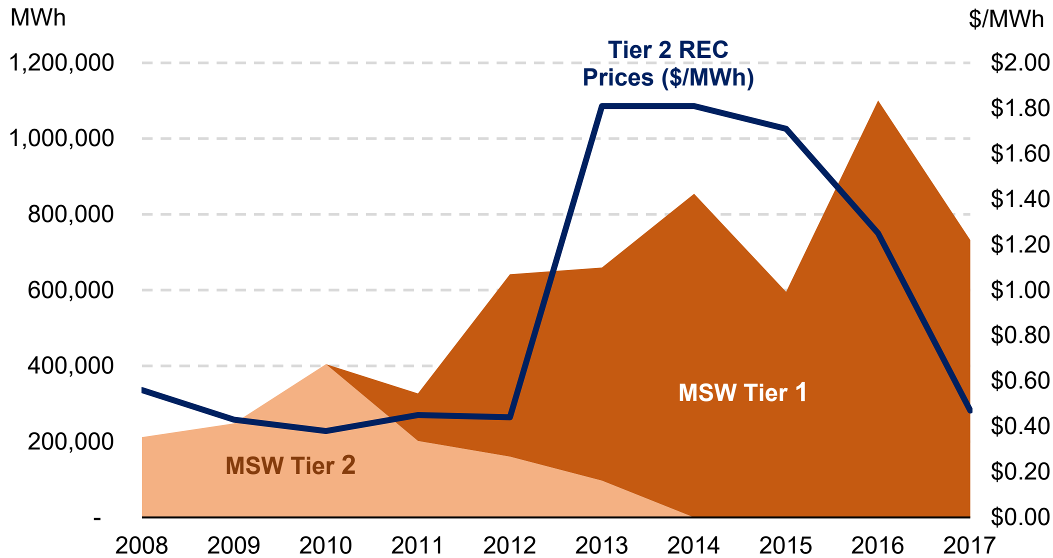

Figure 2-67. Municipal Solid Waste REC Retirements as Compared to Tier 2 REC Prices, by Tier and Year

Source: REC retirements sourced from PJM-GATS; REC prices sourced from Maryland PSC *Renewable Energy Portfolio Standard Reports*.

Geothermal

Geothermal heating and cooling has gained a foothold in Maryland, beginning with 126 RECs in 2014 and rising to 2,738 RECs in 2018 as the number of systems has increased. Still, because of the small size of these systems, total geothermal output represents less than 1% of Tier 1 RECs retired for compliance with Maryland's Tier 1 non-carve-out requirement in any given year.

Animal Waste

Thermal energy associated with animal waste and other agricultural biomass has not yet made significant gains in Maryland. It is has been difficult to make poultry-litter power generation profitable in Maryland. Existing projects have relied on Maryland grants. While technology is improving, consistent system performance has been an issue.[156]

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[155] Ibid.

[156] For example, *See: Comprehensive Engineering and Socioeconomic Assessment of Using Poultry Litter as a Primary Fuel at the Eastern Correctional Institution Cogeneration Facility*, Vol. I, Environmental Resources Management; Exeter Associates, Inc.; and McBurney Corporation, prepared for Maryland Environmental Service, 2000, pprp.info/eci/1-VolumeI-IIPDF.pdf.

Solar Thermal

Adding solar thermal to the solar carve-out has prompted modest solar thermal development and deployment. In 2018 for example, solar thermal systems generated 3,298 SRECs, representing less than half of 1% of all SRECs generated during the year.

2.6.5. Limiting Tier 1 Geographic Eligibility

Under the original 2004 RPS legislation, renewable energy generation could be: (1) within PJM; (2) in a state that is adjacent to PJM; or (3) in a control area (service territory) that is adjacent to the PJM region if the electricity is delivered into PJM. In 2008, HB 375 required that generation either be (1) within PJM; or (2) in a control area that is adjacent to PJM region if the electricity accompanying the RECs is delivered into the PJM region. This was intended to put Tier 1 and Tier 2 resources outside PJM at a slight disadvantage due to the additional transmission charges required to deliver RECS and energy together into PJM. (See Chapter 4 for a discussion of the pros and cons of eliminating geographic restrictions.)

Figure 2-68 shows the origin of Tier 1 RECs retired for Maryland RPS compliance over time. The percentage of Tier 1 RECs coming from resources outside of PJM states—meaning located in a state with no PJM service territory—fluctuated between 5% and 25% before HB 375 went into effect in 2010. The share of resources outside PJM since 2010 has fluctuated between 2% and 19%.[157] Until 2015, small hydro plants in New York were the predominant source of Tier 1 RECs retired by plants outside of PJM states. In 2016-2017, however, wind generation from Iowa, North Dakota, and Missouri was the predominant source of non-PJM state Tier 1 RECs, as shown in Figure 2-69 alongside non-PJM-state hydro figures.

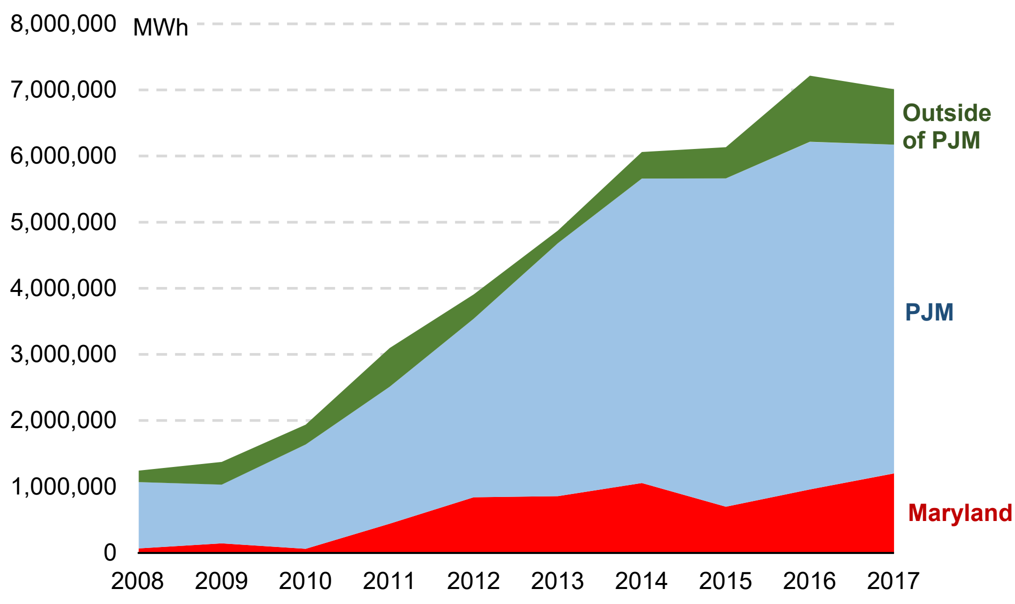

Figure 2-68. Origin of Tier 1 RECs Retired for Maryland RPS Compliance

Source: PJM-GATS. Note: "Outside of PJM" does not include resources located in non-PJM portions of states that are partially served by PJM.

[157] This approach treats all resources in states with partial PJM participation, such as North Carolina, Michigan, and Tennessee. This approach may treat some resources that are actually located outside of PJM as within PJM.

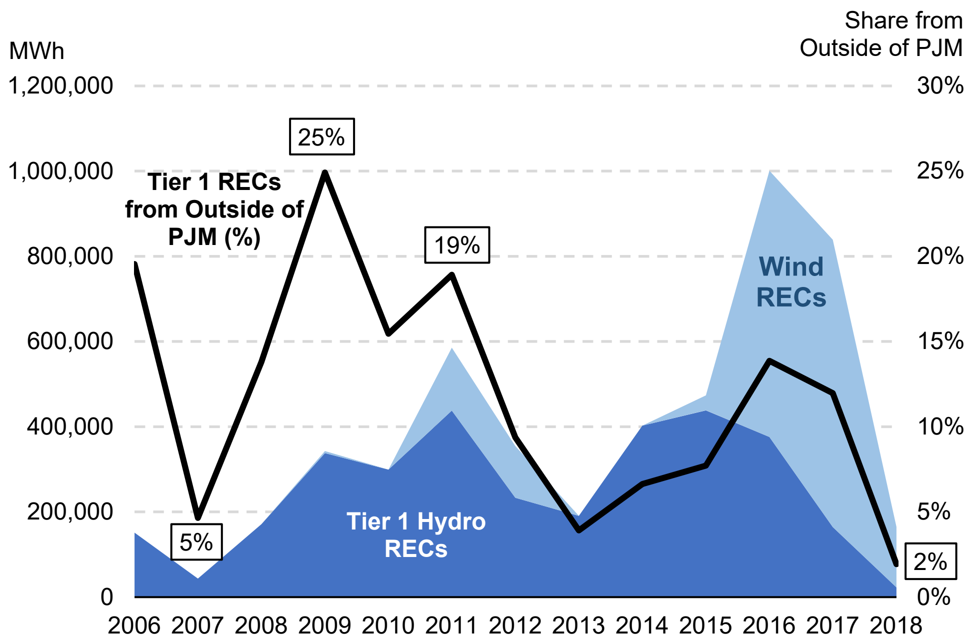

Figure 2-69. Tier 1 Hydro and Wind RECs Retired by Plants Outside of PJM States

Source: PJM-GATS. Note: "Outside of PJM" does not include resources located in non-PJM portions of states that are partially served by PJM.

2.6.6. Lowering Alternative Compliance Payment Levels

To show compliance with the Maryland RPS, LSEs must retire the appropriate number of RECs in a tracking account or pay an ACP. Except at the outset of the solar carve-out in 2008-2010, LSEs have rarely used ACPs for compliance with the Maryland RPS, as described earlier in Subsection 2.4.1, "Availability of Renewable Energy at Affordable and Reasonable Rates." During the first year of the solar carve-out in 2008, LSEs relied on ACPs for 92% of the RPS obligation. In 2009, ACP reliance dropped to 47%. In 2010, it fell to 3%. Other than this period, the use of ACPs for RPS compliance, for any tier, has always been below one-fifth of 1%. ACP reliance has been minimal because low load growth and a large increase in the number of new renewable energy projects, including solar, have resulted in more RECs than are needed to meet state RPS requirements. As a result, Tier 1 REC prices for both solar carve-out and non-carve-out resources have fallen in recent years, especially from 2016-2017. Figure 2-70 and Figure 2-71 compare solar carve-out and non-carve-out

REC prices with ACPs for all tiers between 2008-2018. In all cases, REC prices have been significantly lower than the corresponding ACP.

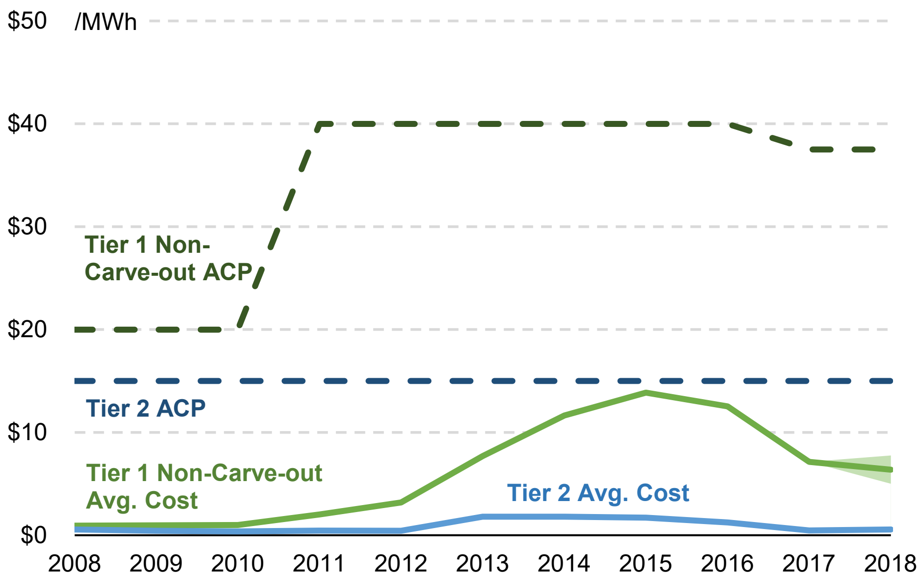

Figure 2-70. Tier 1 Non-Carve-out and Tier 2 Average Cost of RECs Compared to Alternative Compliance Payment Costs

Source: Average costs for 2008-2017 sourced from the Maryland PSC 2018 *Renewable Energy Portfolio Standard Report*. Average costs for 2018 (presented as a range) sourced from Marex Spectrometer.

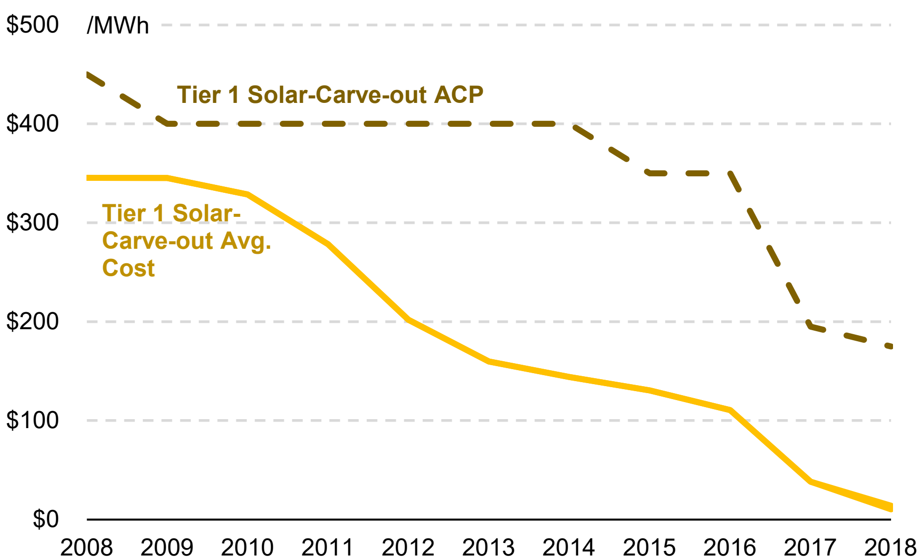

Figure 2-71. Tier 1 Solar Carve-out Average Cost of RECs Compared to Alternative Compliance Payment Costs

Source: Average costs for 2008-2017 sourced from the Maryland PSC 2018 *Renewable Energy Portfolio Standard Report*. Average costs for 2018 sourced from Marex Spectrometer.

Effective in 2017, HB 1106 lowered both Tier 1 and SREC ACPs in an attempt to account for reductions in renewable energy costs as well as to further strengthen the cost-cap aspects of the ACP. The ACP for Tier 1 RECs was lowered from $40 to $37.50/MWh, which is still well above the cost of Tier 1 RECs in 2018. The ACP for SRECs was adjusted so that it declines steadily from $150/MWh in 2019 to $50/MWh in 2024, rather than in a stairstep fashion. The solar ACP adjustments are illustrated in Figure 2-72. SREC spot market prices in 2018, which averaged between $7 and $16/MWh according to Marex Spectrometer data, were well below the updated ACPs.

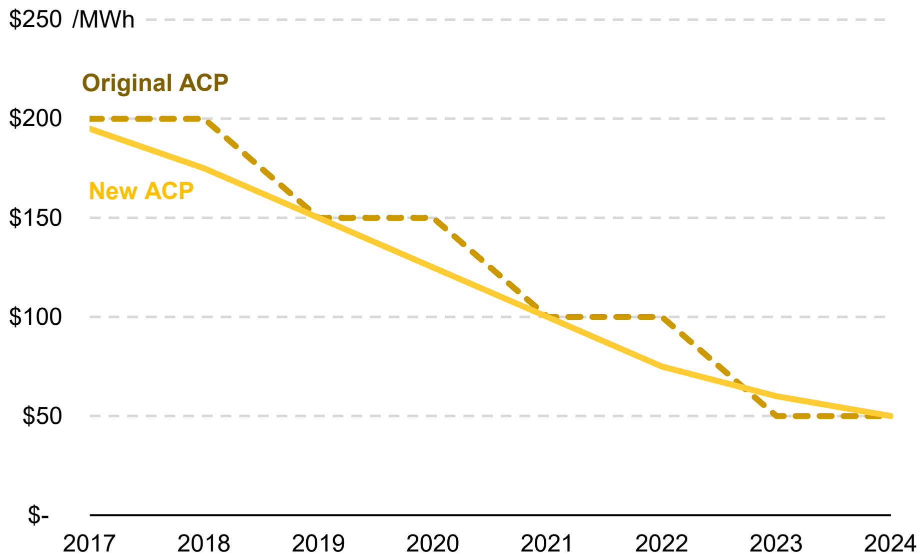

Figure 2-72. Comparison of Original and Current Tier 1 Solar Alternative Compliance Payment Levels

3. Maryland RPS Moving Forward

This chapter of the final report looks ahead, evaluating RPS requirements from multiple perspectives, including resource availability, resource potential, environmental impacts, and economic impacts. Discussions consider impacts over the next decade, or longer in certain cases. Because research and analysis for this chapter began in summer 2018, the chapter considers primarily the 25% Maryland RPS that was in effect at the time. Several sections also consider the possible impacts of a 50% Maryland RPS.

Section 3.1, "Meeting Existing and Future Targets" discusses whether Maryland can meet its RPS requirements by relying on capacity in PJM. The section relies on PPRP's interim report, which catalogues all RPS-eligible capacity in PJM, projects the growth of such capacity and generation, and compares these values with projected RPS requirements for all states in PJM that have RPS policies.

Section 3.2, "Potential for Renewable Energy Generation in Maryland and PJM" looks more broadly at the potential for renewable energy generation in the region. It draws primarily on research conducted by NREL to estimate the technical potential for renewable energy projects in both Maryland and PJM, and the portion of this generation that would be economic.

Section 3.3, "Impact of the Maryland RPS on Air Emissions" considers the impact of the Maryland RPS on in-state air emissions and the carbon content associated with electricity consumption in the state. It relies on production cost modeling conducted for PPRP's 2016 LTER. This modeling included: simulations of separate hourly energy and annual capacity markets in PJM; the dispatch of individual generating units; and conventional power plant capacity additions, retirements, and retrofits.

Section 3.4, "Impact of the Maryland RPS on Jobs and Economic Output" discusses the impact of the Maryland RPS on in-state job creation and economic activity, as well as opportunities to enhance this impact. It relies on input-output (I-O) modeling conducted for this report using IMPLAN (IMpact analysis for PLANning), a widely used framework for estimating economic impacts. Like all I-O models, IMPLAN is based on the interdependencies that exist in the economy. IMPLAN divides the economy into 536 sectors, comprising industry, government, and households, and then tracks the dollar flows between them.

Finally, Section 3.5, "Future Ratepayer Impacts in Maryland" considers the likely impact of Maryland's 25% RPS on customer bills. It is based on projections for REC, SREC, and OREC prices. These projections incorporate REC/SREC forward prices, load projections from the Maryland PSC's *Ten-Year Plan (2018-2027) of Electric Companies in Maryland*, sector-based electricity rate projections from EIA, and PSC-approved OREC rates.

As is the case throughout this report, each section begins with a short introduction and a summary of key findings.

3.1. Meeting Existing and Future Targets

PPRP has prepared two editions of the Renewable Energy Inventory.[158] These inventories evaluate whether there are enough operating, planned, and projected renewable energy

[158] Jim McVeigh, Joseph Cohen and Kevin Porter, *et al.*, *Inventory of Renewable Energy Resources Eligible for the Maryland Renewable Energy Portfolio Standard*, Maryland Department of Natural Resources, Power Plant Research Program, 2006, ntrl.ntis.gov/NTRL/dashboard/searchResults/titleDetail/PB2006110517.xhtml; Christina Mudd,

resources that deliver power in PJM to meet current and projected RPS requirements throughout the states in PJM. Data in this section are based on the unpublished third edition, as summarized in the interim report, which evaluates whether the projected supply of RPS-eligible generation is sufficient for a 25% Maryland RPS (i.e., current law when the interim report was written) or a 50% Maryland RPS modeled on legislation introduced, but not yet passed, in 2018.[159] The report has two key findings:

1. There is enough operating and projected solar generation in Maryland to meet the solar carve-out requirement of the (now-superseded) 25% Maryland RPS. Likewise, there are enough Tier 1 non-carve-out resources in the PJM service area to meet all state RPS requirements within PJM, including Maryland's, through 2030.
2. Under a 50% Maryland RPS, non-solar-carve-out (i.e., inclusive of the offshore wind carve-out) Tier 1 requirements of state RPS policies within PJM would be met through 2020, and from 2028-2030, but will not be met from 2021-2027. Anticipated growth in solar capacity would make it possible to meet the 14.5% solar carve-out requirement in 2030, but not in the years leading up to 2030 (i.e., 2019-2029).

These projections do not account for reliance on outside-of-PJM renewable generation (for Tier 1 non-carve-out RECs) or the market dynamics of increasing or decreasing REC and SREC prices. Higher REC and SREC prices, due to potential shortfalls, would provide an incentive for renewable energy project developers to construct new qualifying projects inside Maryland and the rest of PJM. Also note that the 50% scenario presented in the interim report is distinct from the CEJA.

3.1.1. Meeting RPS Requirements Under the 25% Maryland RPS

Table 3-1 and Table 3-2 identify the anticipated non-solar-carve-out Tier 1 and solar generation requirements for state RPS policies in PJM, including the (now superseded) 25% RPS in Maryland, and the expected renewable and solar energy generation, both from existing and future renewable and solar energy resources. The assumptions used to derive these estimates are described in the interim report. (Several assumptions that warrant mention, because they may have a significant impact on the final report's conclusions, are summarized later in Subsection 3.1.3., "Key Assumptions in the Interim Report.") This includes assumptions for the growth rates of various forms of renewable energy capacity in PJM. As shown in Table 3-1, anticipated solar development is more than sufficient to meet Tier 1 solar requirements of Maryland and other states in PJM. (Note that solar development is assumed to occur in states where it is required by RPS carve-outs. PJM-wide solar development estimates are used primarily to determine whether solar generation is likely to exceed solar carve-out requirements, in aggregate.) Some of the solar development that exceeds the solar carve-out requirements of state RPS policies can also contribute to meeting some of the non-solar-carve-out Tier 1 requirements, as shown in Table 3-2. For non-solar-carve-out Tier 1 generation, state RPS requirements within PJM are met through 2021, and from 2026-2030. The deficits from 2022-2025 are relatively small after accounting for "excess solar," over and above any solar carve-out requirements, that could

Patrick O'Connor and Bill Choate, *et al.*, *Inventory of Renewable Energy Generators Eligible for the Maryland Renewable Energy Portfolio Standard*, Maryland Department of Natural Resources, Power Plant Research Program, 2012, ntrl.ntis.gov/NTRL/dashboard/searchResults/titleDetail/PB2012100430.xhtml.

[159] The interim report was revised in 2018, based on feedback PPRP received in response to the draft report. At that time, the report was also updated to reflect the passage of a 50% RPS in New Jersey and the proposed 50% RPS requirements in Maryland HB 1543. Subsequent changes to the Maryland RPS (e.g., Ch. 757) or other state RPS policies are not reflected in these estimates.

be used to meet Tier 1 non-carve-out requirements. These results are also illustrated in Figure 3-1 and Figure 3-2.

For all the states in PJM with RPS policies to meet their non-solar-carve-out Tier 1 RPS requirements by 2030 from resources in PJM, available non-solar-carve-out Tier 1 renewable energy generation in PJM, including offshore wind and "excess solar" above solar carve-out requirements, would require an annual growth rate (from 2017-2030) of approximately 6.6%. As noted above, this rate of required growth in PJM renewable generation does not recognize the potential for reliance on outside-of-PJM renewable generation or the market incentive for renewable project developers to construct qualifying new projects. As a result, it is likely that enough renewable energy resources would continue to be available to supply the Maryland 25% RPS and other states' RPS requirements.

Table 3-1. Solar RPS Requirements in PJM Compared to Projected Available Solar Energy Generation in PJM, 25% RPS (GWh)

Year	Generation Requirement	Projected Generation	Excess Solar
2018	5,094	13,065	7,971
2019	6,457	16,255	9,798
2020	7,509	19,445	11,936
2021	7,932	22,362	14,430
2022	8,141	25,716	17,575
2023	8,354	29,574	21,220
2024	8,403	34,010	25,607
2025	8,531	39,111	30,580
2026	8,525	44,978	36,452
2027	8,463	51,724	43,261
2028	8,520	59,483	50,963
2029	8,572	68,405	59,834
2030	7,025	78,666	71,642

Source: Interim report.

Table 3-2. Non-Solar-Carve-out Tier 1 RPS Requirements in PJM Compared to Projected Available Renewable Energy Generation in PJM, 25% RPS (GWh)

Year	Generation Requirement	Projected Generation	Excess Solar[1]	Net
2018	49,354	51,065	7,971	**9,681**
2019	57,207	53,563	9,798	**6,154**
2020	64,797	56,061	11,936	**3,200**
2021	72,394	58,362	14,430	**398**
2022	77,820	59,749	17,575	**(496)**
2023	83,347	61,591	21,220	**(536)**
2024	89,324	62,978	25,607	**(739)**
2025	95,132	64,365	30,580	**(186)**
2026	100,697	65,752	36,452	**1,508**
2027	103,467	67,139	43,261	**6,933**
2028	106,341	68,526	50,963	**13,148**
2029	109,052	69,913	59,834	**20,695**
2030	111,799	71,300	71,642	**31,143**

Source: Interim report.

[1] From *Table 3-1*.

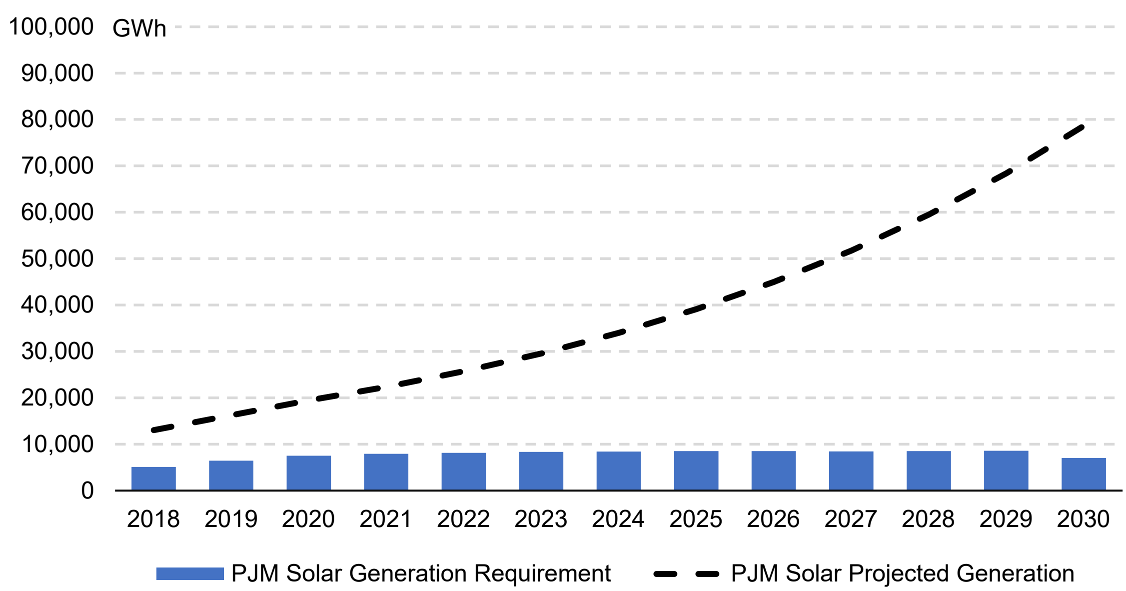

Figure 3-1. Solar RPS Requirements in PJM Compared to Projected Available Solar Energy Generation in PJM, 25% RPS

Source: Interim report.

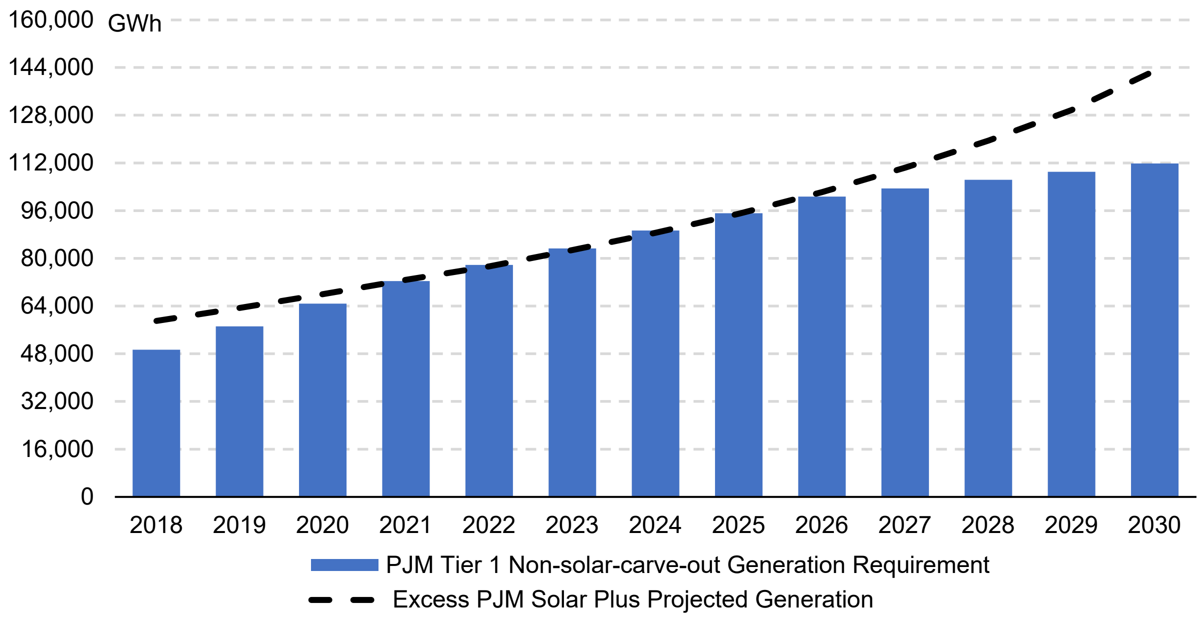

Figure 3-2. Non-Solar-Carve-out Tier 1 RPS Requirements in PJM Compared to Projected Available Renewable Energy Generation in PJM, 25% RPS

Source: Interim report.

3.1.2. Meeting RPS Requirements Under a 50% Maryland RPS Scenario

In the years leading up to 2019, when the passage of SB 516 raised the Maryland RPS to 50%, several similar bills were introduced. One example, presented in Table 3-3, is taken from HB 1453, which was introduced in the 2018 session of the Maryland General Assembly, but was not enacted. The bill called for a 50% RPS by 2030, including a 14.5% solar carve-out and a PSC-determined offshore wind carve-out not to exceed 10% from 2025 onward. The bill's proposed RPS requirement schedule began in 2019, and it did not include a Tier 2 requirement. These are the requirements used to evaluate a 50% RPS in the interim report.

Table 3-3. Interim Report 50% RPS Scenario

Year	Tier 1 Solar[1]	ORECs[1]	Tier 1 Non-Carve-out	TOTAL
2018[2]	1.50%	0.00%	14.30%	**15.80%**
2019	5.50	2.50	18.20	**26.20**
2020	6.00	2.50	19.50	**28.00**
2021	6.75	2.50	20.80	**30.05**
2022	7.25	2.50	22.10	**31.85**
2023	8.75	2.50	23.40	**34.65**
2024	10.25	2.50	24.70	**37.45**
2025	11.50	10.00	18.50	**40.00**
2026	12.50	10.00	20.00	**42.50**
2027	13.50	10.00	22.00	**45.50**
2028	14.50	10.00	23.00	**47.50**
2029	14.50	10.00	25.00	**49.50**
2030	14.50	10.00	25.50	**50.00**

Source: Interim report.

[1] Note that the interim report was written before Ch. 757 was enacted in May 2019. The Tier 1 solar carve-out requirements shown above are almost identical to those in Ch. 757; they differ only in the years 2020-2023. However, the requirements for offshore wind are different from Ch. 757, and therefore produce somewhat different results than the requirements in Ch. 757 would produce.

[2] The 2018 total includes 2.5% for the final year of Tier 2 compliance.

The percentages from Table 3-3 are applied to the total retail sales projections discussed in the interim report to produce RPS requirements in Maryland, in GWh, as shown in Table 3-4. These estimates assume that other PJM jurisdictions maintain the trajectory of their RPS requirements through 2030.

Table 3-4. RPS-Eligible Generation Required in Maryland, 50% RPS Scenario (GWh)

Year	Tier 1 Solar	ORECs	Tier 1 Non-Carve-out	TOTAL
2018	916	-	8,730	**9,646**
2019	3,353	1,524	11,097	**15,975**
2020	3,667	1,528	11,919	**17,115**
2021	4,129	1,529	12,725	**18,384**
2022	4,443	1,532	13,544	**19,519**
2023	5,376	1,536	14,377	**21,288**
2024	6,315	1,540	15,217	**23,072**
2025	7,100	6,174	11,422	**24,696**
2026	7,733	6,186	12,373	**26,292**
2027	8,368	6,199	13,637	**28,204**
2028	9,006	6,211	14,286	**29,503**
2029	9,024	6,224	15,559	**30,807**
2030	9,042	6,236	15,902	**31,181**

Source: Interim report.

Doubling the Maryland RPS requirement increases competition for Tier 1 non-carve-out resources in PJM because LSEs in the other states in PJM must vie for most of the same Tier 1 resources to meet their respective RPS requirements. As indicated in Table 3-5, under the 50% RPS, the deficits would range over a greater number of years (2021-2027), and the amounts of the deficits would be higher (reaching 8,089 GWh in 2024) than under the 25% RPS. That said, it is projected in the interim report that the 50% requirement would be met through 2020, and from 2028-2030, as shown in Table 3-5 and Figure 3-3.

Table 3-5. Non-Solar-Carve-out Tier 1 RPS Requirements in PJM, 50% RPS Scenario (GWh)

Year	RPS Generation Requirements in PJM (A)	Projected Supply of RPS-Eligible Generation in PJM (B)	Excess PJM Solar (14.5% Solar Carve-out in Maryland) (C)	Difference Between Projected RPS Requirements and Generation (B)+(C)-(A)
2018	49,354	51,065	7,971	**9,681**
2019	58,579	55,087	7,634	**4,142**
2020	64,492	57,589	9,797	**2,894**
2021	72,783	58,978	11,830	**(1,976)**
2022	79,008	60,367	14,664	**(3,977)**
2023	85,283	61,758	17,380	**(6,145)**
2024	92,070	63,149	20,832	**(8,089)**
2025	98,689	69,170	25,024	**(4,496)**
2026	105,192	70,569	30,266	**(4,357)**
2027	109,214	71,969	36,442	**(803)**
2028	112,723	73,368	43,509	**4,154**
2029	116,694	74,767	52,365	**10,438**
2030	119,771	76,167	64,158	**20,554**

Source: Interim report.

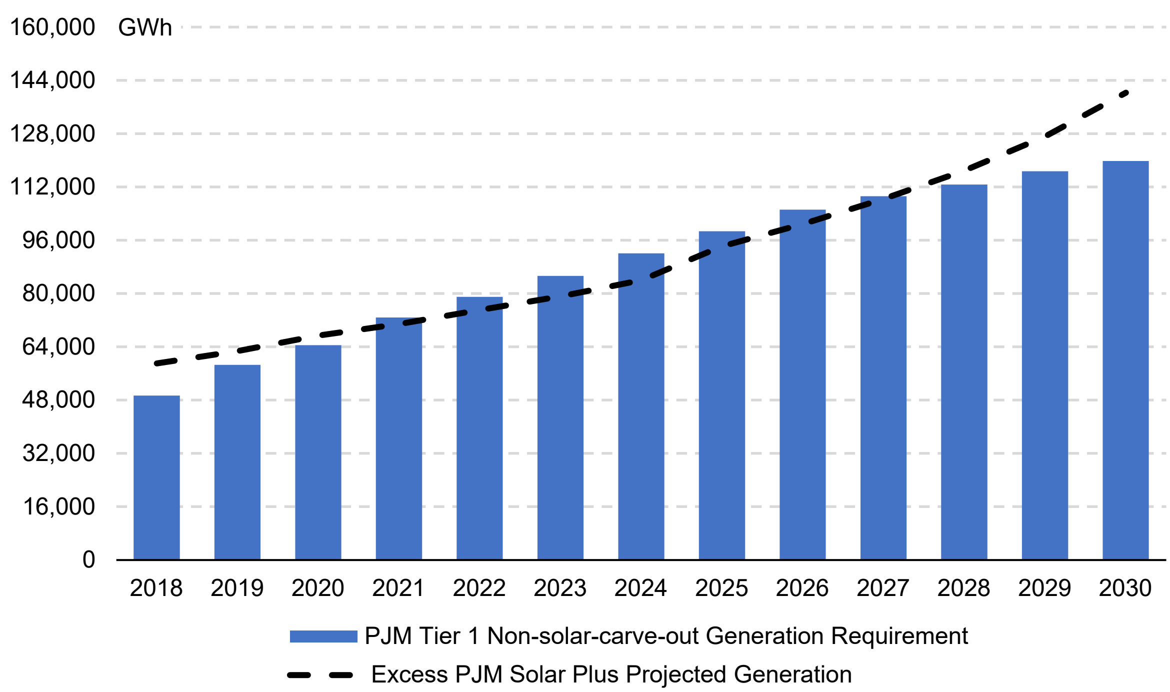

Figure 3-3. Non-Solar-Carve-out Tier 1 RPS Requirements in PJM, 50% RPS Scenario

Source: Interim report.

Table 3-6 and Figure 3-4 compare a 14.5% solar carve-out generation requirement (under the 50% RPS scenario) with current and projected solar energy generation. As shown in Table 3-6 and Figure 3-4, Maryland would not meet a 14.5% solar carve-out until 2030.

Table 3-6. Projected Maryland Solar Energy Generation, 14.5% Solar Carve-out, 50% RPS Scenario (GWh)

Year	14.5% Solar Carve-out Generation Requirement	Projected Generation	Difference
2018	916	2,055	**1,139**
2019	3,353	2,231	**(1,122)**
2020	3,667	2,407	**(1,261)**
2021	4,129	2,768	**(1,361)**
2022	4,443	3,183	**(1,260)**
2023	5,376	3,661	**(1,715)**
2024	6,315	4,210	**(2,105)**
2025	7,100	4,841	**(2,259)**
2026	7,733	5,567	**(2,166)**
2027	8,368	6,402	**(1,966)**
2028	9,006	7,363	**(1,644)**
2029	9,024	8,467	**(557)**
2030	9,042	9,737	**695**

Source: Interim report.

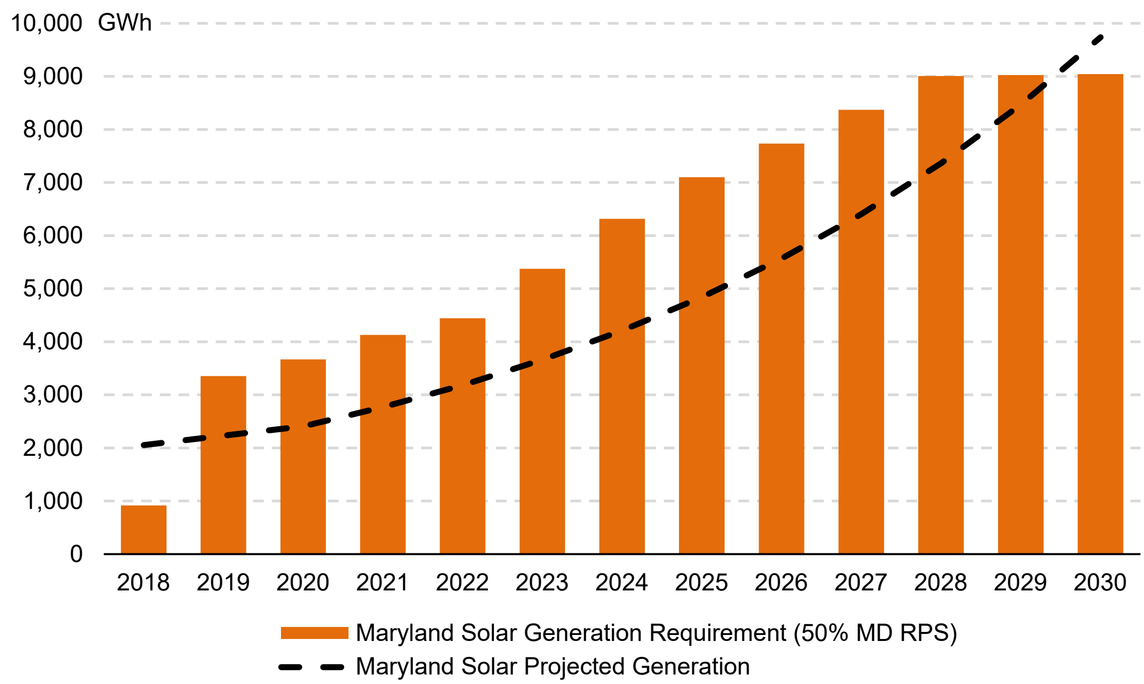

Figure 3-4. 14.5% Solar Carve-out Tier 1 Requirements in Maryland Compared to Projected Maryland Solar Generation, 50% RPS Scenario

Source: Interim report.

Again, market dynamics will affect the degree to which Maryland will be able to meet its renewable energy requirements using PJM and outside-of-PJM resources. With any increase in the Maryland RPS requirement, Maryland REC prices may increase. RECs that would have otherwise been used to satisfy the RPS requirements in other states may be applied to the Maryland RPS for economic reasons. This results in upward pressure on REC prices in other states in PJM, since those states compete with Maryland for the same pool of RECs. With an increase in REC prices, renewable energy projects that would have been unprofitable at lower REC prices may become profitable, and therefore be built, thus increasing the total amount of RECs available in the market to meet the higher Maryland requirements. Additionally, projects located outside of PJM find selling renewable energy into PJM more attractive, thus increasing the pool of available RECs from sources external to PJM. In short, the complex interrelationships of REC prices, project development, ACP levels, and power supply imports from other RTOs/ISOs affect the degree to which Maryland can meet a 50% RPS requirement or whether the requirement would be met, at least for a period of time, with payment of ACPs in lieu of the retirements of Maryland-eligible RECs.

3.1.3. Key Assumptions in the Interim Report

The interim report contains several assumptions that may have a significant impact on the report's conclusions. The following bullets summarize these key assumptions and, in certain cases, discuss the potential impact of changing these assumptions:

- For solar generation projections through 2020, the active and under-construction projects in the PJM Generation Interconnection Queue (PJM Queue) for 2015 through 2017 were aggregated and then multiplied by 24% to estimate the projects that would reach in-service status over a period of three years (the average time for a project to go into service after entering the queue). The resulting total of approximately 5,100 MW was then divided by three and incrementally added over three years (2018, 2019, and 2020) to the base 2017 installed capacity. From 2021-2030, the solar projections are based on a growth rate of 15%, which is one-half of the average annual growth rate of solar generation in PJM from 2014-2017.

- The capacity growth rates for PJM, with the exception of onshore and offshore wind, were calculated using the average annual capacity additions for the years 2009-2017. Onshore wind projections began with the average annual capacity additions like the other technologies, but were then decreased by 50% in 2021. The assumption here is that new onshore wind capacity will decrease upon the expiration of the federal PTC, although exactly how much of a decrease differs among several industry forecasters. Offshore wind capacity additions were based specifically on the two projects already approved by the Maryland PSC, but do not include potential incremental offshore wind capacity in other states, such as New Jersey.[160]
- It is assumed that states in PJM will not change their existing RPS policies, and that states in PJM without an RPS will remain that way during the next 12 years. If a state strengthens or weakens its RPS, or a state previously without an RPS enacts one, that will affect the results of the interim report.
- Higher load growth than assumed will increase the demand for RPS-eligible generation within PJM. The opposite holds true if load growth is lower than assumed.
- Only eligible resources and demand within states in PJM were examined in the interim report, but renewable energy resources that are located outside of PJM are also eligible to meet Tier 1 non-carve-out requirements in PJM. In 2017, 14% of Tier 1 non-carve-out requirements in Maryland were met using outside-of-PJM resources.[161] Depending on market conditions, a higher percentage of outside-of-PJM resources could conceivably be used to meet Maryland RPS requirements.
- It is assumed that all projected generation is available for RPS compliance. In reality, some of this generation and the associated RECs may be contracted to entities that are retiring those RECs for reasons other than RPS compliance (e.g., corporate procurement and other voluntary green power markets).
- The capacity growth rates for PJM, with the exception of solar, onshore wind, and offshore wind, were calculated using the average annual capacity additions from the years 2009-2017. In aggregate, Tier 1 non-carve-out renewable energy projects have an estimated capacity growth rate from 2018-2030 of 3%. Black liquor, geothermal, and waste-to-energy are not expected to experience any market growth during this period.
- Solar generation projections from 2021-2030 are based on a growth rate of 15%, which is one-half of the average annual growth rate of solar generation in PJM from 2014-2017. Uncertainties that may affect future solar market growth include the

[160] There is considerable uncertainty regarding the construction and service dates of both offshore wind projects. For the purposes of the final report, in-service dates of 2021 for US Wind and 2023 for Skipjack were assumed, with construction taking place during the preceding year. These dates do not account for recent adjustments in the US Wind project schedule.

[161] Derived using data from: Public Service Commission of Maryland, *Renewable Energy Portfolio Standard Report*, November 2018, psc.state.md.us/wp-content/uploads/FINAL-Renewable-Energy-Portfolio-Standard-Report-with-data-for-CY-2017.pdf.

impact of the reduction in, or expiration of, the federal ITC;[162] the imposition of tariffs on imported solar cells and panels; and anticipated continued decreases in the costs of solar energy.

- Several utilities plan to add more solar capacity. For example, in Virginia, Dominion Energy, Inc. (Dominion) states it could add at least 5,200 MW of solar over the next 25 years. As of May 2019, the company had 250 MW of solar PV under construction in Virginia.[163] Meanwhile, Appalachian Power's 2017 Integrated Resource Plan (IRP) includes plans for adding 525 MW by 2031.[164] This capacity is not incorporated in the interim report. Should these or other comparable plans come to fruition, either partially or fully, it may add to the available generation to meet non-solar-carve-out Tier 1 requirements in PJM. However, some of these RECs may be earmarked for other uses, such as fulfilling corporate renewable energy procurement targets.
- Onshore wind projections began with the average annual capacity additions like the other technologies, but they were then decreased by 50% in 2021. The assumption here is that new onshore wind capacity will decrease upon the expiration of the federal PTC, although exactly how much of a decrease differs among several industry forecasters.[165]
- Future offshore wind capacity is limited to the two projects approved by the Maryland PSC. However, substantially more offshore wind capacity could be developed within PJM. New Jersey has a goal of 3,500 MW of offshore wind by 2030, for instance, and Dominion recently contracted with Ørsted to construct two 6-MW turbines off the coast of Virginia Beach by 2022. States outside of PJM such as Massachusetts and New York also have ambitious offshore wind initiatives underway. Further cost reductions in offshore wind could lead to additional growth in Maryland.

Further assumptions used for the interim report are provided in Appendix F.

3.2. Potential for Renewable Energy Generation in Maryland and PJM

The development of renewable energy sources in the U.S. and globally has grown rapidly in the last two decades. According to EIA, renewable energy sources accounted for approximately 9% of electricity generation in 2001, largely from hydro.[166] By 2018, this share had grown to 16%. Globally, renewables accounted for over three-fourths of new

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[162] The ITC is scheduled to decrease from 30% to 10% for commercial installations in 2022. The ITC for residential customers expires altogether in 2022. The ITC percentage for a project is determined based on the year in which project construction begins. Projects must enter service before 2024 to receive credits greater than 10%, per the Internal Revenue Service (IRS) 2018 safe harbor guidance. *See:* irs.gov/pub/irs-drop/n-18-59.pdf for more information.

[163] Dominion Energy, "Virginia Solar Projects," dominionenergy.com/company/making-energy/renewable-generation/solar-generation/virginia-solar-projects.

[164] Appalachian Power, *Integrated Resource Planning Report to the Commonwealth of Virginia State Corporation Commission*, Case No. PUR-2017-00045, 2017, appalachianpower.com/global/utilities/lib/docs/info/projects/APCOIntegratedResourcePlans/2017APCOVAIRPPublicVersion04262017.pdf.

[165] The PTC is scheduled to phase out between 2016-2019, decreasing by 20 percentage point increments. The percentage a project receives is determined based on the year in which project construction begins so long as the project enters service within four years. *See:* irs.gov/pub/irs-drop/n-16-31.pdf for additional information.

[166] Inclusive of large hydro, wind, geothermal, biomass, wood and wood-derived fuels, and solar. Solar generation figures only include utility-scale projects until January 2014, after which small-scale solar PV projects are included. *Source:* U.S. Energy Information Administration, "Net generation, United States, all sectors, monthly," October 2018, eia.gov/electricity/data/browser/.

electricity capacity in 2018, according to the International Renewable Energy Agency (IRENA).[167] Concurrent with the rapid expansion of renewable energy capacity, the LCOE of many renewable energy resources has plummeted. Notably, the global weighted-average LCOE of utility-solar PV and onshore wind resources fell by 73% and 23%, respectively, between 2010-2017 according to the IRENA Renewable Cost Database.[168] The direction and magnitude of this trend is consistent with Lazard's findings of approximately 88% and 69% drops in the average LCOE of utility-scale solar PV and onshore wind, respectively, in the U.S. between 2009-2018.[169] As a consequence, renewable energy is available at rates that are becoming more cost-competitive with existing fossil fuel generation and, after accounting for subsidies and incentives, can be lower than other resources.[170] Renewable energy projects in states with especially strong wind or solar resources, such as Colorado and Arizona, have tended to be the first to rival fossil fuel generation purely on cost.

The market and policy forces contributing to the availability and declining costs of renewable energy resources in the U.S. and globally are also at work in Maryland and PJM. The trajectory of renewable energy development in Maryland and PJM, both in terms of capacity and cost, is important to Maryland stakeholders insofar as it impacts the state's ability to meet its RPS requirements. This section of the final report reviews recent research estimating the economic and technical viability of renewable generation in Maryland and PJM. Key findings from the section include the following:

- Based on analyses conducted by NREL, Maryland and PJM have more technical and economic renewable energy resource potential than needed to meet current and projected RPS requirements in Maryland and within PJM during the next decade.
- Specifically, NREL estimates that the states in PJM have the technical potential to sustain 41,499,625 GWh, or 23,808 GW, of annual generation by solar, wind, hydro, and biopower resources. Under a set of assumptions specified by NREL, approximately 235,000 GWh of this potential would be economic in addition to already existing levels as of 2013 (i.e., incremental to 2013 generation). This economic potential exceeds the projected 2030 RPS requirement of the 50% Maryland RPS scenario from the interim report for the states in PJM (134,300 GWh) by nearly 75%.
- Based on the same NREL analyses, Maryland has the technical potential to sustain over 920,000 GWh, or 500 GW, of annual generation by solar, wind, hydro, and biopower resources. Approximately 5,400 GWh of this potential would be economic and incremental to 2013 generation levels. This includes 4,900 GWh of distributed PV potential, which exceeds the projected 2030 solar carve-out requirement of the 50% Maryland RPS scenario from the interim report for Maryland (1,559 GWh) by over 200%.
- In addition to distributed PV, the economic resource potential that NREL identified in Maryland includes 300 GWh of onshore wind and 200 GWh of hydro. (This hydro

[167] International Renewable Energy Agency, "Renewable Capacity Highlights," March 2019, irena.org/-/media/Files/IRENA/Agency/Publication/2019/Mar/RE_capacity_highlights_2019.pdf?la=en&hash=BA9D38354390B001DC0CC9BE03EEE559C280013F&hash=BA9D38354390B001DC0CC9BE03EEE559C280013F.

[168] International Renewable Energy Agency, *Renewable Power Generation Costs in 2017*, October 2018, irena.org/-/media/Files/IRENA/Agency/Publication/2018/Jan/IRENA_2017_Power_Costs_2018.pdf, Figure 2.1.

[169] *Lazard's Levelized Cost of Energy Analysis: Version 12.0*, November 2018, lazard.com/media/450784/lazards-levelized-cost-of-energy-version-120-vfinal.pdf.

[170] U.S. Energy Information Administration, "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2019," eia.gov/outlooks/aeo/pdf/electricity_generation.pdf.

potential would involve new, small-scale dams or powering existing dams that currently serve other purposes.) No new biopower was found to be economic.

- Some of the technical potential NREL identified is duplicative, because NREL did not preclude different forms of generation, such as wind and solar, being developed in the same physical space. On the other hand, NREL's report was published in 2012, and therefore does not capture certain advances, such as higher wind turbines, that have increased the technical potential of renewable energy resources.
- NREL's analysis of economic potential is based on 2014 data. As renewable energy generation costs continue to decline, particularly for wind and solar projects, additional renewable energy generation has or will become economic. Thus, NREL's estimates of economic potential can be understood as a lower bound.

3.2.1. Aggregate Technical and Economic Potential

Several NREL studies of renewable energy resource potential suggest a substantial amount of renewable energy capacity is available in both Maryland and PJM. These studies, which examine renewable energy potential along both technical and economic dimensions, are largely consistent with parallel studies conducted by other federal, state, and private-sector entities. This body of existing research is the focus of this subsection. It is also backed up by evidence that project developers continue to add a high number of potential new renewable energy projects to the PJM Queue for near-term development, as shown in Appendix G.

NREL develops resource- and region-specific estimates of renewable energy potential. Although these estimates do not indicate where and when developers will propose projects, they do reveal the aggregate renewable energy potential of certain areas based on specified conditions, including technical and economic characteristics. NREL has published two separate comprehensive, U.S.-wide reports evaluating renewable energy's technical and economic potential, respectively, as well as a comprehensive assessment of offshore wind technical potential.[171] Select findings from these reports are summarized for PJM in Table 3-7 and Table 3-8. The resource potential identified in these reports, measured both in terms of installed capacity and estimated generation, is sensitive to the assumptions employed. Additional recent NREL research assessing specific renewable energy technologies, as well as other DOE and state

Use of the Term "PJM States"

Throughout this subsection, statistics are provided on renewable energy potential in the District of Columbia, which is wholly served by PJM, and in the 13 states that are wholly served, or served in part, by PJM. This renewable energy potential includes the portions of each state that lie outside of PJM's service territory. These areas are considered pertinent, since they can deliver energy into PJM. Thus, new renewable resource projects in these areas could potentially retire RECs to comply with the Maryland RPS or the RPS requirements of other states within PJM. In this subsection, these states and the District of Columbia

[171] Anthony Lopez, Billy Roberts and Donna Heimiller, *et al.*, *U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis*, National Renewable Energy Laboratory, 2012, nrel.gov/docs/fy12osti/51946.pdf; Austin Brown, Philipp Beiter and Donna Heimiller, *et al.*, *Estimating Renewable Energy Economic Potential in the United States: Methodology and Initial Results*, National Renewable Energy Laboratory, 2016, nrel.gov/docs/fy15osti/64503.pdf; Walt Musial, Donna Heimiller and Philipp Beiter, *et al.*, *2016 Offshore Wind Energy Resource Assessment for the United States*, National Renewable Energy Laboratory, 2016, nrel.gov/docs/fy16osti/66599.pdf. Note that the latter two reports update the results of the first report to account for updated assumptions and data. Some of the data and assumptions used in these reports were drawn from DOE, EIA, EPA, and academic research, among other expert sources.

studies, are addressed in the following subsection, "Resource-Specific Technical and Economic Potential."

NREL conducted its first major assessment of technical resource potential (Lopez, *et al*., 2012) using geospatial analysis of environmental, topographical, and land use conditions. The resultant resource potential estimates account for both resource availability and quality as well as the generation potential and system performance characteristics of each assessed technology. These estimates represent upper-bound estimates of total resource potential because they do not account for limiting economic or regulatory factors. Key assumptions used by NREL in the initial technical potential study, as updated in the 2016 economic potential and offshore wind studies, include: the use of 80-meter onshore and 100-meter offshore wind turbines; the use of 1-axis tracking, utility-scale solar collectors; and biomass feedstock levels as reported in DOE's 2011 *Billion Ton Update*.[172] Concentrating solar, enhanced geothermal, and hydrothermal generation are not listed in Table 3-7 due to limited technical potential in states in PJM, according to NREL.

NREL's assessment of economic resource potential builds on the technical potential findings; a resource is economic if it is both technically feasible and the benefits outweigh the costs. Specifically, NREL compared the expected cost of generating electricity using a new renewable energy project (i.e., its LCOE), with the new project's value to the grid (i.e., its LACE). The LACE is equivalent to the value of utility services that are not necessary (i.e., avoidable) as a result of the new renewable energy project. If LACE is greater than LCOE, a project is considered economic. Although the technical potential estimates are irrespective of existing generation, NREL's economic potential estimates are incremental to 2013 generation levels. Consequently, some portion of the gap between technical and economic potential can be explained by including existing generation. Key variables used as part of the economic assessment include: capital costs; annual expected generation hours; fixed and variable O&M costs; fuel costs; wholesale electricity prices, represented as locational marginal prices (LMPs); cost of grid-ties; diminishing returns of increasing variable generation; and federal tax incentives. (Note that state-level incentives or payments, such as REC and SREC prices, are not incorporated.)

NREL developed multiple scenarios in order to evaluate the various sensitivities of its economic resource potential estimates. The numbers in Table 3-8 represent Primary Case 3B, in which the LACE includes the value of avoided external costs (i.e., avoided cost of carbon with a 3% discount rate), reflects the diminishing returns from higher levels of wind and solar generation (i.e., lower energy and capacity values), and assumes a very conservative $0/MWh capacity value for wind and solar.[173] Concentrating solar power, marine hydrokinetic, offshore wind, and enhanced geothermal were excluded from NREL's study of economic potential due to small market share, and are therefore not represented in Table 3-8. NREL did not identify any economic biopower or hydrothermal within states in PJM under the Primary Case 3B scenario. The complete list of considerations and definitions used by NREL for both the technical and economic estimates are outlined in the full reports. The values in Table 3-8 differ somewhat from the types of projects in the PJM Queue as of November 2018 (see Appendix G). In keeping with NREL's findings, solar PV and onshore wind make up the majority of renewable energy projects in the PJM Queue, and very little hydro or biomass has been proposed. However, the PJM Queue contains twice as much solar PV as onshore wind, while NREL's study found that the two technologies had nearly identical

[172] Oak Ridge National Laboratory, *U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry*, U.S. Department of Energy, 2011, energy.gov/sites/prod/files/2015/01/f19/billion_ton_update_0.pdf.

[173] Additional cases can be found at: Austin Brown, Philipp Beiter and Donna Heimiller, *et al.*, *Estimating Renewable Energy Economic Potential in the United States: Methodology and Initial Results*, National Renewable Energy Laboratory, 2016, nrel.gov/docs/fy15osti/64503.pdf, p. 98 (pdf page 125).

levels of economic potential. In addition, the PJM Queue contains several offshore wind projects. These differences underscore the changing economics of renewable energy projects and the importance of state-level policies and incentives, which were not factored into NREL's analysis.

Table 3-7. NREL Estimates of Technical Resource Potential for Select Renewable Energy Sources in PJM States

	UTILITY-SCALE PV		DISTRIBUTED PV				WIND				HYDRO		BIOPOWER[1]		TOTAL[2]	
			Residential		Commercial		Onshore		Offshore							
State	GW	GWh	GW	GWh	GW	GWh	GW	GWh	GW	GWh	GW	GWh	GW	GWh	GW	GWh
MD	**466.6**	**796,000**	**7.8**	**10,600**	**8.8**	**11,900**	**0.9**	**3,000**	**26.5**	**96,289**	**0.2**	**1,100**	**0.2**	**1,700**	**511.0**	**920,589**
DE	142.1	242,000	1.5	2,000	1.8	2,500	-	-	5.9	20,604	0.1	100	0.1	500	**151.5**	**267,704**
DC	-	-	0.2	300	0.9	1,300	-	-	-	-	-	-	-	-	**1.1**	**1,600**
IL	4,524.4	7,641,000	19.8	26,000	19.6	25,700	146.7	480,000	4.5	16,762	1.1	6,500	2.0	15,900	**4,718.1**	**8,211,862**
IN	2,787.3	4,612,000	13.0	16,800	15.6	20,100	85.0	274,000	1.0	3,423	0.5	2,900	0.9	7,400	**2,903.3**	**4,936,623**
KY	1,647.4	2,806,000	8.3	10,800	8.9	11,600	3.2	9,000	-	-	2.5	13,300	0.6	4,500	**1,670.9**	**2,855,200**
MI	3,402.7	5,395,000	20.8	25,900	23.6	29,200	50.4	151,000	57.3	199,440	0.1	500	2.3	18,100	**3,557.2**	**5,819,140**
NJ	257.3	438,000	12.2	16,100	13.3	17,500	-	-	71.2	280,193	0.1	500	0.1	100	**354.2**	**752,393**
NC	2,619.6	4,851,000	17.9	25,500	23.3	33,100	0.9	3,000	173.5	634,153	0.6	3,300	2.0	16,100	**2,837.8**	**5,566,153**
OH	2,352.0	3,796,000	22.4	28,000	27.7	34,600	57.1	165,000	18.0	62,657	0.5	2,600	1.2	9,400	**2,478.9**	**4,098,257**
PA	841.6	1,367,000	20.2	25,000	18.7	23,100	12.0	35,000	3.6	12,792	2.4	13,000	0.8	6,600	**899.3**	**1,482,492**
TN	1,822.5	3,107,000	12.3	16,800	13.2	18,000	2.3	7,000	-	-	0.6	3,300	1.0	7,600	**1,851.9**	**3,159,700**
VA	1,689.9	3,022,000	13.4	18,600	15.0	20,800	1.7	5,000	45.2	161,812	0.7	3,800	1.3	10,300	**1,767.2**	**3,242,312**
WV	92.5	156,000	4.0	5,100	4.3	5,600	3.2	10,000	-	-	1.0	5,000	0.5	3,900	**105.5**	**185,600**
TOTAL	**22,646**	**38,229,000**	**174**	**227,500**	**195**	**255,000**	**363**	**1,142,000**	**407**	**1,488,125**	**10**	**55,900**	**13**	**102,100**	**23,808**	**41,499,625**

Source: Offshore wind data are from nrel.gov/docs/fy16osti/66599.pdf (Appendices H and I). All other data are from nrel.gov/docs/fy15osti/64503.pdf (Appendix A), which updates the original assumptions laid out in nrel.gov/docs/fy12osti/51946.pdf.

Notes:

- There is limited potential for concentrating solar, enhanced geothermal, or hydrothermal generation in states in PJM, according to NREL estimates. NREL did not assess other potential renewable technologies that are in early stages of development.
- Estimates account for resource availability, resource quality, technology, environment, topography, and land use. They do not account for economic, market, political, or regulatory constraints. These figures are inclusive of both potential and existing resources (i.e., total technical capability).
- For ease of reference, resource estimates of less than 0.1 GW or 100 GWh are rounded up to 0.1 GW and 100 GWh, respectively.

[1] Biopower is inclusive of both solid (e.g., wood waste, crops) and gaseous (e.g., methane from animal manure, landfills, and wastewater treatment) sources of energy. Some sources, such as black liquor, depend on commercial enterprise and are not included.

[2] Estimates do not allocate land to a particular technology (i.e., the same land area may be the basis of estimates for multiple technologies). Although some technologies can coexist in the same area, the total estimates are likely inflated as a result of using this approach.

Table 3-8. NREL Estimates of Economic Resource Potential for Select Renewable Energy Sources in PJM States (GWh)

	UTILITY-SCALE PV			DISTRIBUTED PV (Res. + Comm.)			ONSHORE WIND			HYDRO			TOTAL[3]		
State	Tech.[1]	Econ.	%[2]	Tech.	Econ.	%	Tech.	Econ.	%	Tech.	Econ.	%	Tech.	Econ.	%
MD	**796,000**	**-**	**0.0%**	**22,500**	**4,900**	**21.8%**	**3,000**	**300**	**10.0%**	**1,100**	**200**	**18.2%**	**920,589**	**5,400**	**0.6%**
DE	242,000	-	0.0	4,500	300	6.7	-	-	0.0	100	-	0.0	**267,704**	**300**	**0.1**
DC	-	-	0.0	1,600	100	6.3	-	-	0.0	-	-	0.0	**1,600**	**100**	**6.3**
IL	7,641,000	-	0.0	51,700	100	0.2	480,000	38,900	8.1	6,500	4,800	73.8	**8,211,862**	**43,800**	**0.5**
IN	4,612,000	-	0.0	36,900	-	0.0	274,000	35,000	12.8	2,900	300	10.3	**4,936,623**	**35,300**	**0.7**
KY	2,806,000	-	0.0	22,400	800	3.6	9,000	-	0.0	13,300	11,000	82.7	**2,855,200**	**11,800**	**0.4**
MI	5,395,000	-	0.0	55,100	200	0.4	151,000	14,900	9.9	500	200	40.0	**5,819,140**	**15,300**	**0.3**
NJ	438,000	-	0.0	33,600	12,400	36.9	-	-	0.0	500	100	20.0	**752,393**	**12,500**	**1.7**
NC	4,851,000	-	0.0	58,600	800	1.4	3,000	200	6.7	3,300	500	15.2	**5,566,153**	**1,500**	**0.0**
OH	3,796,000	-	0.0	62,600	-	0.0	165,000	5,000	3.0	2,600	1,200	46.2	**4,098,257**	**6,200**	**0.2**
PA	1,367,000	-	0.0	48,100	-	0.0	35,000	200	0.6	13,000	7,000	53.8	**1,482,492**	**7,200**	**0.5**
TN	3,107,000	-	0.0	34,800	1,200	3.4	7,000	-	0.0	3,300	100	3.0	**3,159,700**	**1,300**	**0.0**
VA	3,022,000	78,100	2.6	39,400	11,700	29.7	5,000	1,800	36.0	3,800	100	2.6	**3,242,312**	**91,700**	**2.8**
WV	156,000	-	0.0	10,700	-	0.0	10,000	1,700	17.0	5,000	900	18.0	**185,600**	**2,600**	**1.4**
TOTAL	**38,229,000**	**78,100**	**0.2%**	**482,500**	**32,500**	**6.7%**	**1,142,000**	**98,000**	**8.6%**	**55,900**	**26,400**	**47.2%**	**41,499,625**	**235,000**	**0.6%**

Tech. = technical potential; Econ. = economic potential.

Source: Table 3-7 and nrel.gov/docs/fy15osti/64503.pdf (Appendix F).

Notes:

- NREL developed multiple scenarios in order to evaluate the various sensitivities of its economic resource potential estimates. The baseline framework assumptions are detailed in Appendix D of NREL's report. The numbers above represent Primary Case 3B, in which the LACE includes the value of avoided external costs (i.e., avoided cost of carbon with a 3% discount rate), reflects the diminishing returns from high levels of wind and solar generation, and assumes a very conservative $0/MWh capacity value. The estimates of economic additional resources are incremental to existing generation as of 2013.
- NREL does not examine concentrating solar power, marine hydrokinetic, offshore wind, or enhanced geothermal because they represent less than 0.2% of total U.S. generation. NREL did not identify any economic biopower or hydrothermal within states in PJM under the Primary Case 3B scenario.

[1] Technical potential figures all derived from *Table 3-7*.

[2] Percentages reflect economic potential (incremental of 2013 generation) divided by technical potential (inclusive of the total resource capability).

[3] Total reflects the technical potential of all listed resources in *Table 3-7* (i.e., inclusive of offshore wind and biomass).

As identified in Table 3-7 and Table 3-8, Maryland has the technical potential to sustain over 500 GW and 920,000 GWh of combined solar, wind, hydro, and biopower capacity and annual generation, respectively. The technical potential for all states in PJM is substantially higher, totaling 23,808 GW and 41,499,625 GWh. Within the above totals, NREL estimates that there is approximately 5,400 GWh of economic renewable energy potential in Maryland on an annual basis incremental to 2013 levels. Within states in PJM, NREL estimates approximately 235,000 GWh of additional economic renewable energy potential each year.

The above figures use economic assumptions from 2014, and they are subject to upward revision as the economic costs of renewable energy decline and the technical capabilities of renewable energy resources, such as capacity factor, improve. NREL's estimates also, however, do not preclude colocation of resources, meaning these figures may assume several different sources of generation (e.g., wind and solar generators) are in the same physical space.

Despite the limitations inherent to NREL's estimates, the above estimates generally indicate that both Maryland and PJM have more technical and economic renewable energy resource potential than needed to meet current and projected RPS requirements in Maryland and within PJM during the next decade. Table 3-9 compares estimates of PJM's 2030 projected supply of RPS-eligible generation with the 2030 projected RPS requirement and NREL's estimated technical and economic resource estimates for states in PJM. The PJM projected supply, as well as the RPS requirement figures, are drawn from the interim report based on the 50% Maryland RPS scenario. Based on NREL's estimates, there is currently sufficient economic renewable energy potential in the states in PJM to exceed the projected 2030 RPS requirement for these states of 134,277 GWh by nearly 75%.[174] NREL also estimates sufficient economic solar potential from distributed systems to surpass Maryland's projected solar carve-out requirement by 662%.

The economic potential estimates produced by NREL are in line with the supply projections in the interim report. The interim report estimates just under 150,000 GWh of RPS-eligible generation in 2030, which is approximately 57% of NREL's estimate of 235,000 GWh of economic generation potential in the states in PJM. Thus, NREL's research suggests that an even higher amount of renewable generation is technically and economically possible than the levels currently projected in the interim report. The exception to this is Maryland solar resources; NREL's projections for economic solar resources are approximately half of the projected supply of RPS-eligible generation identified in the interim report. This difference is attributable to reductions in solar generation costs since the 2014 base period used for NREL's estimates.

[174] PJM's own estimates of its projected renewable energy requirements are slightly more conservative but consistent. PJM projects a requirement of 117,000 GWh, including 27 GW of wind and 8 GW of solar, by 2033. *Source:* Ken Schuyler, *Integrating Renewables in PJM*, PJM, April 2018, dnr.maryland.gov/pprp/Documents/PJM-Renewable-Integration-Study-Ken-Schuyler.pdf.

Table 3-9. Comparison of NREL Technical and Economic Resource Potential Estimates to 2030 Projections of RPS-Eligible Generation and RPS Requirements in Maryland and PJM, 50% RPS Scenario (GWh)

	PJM[1]				MARYLAND-Specific	
	Tier 1 Solar	Tier 1 Offshore Wind	Tier 1 Non-Carve-out and RPS Compliance	TOTAL RPS	Tier 1 Solar	Tier 1 Offshore Wind
Interim Report						
2030 Projected Supply of RPS-Eligible Generation	78,666	1,369	69,931	**149,966**	9,737	1,369
2030 Projected RPS Requirements	14,508	6,236	113,533	**134,277**	9,042	6,236
NREL						
Technical Potential	38,711,500	1,488,125	1,300,000	**41,499,625**	818,500	96,289
% above 2030 Projected Supply	49,110%	108,602%	1,759%	**27,573%**	8,306%	6,934%
% above 2030 Projected Requirement	266,729%	23,763%	1,045%	**30,806%**	8,952%	1,444%
Economic Potential[2]	110,600	0	124,400	**235,000**	4,900	0
% above 2030 Projected Supply	41%	0%	78%	**57%**	-50%	0%
% above 2030 Projected Requirement	662%	0%	10%	**75%**	-46%	0%

Sources: Offshore wind technical potential is from nrel.gov/docs/fy16osti/66599.pdf (Appendices H and I). All other information is sourced from nrel.gov/docs/fy15osti/64503.pdf (Appendices A and F). See full report for additional descriptions of the data and underlying assumptions.

[1] Note that the interim report adjusts supply and RPS requirement estimates for states with partial PJM participation in accordance to the percent share of the state's load that is served by PJM. NREL estimates are inclusive of the totality of states located partially or fully in PJM, based on the assumption that generators throughout these states can potentially deliver power into PJM.

[2] Economic potential is incremental to 2013 generation levels.

3.2.2. Resource-Specific Technical and Economic Potential

This subsection looks at the technical and economic potential for selected renewable energy resources in greater detail. It draws on information from the two NREL studies summarized previously in this section as well as from complementary—and often more recent—resource-specific studies and maps. Throughout this subsection, all references to economic generation potential should be considered incremental to 2013 levels of generation, as discussed earlier in the section.

Solar Potential

Existing solar capacity in PJM is concentrated in three states: North Carolina, Maryland, and New Jersey, as shown in Figure 3-5. Figure 3-6 shows the gradient of solar resource quality for the entire United States, including PJM. As apparent in this figure, PJM receives substantially less solar radiation than the national average. Solar resources within PJM are strongest along the Atlantic Coast and in the southeast portion of PJM.

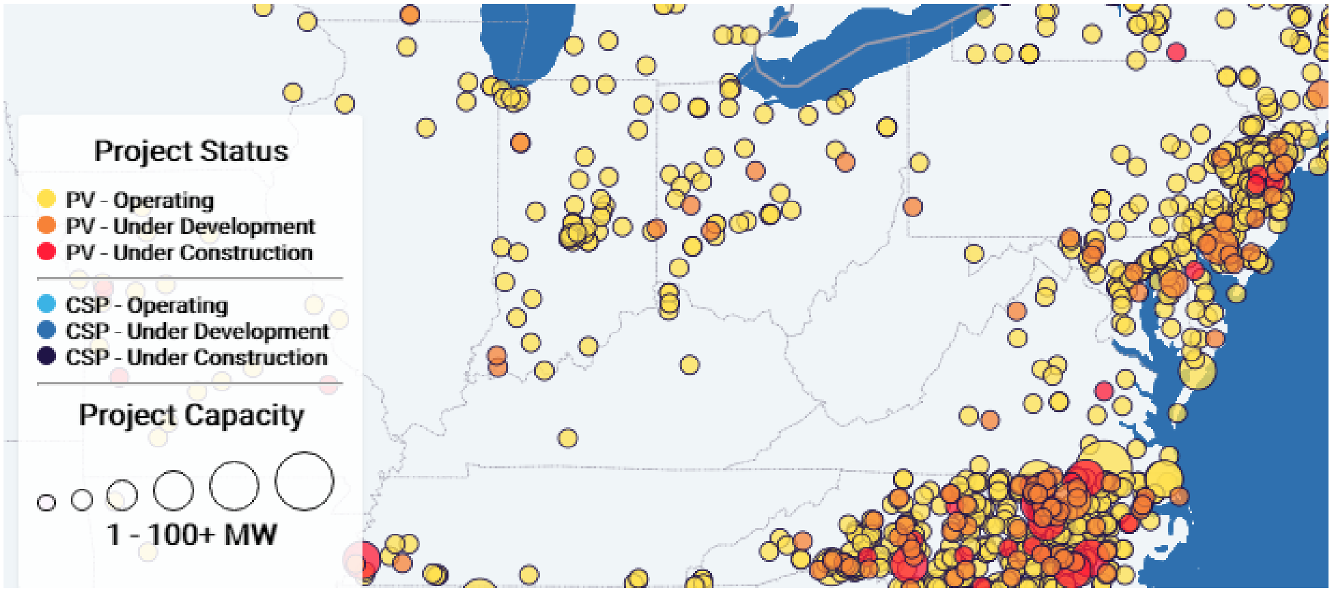

Figure 3-5. Existing Solar PV Facilities in the PJM Region with >1 MW Nameplate Capacity, as of February 2019

Source: SEIA, "Major Solar Projects List," October 2019, seia.org/research-resources/major-solar-projects-list.

Note: No concentrating solar power (CSP) projects are shown in this portion of SEIA's nationwide map.

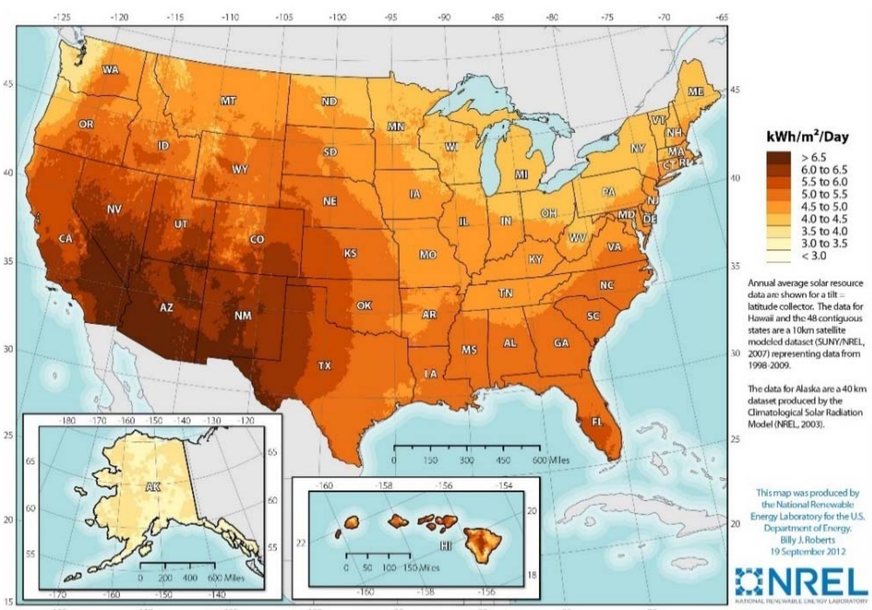

Figure 3-6. Estimated Solar Resource Quality in the U.S., as of 2012

Source: NREL's Solar Maps, nrel.gov/gis/solar.html.

As identified earlier in Table 3-7 and Table 3-8, NREL estimates that Maryland has the technical potential to support as much as 796,000 GWh of utility-scale solar PV, 10,600 GWh of distributed residential solar PV, and 11,900 GWh of distributed commercial solar PV generation on an annual basis. These estimates are based on several assumptions about installation density, slope exclusions, state-level capacity factors, and rooftop suitability, among other factors. Based on these assumptions, Maryland has substantial technical solar potential. Accounting for economic viability, however, reduces the estimated amount of viable solar generation. NREL's analysis, which was published in 2016, predates the past three years of rapidly declining solar PV costs. Also, by design, NREL's analysis does not include SREC revenues. Thus, NREL's conclusions understate the share of technical PV potential that is (or has become) economic. According to NREL's analysis, no utility-scale solar PV is economically viable in Maryland, and only 4,900 GWh per year of distributed PV is viable in Maryland and incremental to existing generation. Within PJM, NREL estimates the total economic solar potential to be 110,600 GWh per year, inclusive of utility-scale and distributed resources.

In Maryland, the optimal locations for solar facilities are in the southeast portion of the state, especially in counties adjacent to the Chesapeake Bay. This area corresponds with the portion of Maryland that has the best solar resource quality (i.e., higher potential generation per square meter per day for an indicative unit). In comparison, solar potential is lowest in the western portion of the state. Figure 3-7 maps the solar gradient for Maryland.

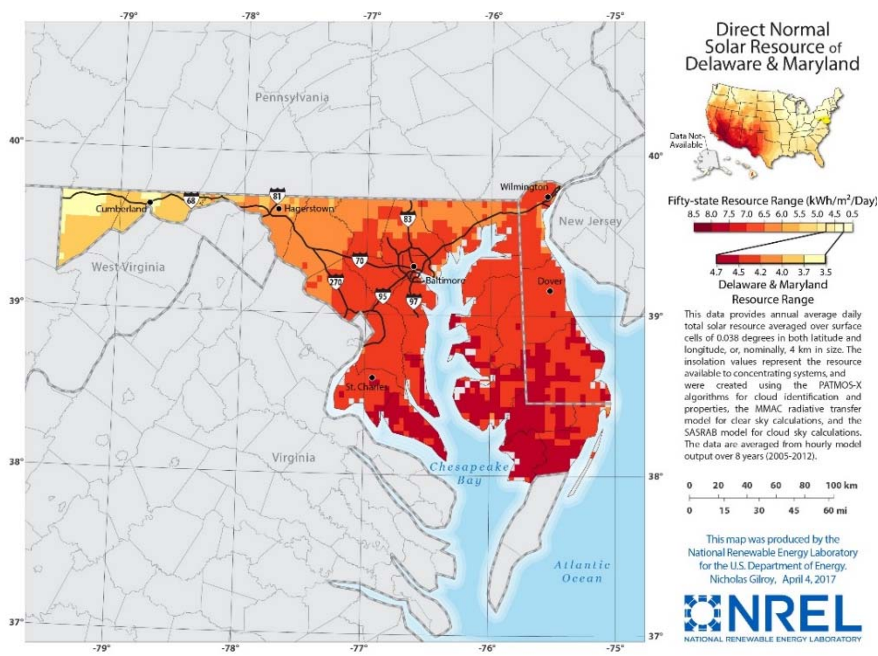

Figure 3-7. Estimated Solar Resource Quality in Maryland, as of 2017

Source: NREL's Solar Maps, nrel.gov/gis/solar.html.

NREL has also developed estimates of distributed solar PV technical potential for small, medium, and large buildings in the U.S.[175] These estimates take into account the tilt, orientation, and shading of the rooftop and assesses distributed solar PV potential at a zip-code level. Figure 3-8 shows the map of distributed PV potential for small buildings, which is consistent with that for medium/large buildings. Much like the U.S. solar potential map (refer to Figure 3-6), the most suitable areas for distributed solar PV are in the South. In this case, however, areas with a higher concentration of buildings, including population hubs in the Midwest and mid-Atlantic, are also potentially suitable (i.e., at least 70% of small buildings are feasible locations for distributed solar PV).

[175] Pieter Gagnon, Robert Margolis and Jennifer Melius, *et al.*, *Rooftop Solar Photovoltaic Technical Potential in the United States*, National Renewable Energy Laboratory, 2016, nrel.gov/docs/fy16osti/65298.pdf.

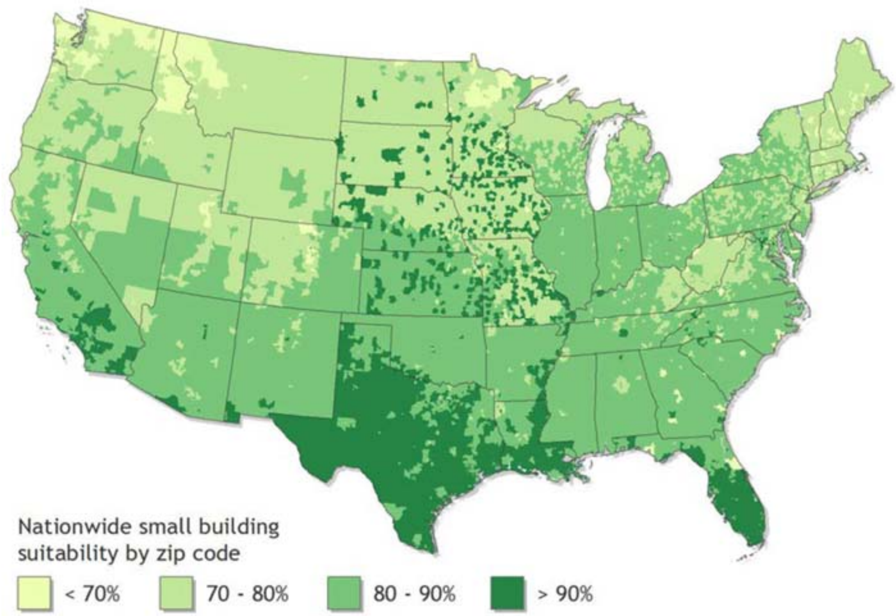

Figure 3-8. Estimated Percent of Small Buildings Suitable for Distributed Solar PV in the Continental U.S., as of 2016

Source: NREL, *Rooftop Solar Photovoltaic Technical Potential in the United States*, 2016.

NREL's estimates for distributed solar PV potential in PJM are broken down by state (and the District of Columbia) and building type in Table 3-10. The net generation and capacity estimates are roughly proportional to state size and total population, as would be expected insofar as larger, more populous states are more likely to have a high number of buildings. Maryland is estimated to have as much as 19.4 GW, or 24,000 GWh, of technical potential. This estimate is slightly higher than the numbers presented in NREL's previous technical assessment (as discussed above), which estimated 16.6 GW, or 22,500 GWh, of distributed residential and commercial PV potential in Maryland.

Table 3-10. NREL Estimates of Rooftop Solar PV Technical Potential in PJM, as of 2016

State	BUILDING SIZE: SMALL Potential Annual Generation (GWh)	SMALL Potential Capacity (GW)	MED./LARGE Potential Annual Generation (GWh)	MED./LARGE Potential Capacity (GW)	TOTAL Generation Potential (GWh)	TOTAL Capacity Potential (GW)
MD	**13,300.0**	**10.9**	**10,700.0**	**8.5**	**24,000.0**	**19.4**
DE	2,500.0	2.0	1,000.0	0.8	**3,500.0**	**2.8**
DC	500.0	0.4	1,200.0	1.0	**1,700.0**	**1.4**
IL	33,500.0	28.4	19,000.0	15.7	**52,500.0**	**44.1**
IN	21,400.0	18.3	9,700.0	8.0	**31,100.0**	**26.3**
KY	13,600.0	11.6	7,800.0	6.4	**21,400.0**	**18.0**
MI	31,500.0	28.3	15,800.0	13.7	**47,300.0**	**42.0**
NJ	18,600.0	15.6	11,600.0	9.3	**30,200.0**	**24.9**
NC	30,600.0	23.9	14,700.0	11.1	**45,300.0**	**35.0**
OH	34,700.0	31.0	18,300.0	15.8	**53,000.0**	**46.8**
PA	33,900.0	29.6	16,500.0	14.0	**50,400.0**	**43.6**
TN	21,300.0	17.0	9,600.0	7.4	**30,900.0**	**24.4**
VA	22,800.0	18.3	13,100.0	10.2	**35,900.0**	**28.5**
WV	5,400.0	4.8	1,800.0	1.5	**7,200.0**	**6.3**
TOTAL	**283,600.0**	**240.1**	**150,800.0**	**123.4**	**434,400.0**	**363.5**

Source: NREL, *Rooftop Solar Photovoltaic Technical Potential in the United States*, 2016.

Table 3-11 identifies total existing solar PV capacity and annual generation within PJM states according to EIA. Maryland hosted approximately 791.7 MW of solar PV capacity in 2017, which is approximately 5.2% of the state's total power capacity.[176] This ranks third among the 13 states in PJM tracked in Table 3-11, behind North Carolina and New Jersey. The total amount of generation from Maryland solar PV facilities in 2017, just over 1,000,000 MWh, comprises approximately 2.9% of the state's total generation and 1.7% of its retail sales. Note that the solar generation levels correspond with Maryland's solar carve-out requirement in the Maryland RPS.

In addition to listing existing solar PV, Table 3-11 also tracks the estimates of total potential solar PV in PJM states. These estimates reflect the combined technical potential from both distributed and utility-scale solar PV sources using data from NREL's most recent (2016) distributed PV report and the Brown *et al.* (2016) analysis described above. The states within PJM have as much as 38,663,400 GWh of potential solar PV generation and 23,009 GW of potential capacity, of which over 98% is utility-scale solar PV. The total solar PV potential is significantly larger than existing solar generation and capacity, exceeding 10,000% higher in both cases. If all technical potential solar PV came online, it would represent approximately 3,000% of total 2017 generation in the states in PJM, over 6,000%

[176] Data in this subsection are from EIA, which tracks capacity and generation by all forms of generation at the state level. (PJM only tracks renewable generation at the state level.) For solar PV, EIA's values tend to be lower than the PJM-GATS. At the end of 2017, for instance, there were 976 MW of solar PV capacity in Maryland registered with PJM-GATS.

of total existing capacity, and over 3,000% of total retail sales. As apparent from these figures, there is more than sufficient technical solar potential in PJM states to meet all current and future RPS needs, not accounting for economic and other constraints.

Table 3-11. Existing and Potential Solar PV in PJM States

	MD	DE	DC	IL	IN	KY	MI	NJ
Total Retail Sales (MWh)[1]	**59,303,885**	**11,128,603**	**10,916,446**	**137,196,310**	**98,965,968**	**72,634,387**	**101,899,093**	**73,382,940**
Existing Generation (excl. Solar)[1]								
Generation (MWh)	**33,837,149**	7,445,691	66,871	183,539,230	98,652,143	73,159,311	112,250,197	74,718,516
Nameplate Capacity (MW)	**14,310.9**	3,559.9	35.9	50,915.2	28,720.1	23,898.0	32,095.5	18,828.0
Existing Solar[1]								
Generation (MWh)	**1,002,090**	142,285	52,000	110,147	312,675	44,885	128,304	2,585,997
% Total Generation	**2.9%**	1.9%	43.7%	0.1%	0.3%	0.1%	0.1%	3.3%
% Total Sales	**1.7%**	1.3%	0.5%	0.1%	0.3%	0.1%	0.1%	3.5%
Nameplate Capacity (MW)	**791.7**	101.5	37.7	85.0	242.4	43.3	125.8	1,942.2
% Total Capacity	**5.2%**	2.8%	51.2%	0.2%	0.8%	0.2%	0.4%	9.4%
Potential Solar[2]								
Generation (MWh)	**820,000,000**	245,500,000	1,700,000	7,693,500,000	4,643,100,000	2,827,400,000	5,442,300,000	468,200,000
% Total Existing Generation	**2,353.7%**	3,235.4%	1,430.1%	4,189.2%	4,691.7%	3,862.3%	4,842.8%	605.7%
% Existing Solar	**81,829.0%**	172,541.0%	3,269.2%	6,984,756.7%	1,484,960.4%	6,299,209.1%	4,241,722.8%	18,105.2%
% Total Sales	**1,382.7%**	2,206.0%	15.6%	5,607.7%	4,691.6%	3,892.6%	5,340.9%	638.0%
Nameplate Capacity (MW)	**486,000.0**	144,900.0	1,400.0	4,568,500.0	2,813,600.0	1,665,400.0	3,444,700.0	282,200.0
% Total Existing Capacity	**3,218.0%**	3,957.5%	1,902.2%	8,957.8%	9,714.6%	6,956.2%	10,690.8%	1,358.7%
% Existing Solar Capacity	**61,386.9%**	142,758.6%	3,713.5%	5,374,705.9%	1,160,726.1%	3,846,189.4%	2,738,235.3%	14,529.9%

Table 3-11. (cont.)

	NC	OH	PA	TN	VA	WV	TOTAL
Total Retail Sales (MWh)[1]	**131,421,319**	**146,643,789**	**142,990,896**	**97,239,885**	**111,529,732**	**31,709,019**	**1,226,962,272**
Existing Generation (excl. Solar)[1]							
Generation (MWh)	123,354,000	119,446,962	213,569,683	78,954,055	90,104,130	73,357,080	**1,282,455,018**
Nameplate Capacity (MW)	32,683.8	33,150.6	48,199.4	23,556.3	29,021.7	15,552.0	**354,527.3**
Existing Solar[1]							
Generation (MWh)	5,300,235	234,178	426,616	179,342	379,221	8,000	**10,905,975**
% Total Generation	4.1%	0.2%	0.2%	0.2%	0.4%	0.0%	**0.8%**
% Total Sales	4.0%	0.2%	0.3%	0.2%	0.3%	0.0%	**0.9%**
Nameplate Capacity (MW)	3,461.6	171.3	330.5	146.2	452.5	5.8	**7,938**
% Total Capacity	9.6%	0.5%	0.7%	0.6%	1.5%	0.0%	**2.2%**
Potential Solar[2]							
Generation (MWh)	4,896,300,000	3,849,000,000	1,417,400,000	3,137,900,000	3,057,900,000	163,200,000	**38,663,400,000**
% Total Existing Generation	3,805.8%	3,216.0%	662.3%	3,965.3%	3,379.5%	222.4%	**2,989.4%**
% Existing Solar	92,378.9%	1,643,621.5%	332,242.6%	1,749,673.8%	806,363.6%	2,040,000.0%	**354,515.8%**
% Total Sales	3,725.7%	2,624.7%	991.3%	3,227.0%	2,741.8%	514.7%	**3,151.1%**
Nameplate Capacity (MW)	2,654,600.0	2,398,800.0	885,200.0	1,846,900.0	1,718,400.0	98,800.0	**23,009,400.0**
% Total Existing Capacity	7,344.2%	7,198.9%	1,824.0%	7,792.0%	5,830.2%	635.1%	**6,348.0%**
% Existing Solar Capacity	76,687.1%	1,400,350.3%	267,836.6%	1,263,269.5%	379,756.9%	1,703,448.3%	**289,882.2%**

[1] *Source:* EIA, "Detailed State Data," 2017. Solar information supplemented with small-scale/distributed system data from eia.gov/electricity/annual/html/epa_03_21.html and eia.gov/electricity/annual/html/epa_04_07_b.html.

[2] Based on utility-scale solar data from NREL Technical Estimates, updated as of 2016, and distributed solar estimates from nrel.gov/docs/fy16osti/65298.pdf, also as of 2016.

Outside of NREL's assessments, Daymark Energy Advisors (Daymark) prepared a recent report on solar resources in Maryland.[177] As part of the report, Daymark produced its own estimates of the technical resource potential of solar in Maryland. These estimates account for electrical hosting capacity and the availability of suitable rooftop and land areas, both of which serve as the upper bound constraints for technical potential. Daymark assessed electrical hosting capacity for distributed PV based on distribution system data from Maryland's four major IOUs. Suitability for distributed solar was then determined using NREL's distributed solar potential dataset as well as forecasted customer data from the ten-year plans filed by each utility with the Maryland PSC. Utility-scale solar potential was separately calculated at a county level using the assumption of 1 MW of solar potential per 7.25 acres of available land.[178] Daymark's estimates for Maryland's distributed and utility-scale solar PV technical potential estimates are summarized in Table 3-12 and Table 3-13, respectively. These estimates are net existing solar.

Daymark's figures are less than 10% of NREL's technical feasibility estimates, reflecting the impact of accounting for hosting capacity. Nevertheless, Daymark's potential distributed and utility-scale solar PV estimates suggest substantially more solar is possible as compared to current levels. Daymark's combined estimate, 32,702 MW, is 216.5% more than total installed generating capacity in Maryland and 4,130% more than existing solar PV capacity, according to the 2017 EIA data cited earlier.

Table 3-12. Daymark Estimates of Distributed Solar PV Technical Potential in Select Maryland Utility Territories, as of November 2018 (MW)

Distribution Utility	Total Distributed Potential	Electrical Hosting Capacity	Distributed Technical Potential
BGE	16,177	11,029	11,029
Pepco	4,433	5,746	4,433
DPL	2,310	1,452	1,452
Potomac Edison	2,823	1,426	1,426
TOTAL	**25,742**	**19,653**	**18,340**

Source: Daymark Energy Advisors, RLC Engineering, and ESS Group, *Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland*, November 2018, Table 21.

Note: Rooftop Technical Potential is defined as the lesser of Total Rooftop Potential or Electrical Hosting Capacity in each region.

177 Daymark Energy Advisors, RLC Engineering and ESS Group, *Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland*, November 2018, cleantechnica.com/files/2018/11/MDVoSReportFinal11-2-2018.pdf.

178 Note that counties served by utilities not covered in the study, such as Choptank Electric Cooperative and Easton Utilities Commission, are excluded from the estimates.

Table 3-13. Daymark Estimates of Utility-Scale Solar PV Technical Potential in Maryland Counties, as of November 2018 (MW)

County	Utility-Scale Land Capacity	Electrical Hosting Capacity	Utility-Scale Technical Potential
Allegany	2,290	0	0
Anne Arundel	3,547	2,506	2,506
Baltimore	8,419	3,207	3,207
Baltimore City	0.6	2,050	1
Calvert	5,110	0	0
Caroline	6,984	82	82
Carroll	2,669	481	481
Cecil	8,171	141	141
Charles	9,266	0	0
Dorchester	6,310	134	134
Frederick	10,955	0	0
Garrett	8,923	0	0
Harford	365	1,013	365
Howard	4,525	1,045	1,045
Kent	484	100	100
Montgomery	2,301	3,393	2,301
Prince George's	6,414	3,024	3,024
Queen Anne's	6,159	210	210
Somerset	3,456	57	57
St. Mary's	7,899	0	0
Talbot	5,588	82	82
Washington	10,040	0	0
Wicomico	6,950	296	296
Worcester	6,067	330	330
TOTAL	**132,893**	**18,151**	**14,362**

Source: Daymark Energy Advisors, RLC Engineering, and ESS Group, *Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland*, November 2018, Table 23.

Note: Utility-Scale Technical Potential is defined as the lesser of Utility-Scale Land Capacity or Electrical Hosting Capacity in each county.

Wind Potential

Most existing wind capacity in the PJM region is concentrated in three areas: along the Appalachian Mountains, on the shores of the Great Lakes, and inland within the Midwest. Within these regions, wind capacity is often clustered. The placement and concentration of existing wind capacity in PJM is shown in Figure 3-9. Figure 3-10 shows the quality of wind resources throughout the U.S., including PJM.

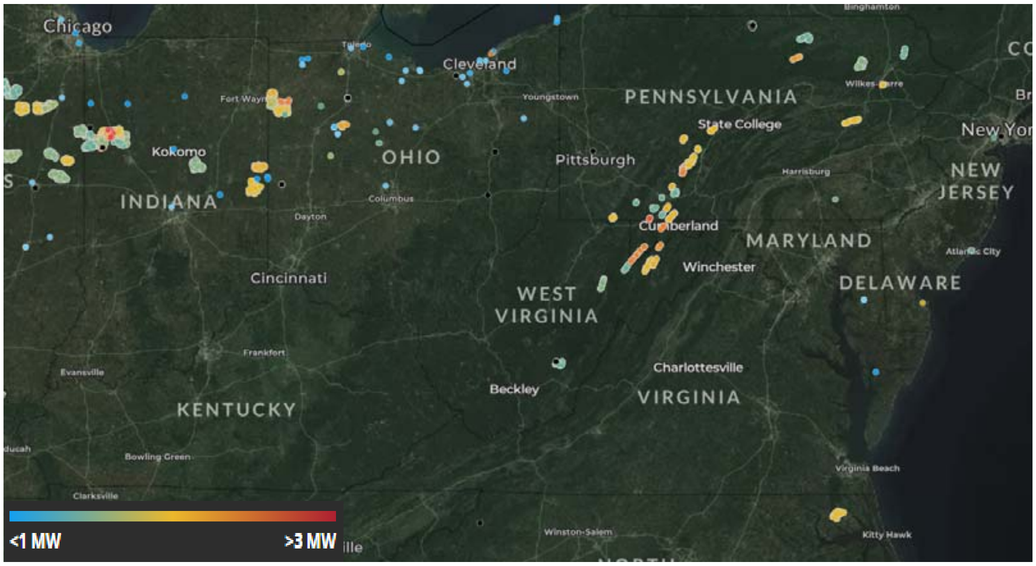

Figure 3-9. Onshore Wind Facilities in the PJM Region, as of October 2019

Source: USGS, LBNL and AWEA, "The U.S. Wind Turbine Database," eerscmap.usgs.gov/uswtdb/.

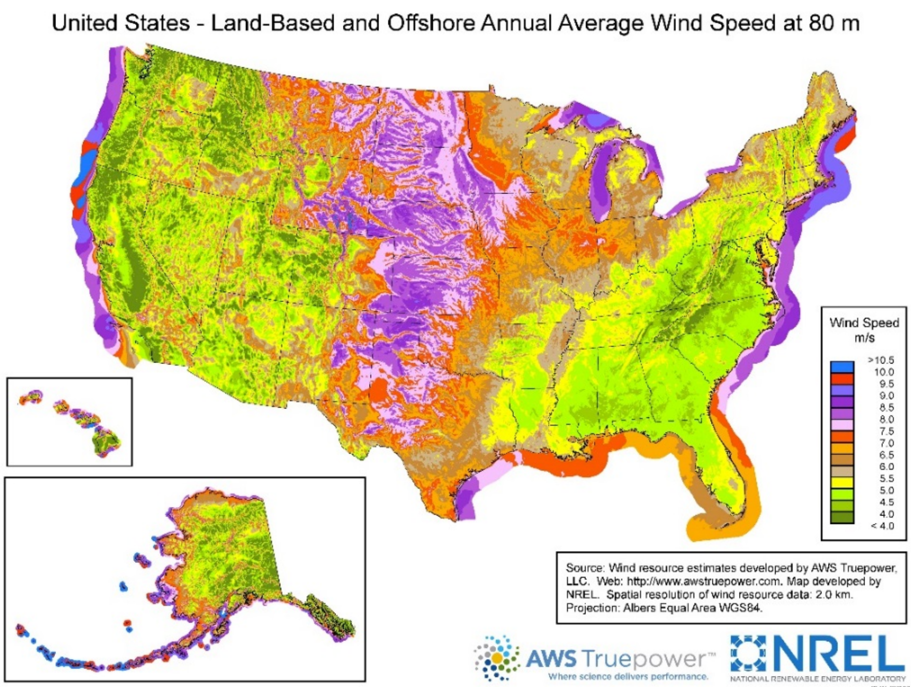

Figure 3-10. Onshore and Offshore Wind Quality in the U.S.

Source: NREL, 2012, nrel.gov/gis/images/80m_wind/awstwspd80onoffbigC3-3dpi600.jpg.

NREL has produced several estimates of the technical potential of onshore wind generation in the U.S. using varying assumptions regarding equipment conditions, such as mechanical stress limits and turbine height. The most recent findings were incorporated into the NREL technical and economic potential estimates discussed above. As shown earlier in Table 3-7 and Table 3-8, NREL estimates that Maryland has the technical potential to support 0.9 GW, or 3,000 GWh, of onshore wind energy. After screening for economic potential, this estimate falls to 300 GWh per year, or approximately 10% of the technical potential. The greatest wind resources in Maryland are in the western-most counties and off the Atlantic Coast, as mapped in Figure 3-11. There are also several smaller areas, in the middle of the state, that are technically amenable to wind development. Within PJM, NREL estimates 1,142,000 GWh of technical onshore wind generation potential per year, of which 98,000 GWh would be economic.

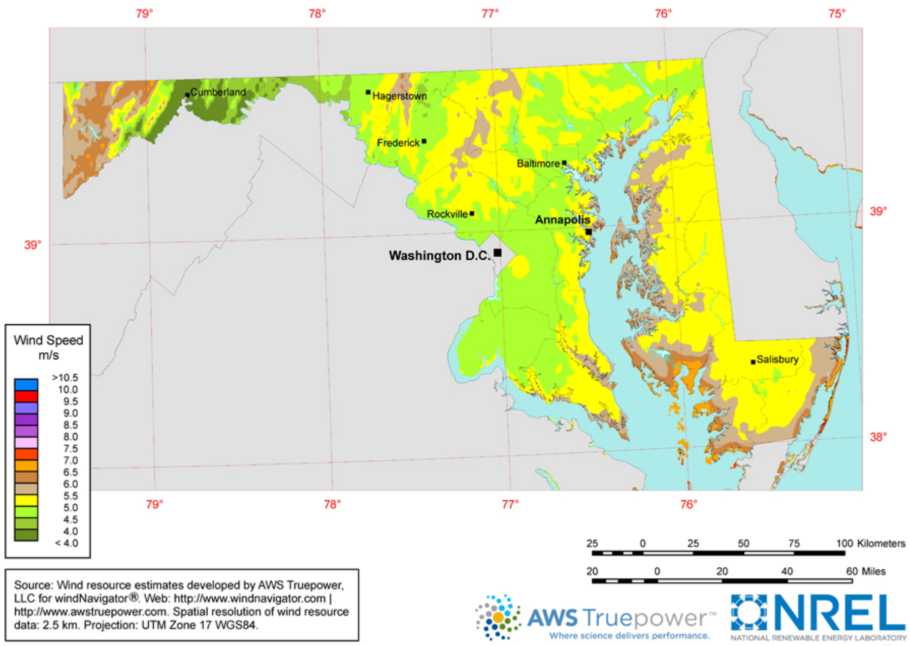

Figure 3-11. Onshore Wind Resource Quality in Maryland

Source: WINDExchange, 2010, windexchange.energy.gov/states/md.

In addition to onshore wind resources, Maryland and other states in PJM have substantial offshore wind technical potential. Although, as shown above in Figure 3-10, onshore wind speeds are lower in PJM than in the center of the country, offshore wind speeds in PJM are among the highest in the country. As shown in Table 3-7, NREL estimates that Maryland alone has more than 25 GW of technical potential for offshore wind, after accounting for operational losses (e.g., wake and line losses) and selected exclusions (e.g., environmental and land use). A separate study of offshore wind energy leasing areas, conducted for the Bureau of Ocean Energy Management (BOEM), also identified several potential project areas in Maryland with high levels of technical potential for offshore wind.[179] If ever fully developed, offshore wind could supply a substantial portion of the state's electric demand. NREL, however, did not identify any economically feasible projects. This may be changing as East Coast states pursue development opportunities with offshore wind.

Table 3-14 identifies total existing wind capacity and annual generation within PJM according to EIA. Maryland had 190 MW of wind capacity in 2017, which is approximately 1.3% of the state's total power capacity. The total amount of generation from Maryland wind facilities in 2017, 561,349 MWh, comprises approximately 1.6% of the state's total generation and 0.9% of Maryland retail sales.

[179] W. Musial, D. Elliot and J. Fields, *et al.*, *Assessment of Offshore Wind Energy Leasing Areas for the BOEM Maryland Wind Energy Area*. National Renewable Energy Laboratory, 2013, nrel.gov/docs/fy13osti/58562.pdf.

In addition to listing existing wind, Table 3-14 also lists total potential wind capacity, as drawn from the above NREL tables. They reflect the combined potential from both onshore and offshore wind sources. States in PJM have as much as 2,630,125 GWh of potential generation and 770.1 GW of potential capacity, split between approximately 47.2% onshore and 52.8% offshore wind potential capacity. Like solar, the total wind potential is substantial, equaling over 6,000% of existing wind generation and capacity. If all technical potential wind came online, it would represent approximately 204% of total 2017 generation in PJM states, 214% of total existing capacity, and 214% of total retail sales. Illinois, Indiana, and Michigan have the greatest potential wind resources, according to NREL. This is consistent with the current wind resource deployment patterns in PJM; approximately two-thirds of all operating wind capacity in PJM are in Indiana and Illinois. Several states, such as New Jersey and North Carolina, also have enormous wind potential despite minimal existing wind deployment, often because of untapped offshore wind resources.

Several studies have further examined offshore wind potential in Maryland. A study by the University of Delaware identified as much as 39,214 MW and 117,024 GWh of cumulative technical offshore wind potential for areas within Maryland's jurisdiction.[180] This estimate includes the cumulative potential of offshore wind resources from depths of zero to 1,000 meters, after accounting for shipping lane conflicts. These estimates are higher than NREL's projections and represent an upper bound of the technical potential of Maryland offshore wind.

[180] Jeremy Firestone and Willett Kempton, *Maryland's Offshore Wind Power Potential*, University of Delaware's Center for Carbon-free Power Integration, College of Earth, Ocean, and Environment, 2010, abell.org/sites/default/files/publications/env_Offshore.full_.report-2-18-10.pdf.

Table 3-14. Existing and Potential Wind Power in PJM States

	MD	DE	DC	IL	IN	KY	MI	NJ
Total Retail Sales (MWh)[1]	**59,303,885**	**11,128,603**	**10,916,446**	**137,196,310**	**98,965,968**	**72,634,387**	**101,899,093**	**73,382,940**
Existing Generation (excl. Wind)[1]								
Generation (MWh)	**33,542,890**	7,491,011	66,871	171,323,611	93,840,428	73,179,196	107,122,228	75,622,066
Nameplate Capacity (MW)	**14,295.6**	3,589.9	35.9	46,663.8	26,807.5	23,924.3	30,310.6	19,490.2
Existing Wind[1]								
Generation (MWh)	**561,349**	4,965	0	12,267,766	5,089,390	0	5,191,273	22,447
% Total Generation	**1.6%**	0.1%	0.0%	6.7%	5.1%	0.0%	4.6%	0.0%
% Total Sales	**0.9%**	0.0%	0.0%	8.9%	5.1%	0.0%	5.1%	0.0%
Nameplate Capacity (MW)	**190.0**	2.0	0.0	4,286.5	2,109.4	0.0	1,857.9	9.0
% Total Capacity	**1.3%**	0.1%	0.0%	8.4%	7.3%	0.0%	5.8%	0.0%
Potential Wind[2]								
Generation (MWh)	**99,289,000**	20,604,000	0	496,762,000	277,423,000	9,000,000	350,440,000	280,193,000
% Total Existing Generation	**291.1%**	274.9%	0.0%	270.6%	280.4%	12.3%	312.0%	370.4%
% Existing Wind	**17,687.6%**	414,984.9%	-	4,049.3%	5,451.0%	-	6,750.6%	1,248,242.5%
% Total Sales	**167.4%**	185.1%	0.0%	362.1%	280.3%	12.4%	343.9%	381.8%
Nameplate Capacity (MW)	**27,400.0**	5,900.0	0.0	151,200.0	86,000.0	3,200.0	107,700.0	71,200.0
% Total Existing Capacity	**189.2%**	164.3%	0.0%	296.8%	297.4%	13.4%	334.8%	365.1%
% Existing Wind Capacity	**14,421.1%**	295,000.0%	-	3,527.4%	4,077.0%	-	5,796.9%	791,111.1%

Table 3-14. (cont.)

	NC	OH	PA	TN	VA	WV	TOTAL
Total Retail Sales (MWh)[1]	**131,421,319**	**146,643,789**	**142,990,896**	**97,239,885**	**111,529,732**	**31,709,019**	**1,226,962,272**
Existing Generation (excl. Wind)[1]							
Generation (MWh)	127,997,492	117,963,580	210,048,734	79,003,070	90,417,351	71,674,739	**1,259,293,267**
Nameplate Capacity (MW)	35,822.5	32,616.9	46,881.2	23,619.1	29,427.7	14,865.7	**348,350.9**
Existing Wind[1]							
Generation (MWh)	470,743	1,588,560	3,590,565	43,327	0	1,682,341	**30,512,726**
% Total Generation	0.4%	1.3%	1.7%	0.1%	0.0%	2.3%	**2.4%**
% Total Sales	0.4%	1.1%	2.5%	0.0%	0.0%	5.3%	**2.5%**
Nameplate Capacity (MW)	208.0	604.4	1,373.4	28.8	0.0	686.3	**11,356**
% Total Capacity	0.6%	1.8%	2.8%	0.1%	0.0%	4.4%	**3.2%**
Potential Wind[2]							
Generation (MWh)	637,153,000	227,657,000	47,792,000	7,000,000	166,812,000	10,000,000	**2,630,125,000**
% Total Existing Generation	496.0%	190.4%	22.4%	8.9%	184.5%	13.6%	**203.9%**
% Existing Wind	135,350.5%	14,331.0%	1,331.0%	16,156.2%	-	594.4%	**8,619.8%**
% Total Sales	484.8%	155.2%	33.4%	7.2%	149.6%	31.5%	**214.4%**
Nameplate Capacity (MW)	174,400.0	75,100.0	15,600.0	2,300.0	46,900.0	3,200.0	**770,100.0**
% Total Existing Capacity	484.0%	226.1%	32.3%	9.7%	159.4%	20.6%	**214.1%**
% Existing Wind Capacity	83,846.2%	12,425.5%	1,135.9%	7,986.1%	-	466.3%	**6,781.6%**

[1] *Source:* EIA, "Detailed State Data," 2017. "Existing Generation" figures only reflect utility-scale sources. Based on large hydro facilities; does not account for small hydro or pumped storage.

[2] Offshore wind data are from nrel.gov/docs/fy16osti/66599.pdf (Appendices H and I). All other data are from nrel.gov/docs/fy15osti/64503.pdf (Appendix A), which updates the original assumptions laid out in nrel.gov/docs/fy12osti/51946.pdf.

Hydro Potential

Most hydro today comes from large, conventional hydro facilities. As shown in Figure 3-12, these facilities are located predominantly on major waterways in the Northeast, Northwest, California, and Tennessee Valley regions. There are two primary opportunities to expand hydro generation in the U.S.: new stream-reach development (NSD), which entails adding hydro to waterways that do not currently have dams, or powering existing, nonpowered dams (NPDs). NPDs provide a variety of services, such as flood control and water supply management. The advantage of using these locations as a source of hydro is that, by nature of having an existing dam structure, many of the ecological, legal, political, and economic hurdles of building a dam have already been addressed.[181] In comparison, NSD is potentially more complex.[182] However, these resources also have a significant aggregate potential given the high number of waterways in the U.S. Building new hydro facilities on even a fraction of NSD or NPD sites would substantially increase the country's hydro capacity.

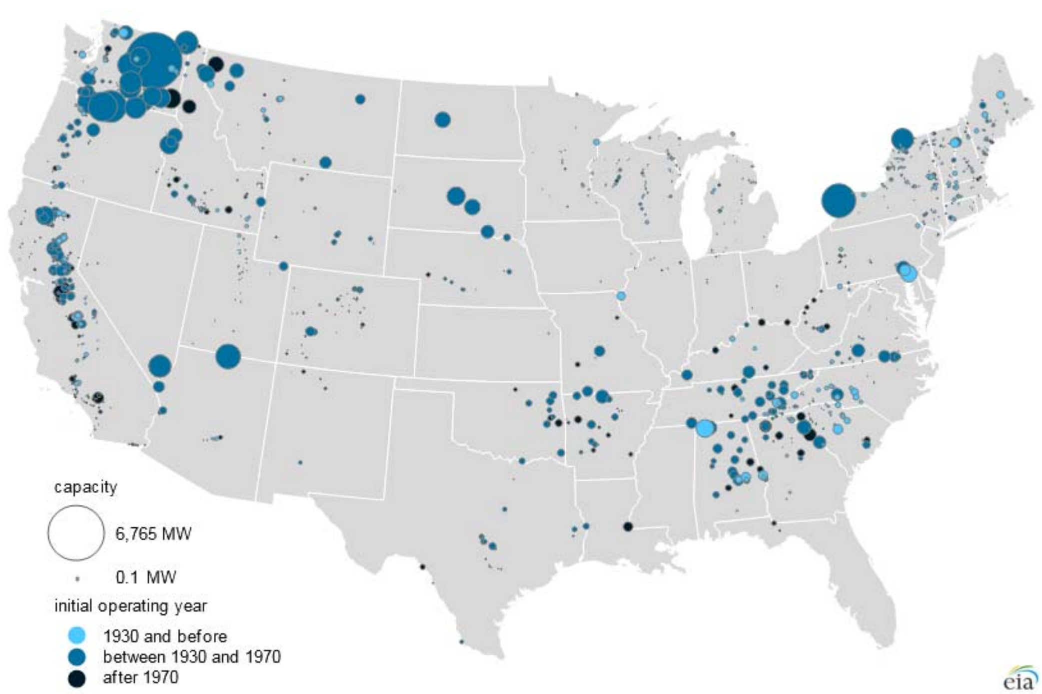

Figure 3-12. Large Hydro Facilities in the Continental U.S., as of 2017

Source: EIA, "Preliminary Monthly Electric Generator Inventory," December 2018, eia.gov/electricity/data/eia860M/.

The technical and economic potential of NSD and NPD are the focus of several recent studies by Oak Ridge National Laboratory (ORNL). These studies were the basis for NREL's estimates of technical and economic hydro potential. As shown earlier in Table 3-7 and Table 3-8, NREL estimates that states within PJM have the technical potential for as much as 55,900 GWh of hydro generation per year, of which almost half, 26,400 GWh, is

[181] Boualem Hadjerioua, Yaxing Wei and Shih-Chieh Kao, *An Assessment of Energy Potential at Non-Powered Dams in the United States*, U.S. Department of Energy Wind & Water Power Program, 2012, eere.energy.gov/water/pdfs/npd_report.pdf.

[182] Shih-Chieh Kao, Ryan McManamay and Kevin Stewart, *et al.*, *New Stream-reach Development: A Comprehensive Assessment of Hydropower Energy Potential in the United States*, U.S. Department of Energy Wind and Water Power Program, 2014, osti.gov/biblio/1130425-new-stream-reach-development-comprehensive-assessment-hydropower-energy-potential-united-states.

economically feasible and incremental to existing hydro, as of 2013. Within this total, Maryland is estimated to have 200 GWh per year of incremental economic hydro capability. ORNL's research is based on the gross power potential of every stream in the U.S. after accounting for land accessibility and environmental sensitivity. ORNL assumes only small hydro facilities and powered NPDs are feasible.

The NPD portion of NREL's estimates, derived from ORNL's original research, are summarized in Table 3-15, alongside the existing hydro and non-hydro generation within PJM states, according to EIA. The total amount of generation from Maryland hydro facilities in 2017, 1,965,459 MWh, comprises approximately 5.8% of the state's total generation and 3.3% of Maryland retail sales. Maryland's NPD technical potential is equal to 39.9 MW, or 166,280 MWh, of potential annual production spread across nine NPD facilities. Potential NPD resources total 7.2% of existing large hydro capacity (551 MW) and 8.5% of existing hydro generation (1,965,459 MWh) in the state. Figure 3-13 shows U.S. NPDs with greater than 1 MW of potential capacity. Most of this potential lies along major rivers.

Table 3-15. Existing Hydro and Potential Nonpowered Dam Hydro in PJM States

	MD	DE	DC	IL	IN	KY	MI	NC
Total Retail Sales (MWh)[1]	**59,303,885**	**11,128,603**	**10,916,446**	**137,196,310**	**98,965,968**	**72,634,387**	**101,899,093**	**131,421,319**
Existing Generation (excl. Hydro)[1]								
Generation (MWh)	**32,138,780**	7,495,976	66,871	183,466,246	98,623,738	68,673,178	110,634,544	124,650,218
Nameplate Capacity (MW)	**13,934.8**	3,591.9	35.9	50,910.6	28,824.8	22,831.8	31,806.9	34,140.1
Existing Hydro[1]								
Generation (MWh)	**1,965,459**	0	0	125,131	306,080	4,506,018	1,678,957	3,818,017
% Total Generation	**5.8%**	0.0%	0.0%	0.1%	0.3%	6.2%	1.5%	3.0%
% Total Sales	**3.3%**	0.0%	0.0%	0.1%	0.3%	6.2%	1.6%	2.9%
Nameplate Capacity (MW)	**550.8**	0.0	0.0	39.7	92.1	1,092.5	361.6	1,890.4
% Total Capacity	**3.8%**	0.0%	0.0%	0.1%	0.3%	4.6%	1.1%	5.2%
Potential Hydro[2]								
Generation (MWh)	**166,280**	0	0	2,691,740	331,027	8,775,583	72,005	246,502
% Total Existing Generation	**0.5%**	0.0%	0.0%	1.5%	0.3%	12.0%	0.1%	0.2%
% Existing Hydro	**8.5%**	-	-	2151.1%	108.2%	194.8%	4.3%	6.5%
% Total Sales	**0.3%**	0.0%	0.0%	2.0%	0.3%	12.1%	0.1%	0.2%
Nameplate Capacity (MW)	**39.9**	0	0	549.2	76.9	2,087.9	12.4	105.5
% Total Existing Capacity	**0.3%**	0.0%	0.0%	1.1%	0.3%	8.7%	0.0%	0.3%
% Existing Hydro Capacity	**7.2%**	-	-	1383.5%	83.5%	191.1%	3.4%	5.6%

Table 3-15. (cont.)

	NJ	OH	PA	TN	VA	WV	TOTAL
Total Retail Sales (MWh)[1]	**73,382,940**	**146,643,789**	**142,990,896**	**97,239,885**	**111,529,732**	**31,709,019**	**1,226,962,272**
Existing Generation (excl. Hydro)[1]							
Generation (MWh)	75,630,880	119,274,791	210,515,983	70,355,263	89,300,996	71,698,588	**1,262,526,052**
Nameplate Capacity (MW)	19,484.5	33,092.7	47,335.1	21,148.5	28,605.3	15,181.4	**350,924.3**
Existing Hydro[1]							
Generation (MWh)	13,633	277,349	3,123,316	8,691,134	1,116,355	1,658,492	**27,279,941**
% Total Generation	0.0%	0.2%	1.5%	11.0%	1.2%	2.3%	**2.1%**
% Total Sales	0.0%	0.2%	2.2%	8.9%	1.0%	5.2%	**2.2%**
Nameplate Capacity (MW)	14.7	128.6	919.5	2,499.4	822.4	370.6	**8,782**
% Total Capacity	0.1%	0.4%	1.9%	10.6%	2.8%	2.4%	**2.4%**
Potential Hydro[2]							
Generation (MWh)	16,210	1,009,201	2,677,945	101,827	79,900	785,912	**16,954,131**
% Total Existing Generation	0.0%	0.8%	1.3%	0.1%	0.1%	1.1%	**1.3%**
% Existing Hydro	118.9%	363.9%	85.7%	1.2%	7.2%	47.4%	**62.1%**
% Total Sales	0.0%	0.7%	1.9%	0.1%	0.1%	2.5%	**1.4%**
Nameplate Capacity (MW)	3.9	236.3	638.1	27.3	19.1	187.0	**3,983.5**
% Total Existing Capacity	0.0%	0.7%	1.3%	0.1%	0.1%	1.2%	**1.1%**
% Existing Hydro Capacity	26.5%	183.7%	69.4%	1.1%	2.3%	50.5%	**45.4%**

[1] *Source:* EIA, "Detailed State Data," 2017. "Existing Generation" figures only reflect utility-scale sources. Based on large hydro facilities; does not account for small hydro or pumped storage.

[2] Based on data from ORNL, Non-Powered Dam Resource Assessment, 2012, hydrosource.ornl.gov/hydropower-potential/non-powered-dam-resource-assessment.

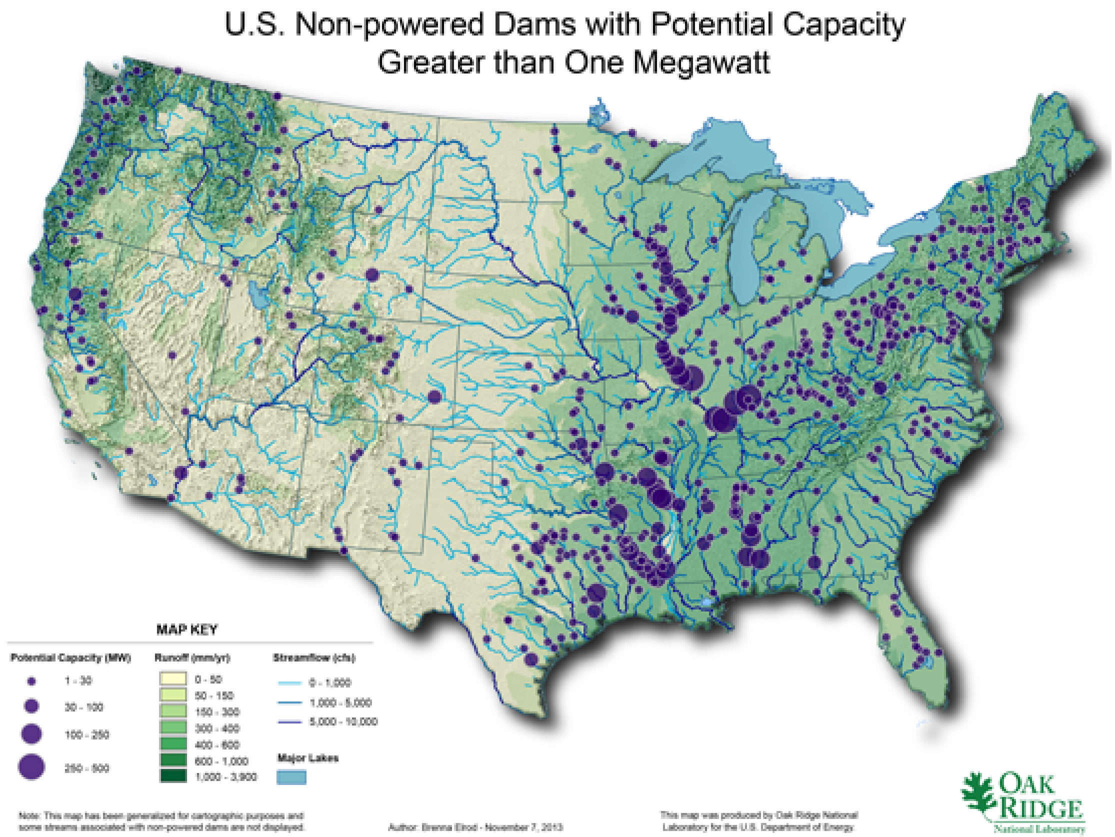

Figure 3-13. Estimated Nonpowered Dam Hydro Sources >1 MW in the Continental U.S., as of 2013

Source: ORNL, "Non-Powered Dam Resource Assessment," hydrosource.ornl.gov/hydropower-potential/non-powered-dam-resource-assessment.

NSD technical potential is not tracked on a state-by-state basis in ORNL's most recent study of potential NSD hydro energy.[183] Instead, ORNL's research identifies undeveloped, high-energy density water resources on a water basin level. Water resource basins are not contiguous with state or utility boundaries, but rather track distinct geographical conditions. The potential estimates provided in ORNL's research account for ecological systems; social, environmental, and cultural constraints; and other policy, management, and legal considerations. Out of the data set of over 3 million U.S. streams, as much as 6,601 MW, or 36,108,610 MWh, of NSD hydro potential is considered possible for streams that intersect with PJM states. The U.S. water basins with NSD potential are shown in Figure 3-14.

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183 Shih-Chieh Kao, Ryan McManamay and Kevin Stewart, *et al.*, *New Stream-reach Development: A Comprehensive Assessment of Hydropower Energy Potential in the United States*, U.S. Department of Energy Wind and Water Power Program, 2014, osti.gov/biblio/1130425-new-stream-reach-development-comprehensive-assessment-hydropower-energy-potential-united-states.

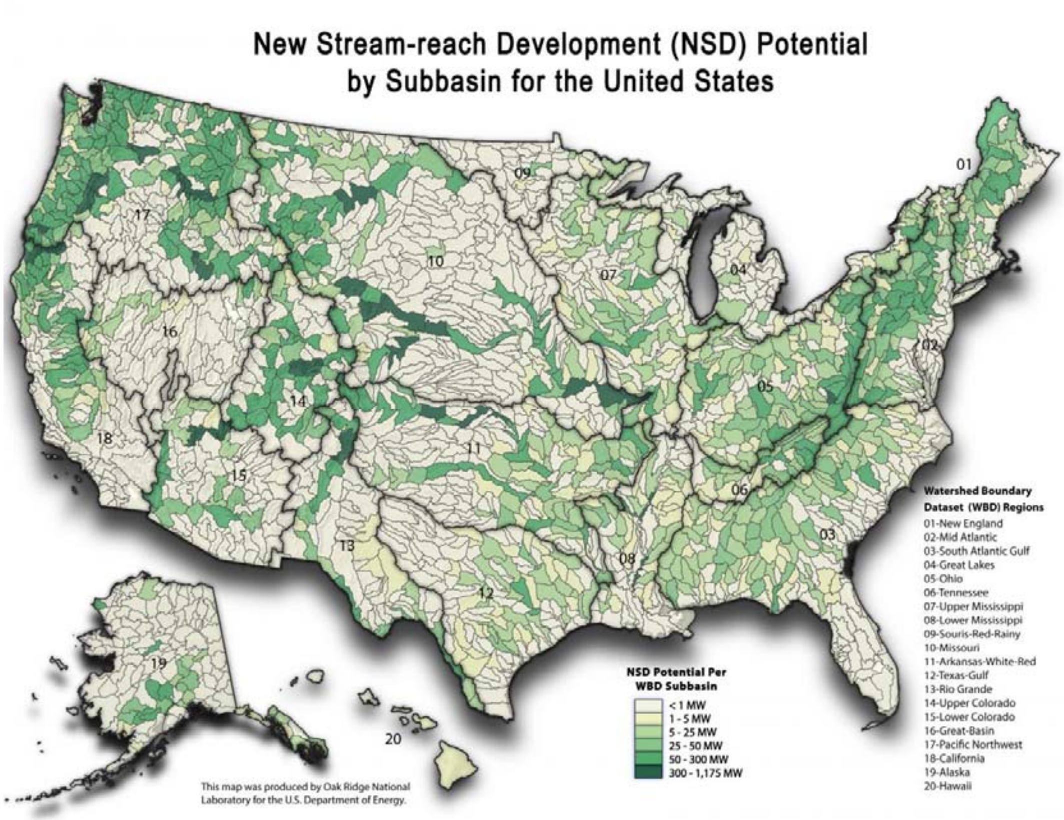

Figure 3-14. Hydro Generation Potential from New Stream-Reach Development in the U.S., as of 2014

Source: ORNL, "New Stream-Reach Development Resource Assessment," hydrosource.ornl.gov/hydropower-potential/new-stream-reach-development-resource-assessment

The specific stream regions applicable to PJM are reviewed on a subregion basis in Table 3-16. Three water basin regions intersect with Maryland, although only the Potomac and Monongahela water basins are assessed by ORNL to have technical NSD hydro potential. Assuming both basins provided power deliverable into (and attributable to) Maryland, NSD resources would total just under 800 MW, or 4,312,852 MWh, of technically feasible power. Relative to the existing conventional resource totals listed above in Table 3-15, the full development of potential NSD would more than double Maryland generation and increase the state's hydro capacity by 145%.

Table 3-16. Estimated Hydro Potential from New Stream-Reach Development in PJM States, as of 2014

HU-04	Water Resource Subregion	Capacity (MW)	Generation (MWh)	States That Intersect Each Subregion													
				MD	DE	DC	IL	IN	KY	MI	NC	NJ	OH	PA	TN	VA	WV
0203	Lower Hudson-Long Island	-	-									■					
0204	Delaware-Mid Atlantic Coastal	632.8	3,693,852		■							■		■			
0205	Susquehanna	1,261.9	6,731,187											■			
0206	Upper Chesapeake	-	-	■	■												
0207	Potomac	428.6	2,304,671	■		■										■	■
0208	Lower Chesapeake	308.7	1,650,646													■	
0301	Chowan-Roanoke	100.3	594,149								■					■	
0302	Neuse-Pamlico	20.2	106,414								■						
0404	Southwestern Lake Michigan	-	-							■							
0405	Southeastern Lake Michigan	31.5	194,172							■							
0410	Western Lake Erie	32.8	165,434					■					■				
0411	Southern Lake Erie	-	-										■				
0412	Eastern Lake Erie	11.9	64,371											■			
0501	Allegany	424.2	2,323,264											■			
0502	Monongahela	371.1	2,008,181	■										■			■
0503	Upper Ohio	86.9	471,331										■	■			■
0504	Muskingum	62.7	351,578										■				
0505	Kanawha	954.0	5,293,479													■	■
0506	Scioto	52.0	268,306										■				
0507	Big Sandy-Guyandotte	122.8	617,627						■							■	■
0508	Great Miami	61.4	324,322										■				
0509	Middle Ohio	13.7	68,784						■				■				
0510	Kentucky-Licking	160.7	764,354						■								
0511	Green	76.1	386,285						■								
0512	Wabash	445.9	2,390,224					■									
0513	Cumberland	195.7	960,886						■								
0601	Upper Tennessee	601.9	3,574,050													■	
0709	Rock	39.7	246,962				■										
0712	Upper Illinois	42.2	241,112				■										
0713	Lower Illinois	61.9	312,960				■										
	TOTAL	**6,601**	**36,108,601**														

Source: Based on data from the National Hydrography Dataset and USGS, NHD View (V1.0), Hydrography viewer.nationalmap.gov/basic/?basemap=b1&category=nhd&title=NHD%20View; and ORNL, "New Stream-Reach Development Resource Assessment," hydrosource.ornl.gov/hydropower-potential/new-stream-reach-development-resource-assessment.

Biopower Potential

The feasibility of biopower plants depends in part on the utilized feedstock; biopower is most economically feasible when the feedstock is self-replenishing or abundant, and when transportation of the feedstock is minimized.[184] Not surprisingly, most existing biopower sources, including biomass and biogas, are located in proximity to their feedstock, be that waste, fuel crops, wood, or otherwise. Figure 3-15 and Figure 3-16 map the distribution of existing biopower facilities across the continental U.S. and PJM, respectively. As apparent in these figures, LFG and MSW are among the more common sources of biopower. These sources of power are especially prevalent in densely populated areas, including urban areas in PJM such as around Chicago, the District of Columbia, and Philadelphia, where waste is a byproduct of large populations. Wood and wood waste plants are more common in less densely populated areas, especially in the Northeast and South, where wooded areas are more abundant. Within PJM, wood and wood waste facilities are more common in the rural portions of Pennsylvania, Virginia, and West Virginia.

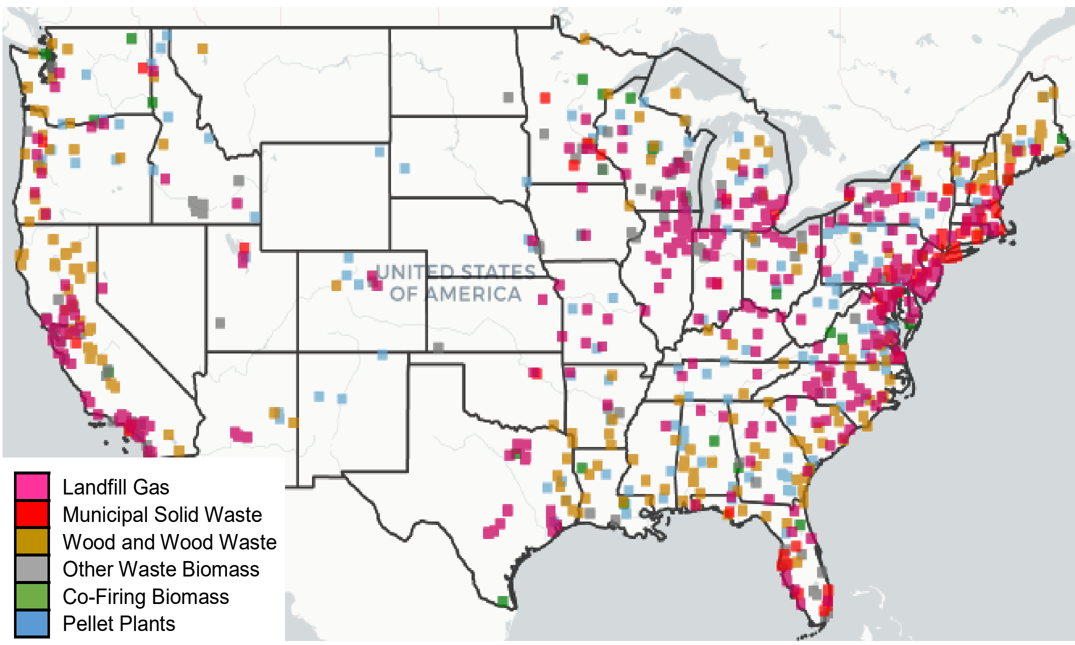

Figure 3-15. Existing Biopower Facilities in the Continental U.S. with >1 MW Nameplate Capacity, as of 2015

Source: Created using NREL's Biofuels Atlas, maps.nrel.gov/biofuels-atlas/.

[184] Kristi Moriarty, Anelia Milbrandt and Ethan Warner, *et al.*, *2016 Bioenergy Status Report*, National Renewable Energy Laboratory, March 2018, nrel.gov/docs/fy18osti/70397.pdf.

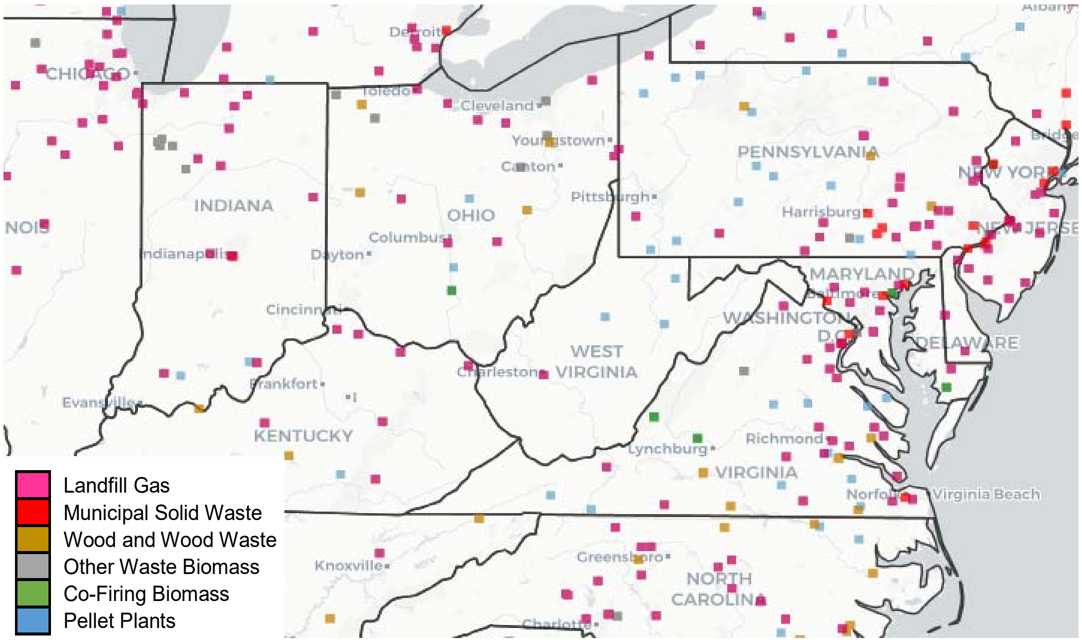

Figure 3-16. Existing Biopower Facilities in the PJM Region with >1 MW Nameplate Capacity, as of 2015

Source: Created using NREL's Biofuels Atlas, maps.nrel.gov/biofuels-atlas/.

As identified earlier in Table 3-7 and Table 3-8, NREL estimates approximately 0.2 GW, or 1,700 GWh, of biopower technical potential in Maryland and 13 GW, or 102,100 GWh, for all PJM states. NREL's estimates, however, are based solely on dedicated combustion units and do not include co-firing plants. Additionally, NREL's estimates exclude biopower potential that is tied directly to commercial production (e.g., black liquor).

Table 3-17 identifies total existing biopower capacity and annual generation within PJM states, according to EIA. Maryland hosted 162.2 MW of biopower capacity in 2017, which is approximately 1.1% of the state's total power capacity. The total amount of generation from Maryland biopower facilities in 2017 (536,278 MWh) comprised approximately 1.6% of the state's total generation and 0.9% of Maryland retail sales. Biomass makes up a slightly higher portion of generation in Maryland than in PJM as a whole, which derives 1.3% of generation from biomass. Biopower is an especially prominent part of the fuel mix in the District of Columbia (which has minimal generation besides MSW), Michigan, Virginia, and North Carolina.

In addition to listed existing biopower, Table 3-17 also tracks estimates of total potential biopower from both biomass and biogas sources. These estimates are up to date as of 2014 as listed in NREL's Biopower Atlas, and are more conservative than the figures represented earlier in Table 3-7 and Table 3-8. This difference stems from stricter definitions regarding the availability of feedstock. According to NREL, states in PJM have as much as 50,181,800 MWh of potential generation and 7,161 MW of potential capacity, split between approximately 15.4% biogas and 84.6% biomass capacity potential. The total biopower potential equals approximately 308% of existing biopower generation and 176% of existing biopower capacity in PJM. If all technical potential biopower came online, it would represent approximately 3.9% of total 2017 generation in PJM states, 2% of total existing capacity, and 4.1% of total sales. However, the technical potential for biopower in PJM is less than 1/20th of the technical potential for onshore wind, offshore wind, or solar PV in PJM.

Table 3-17. Existing and Potential Biopower in PJM States

	MD	DE	DC	IL	IN	KY	MI	NC
Total Retail Sales (MWh)[1]	**59,303,885**	**11,128,603**	**10,916,446**	**137,196,310**	**98,965,968**	**72,634,387**	**101,899,093**	**131,421,319**
Existing Generation (excl. Biopower)[1]								
Generation (MWh)	**33,567,961**	7,433,161	19,704	183,117,319	98,456,415	72,684,506	109,819,384	125,655,982
Nameplate Capacity (MW)	**14,323.4**	3,579.7	10.8	50,817.2	28,836.9	23,810.9	31,555.2	35,386.0
Existing Biopower[1]								
Generation (MWh)	**536,278**	62,815	47,167	474,058	473,403	494,690	2,494,117	2,812,253
% Total Generation	**1.6%**	0.8%	70.5%	0.3%	0.5%	0.7%	2.2%	2.2%
% Total Sales	**0.9%**	0.6%	0.4%	0.3%	0.5%	0.7%	2.4%	2.1%
Nameplate Capacity (MW)	**162.2**	12.2	25.1	133.1	80.0	113.4	613.3	644.5
% Total Capacity	**1.1%**	0.3%	69.9%	0.3%	0.3%	0.5%	1.9%	1.8%
Potential Biopower[2]								
Generation (MWh)	**1,350,199**	285,532	0	9,606,221	5,384,345	3,252,435	4,383,915	6,726,199
% Total Existing Generation	**4.0%**	3.8%	0.0%	5.2%	5.4%	4.4%	3.9%	5.2%
% Existing Biopower	**251.8%**	454.6%	0.0%	2,026.4%	1,137.4%	657.5%	175.8%	239.2%
% Total Sales	**2.3%**	2.6%	0.0%	7.0%	5.4%	4.5%	4.3%	5.1%
Nameplate Capacity (MW)	**193**	41	0	1,371	768	464	626	960
% Total Existing Capacity	**1.3%**	1.1%	0.0%	2.7%	2.7%	1.9%	1.9%	2.7%
% Existing Biopower Capacity	**118.8%**	333.9%	0.0%	1,029.9%	960.4%	409.3%	102.0%	148.9%

Table 3-17. (cont.)

	NJ	OH	PA	TN	VA	WV	TOTAL
Total Retail Sales (MWh)[1]	**73,382,940**	**146,643,789**	**142,990,896**	**97,239,885**	**111,529,732**	**31,709,019**	**1,226,962,272**
Existing Generation (excl. Biopower)							
Generation (MWh)	74,715,736	118,825,218	211,201,144	78,098,722	86,608,472	73,357,080	**1,273,560,804**
Nameplate Capacity (MW)	19,236.9	33,041.0	47,620.3	23,447.6	28,409.5	15,552.0	**355,627**
Existing Biopower[1]							
Generation (MWh)	928,777	726,922	2,438,155	947,675	3,808,879	0	**16,245,189**
% Total Generation	1.2%	0.6%	1.1%	1.2%	4.2%	0.0%	**1.3%**
% Total Sales	1.3%	0.5%	1.7%	1.0%	3.4%	0.0%	**1.3%**
Nameplate Capacity (MW)	262.3	180.3	634.3	200.3	1,018.2	0.0	**4,079**
% Total Capacity	1.3%	0.5%	1.3%	0.8%	3.5%	0.0%	**1.1%**
Potential Biopower[2]							
Generation (MWh)	1,250,147	5,695,033	3,683,496	3,038,369	4,098,190	1,427,713	**50,181,794**
% Total Existing Generation	1.7%	4.8%	1.7%	3.8%	4.5%	1.9%	**3.9%**
% Existing Biopower	134.6%	783.4%	151.1%	320.6%	107.6%	-	**308.9%**
% Total Sales	1.7%	3.9%	2.6%	3.1%	3.7%	4.5%	**4.1%**
Nameplate Capacity (MW)	178	813	526	434	585	204	**7,161**
% Total Existing Capacity	0.9%	2.4%	1.1%	1.8%	2.0%	1.3%	**2.0%**
% Existing Biopower Capacity	68.0%	450.7%	82.9%	216.5%	57.4%	-	**175.5%**

[1] *Source:* EIA, "Detailed State Data," 2017. "Existing Generation" figures only reflect utility-scale sources.

[2] Biopower estimates derived in Appendix H. Based on data listed in NREL's Biopower Atlas, up to date as of October 2014.

The U.S. counties with the greatest biomass and biogas potential are highlighted in Figure 3-17 and Figure 3-18, respectively. As consistent with the locations of existing biopower facilities, biomass potential is highest in areas with high crop and/or forest presence, largely outside of PJM. Biogas potential, meanwhile, is concentrated in more densely populated areas, including large portions of Maryland. States in PJM like Ohio, Illinois, and Indiana have the most room to grow relative to current biopower levels, both because of relatively low existing biopower penetration and large amounts of biomass resources, especially from crops.

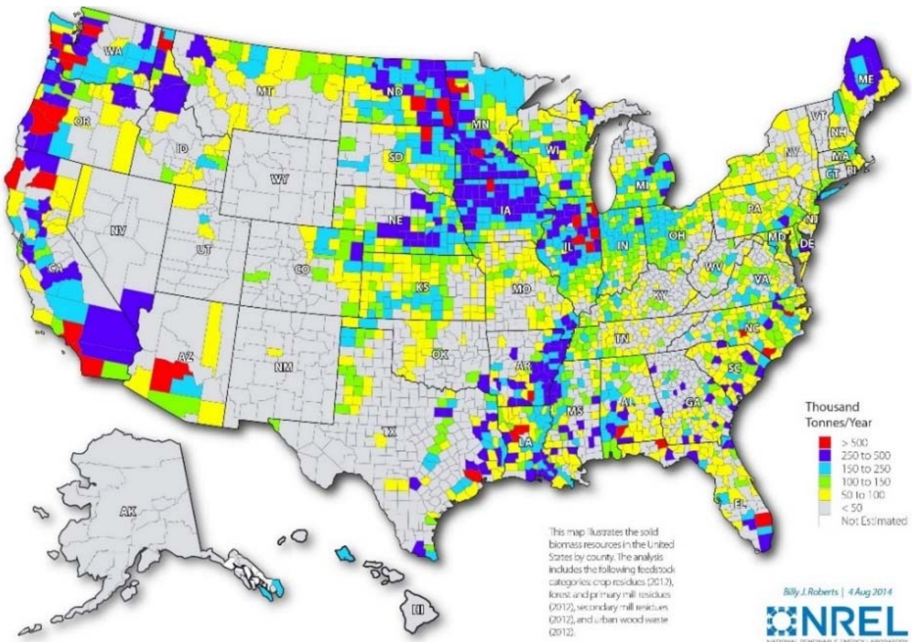

Figure 3-17. Estimated Biomass Potential for Select Biomass Sources, by County, as of 2014

Source: NREL's Biomass Maps, nrel.gov/gis/biomass.html.

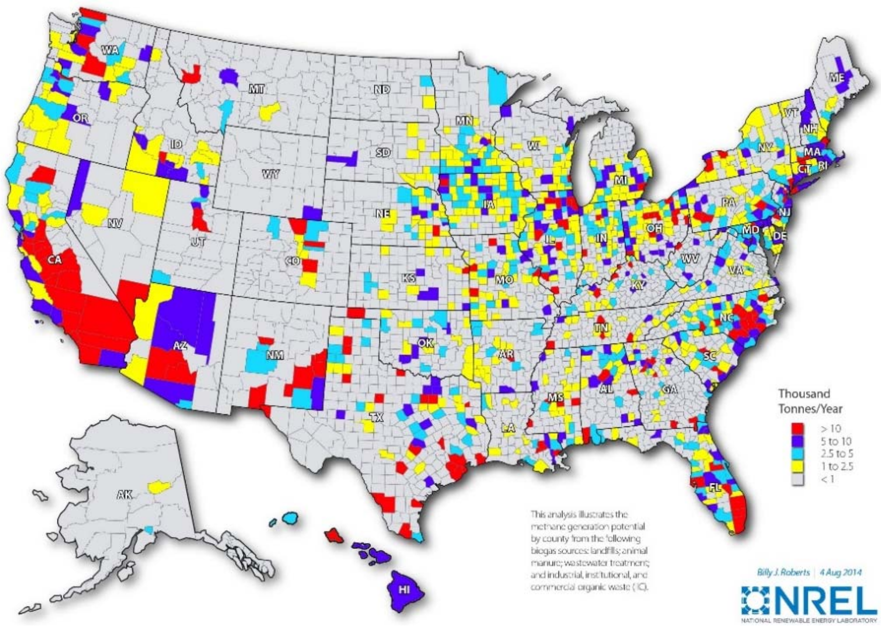

Figure 3-18. Estimated Biogas Potential for Select Biogas Sources, by County, as of 2014

Source: NREL's Biomass Maps, nrel.gov/gis/biomass.html.

Beyond NREL's assessment, there are few other estimates of biopower potential either at the state level or for Maryland specifically. DOE's 2016 Billion-Ton Report provides estimates of resource availability but does not connect these estimates to power production. The Pinchot Institute for Conservation, on behalf of the Maryland DNR, released a report in 2010 assessing the potential for wood-based bioenergy in Maryland.[185] Although the results are dated, its estimates are roughly in line with NREL's projections for technically feasible biomass.

3.3. Impact of the Maryland RPS on Air Emissions

This section of the final report assesses the impact of the Maryland RPS on air emissions from both in-state generation and from electricity imports. PPRP's 2016 LTER provides a basis for evaluating the future impact of the Maryland RPS on air emissions (NOx, SO_2, and mercury) and on GHG emissions from plants both in Maryland and in the rest of PJM. PPRP prepared the LTER per EO 01.01.2010.16.[186] To address the issues set forth in the Order, PPRP assessed future electric energy and peak demand requirements for Maryland over the 20-year study period from 2015-2035.[187] The LTER provides sufficient starting points for this analysis because some of the key data points contemplated are comparable to current market trends. Further information on the differences between the assumptions in the LTER

[185] Brian Kittler and Christopher Beauvais, *The Potential for Sustainable Wood-Based Bioenergy in Maryland*, Pinchot Institute for Conservation, 2010, dnr.maryland.gov/forests/Documents/publications/MDBiomassGuidelines.pdf.

[186] Maryland Department of Natural Resources, Power Plant Research Program, *Long-Term Electricity Report for Maryland*, , 2016, dnr.maryland.gov/pprp/Documents/LTER-December-2016.pdf.

[187] Historical data from 2015 were included for reference purposes.

and what is currently being observed in Maryland and PJM are included in Subsection 3.3.3, "Other Key Assumptions in the 2016 LTER."

The LTER first contemplates a Reference Case, or a business-as-usual scenario, over the 20-year period. Then, it considers a series of alternative scenarios, including a 25% RPS, a 35% RPS, and a 50% RPS in Maryland (Maryland RPS scenarios). A PJM-wide sensitivity scenario was added because PJM's market is shaped less by any single state's actions, and more by the collective actions of its member states. Under the PJM-wide scenario (PJM RPS scenario), each state in PJM reaches 25% renewable consumption by 2020, including a 2.5% solar carve-out. Table 3-18 summarizes these scenarios.

Table 3-18. Overarching RPS Goals, Maryland and PJM RPS Scenarios

Scenario	Abbreviation	RPS Goal
Reference Case	RC	MD RPS rises to 20% by 2022, including 2.0% solar by 2020
Moderate Maryland RPS	25% RPS	MD RPS rises to 25% by 2020, including 2.5% solar
High Maryland RPS	35% RPS	MD RPS rises to 35% by 2030, including 3.0% solar by 2025
Very High Maryland RPS	50% RPS	MD RPS rises to 50% by 2030, including 5.0% solar
Moderate PJM-wide RPS	PJM RPS	PJM-wide RPS of 25% by 2020, including 2.5% solar

After the LTER was published, legislation raised the Tier 1 requirement in Maryland to 25% by 2020 (HB 1106 in 2017) and then to 50% by 2030 (SB 516 in 2019). By comparing the Reference Case with the 25% and 50% RPS scenarios, one can gauge the incremental impact of these policy changes on emissions. However, the LTER's 50% RPS scenario assumes a 5% solar carve-out and no further offshore wind requirements. Current law includes a 14.5% solar carve-out and 1,200 MW of "Round 2" offshore wind. These requirements will significantly increase in-state wind and solar generation relative to the 50% RPS scenario's results. (See Subsection 3.3.3, "Other Key Assumptions in the 2016 LTER" for a discussion of other selected assumptions in the LTER that may warrant updating and the likely impact of doing so.)

Throughout this section, Reference Case results are discussed first, then compared with the results of the various RPS scenarios. The following outcomes are summarized: capacity additions and retirements, net imports, fuel use, and emissions.[188] Key results related to air emissions are summarized here:

Reference Case

- Upward of 8,700 MW of RPS-eligible capacity comes online during the 20-year study period, including approximately 900 MW of solar PV and 200 MW of offshore wind in Maryland. (Note that decisions about renewable energy capacity additions are provided as inputs to the model used for the LTER.)
- New generation resources (other than those developed in response to RPS requirements) are either natural gas combined-cycle units or combustion turbines. Upward of 42,000 MW of new natural gas capacity comes online during the study period.
- Emissions of NOx, SO_2, and mercury from Maryland power plants subject to the state's HAA remain below the HAA's caps throughout the study period.

[188] The LTER also projects energy and capacity prices. These projections are summarized in Section 3.5, "Future Ratepayer Impacts in Maryland."

- CO_2 emissions exceed the state's Regional Greenhouse Gas Initiative (RGGI) budget during the later years of the study period, which will require Maryland generation facilities to purchase RGGI emissions allowances from other RGGI states and/or purchase offsets.[189]

RPS Scenarios

- Across PJM, natural gas capacity additions are marginally impacted by changes in the Maryland RPS, while a PJM-wide RPS diminishes the need for new natural gas capacity by 6,000 MW.
- Raising the Maryland RPS has no impact on coal or natural gas use in the state; fossil plants continue to generate electricity for the PJM-wide market. Therefore, emissions of SO_2, NOx, mercury, and CO_2 by Maryland's electricity plants are also relatively unchanged from the Reference Case.
- However, increasing the Maryland RPS significantly lowers the carbon content associated with electricity consumption in Maryland. For example, raising the Maryland RPS from 25% to 50% lowers CO_2 emissions associated with electricity consumption in Maryland by 3.6 million tons, or 12.5%, per year.
- In the PJM RPS scenario, both coal and, to a greater extent, natural gas use drop relative to the Reference Case, as new renewable energy capacity meets significant portions of PJM's load. As a result, Maryland plant emissions fall modestly relative to the Reference Case. The decrease in CO_2 emissions from Maryland plants brings the state within, or just above, its RGGI budget.

3.3.1. Renewable Capacity Addition Assumptions in the 2016 LTER

Decisions about renewable energy capacity additions are provided as inputs to the production cost model used for the LTER. They are summarized in this subsection to provide context for the scenario results in the following subsection, "Reference Case and RPS Scenarios Results from the 2016 LTER." In the Reference Case, solar capacity growth through 2019 is based on proposed facilities (as of 2015). Solar capacity is then projected to increase 4.0% annually from 2020-2024, as solar developers utilize the federal ITC, then increase 1.5% annually from 2025-2028. In 2020, 200 MW of offshore wind is projected to come online because of the Maryland Offshore Wind Act of 2013. Through 2035, 1,110 MW of renewable energy capacity is added in Maryland, as shown in Table 3-19. This includes 910 MW of solar capacity and 200 MW of offshore wind capacity. Generation associated with existing and projected renewable energy capacity is shown in Figure 3-19.

[189] RGGI is a regional carbon trading system comprised of: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.

Table 3-19. Cumulative Renewable Energy Capacity Additions in Maryland and PJM (MW)

Year	Maryland	PJM Total
2015	13	896
2020	807	5,438
2025	949	7,276
2030	1,020	8,387
2035	1,110	8,742

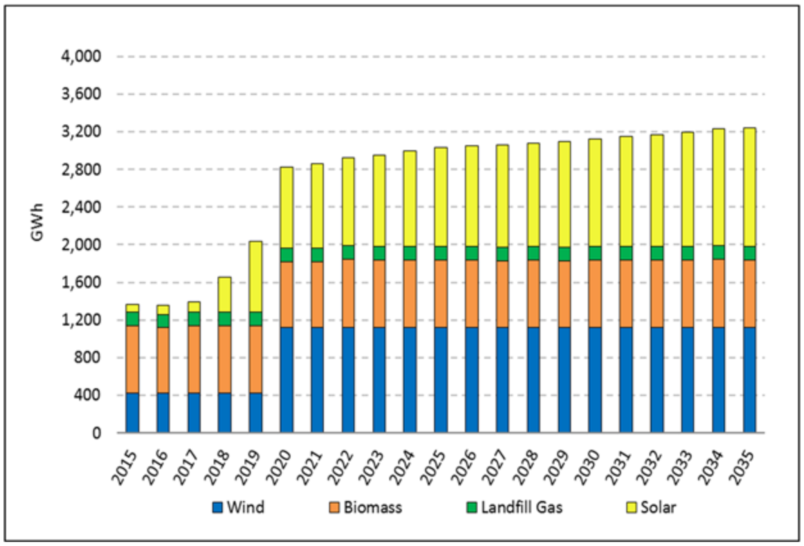

Figure 3-19. Maryland Renewable Energy Generation, Reference Case

Source: 2016 LTER, Figure 4.11.

Note: Distributed solar generation not reflected.

Several assumptions were made about how higher RPS requirements would be met for the RPS scenarios. For example, it was assumed that higher RPS requirements would be fulfilled entirely with actual generation, as opposed to ACPs. Furthermore, it was assumed that new wind capacity would be used to fulfill all new RPS requirements, with the exception of solar carve-outs. For the Maryland RPS scenarios, it was also assumed that all necessary additional renewable energy capacity would either be built in Maryland or within a PJM transmission zone (in the production cost model used for the LTER) that contains a portion of Maryland: PJM-APS, PJM-MidE, or PJM-SW. These three zones are shown in Figure 3-20.[190] For the PJM RPS scenario, renewable energy capacity was apportioned throughout

[190] Throughout this subsection, results are presented for Maryland as a whole, as well as for the three transmission zones (in the grid model used for the LTER) that include portions of Maryland: PJM-APS, PJM-SW, and PJM-MidE, as shown in Figure 3-20. It is helpful to keep in mind that PJM-SW is comprised of the service territories of BGE, Pepco, and Southern Maryland Electric Cooperative (SMECO), and therefore also includes the District of Columbia. All plants added in the PJM-SW zone, however, are assumed to be constructed in Maryland. PJM-MidE includes all of the Delmarva Peninsula (including Delaware), all of New Jersey, and the Philadelphia metropolitan area. As such,

PJM, as necessary. Table 3-20 shows new renewable capacity additions, beyond the Reference Case, associated with each RPS scenario.

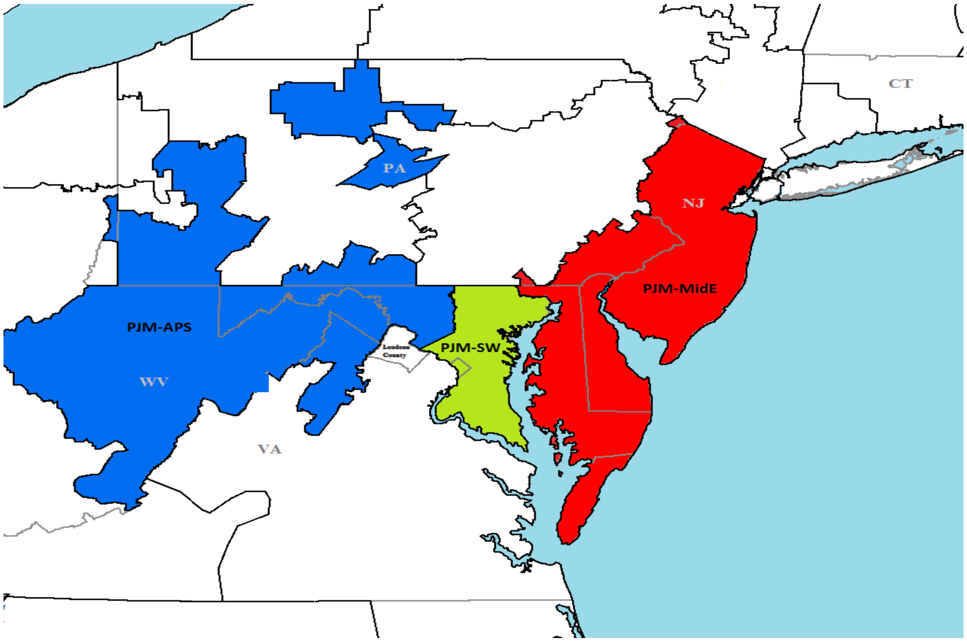

Figure 3-20. Transmission Zones in LTER Model that Include Maryland

Source: 2016 LTER, Figure 4.1.

Maryland's Delmarva territory is only a small portion of the PJM-MidE zone. Similarly, PJM-APS includes all of Allegheny Power Systems, of which Maryland is only a small portion. Consequently, power plants "constructed" by the model that are located in either PJM-MidE or PJM-APS are not assigned to Maryland for purposes of reporting forecasted values such as Maryland emissions, Maryland power plant fuel use, or Maryland electric generating capacity.

Table 3-20. New Renewable Capacity Additions for Maryland and PJM RPS Scenarios Beyond Those Assumed for the Reference Case, by 2035 (MW)

Scenario	Solar[1]	Wind[2]
25% Maryland RPS	270	1,585
35% Maryland RPS	538	3,767
50% Maryland RPS	1,146	6,681
25% PJM RPS[3]	10,706	32,743

[1] For all of the alternative Maryland RPS scenarios, 100% of the Maryland solar energy requirement is located in Maryland, divided between PJM-SW (25%) and PJM-MidE (75%).

[2] For all of the alternative Maryland RPS scenarios, all new wind generation is assumed to be located outside Maryland, divided evenly between PJM-MidE and PJM-APS.

[3] These figures are renewable capacity additions to PJM excluding additions to Maryland, which are identical to those shown in the 25% Maryland RPS scenario row. PJM additions are spread throughout the PJM footprint.

3.3.2. Reference Case and RPS Scenarios Results from the 2016 LTER

Generic Capacity Additions in PJM

To satisfy demand (beyond RPS requirements) in each PJM transmission zone, the model used for the LTER either builds generic power plants or imports energy from other transmission zones, based on least-cost principles and reliability requirements. Total new generic natural gas capacity builds in PJM as a whole reach 42,170 MW by 2035 under the Reference Case. All the plants are natural gas combined cycle (CC) or combustion turbine (CT) facilities. Of the zones containing a portion of Maryland (PJM-SW, PJM-MidE, and PJM-APS), PJM-APS has the largest increase in capacity additions, where just over 7 GW are added. This is largely attributable to PJM-APS having lower power plant construction costs than either PJM-MidE or PJM-SW.

Because Maryland represents a small percentage of energy demand in PJM, raising its RPS has little impact on non-renewable demand in Maryland or in PJM as a whole.[191] Natural gas capacity additions in the Maryland RPS scenarios are less than 1% lower than in the Reference Case by 2035, as shown in Figure 3-21. However, the influx of renewable energy construction in PJM-MidE does make it a slightly less attractive zone for new natural gas capacity additions. For example, under the 50% Maryland RPS scenario, cumulative capacity builds in PJM-MidE are 1 GW, or 36%, lower than the Reference Case. Capacity builds in PJM-APS and PJM-SW are unchanged.

[191] In this subsection, all changes to the Maryland RPS are assumed to occur in isolation. Qualifying statements such as “while other state RPS policies remain static” are omitted for the sake of brevity.

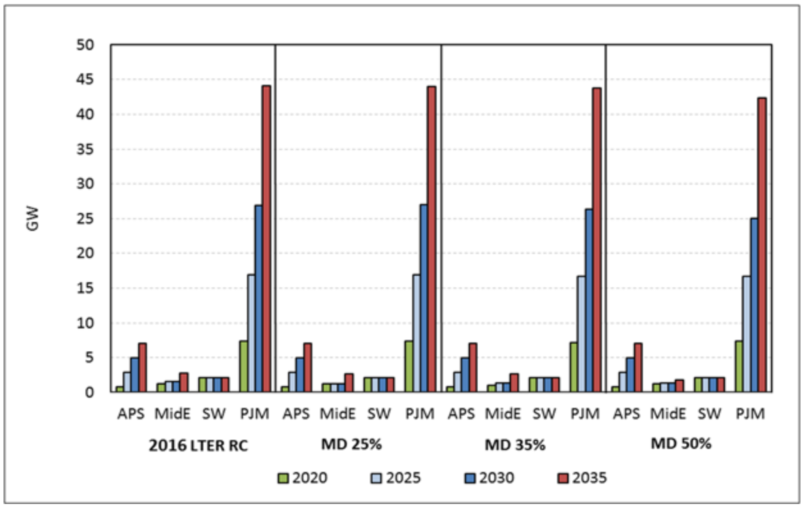

Figure 3-21. Comparison of Cumulative Generic Natural Gas Plant Additions, Maryland RPS Scenarios

Source: 2016 LTER, Figure 7.1.

Under the PJM RPS scenario, shown in Figure 3-22, cumulative generic plant additions in PJM would reach 38 GW by 2035, which is 6 GW lower than the Reference Case. Within the three PJM zones of interest to Maryland, creating a PJM-wide RPS standard has unusually diverse results. The need for new natural gas capacity rises 35% and 150% in PJM-APS and PJM-MidE, respectively, while it decreases a small amount in PJM-SW. The type of natural gas plant changes from intermediate or CC to CTs that can quickly respond to changes in demand or generation.

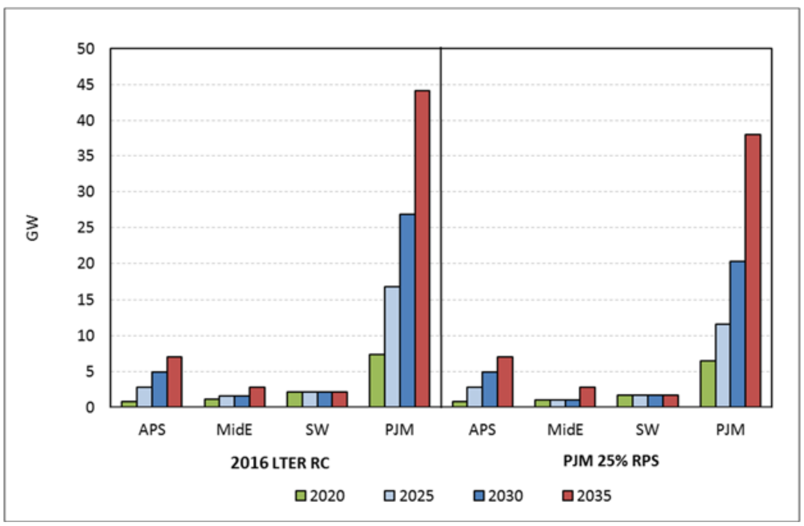

Figure 3-22. Comparison of Cumulative Generic Natural Gas Plant Additions, PJM RPS Scenario

Source: 2016 LTER, Figure 7.19.

Plant Retirements

Retirements in the model occur for either economic or age-based reasons. None of the RPS scenarios impact retirements in PJM. In each case, just one 103-MW plant in PJM-SW retires in 2026. Age-based retirements, shown in Table 3-21, are more substantial, due to the amount of older generating capacity operating in PJM. Just over 22.5 GW of generation capacity retires in PJM, with 47% of that from nuclear facilities, 20% from coal facilities, 19% from petroleum facilities, 13% from natural gas facilities, and 1% from biomass facilities.

Table 3-21. Age-Based Plant Retirements in PJM (MW)

Years	Fossil Fuels	Nuclear	Renewables	TOTAL
2015-2020	3,975	-	131	**4,106**
2021-2025	2,315	-	-	**2,315**
2026-2030	2,850	2,018	-	**4,868**
2031-2035	2,693	8,522	-	**11,215**
TOTAL	**11,833**	**10,540**	**131**	**22,504**

Source: 2016 LTER, Table 4.3.

Note: Coal-fired power plant retirements represent approximately 40% of fossil fuel sources retired, natural gas retirements approximately 25%, and petroleum accounts approximately 35%.

Net Imports

Maryland currently imports 37% of its electricity.[192] This is because power generation is less costly elsewhere in PJM. The Reference Case shows that net imports into PJM-SW are usually higher than the other two PJM transmission zones. In 2022, PJM-APS shifts from a net importer to a net exporter, while PJM-MidE makes the opposite shift, as shown in Figure 3-23.

[192] PJM, *2018 Maryland and District of Columbia Infrastructure Report (January 1, 2018 – December 31, 2018)*, May 2019, pjm.com/-/media/library/reports-notices/state-specific-reports/2018/2018-maryland-dc-state-data.ashx?la=en.

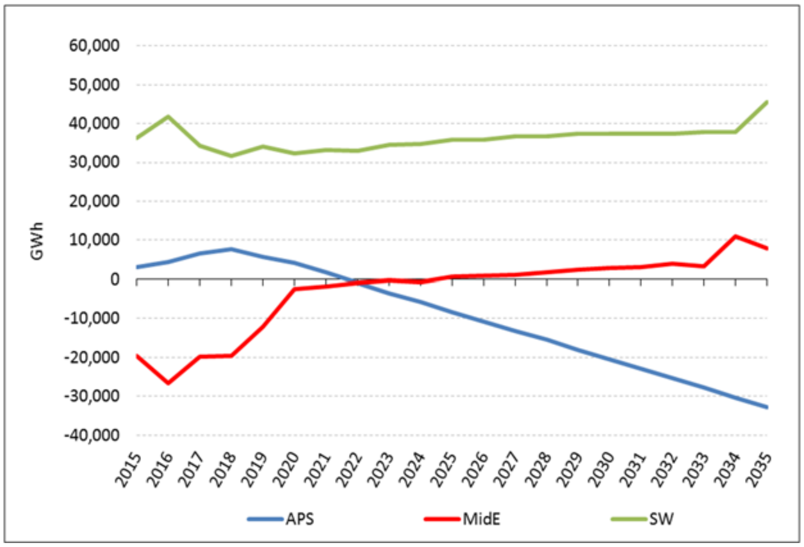

Figure 3-23. Net Imports, by PJM Transmission Zone, Reference Case

Source: 2016 LTER, Figure 4.5.

Note: Negative values represent net exports.

Under the Maryland RPS scenarios, net energy imports in PJM-APS and PJM-MidE drop (relative to the Reference Case), as shown in Figure 3-24 and Figure 3-25, since new wind capacity is built in those regions to meet the higher RPS requirements. For PJM-SW, net imports remain relatively unchanged, as shown in Figure 3-26. This may mean that the new solar capacity in PJM-SW displaces non-solar generation that was added in the Reference Case.

Under the PJM RPS scenario, which is also shown in Figure 3-24 through Figure 3-26, there is an increase in net imports in PJM-SW and PJM-MidE, but a decline in PJM-APS. This is likely due to a disproportionately large amount of new renewable energy capacity being placed in PJM-APS; roughly half of PJM-APS is in West Virginia, which currently does not have an RPS.

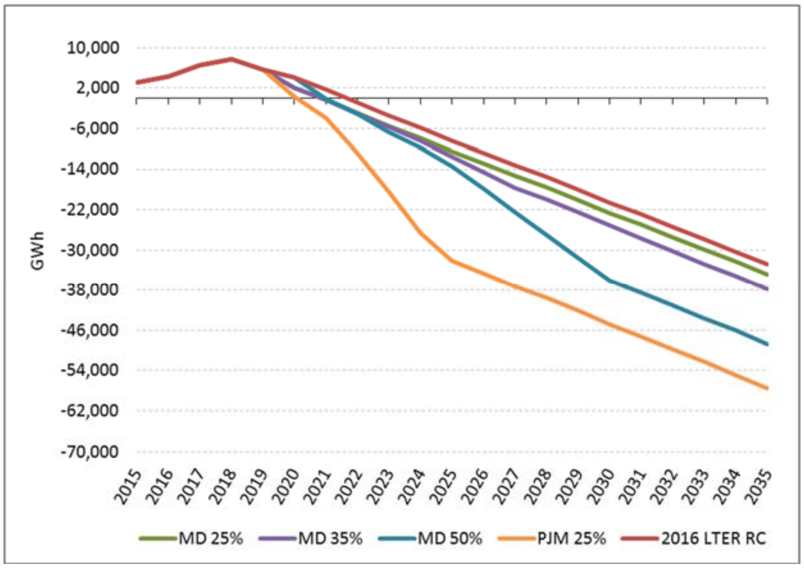

Figure 3-24. PJM-APS Net Energy Imports, All RPS Scenarios

Source: 2016 LTER, Figure 7.5.

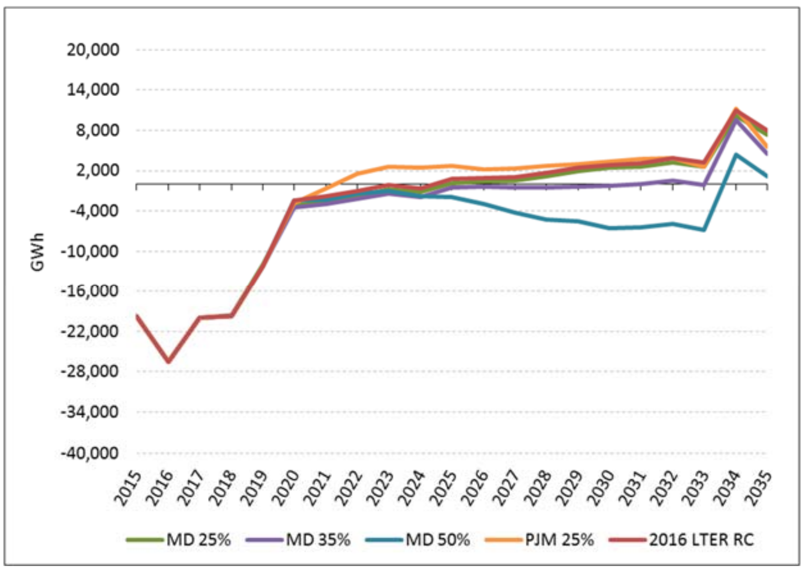

Figure 3-25. PJM-MidE Net Energy Imports, All RPS Scenarios

Source: 2016 LTER, Figure 7.4.

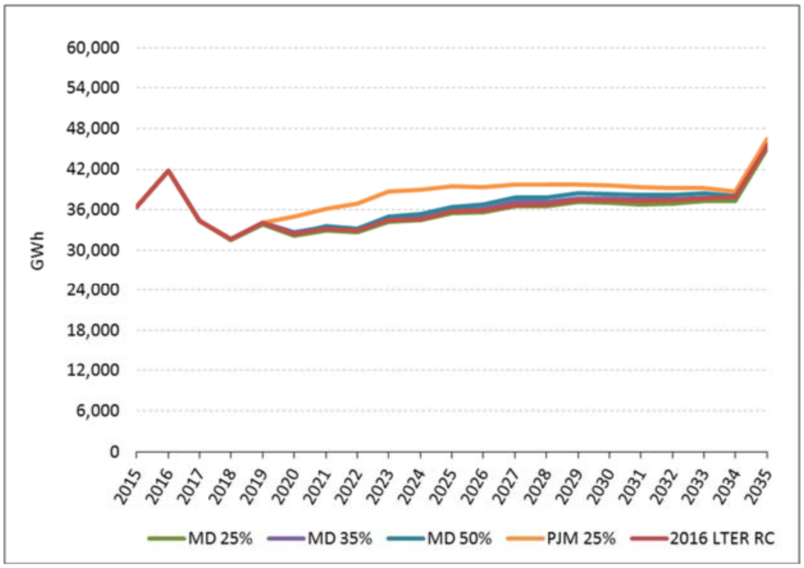

Figure 3-26. PJM-SW Net Energy Imports, All RPS Scenarios

Source: 2016 LTER, Fig 7.3.

Fuel Use

The LTER Reference Case predicted an increase in natural gas generation in Maryland beginning in 2017 as two CC natural gas plants—the 800-MW Keys Energy Center and the 746-MW St. Charles facility—were expected to come online. (Both plants have now come online.) From 2019 onward, natural gas output gradually decreases while coal output increases, because natural gas prices are predicted to rise more sharply than coal prices. No new coal plants are added in Maryland or in PJM in the Reference Case. Also, nuclear generation falls at the end of the study period due to the retirement of the Calvert Cliffs 1 nuclear plant in PJM-SW. These trends are shown in Figure 3-27.

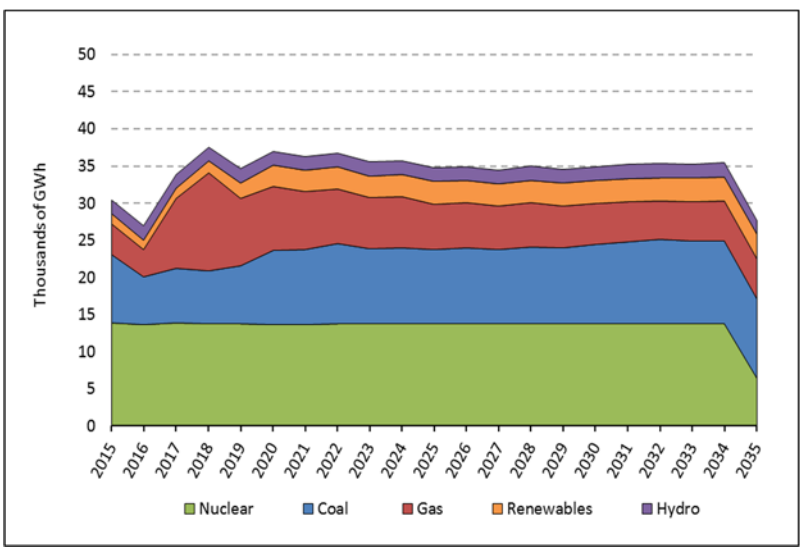

Figure 3-27. Maryland Generation Mix, Reference Case

Source: 2016 LTER, Figure 4.6.

None of the Maryland RPS scenarios affect consumption of natural gas or coal for electricity production, because Maryland's fossil fuel plants generate electricity to meet demand throughout PJM. Under the PJM RPS scenario, coal and natural gas generation within Maryland drops, compared to the Reference Case, as shown in Figure 3-28 and Figure 3-29.

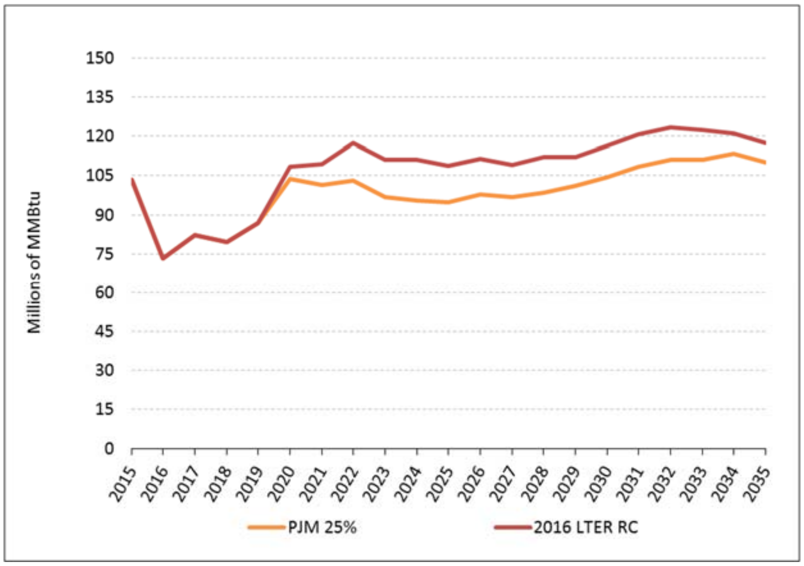

Figure 3-28. Coal Use for Electricity Generation in Maryland, PJM RPS Scenario

Source: 2016 LTER, Figure 7.24.

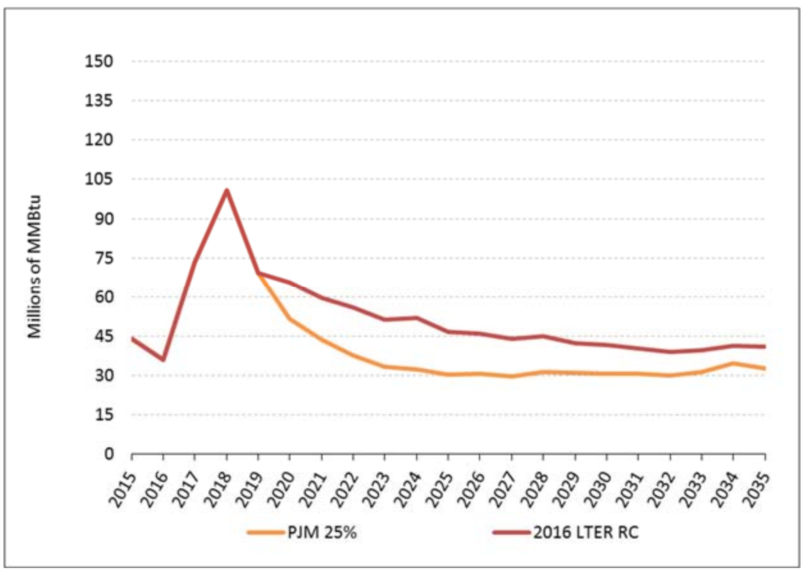

Figure 3-29. Natural Gas Use for Electricity Generation in Maryland, PJM RPS Scenario

Source: 2016 LTER, Figure 7.25.

HAA Emissions

Coal-fired power plants are subject to the Maryland HAA, which requires a 75% reduction in NOx emissions, 85% reduction in SO_2 emissions, and a 90% reduction in mercury emissions, all relative to 2002 levels. As shown in Figure 3-30 through Figure 3-32, the

Reference Case projects that Maryland's coal plants can stay below the HAA emissions caps, even with anticipated increases in coal generation. Emissions in Maryland and in the rest of PJM are impacted very little by the three Maryland RPS scenarios, because (as mentioned earlier) coal and natural gas plants continue to generate electricity at similar levels as in the Reference Case. Under the PJM RPS scenario, a small reduction in HAA emissions in Maryland is predicted because of the aforementioned drop in coal generation.

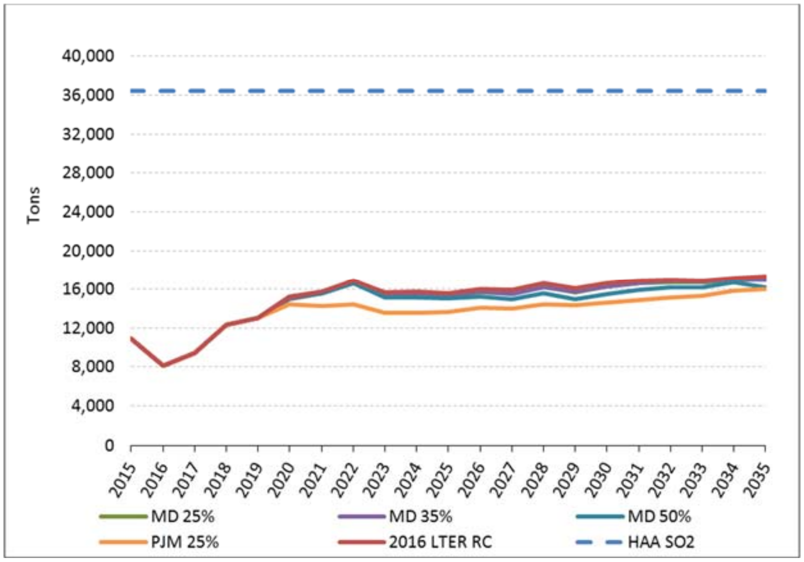

Figure 3-30. Maryland SO_2 Emissions (HAA Plants), All RPS Scenarios

Source: 2016 LTER, Figure 7.14.

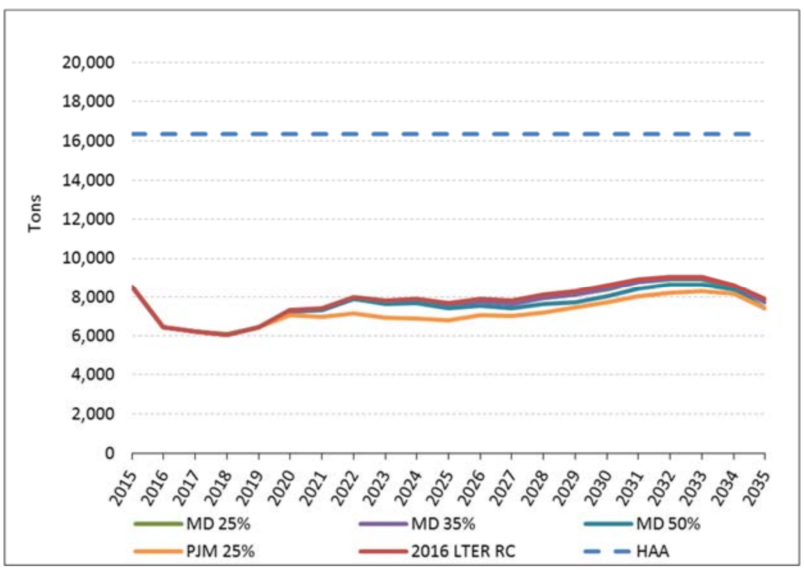

Figure 3-31. Maryland NOx Emissions (HAA Plants), All RPS Scenarios

Source: 2016 LTER, Figure 7.15.

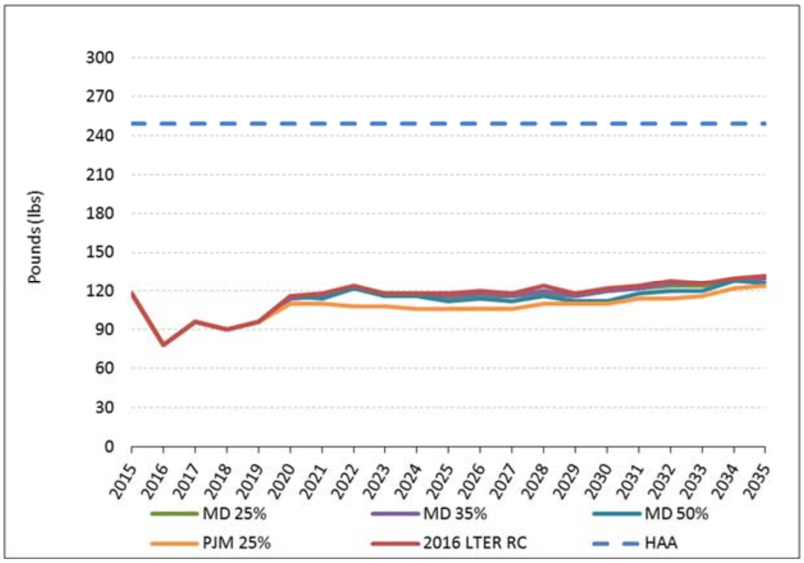

Figure 3-32. Maryland Mercury Emissions (HAA Plants), All RPS Scenarios

Source: 2016 LTER, Fig 7.16.

CO_2 Emissions

Under the Reference Case and the Maryland RPS scenarios, Maryland's CO_2 emissions are higher than the state's allowable level (i.e., the RGGI budget), as shown in Figure 3-33. However, Maryland may purchase emissions allowances that are allocated to other states in RGGI. The PJM RPS scenario brings Maryland within, or just above, its RGGI budget.

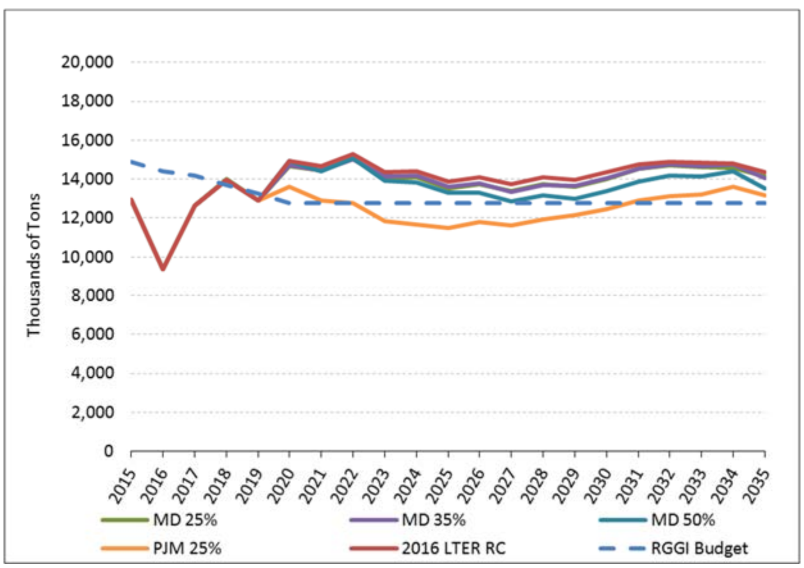

Figure 3-33. Maryland CO_2 Emissions (All Plants), All RPS Scenarios

Source: 2016 LTER, Figure 7.17.

Concerning PJM as a whole, CO_2 emissions drop in the initial years of the Reference Case and the Maryland RPS scenarios, then increase slightly during the rest of the forecast period. Figure 3-34 illustrates these projections. Only the PJM RPS scenario has a significant impact on CO_2 emissions, since it involves all PJM states making a shift to renewable generation.

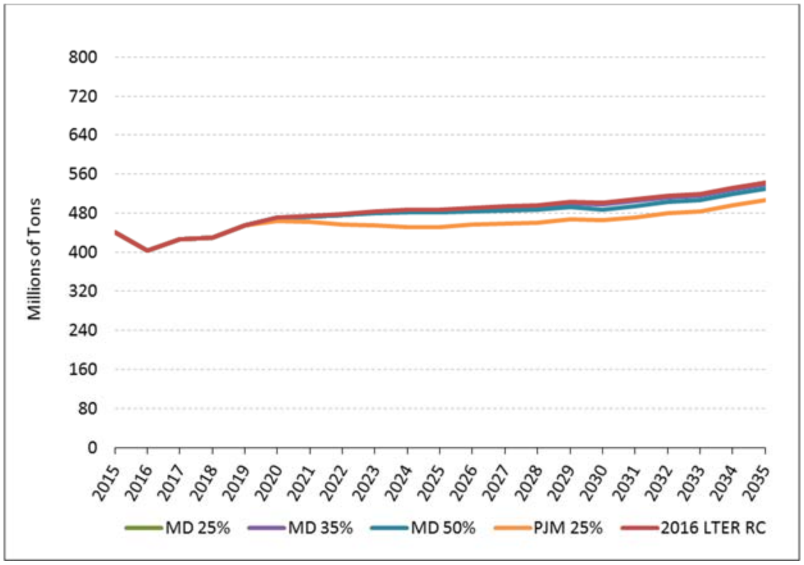

Figure 3-34. PJM CO_2 Emissions, All RPS Scenarios

Source: 2016 LTER, Figure 7.18.

Increasing the Maryland RPS does significantly lower the carbon content associated with electricity consumption in Maryland, as shown in Figure 3-35. For example, raising the Maryland RPS from 25% to 50% lowers average CO_2 emissions associated with electricity consumption by 3.6 million tons, or 12.5%, per year.

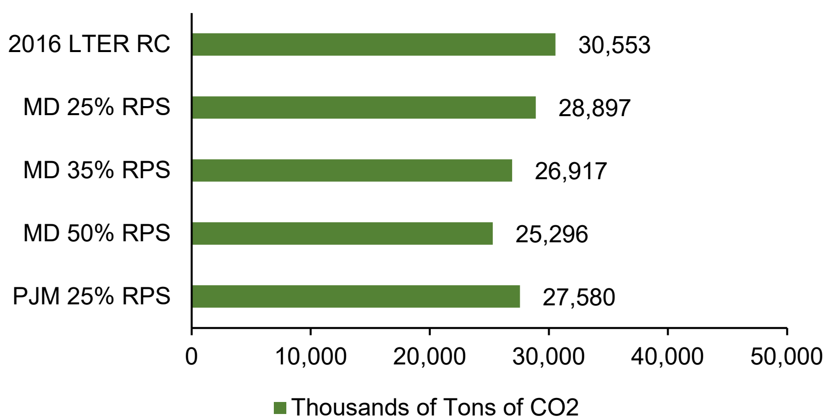

Figure 3-35. Average Annual CO_2 Emissions from Electricity Consumption in Maryland, 2015-2035

Source: 2016 LTER.

3.3.3. Other Key Assumptions in the 2016 LTER

The LTER contains several assumptions that may have a significant impact on the final report's conclusions. The following bullets summarize these key assumptions and, in certain cases, discuss the potential impact of changing these assumptions:

- The LTER is based on the *PJM Load Forecast December 2015*, which projected higher growth rates for both energy and peak load in select Maryland utility territories than PJM's most recent load forecast (January 2019), as shown in Table 3-22. This means the LTER's projections for new natural gas plant builds, generation, and associated emissions are likely higher than necessary.

Table 3-22. Comparison of PJM 2016 and 2019 Load Forecasts for Select Maryland Utilities

	ANNUAL GROWTH RATE (10-yr)			
	PJM Jan. 2016 Forecast[1]		PJM Jan. 2019 Forecast	
Utility	Energy	Summer Peak	Energy	Summer Peak
APS	0.90%	0.80%	0.80%	0.70%
BGE	0.40	0.40	0.10	-0.10
DPL	0.40	0.40	0.30	0.10
Pepco	0.40	0.40	0.10	-0.10

APS = Allegheny Power Systems.

Source: Tables B-1 and E-1 of the 2016 and 2019 *PJM Load Forecast Report*; 2016: pjm.com/-/media/library/reports-notices/load-forecast/2016-load-report.ashx?la=en; 2019: pjm.com/-/media/library/reports-notices/load-forecast/2019-load-report.ashx?la=en.

[1] The 2015 *PJM Load Forecast Report* is no longer available online. It appears to have been superseded by the 2016 *PJM Load Forecast Report*, which is the version of record.

- The LTER used capacity factors for wind and solar PV that are considered conservative (30% for onshore wind, 40% for offshore wind, and 15% for solar PV). Using higher capacity factors would increase the proportion of load met with wind and solar generation and decrease overall emissions from electricity.
- The model used for the LTER never considers renewable energy capacity additions purely on the basis of economics. This might cause the model to underestimate new wind and solar builds, given that both technologies have experienced significant cost declines in recent years.
- The LTER assumed that several plants in Maryland would continue to run throughout the study period, but they have since announced plans to retire by 2020. Collectively, these plants represent 372 MW of capacity, of which 232 MW are natural gas facilities. The remaining 140 MW are a combination of LFG, petroleum liquids, and conventional steam.[193] None of these plants are subject to the HAA. However, they contribute to Maryland's CO_2 emissions. It is likely that the retirement of these plants would cause in-state CO_2 emissions to be lower than those projected in the

[193] U.S. Energy Information Administration, Electric Power Monthly, Table 6.6., "Planned Electric Generating Unit Retirements," March 2019, eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_06.

LTER, but their output could be offset, to some extent, by increasing generation from the state's remaining CO_2-emitting generators.

3.3.4. Other Studies of the Environmental Impacts of the Maryland RPS

MDE has commissioned modeling to understand the economic and environmental impacts of enacting a set of policies contained in the agency's *2019 GGRA Draft Plan*, which was released in October 2019. These policies include:

- A proposed Clean and Renewable Energy Standard (CARES), which would require 100% of Maryland's electricity come from clean resources by 2040;
- Inclusion of additional states in RGGI;
- Continued effort to improve energy efficiency in buildings;
- Stricter vehicle emissions standards and additional Zero-Emission Vehicle (ZEV) sales;
- Expansion of public transportation and a transition to cleaner and more efficient public transportation fleets;
- Additional acreage in forest management and healthy soils conservation practices; and
- A proposed extension of EmPOWER Maryland beyond 2023, as well as additional incentives for residential electric heat pumps.[194]

Together, the policies contained within the GGRA Draft Plan are estimated to reduce annual electricity emissions from roughly 20 million metric tons of carbon dioxide equivalents (MMT CO2e) in 2020 to roughly 10 MMT CO2e in 2030 and roughly 5 MMT CO2e in 2040.[195]

3.4. Impact of the Maryland RPS on Jobs and Economic Output

Methodologies used in economic impact analysis vary, ranging from survey extrapolations to econometric models. Most regional economic studies, however, use I-O models, which are well suited to estimating regional job creation and spending. This study uses the I-O model known as IMPLAN. IMPLAN's client base includes the Maryland Department of Commerce and over 500 state and federal government agencies, as well as the private sector.[196]

The first subsection provides an overview of IMPLAN and defines key terminology used in setting up the model and interpreting results. It also summarizes the current study's scope and the methodologies used to develop all necessary model inputs. The second subsection summarizes the modeling results, including expected economic impacts and possible opportunities to enhance them.

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[194] Energy and Environmental Economics, Inc., *2019 GGRA Draft Plan*, Executive Summary, Maryland Department of the Environment, 2019, mde.maryland.gov/programs/Air/ClimateChange/Documents/2019GGRAPlan/2019%20GGRA%20Draft%20Plan%20Executive%20Summary%20(10-15-2019)%20POSTED.pdf.

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

[196] Sage Policy Group, Inc., *Economic Contributions of the Potential Amazon HQ2 in Maryland*, prepared for the State of Maryland and Montgomery County, MD, February 2018, commerce.maryland.gov/commerce/Documents/sage-mo-co.pdf.

For this study, two primary scenarios were considered: a 25% RPS scenario (25% RPS), based on the Maryland RPS as of 2018 (before it was modified), and a 50% RPS scenario (50% RPS), based on CEJA, which passed in the 2019 legislative season. Supplementary model runs were also conducted to explore higher-than-expected levels of offshore wind manufacturing in Maryland (High-Manufacturing scenario), and the economic impacts of the Maryland RPS not only in Maryland but also in the District of Columbia and neighboring states in PJM: Delaware, New Jersey, Pennsylvania, Virginia, and West Virginia (PJM scenario). All scenarios are considered from 2019-2030.

It was assumed that new solar PV capacity would fully meet the Maryland RPS solar carve-out requirements and that new offshore wind projects would satisfy the Maryland RPS offshore wind carve-outs. All other new capacity developed in response to the Maryland RPS, such as onshore wind, was assumed to be built outside of Maryland, as has mostly been the case in recent years.[197] Because of this assumed resource allocation, the study focuses solely on the economic impacts of solar PV located in Maryland and offshore wind projects located in the Maryland Wind Energy Area (WEA), as identified by the BOEM. Key findings from this section are summarized below.

Overall Economic Impacts

- The future economic impact of a 25% RPS is modest, particularly for new solar jobs, because the goals of a 25% RPS have already been or will likely be met by 2020. All future impacts from the 25% RPS are from offshore wind development associated with the US Wind and Skipjack proposals already approved by the Maryland PSC.
- The cumulative economic impacts of a 50% RPS include: more than 34,000 full-time equivalent (FTE)[198] jobs, with nearly $5 billion (2018$) in sales in Maryland attributable to construction, and an additional 5,300 FTE jobs with $2.6 billion in sales in Maryland attributable to O&M. (Note that these are gross impacts; they do not account for job losses associated with reduced fossil fuel capacity and generation, nor for any macroeconomic effects associated with the impact of the RPS on electric prices.)
- Under the 50% RPS, 42% of the FTE jobs created as a result of the Maryland RPS are associated with distributed PV, 40% with offshore wind, and 17% with utility-scale PV.
- The identified economic benefits of the Maryland RPS are concentrated in the construction and service industries. The manufacturing sector benefits less because most solar and offshore wind components are manufactured out of state. Data from the *National Solar Jobs Census* suggest that PV construction and project development jobs have comparable compensation levels, on an hourly basis, with manufacturing.

Supply Chain Growth Potential

- Major solar PV components, such as modules and inverters, are largely imported. In comparison, structural BOS components (e.g., racking, mounting, and tracking systems) and electrical BOS components (e.g., conductors and monitoring devices)

[197] For instance, from January 2015 – December 2017, only 2.3 MW of new, non-solar renewable capacity in Maryland registered with PJM-GATS. This capacity consists of a 1-MW landfill gas facility and several small geothermal projects.

[198] FTE represents the hours logged by one employee working on a full-time basis (i.e., 2,080 hours/year = 1 FTE job).

are more often sourced from domestic manufacturing. According to SEIA's National Solar Database, at least two companies selling structural BOS components are located in Maryland.

- Opportunities for PV-related manufacturing growth in Maryland are probably limited to BOS supply chains. However, the largest U.S. markets for solar PV are currently in the South and West. Given this, it may be difficult to attract further manufacturing to Maryland.
- Offshore wind installations require many specialized components that are not currently produced in the United States. Even though facilities serving the U.S. onshore wind market may be capable of manufacturing offshore wind components, logistical challenges (such as long-distance transport of offshore wind turbine blades on roads and highways) are expected to limit their ability to supply the offshore market.
- This study allocates the majority of in-state offshore wind expenditures to the construction and service industries. These industries have a significant presence and established supply chains in coastal states.
- In approving the OREC applications of US Wind and Skipjack, the Maryland PSC required that each company allocate significant percentages of construction expenditures to Maryland businesses, and specifically target investment in a Maryland steel fabrication facility and port infrastructure. Besides this targeted investment, there is considerable uncertainty about which industries will benefit.
- Most near-term, in-state manufacturing opportunities are limited to upstream materials and subcomponents that can be easily transported. Upstream products include scaffolding, coatings, ladders, fastenings, hydraulics, concrete, and electrical components.
- Many reports predict that future opportunities for domestic suppliers will be greatest in industries responsible for providing foundations and substructures, towers, blade materials, power converters, and transformers.
- Multiple ports will probably be required if offshore wind off the Atlantic coast is developed to projected capacities. To meet this demand, U.S. ports will need to be improved to support staging and manufacturing operations. As a condition for Maryland PSC approval of ORECs, both US Wind and Skipjack are required to use a port facility in the greater Baltimore region for marshalling project components, use Ocean City as the O&M port, and invest in upgrades at the Tradepoint Atlantic shipyard. As such, Tradepoint Atlantic has positioned itself to potentially become an offshore wind hub on the East Coast. This facility has space for offshore wind laydown, manufacturing, and vessel loading.[199] Tradepoint Atlantic has leased 50 acres to Ørsted for laydown and assembly, as part of the company's commitment to invest over $13 million in the port.[200]

3.4.1. IMPLAN Overview, Scope, and Methodology

The IMPLAN model is used to estimate economic impacts in this study. Like all I-O models, IMPLAN is based on the interdependencies that exist in the economy. IMPLAN divides the

[199] Tradepoint Atlantic, "Offshore Wind Factsheet," tradepointatlantic.com/downloads/.

[200] Ørsted, "Ørsted U.S. Offshore Wind, Tradepoint Atlantic Partner on Maryland's First Offshore Wind Energy Center," July 23, 2019, us.orsted.com/News-Archive/2019/07/Tradepoint-Atlantic-Partnership.

economy into 536 sectors, comprising industry, government, and households, and then tracks the dollar flows between them. For national-level data, IMPLAN relies primarily on tables produced by the U.S. Bureau of Economic Analysis (BEA). These tables summarize the flow of commodities and services between industries. IMPLAN also uses state- and county-level data from BEA, BLS, and other sources to "regionalize" these tables.

In IMPLAN, an initial change in spending is referred to as a change in "final demand." It is considered a direct effect, which then creates indirect and induced effects.[201] Indirect effects stem from local industries' purchases of inputs (goods and services) from other local industries. These purchases are also known as intermediate expenditures. Induced effects reflect the spending of wages from workers involved in providing the goods and services being modeled. The multiplier effect in Figure 3-36 represents the additional economic activity generated by a change in final demand of an industry (e.g., for every dollar spent on something, an additional $0.25 of economic activity is generated locally, implying a multiplier of 1.25). IMPLAN's multipliers are based on historical patterns of economic activity.

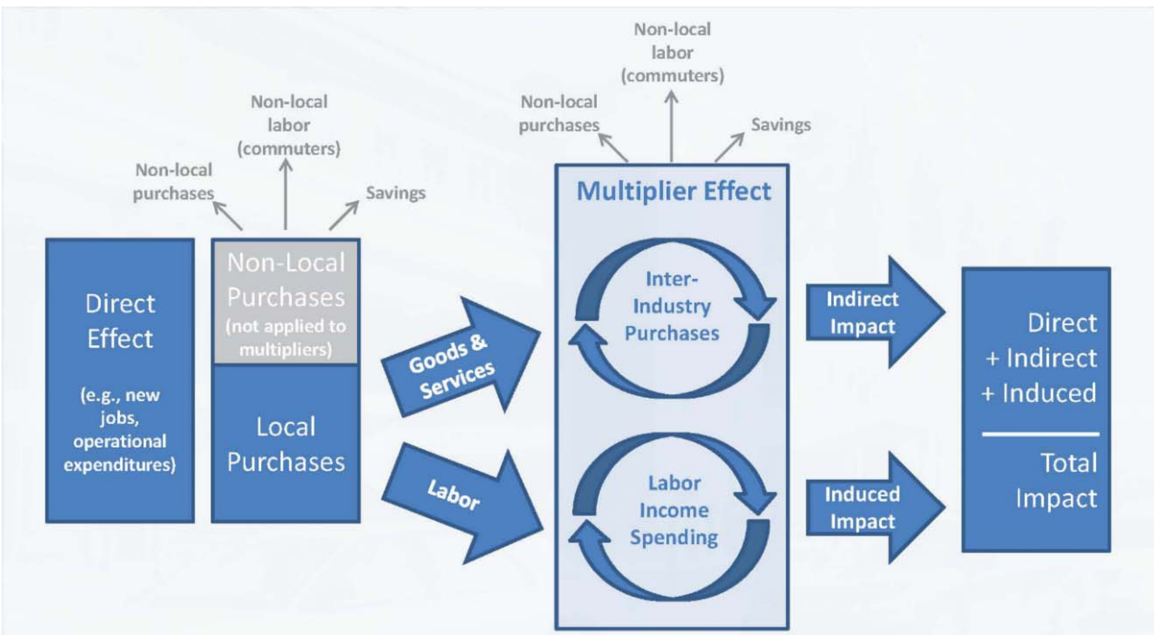

Figure 3-36. Impact of a Change in Spending in an Input-Output Model

Source: Adapted from AKRF Inc., North Bergen Liberty Generating, LLC: *Economic and Fiscal Analysis*, August 2017, documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={CF578449-B169-4EAF-9661-BE1A91A35A3B} (webpage now cached).

Economic impacts in IMPLAN are typically measured in terms of jobs created, earnings, output, and value added, each of which is defined briefly below:

- *Jobs* are expressed as full-time equivalents, meaning the hours logged by one employee working on a full-time basis (i.e., 2,080 hours/year = one FTE job);
- *Earnings* represents labor wages and benefits;
- *Output* represents total sales; and

[201] Final demand is the demand for goods that is not used to produce other goods.

- *Value Added* represents total sales minus the cost of production inputs (e.g., components purchased from other businesses).

IMPLAN has important limitations. IMPLAN multipliers, upon which results depend, reflect industry linkages in a local economy at a given time; the multipliers do not account for price elasticities. IMPLAN also does not estimate economy-wide *net* impacts. For example, increases in jobs and spending for renewable energy projects may be offset by contractions in other parts of a regional or national economy, such as fossil fuel power production. Additionally, IMPLAN does not reflect job reductions as a result of increased electricity prices.

As noted earlier, two primary scenarios were considered from 2019-2030: the 25% and the 50% RPS. Both scenarios focus solely on the economic impacts of solar PV located in Maryland and offshore wind projects located in the Maryland WEA, as identified by BOEM. Two supplemental scenarios were added: a 50% RPS with impacts modeled in neighboring PJM states (PJM scenario); and a 50% RPS with high manufacturing in Maryland (High-Manufacturing scenario).

Figure 3-37 provides an overview of the steps necessary to develop annual spending projections for solar PV and offshore wind under each scenario (i.e., the inputs necessary to run IMPLAN). With traditional investments, such as a new hospital, IMPLAN can automatically apportion project costs to the appropriate industry sectors because historical inter-industry relationships for this activity already exist. In situations where an industry is relatively new or non-existent in a region, inter-industry relationships are not embedded in the model's database. Therefore, the user must apportion the initial investment into purchases of goods and services by initially affected industries. This is known as the bill-of-goods approach. Each step in Figure 3-37 is described in detail on the following pages.

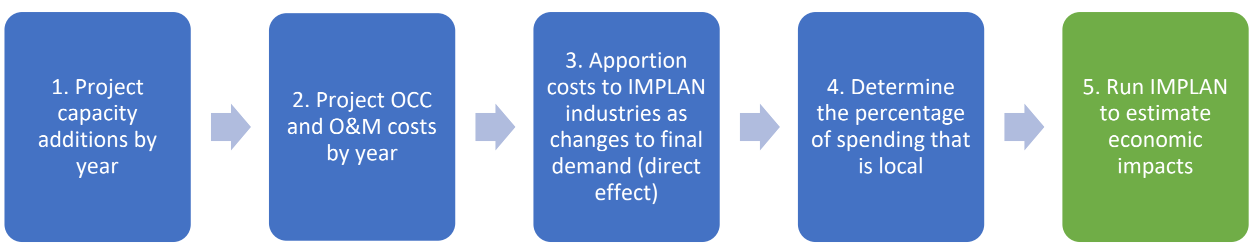

Figure 3-37. Basic Steps to Developing IMPLAN Spending Projections

3.4.2. Step 1. Project Annual Solar PV and Offshore Wind Capacity Additions

Solar PV Projections

Since Maryland's solar carve-out is based on retail sales, sales projections serve as the starting point for estimating solar PV capacity additions. Retail sales projections were drawn from the most recent Maryland PSC *Ten-Year Plan*.[202] The *Ten-Year Plan* provides "Net of DSM (Demand Side Management)" retail sales projections for 2018-2027 by utility for Maryland-only service areas. During this period, annual demand is expected to fall gradually from 59,432 GWh to 54,994 GWh, due in large part to energy efficiency measures

[202] Public Service Commission of Maryland, *Ten-Year Plan (2018-2027) of Electric Companies in Maryland*, December 2018, psc.state.md.us/wp-content/uploads/Ten-Year-Plan-2018-2027-FINAL.pdf, Appendix Table 2(a)(ii).

associated with the EmPOWER Maryland program.[203] Since this study estimated economic impacts through 2030, retail sales projections in the *Ten-Year Plan* were extended beyond 2027 using a linear trend estimator.

A 1.9% downward adjustment was made in the retail sales projections to account for IPL sales, which are essentially exempt from Maryland RPS requirements through reduced ACPs. The Maryland PSC defines IPL as the consumption of electricity by a manufacturing process at a facility categorized as a manufacturer under the North American Industry Classification System (NAICS). The 1.9% figure is an estimate based on historical Maryland PSC data from 2013-2015.

Each year's adjusted retail sales projection was multiplied by the corresponding carve-out percentage to project solar generation requirements. Using this approach, the 25% RPS solar carve-out requires approximately 1,458 GWh of in-state solar generation when it reaches 2.5% in 2020. The 50% RPS Tier 1 solar carve-out requires 3,207 GWh of in-state solar generation in 2019 and approximately 7,734 GWh when the solar requirement reaches 14.5% in 2028.

It was assumed that new solar capacity built to fulfill the solar carve-out would be split evenly between utility-scale PV and distributed PV, the latter of which is defined as <2 MW for this section. This represents a middle ground between historical trends and industry forecasts, which tend to project that future growth will be dominated by utility-scale PV (currently, distributed PV represents 67% of PV capacity in the state).[204]

Capacity factors were used to determine the amount of utility-scale PV and distributed PV capacity needed in each year to fulfill the generation carve-outs.[205] The capacity factors for utility-scale PV and distributed PV systems were assumed to be 25% and 18%, respectively.[206] Based on these capacity factors, achieving the 50% RPS solar carve-out targets would require approximately 1,703 MW of installed solar capacity by 2019 and 4,106 MW by 2028. By contrast, achieving the final 2.5% carve-out target associated with the 25% RPS would require roughly 770 MW less capacity than is currently installed in Maryland. Because of this, no new PV construction (nor any subsequent O&M activity) was modeled for the 25% RPS.

Figure 3-38 shows the solar carve-out for the 50% RPS (and the 25% RPS, for reference), while Figure 3-39 shows annual distributed PV and utility-scale PV capacity additions. Years with major capacity additions correspond to significant increases in carve-out requirements. For example, in 2019, over 600 MW of new capacity are needed to bridge the gap between the 1,084 MW of PV capacity online in Maryland at the end of 2018 and the 1,703 MW needed to fulfill a 5.5% carve-out in 2019. For the next three years, the carve-out rises gradually (i.e., never more than 0.75% per year), resulting in modest capacity additions. Between 2022-2023, the carve-out rises 1.5%, causing the next spike in capacity additions.

[203] EmPOWER Maryland, Annotated Code of Maryland, PUA § 7-211.

[204] For example, NREL produces an annual outlook on the electricity sector called the *Standard Scenarios Report*. Its mid-case scenario anticipates that, between 2020-2030, roughly seven times more utility-scale PV capacity will be added in the Eastern Interconnection than distributed PV.

[205] The capacity factor of an electric generating unit is measured as the ratio of the actual energy output (MWh) over a period of time to the output at full nameplate capacity over that same period. For instance, a 10-MW PV system that generates 17,520 MWh/year has a 20% capacity factor (i.e., 17,520 MWh/(10 MW x 8,760 hours) = 0.2).

[206] Both capacity factors are based on a combination of the national values as reported by the NREL Open Energy Information (OpenEI) Transparent Cost Database, as well as capacity factors derived from EIA generation data for renewable energy units within PJM.

The solar carve-out plateaus at 14.5% in 2028. Given this, and the fact that load is expected to decrease each year, no new capacity is assumed in 2029 or 2030.

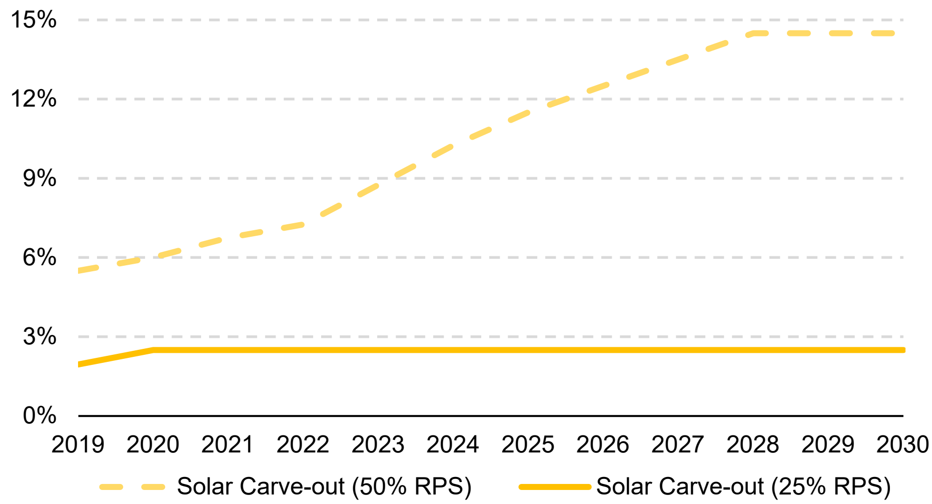

Figure 3-38. Solar Carve-out Requirements, 25% RPS and 50% RPS

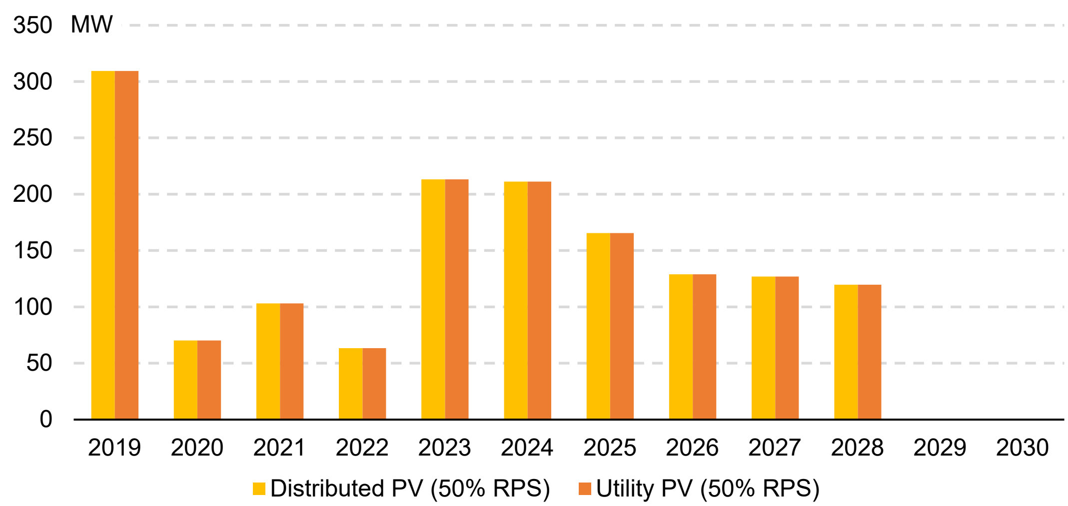

Figure 3-39. Projected Annual Solar PV Capacity Additions, 50% RPS

Offshore Wind Projections

Under the 25% RPS, the offshore wind carve-out is 2.5% beginning in 2017. However, to better approximate the real-world impact of current law, only the US Wind and Skipjack projects were included. US Wind and Skipjack capacity additions are projected to be slightly higher than required by the offshore wind carve-out. Construction dates for the two projects were assumed to be 2020 and 2022, respectively.[207] Under the 50% RPS, SB 516 requires no more than 2.5% of retail electricity sales in Maryland to be derived from offshore wind

[207] At the time of the PSC Order, the US Wind project was projected to come online in 2020 and the Skipjack Project in late 2022. In conducting the analysis for this report, the online dates for both projects were pushed back one year to account for permitting delays (i.e., US Wind would come online in 2021, while Skipjack would come online in 2023). Skipjack continues to predict that its online date will be 2022, while US Wind has since delayed its projected operating date to 2023.

energy for 2020 and 2021, then requires the Maryland PSC to set a new percentage level for offshore wind after 2021. For this study, the offshore wind requirement for Round 1 projects, defined as qualified offshore wind projects approved by the PSC before July 1, 2017, is assumed to be identical to the 25% RPS.[208] For Round 2 projects, SB 516 requires at least 400 MW of new offshore wind capacity to be operational in 2026. This increases to at least 800 MW in 2028 and 1,200 MW in 2030. It was therefore assumed that 400-MW capacity increments would be built in each of the years preceding the 2026, 2028, and 2030 generation requirements, as shown in Figure 3-40.

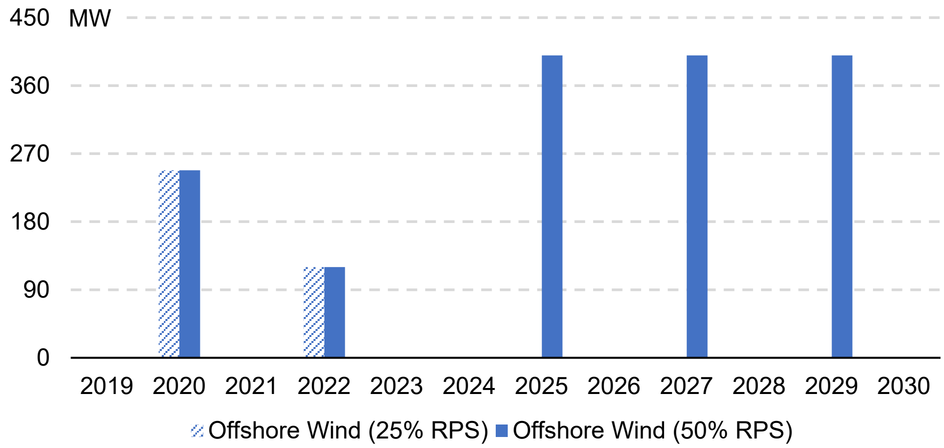

Figure 3-40. Projected Annual Offshore Wind Capacity Additions, 25% RPS and 50% RPS

Note: Offshore wind construction activities occur during the year prior to the year when additional carve-out generation is required, as these projects are expected to take about one year to build.

3.4.3. Step 2. Project Annual Overnight Capital Costs and O&M Costs by Project Type

Projections for overnight capital costs (OCCs) and O&M costs were based on NREL's Annual Technology Baseline (ATB), which contains cost projections for 12 generation technologies.[209] Each of these projections is based on multiple studies. For example, the ATB's OCC projections for utility-scale PV are based on 15 short-term projections (published between November 2016 and December 2017) and four long-term projections made in the last four years.[210]

To reflect the diversity of real-world projects, the ATB provides two sets of distributed PV cost projections—residential (5-kW, fixed-tilt) and commercial (300-kW, fixed-tilt)—and 14 sets of offshore wind cost projections, representing various combinations of project foundations, wind speeds, and water depths. Given the relative uniformity of costs (per kW) for utility-scale solar projects, only one set of utility-scale PV cost projections (100-MW,

[208] The existing offshore wind application and approval process is comprised of Round 1 and Round 2 projects. Round 1 projects occur between 2018-2024 and correspond to the 2.5% offshore wind carve-out as set by the Maryland PSC under §7-704.2(A). Round 2 projects create ORECs after 2025. Both Round 1 and Round 2 are part of the 50% RPS.

[209] OCC is the cost of building a project without associated financing costs, as if the project was constructed overnight. This eliminates the interest rate and time needed to construct a project, making it easier to compare to other projects.

[210] National Renewable Energy Laboratory, Annual Technology Baseline, "Utility Scale PV," 2018, atb.nrel.gov/electricity/2018/index.html?t=su.

single-axis tracking) is provided. For distributed PV, the ATB's commercial PV cost projections were used. These projections are lower than the residential PV cost projections, and thus unlikely to overestimate the economic impacts of distributed PV deployment in the state. For offshore wind, the ATB's Technology Resource Group 1 turbine cost projections were used, since the turbine's project specifications and offshore wind characteristics were similar to those in the Skipjack and US Wind applications. Based on these choices, annual OCC and O&M cost projections for distributed PV, utility-scale PV, and offshore wind are shown in Figure 3-41 and Figure 3-42, respectively.

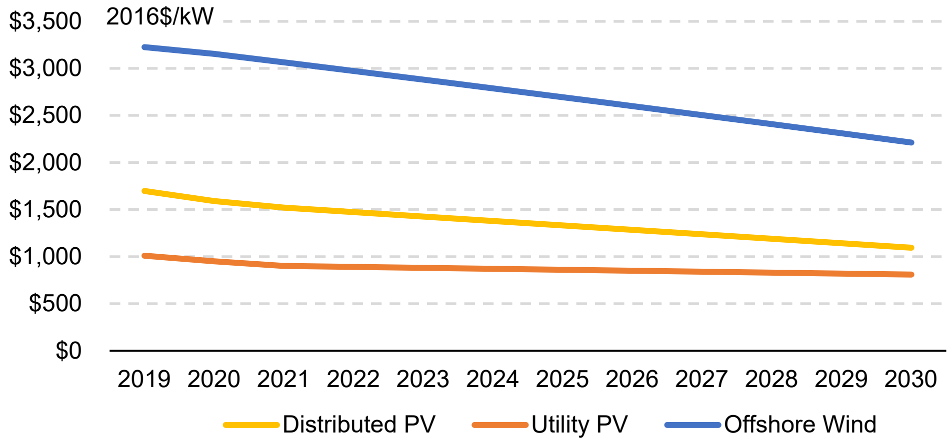

Figure 3-41. Projected Overnight Capital Costs for Solar PV and Offshore Wind Projects

Source: NREL Annual Technology Baseline, 2017.

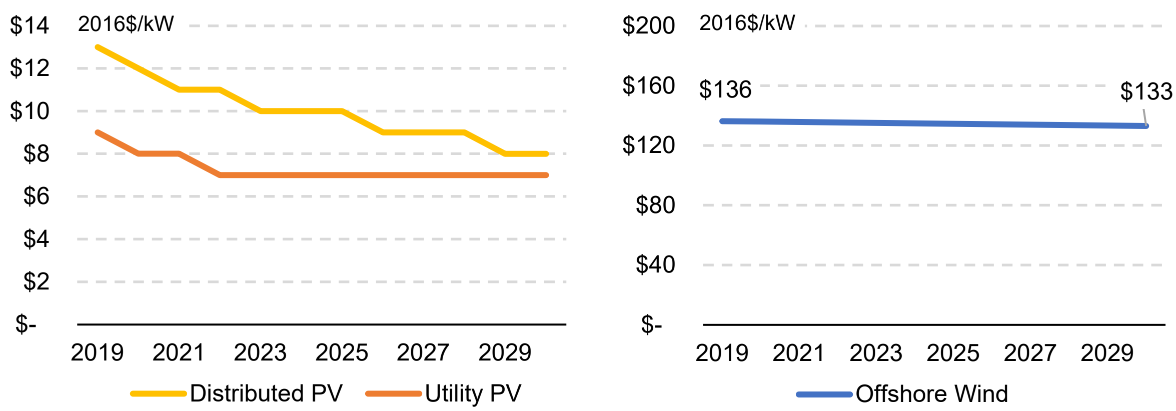

Figure 3-42. Projected O&M Costs for Solar PV and Offshore Wind Projects

Source: NREL Annual Technology Baseline, 2017.

Whenever incremental distributed PV, utility-scale PV, or offshore wind capacity additions were projected for a given year (refer to Figure 3-39 and Figure 3-40), this additional capacity was multiplied by the appropriate unit OCC value ($/kW) to project annual construction costs by project type. Similarly, each year's cumulative capacity values for distributed PV, utility-scale PV, and offshore wind were multiplied by the appropriate O&M value to project annual O&M costs by project type.

Figure 3-43 and Figure 3-44 show projected OCCs and O&M costs, respectively, for PV systems in the 50% RPS. Figure 3-45 and Figure 3-46 show the analogous values for offshore wind. Even though equivalent amounts of distributed and utility-scale PV are deployed each year (refer to Figure 3-39), the higher per-kW capital cost of distributed PV leads to more overall investment in distributed PV each year. The discrepancy diminishes over time as the gap between OCCs for distributed versus utility-scale PV diminishes (refer to Figure 3-42, above).

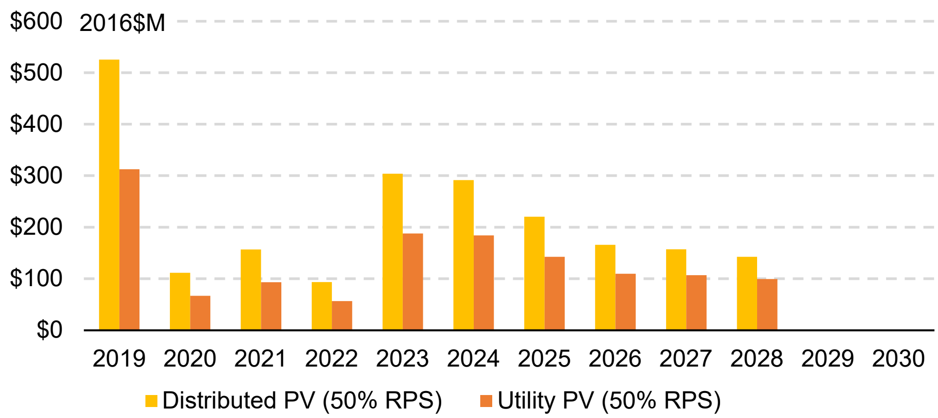

Figure 3-43. Projected Overnight Capital Costs for Solar PV Projects, 50% RPS

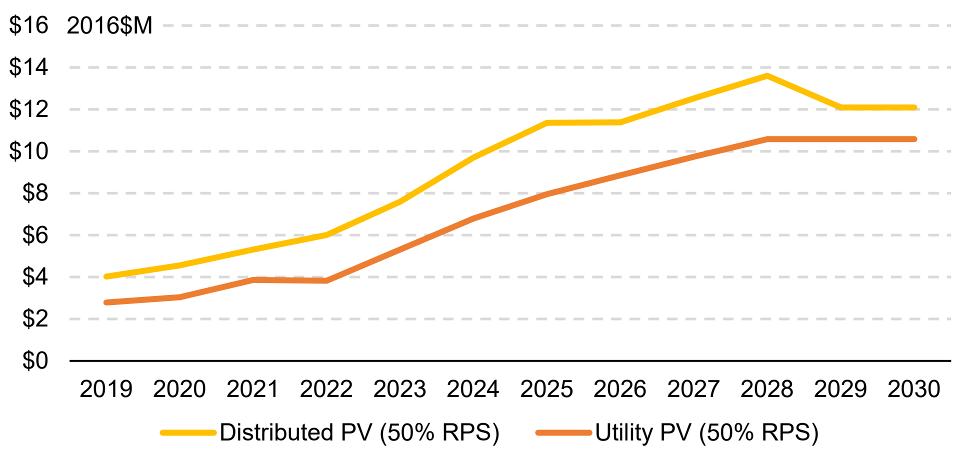

Figure 3-44. Projected O&M Costs for Solar PV Projects, 50% RPS

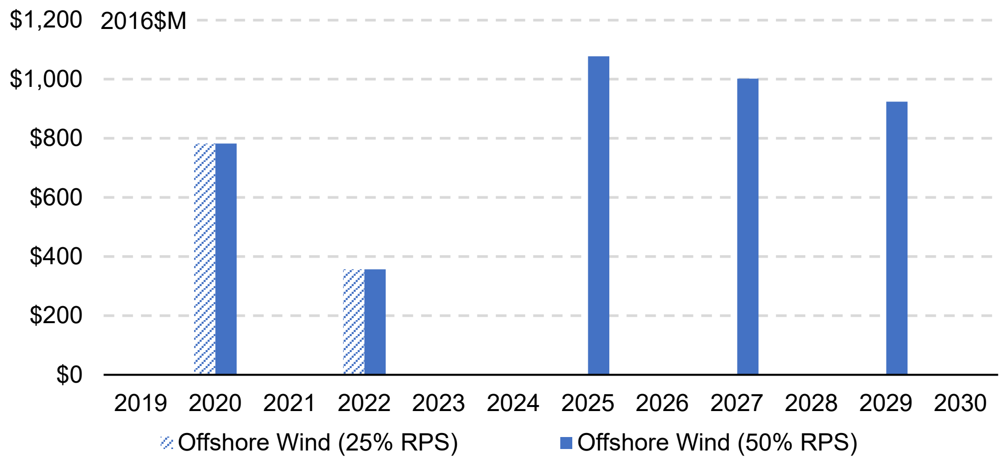

Figure 3-45. Projected Overnight Capital Costs for Offshore Wind Projects, 25% RPS and 50% RPS

Note: Offshore wind construction expenditures occur in the year prior to the year the carve-out is required, as these projects are expected to take about one year to build.

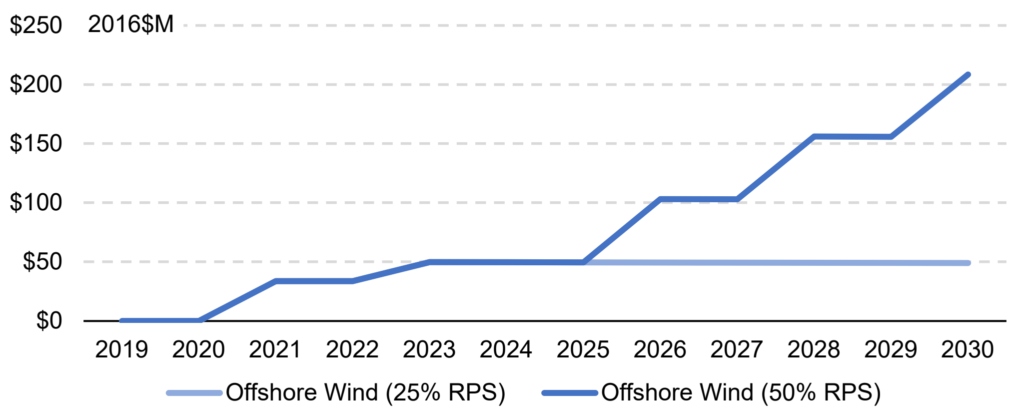

Figure 3-46. Projected O&M Costs for Offshore Wind Projects, 25% RPS and 50% RPS

3.4.4. Step 3. Apportion Costs to IMPLAN Industries

Because established supply chains for solar PV and offshore wind are either nascent or non-existent in Maryland, annual OCCs and O&M costs were broken down by IMPLAN sector using a bill-of-goods approach. This breakdown was based on expenditure patterns observed in the solar PV and offshore wind industries. For this step, three additional NREL reports (detailed below) were relied upon, as well as numerous supplemental resources related to the offshore wind projects. The processes for breaking down solar PV and offshore wind OCCs and O&M costs are discussed separately below.

Solar PV Overnight Capital Costs

NREL's Q1 2017 *U.S. Solar Photovoltaic System Cost Benchmark* (PV Benchmark) was used to break down solar PV OCCs. NREL uses bottom-up accounting for all system and project development costs, then aggregates these costs to arrive at total system installed costs.[211]

[211] Bottom-up accounting attempts to tally all system and project development costs incurred during the installation of solar PV projects, rather than beginning with an overall project cost.

For example, NREL's breakdown of utility-scale PV costs for various sizes of fixed-tilt and one-axis tracking systems is shown in Figure 3-47.

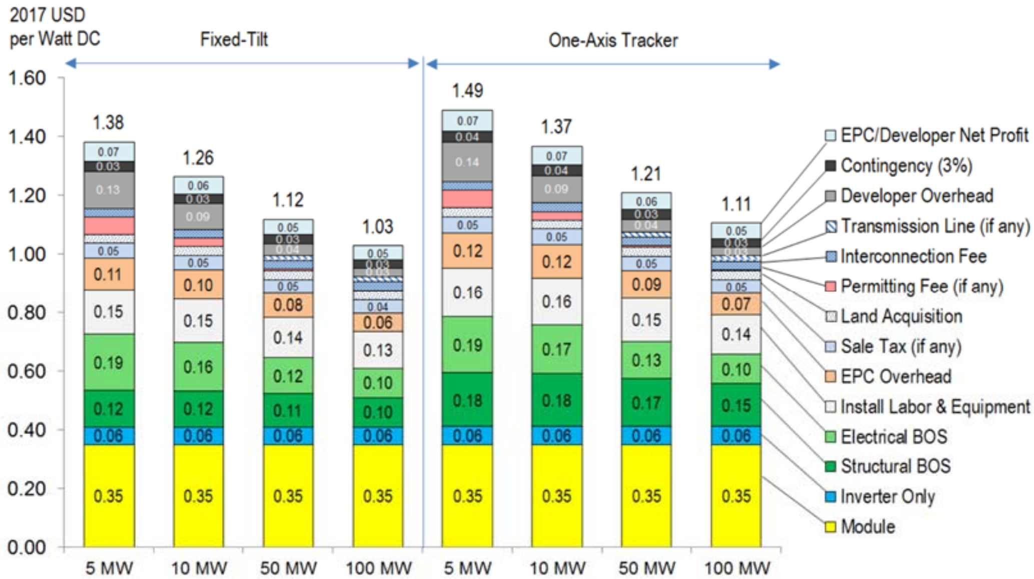

Figure 3-47. U.S. Benchmark: Utility-Scale PV Total Cost, 2017$/Watt Direct Current

Source: NREL, *U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017*.

The cost categories shown in Figure 3-47 were grouped by type, then mapped onto corresponding industry sectors in IMPLAN. NREL unit cost estimates were then converted into percentages in order to apportion projected OCCs to specific IMPLAN industrial sectors on an annual basis. This process is summarized in Table 3-23. In general, unit costs for utility-scale PV (100 MW) are lower than for commercial PV (200 kW) due primarily to economies of scale.

Table 3-23. Mapping of Solar PV Overnight Capital Costs to IMPLAN Sectors

NREL Cost Category	IMPLAN Industrial Sector	2017$/watt direct current		% of Total Cost	
		200 kW	100 MW	200 kW	100 MW
Installation Labor & Equipment, Developer Net Profit	Construction of new power & communication structures	$0.27	$0.20	15%	18%
	Total Construction:	**$0.27**	**$0.20**	**15%**	**18%**
Module	Semiconductor & related device manufacturing	$0.38	$0.39	21%	35%
Inverter	Power, distribution & specialty transformer manufacturing	0.11	0.07	6	6
Structural BOS	Fabricated structural metal manufacturing	0.15	0.17	9	15
Electrical BOS	Other communication & energy wire manufacturing	0.16	0.11	9	10
	Total Manufacturing:	**$0.81**	**$0.73**	**45%**	**66%**
Developer Overhead	Architectural & engineering services	$0.59	$0.10	33%	9%
Permitting, Land Acquisition, Interconnection, Transmission	Legal services	0.12	0.08	7%	7%
	Total Services:	**$0.72**	**$0.19**	**40%**	**17%**
	TOTAL:	**$1.79**	**$1.11**	**100%**	**100%**

Source: NREL, *U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017*, Figures 21 and 28.

Note: Sales tax was applied to manufacturing costs. Contingency costs, which are a separate JEDI cost category (see *Table 3-26*), are instead allocated proportionally to all other cost categories.

Between 2018-2030, OCCs for distributed PV and utility-scale PV are projected to decline to $603/kW and $240/kW, respectively.[212] Historically, OCC reductions have varied by cost category. Between 2010-2017, for example, the cost reductions were distributed among cost categories as follows:

- Distributed PV: 82% hardware, 4% labor, and 14% soft costs
- Utility-scale PV: 64% hardware, 11% labor, and 25% soft costs[213]

The proportions above were applied to the capital costs declines forecast in the 2018 ATB based on the assumption that these historical trends would continue. For example, between 2018-2030, 64% (i.e., $144/kW) of the total declines in utility-scale PV OCCs (i.e., $240/kW) were apportioned to hardware.

[212] National Renewable Energy Laboratory, Annual Technology Baseline, "Utility Scale PV," 2018, atb.nrel.gov/electricity/2018/index.html?t=su.

[213] Ran Fu, David Feldman and Robert Margolis, *et al.*, *U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017*, National Renewable Energy Laboratory, 2017, nrel.gov/docs/fy17osti/68925.pdf, Section 4.3, "Commercial PV Price Benchmark Historical Trends."

Solar PV O&M Costs

NREL's *PV O&M Cost Model* was used to break down solar PV O&M costs.[214] Hardware replacement costs were excluded since replacement of major project components would either be covered by warranty and/or sourced from out of state. Other O&M costs were categorized by service type and allocated to IMPLAN sectors. Table 3-24 shows the results of this process.

Table 3-24. Mapping of Solar PV O&M Costs to IMPLAN Sectors

NREL Cost Category	IMPLAN Industrial Sector	% of Total Cost
Administrator	Office & administrative services	5%
Cleaner/Pest Control	Services to buildings	16
Mower/Trimmer	Landscape & horticultural services	10
Inverter Specialist/Electrician/Array Specialist/Mechanic	C&I machinery & equipment repair & maintenance	53
Inspector	Architectural & engineering services	16
	TOTAL:	**100%**

Offshore Wind Overnight Capital Costs

NREL's *2016 Cost of Wind Energy Review* (Wind Review) was used to break down offshore wind OCCs. The Wind Review contains a bottom-up accounting for wind project costs. Figure 3-48 shows the Wind Review's percentage-based breakdown of capital expenditures for a fixed-bottom offshore wind "reference project." Once again, these cost categories were grouped by type and then mapped to analogous sectors in IMPLAN, as shown in Table 3-25.

[214] National Renewable Energy Laboratory, "PV O&M Cost Model and Cost Reduction," U.S. Department of Energy, 2017 Photovoltaic Module Reliability Workshop, February 2017.

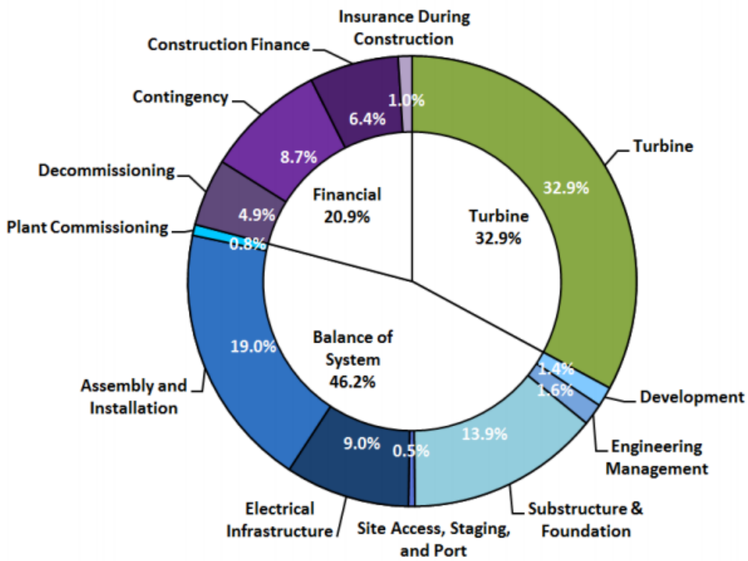

Figure 3-48. Capital Expenditures for a Fixed-Bottom Offshore Wind Project

Source: NREL, *2016 Cost of Wind Energy Review*, December 2017, Figure 6.

Table 3-25. Mapping of Offshore Wind Overnight Capital Costs to IMPLAN Sectors

NREL Cost Category	IMPLAN Industrial Sector	% of Total Cost
Assembly & Installation	Construction of new power & communication structures	19%
	Total Construction:	**19%**
Turbine	Turbine & turbine generator set units manufacturing	26%
Electrical Infrastructure	Power, distribution & specialty transformer manufacturing	9
Tower	Rolled steel shape manufacturing	7
Substructure & Foundation	Substructure & foundation	14
	Total Manufacturing:	**56%**
Engineering Management + Development	Architectural & engineering services	3%
Decommissioning & Plant Commissioning	Legal services	6
Contingency & Construction Finance	Banking[1]	9
Construction Insurance	Insurance carriers	1
	Total Services:	**18%**
Site Access, Staging, & Port	Water transportation	1%
	Total Transport:	**1%**
	TOTAL:	**94%**[1]

Source: NREL data sourced from NREL's *2016 Cost of Wind Energy Review*, December 2017, Figure 6.

[1] Construction finance expenses (6.4% of total costs) have been removed in order to match OCC values throughout this section, which do not include finance expenses.

Offshore Wind O&M Costs

The Jobs and Economic Development Impact (JEDI) model developed by NREL was used to break down total offshore wind O&M costs into cost categories associated with five broad industrial sectors. A South Carolina supply chain survey and other sources were used to associate JEDI O&M cost categories to NAICS codes.[215] NAICS codes were then paired to analogous industry sectors in IMPLAN, as shown in Table 3-26.

[215] Elizabeth Colbert-Busch and Robert Carey, *South Carolina Wind Energy Supply Chain Survey and Offshore Wind Economic Impact Study*, prepared for the South Carolina Energy Office, 2012, energy.sc.gov/files/WindEnEconImpact7-2012FINAL.pdf.

Table 3-26. Mapping of JEDI Offshore Wind O&M Costs to IMPLAN Sectors

JEDI Cost Category	NAICS Code	IMPLAN Industrial Sector	% of Total Cost
Water Transportation	483113	Water transportation	23%
Site Facilities	532411	C&I machinery and equipment rental and leasing	11
Subcontractors	811310	C&I machinery and equipment repair and maintenance	7
Machinery & Equipment	333618	Other engine and equipment manufacturing	5
Machinery (Corrective Maintenance Parts)	333611	Turbine and turbine generator set units manufacturing	53
	TOTAL:		**100%**

3.4.5. Step 4. Determine In-State Spending Versus Imports

Determining what services and goods are likely to be purchased from in-state or regional sources is one of the more influential steps in modeling the economic impacts of new renewable energy projects. (Recall from Figure 3-36 that non-local spending is excluded from IMPLAN's modeling process.) The allocation assumptions used for this study are outlined below. Once again, since methodologies differ by technology, solar PV and offshore wind are discussed separately.

Solar PV Overnight Capital Costs

All PV-related construction labor and professional services were assumed to be sourced within Maryland, since both are in ample supply. (Installation jobs represent 72% of the 4,515 solar jobs in Maryland, according to The Solar Foundation.)[216] By contrast, it was assumed that almost no hardware would come from manufacturers located in Maryland and only modest amounts would come from neighboring PJM states, for reasons discussed below.

The Solar Foundation's annual *National Solar Jobs Census* provides a tally of PV-related manufacturing jobs by state. Table 3-27 shows the *National Solar Jobs Census* tallies for the states included in this study.[217] Collectively, the six states (and the District of Columbia) have a total of 2,771 solar manufacturing jobs, representing roughly 8% of all self-reported PV manufacturing jobs in the country. Maryland's 270 PV manufacturing jobs represent less than 1% of solar manufacturing jobs in the United States. In contrast, Pennsylvania has over 1,400 PV-related manufacturing jobs.

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[216] The Solar Foundation, *National Solar Jobs Census 2018*, solarstates.org/#states/solar-jobs/2018.

[217] The *National Solar Jobs Census* is based on a survey of employers. Sector employment numbers are based on what each employer reports as its primary focus.

Table 3-27. Number of Solar Manufacturing Jobs in Select PJM States

MD	DE	DC	NJ	PA	VA	WV	Regional Total	U.S. Total
270	84	46	609	1,425	288	49	**2,771**	**33,726**

Source: The Solar Foundation, *National Solar Jobs Census*.

Numerous industry publications, as well as the Maryland-District of Columbia-Delaware-Virginia group of the SEIA (MDV-SEIA), were consulted in order to better understand the nature of in-state and regional solar manufacturing. It was concluded that few primary components for utility-scale PV systems are being manufactured in or around Maryland. Instead, the market for PV modules and inverters is global, with most manufacturing occurring overseas. However, there is evidence of some regional manufacturing associated with the PV system components (e.g., wire management, direct current combiner boxes, wiring harnesses, module clamps, and structures).

In order to reflect the existence of a relatively small amount of solar manufacturing activity in the state, it was assumed that, for distributed PV, 2% of racking structures and 2% of other communications and energy wire manufacturing could be sourced in-state. The analogous structures and manufacturing for utility-scale components were assumed to be more commoditized and thus, non-local. These assumptions are summarized in Table 3-28.

Table 3-28. Projected In-State Spending for Solar PV Construction

IMPLAN Industry Sector	Distributed PV	Utility-Scale PV
Construction of new power & communication structures	100%	100%
Semiconductor & related device manufacturing	0%	0%
Power, distribution & specialty transformer manufacturing	0%	0%
Fabricated structural metal manufacturing	2%	0%
Other communication & energy wire manufacturing	2%	0%
Architectural & engineering services	100%	100%
Legal services	100%	100%

Solar PV O&M Costs

It was assumed that all PV-related O&M services would be sourced within Maryland. This assumption represents the fact that services included in solar O&M do not require specialization and are well-represented in Maryland's workforce.

Offshore Wind Overnight Capital Costs

For the two RPS scenarios, 19% of US Wind's OCCs were allocated to Maryland in 2020, and 34% of Skipjack's OCCs were allocated in 2022. These percentages correspond to the two projects' in-state content commitments as annotated in the Maryland PSC order approving the projects.[218] The study assumes an in-state content percentage of 34% for Round 2 projects as well. The remaining expenditures were assumed to be distributed to other regions of the U.S. and to foreign countries, primarily in Europe.

Although Maryland has a robust construction sector, only 80% of construction expenditures were assumed to be sourced within the state. Some specialized skills are likely to come from Europe or, as was the case with the Block Island Wind Farm, from other states.[219,220] In addition, until there is large and consistent demand (~800 MW to 1 GW/year) in the mid-Atlantic region, most substructure and foundation construction labor is projected to come from the Gulf Coast region where similar industries exist for the offshore oil industry.[221] Significant manufacturing in the mid-Atlantic region has yet to materialize, largely due to delays in proposed offshore wind projects.[222] Likewise, little new investment in port-side manufacturing facilities is expected until there is sufficient demand from offshore wind developers. Furthermore, some component manufacturers are unlikely to relocate to the mid-Atlantic region. For example, foundation producers that are located in the Gulf Coast region can serve mid-Atlantic markets from their existing facilities.[223] Thus, only a small proportion of manufacturing expenditures were allocated to Maryland. Given the steel manufacturing requirements in the Maryland PSC order, 13% of rolled steel shape manufacturing was allocated to Maryland. This was the only manufacturing sector with non-zero local content. All expenditures on services were assumed to be captured by Maryland businesses. These local content assumptions were factored into NREL's OCC distribution and then scaled to yield a total of 34% in-state spending, as shown in Table 3-29.

[218] Maryland PSC Order No. 88192, Case No. 9431, psc.state.md.us/wp-content/uploads/Order-No.-88192-Case-No.-9431-Offshore-Wind.pdf.

[219] The Block Island Wind Farm is the first commercial offshore wind farm in the United States. It is a 30-MW project located off the coast of Block Island, Rhode Island. It became operational in December 2016.

[220] Bristol Community College, UMass Dartmouth Public Policy Center and Massachusetts Maritime Academy, *2018 Massachusetts Offshore Wind Workforce Assessment*, prepared for the Massachusetts Clean Energy Center, files.masscec.com/2018%20MassCEC%20Workforce%20Study.pdf.

[221] Navigant Consulting Inc., *Offshore Wind Market and Economic Analysis*, prepared for the U.S. Department of Energy, 2013, eere.energy.gov/wind/pdfs/offshore_wind_market_and_economic_analysis.pdf.

[222] In July 2019, Denmark-based Ørsted won a competitive bidding process to develop 1.1 GW of offshore wind off the coast of New Jersey. As part of its winning bid, Ørsted included plans to construct a local factory for steel foundations in southern New Jersey. The site is near Philadelphia and in contention to host the first U.S. factory for offshore wind turbine components.

[223] Navigant Consulting Inc., *Offshore Wind Market and Economic Analysis*, prepared for the U.S. Department of Energy, 2013, eere.energy.gov/wind/pdfs/offshore_wind_market_and_economic_analysis.pdf.

Table 3-29. Projected In-State Spending for Offshore Wind Construction

IMPLAN Industry Sector	Percent of Total OCCs	Original Attribution to In-State Sources	Original Percent of Total OCCs Attributed to In-State Sources	Scaled Percent of Total OCCs Attributed to In-State Sources: 2020[1]	Scaled Percent of Total OCCs Attributed to In-State Sources: All Other Yrs. (2021-2030)
Construction of new power & communication structures	20%	80%	16%	8%	15%
Turbine & turbine generator set units manufacturing	27	0	0	0	0
Power, distribution & specialty transformer manufacturing	10	0	0	0	0
Rolled steel shape manufacturing	8	13	1	1	1
Fabricated structural metal manufacturing	15	0	0	0	0
Architectural, engineering & related services	3	100	3	2	3
Legal services	6	100	6	3	6
Banking	9	100	9	5	8
Insurance carriers	1	100	1	1	1
Water transportation	<1	100	<1	<1	<1
TOTAL	**100%**	-	**37%**	**19%**	**34%**

[1] Reflects solely the US Wind project, which has a 19% in-state content commitment as annotated in the Maryland PSC order approving the project.

Offshore Wind O&M Costs

Maryland's proportion of total annual O&M expenditures was assumed to comprise 30% of total offshore wind O&M expenditures. This in-state content assumption is in range with other East Coast states.[224] Allocations to specific industries were based on a review of JEDI internal calculations and studies sponsored by DOE.[225] O&M labor, professional services, and some manufactured items were assumed to be sourced within Maryland. Corrective maintenance parts were not. On this basis, the O&M expense categories with an in-state component represent about 47% of total O&M (see Table 3-26). These percentages were scaled to arrive at values that would yield a total of 30% in-state spending, as shown in Table 3-30.

[224] *See:* E2, *Offshore Wind: Generating Economic Benefits on the East Coast*, 2018, e2.org/wp-content/uploads/2018/08/E2-OCS-Report-Final-8.30.18.pdf.

[225] *See, for example:* Elizabeth Colbert-Busch and Robert Carey, *South Carolina Wind Energy Supply Chain Survey and Offshore Wind Economic Impact Study*, prepared for the South Carolina Energy Office, 2012, energy.sc.gov/files/WindEnEconImpact7-2012FINAL.pdf.

Table 3-30. Projected In-State Spending for Offshore Wind O&M

IMPLAN Industry Sector	Percent of Total O&M Cost	Original Attribution to In-State Sources	Original Percent of Total O&M Attributed to In-State Sources	Scaled Percent of Total O&M Attributed to In-State Sources
Water transportation	23%	100%	23%	15%
C&I machinery & equipment rental and leasing	12	100	12	7
C&I machinery & equipment repair and maintenance	7	100	7	5
Other engine & equipment manufacturing	5	100	5	3
Turbine & turbine generator set units manufacturing	53	0	0	0
TOTAL	**100%**	**-**	**47%**	**30%**

3.4.6. Step 5. Estimate Economic Impacts with Final IMPLAN Inputs

Based on the five steps above, inputs (i.e., changes in final demand) associated with distributed PV, utility-scale PV, and offshore wind projects were developed for each RPS scenario. These inputs are illustrated in Figure 3-49 and Figure 3-50, using distributed PV for the 50% RPS as a sample.

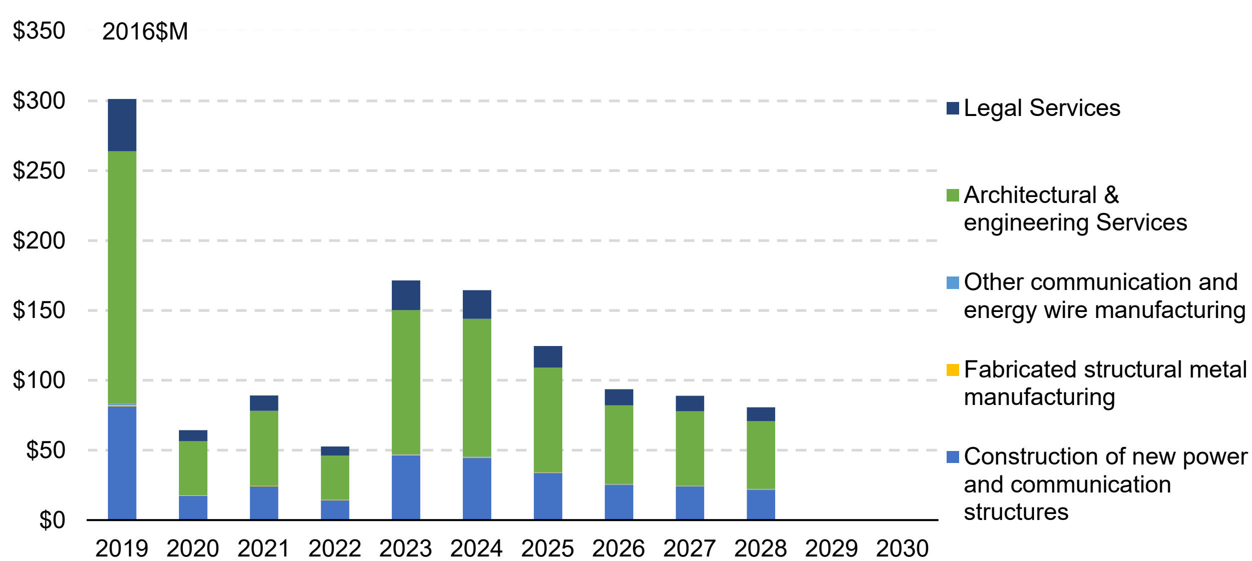

Figure 3-49. Projected In-State Spending for Distributed PV Construction, 50% RPS

Note: Construction ends in 2028, when the solar carve-out peaks at 14.5%.

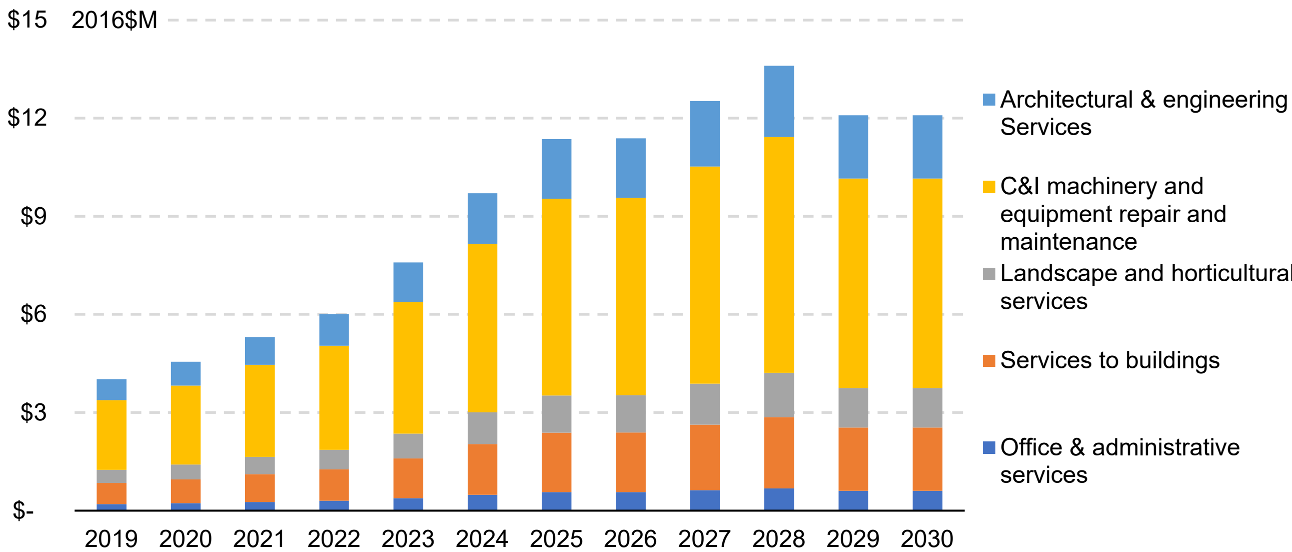

Figure 3-50. Projected In-State Spending for Distributed PV O&M, 50% RPS

3.4.7. Results and Discussion

This subsection presents the economic impacts of solar PV and offshore wind that, by virtue of carve-outs, are likely to constitute the bulk of new, in-state renewable generation used to meet the Maryland RPS generation requirements between 2019-2030. Economic impacts reported in this study are cumulative over the years 2019-2030. Figure 3-51 and Figure 3-52 provide a high-level comparison of job creation and economic activity for each scenario, both of which are discussed in further detail in the following pages.

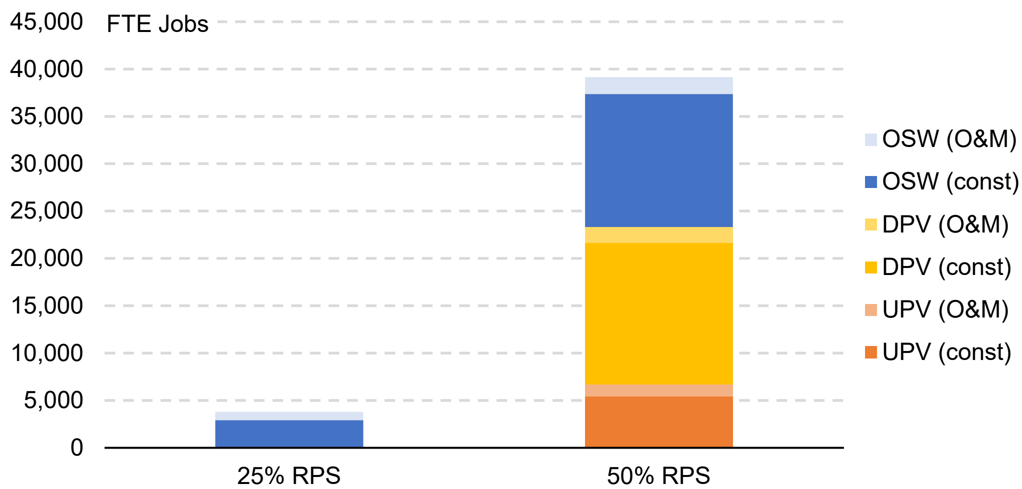

Figure 3-51. Cumulative Full-Time Equivalent Job Creation, by Technology, 25% RPS and 50% RPS

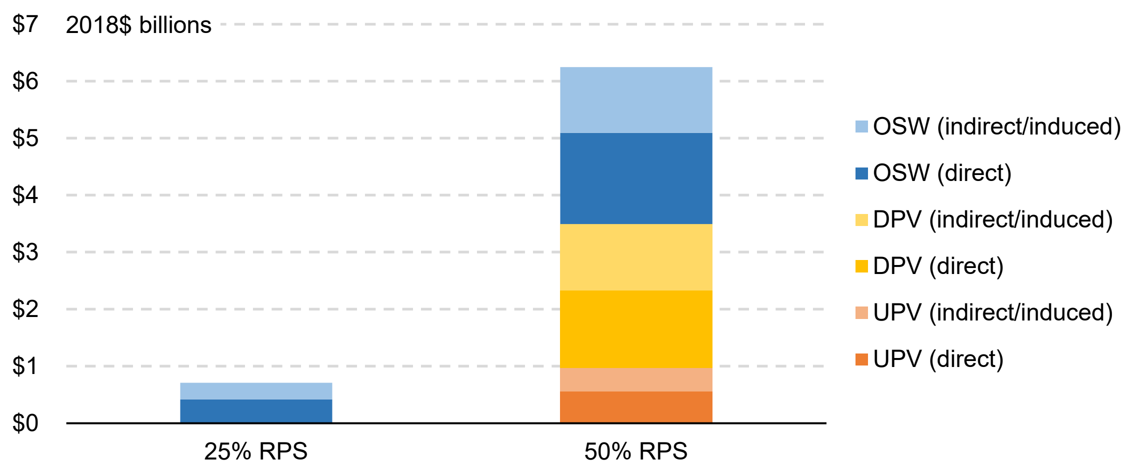

Figure 3-52. Cumulative Output, by Technology, 25% RPS and 50% RPS

25% RPS Scenario

The 25% RPS contains a Tier 1 solar carve-out of 1.5% of total retail electricity sales in 2018 that increases to 1.95% in 2019, and 2.5% in 2020 and beyond. With Maryland's electricity sales projected to decline throughout the study period, no additional PV capacity is required to meet the solar carve-out in the 25% RPS. Therefore, no incremental economic impact is expected from the solar carve-out in the 25% RPS.

The offshore wind carve-out for the 25% RPS analyzed here, however, is based on the Maryland PSC order approving the offshore wind project applications of US Wind and Skipjack.[226] Commercial operation dates for US Wind and Skipjack were assumed to be

[226] Maryland PSC Order No. 88192, Case No. 9431, psc.state.md.us/wp-content/uploads/Order-No.-88192-Case-No.-9431-Offshore-Wind.pdf.

2021 and 2023, respectively, to account for delays in permitting.[227] In the 25% RPS, construction is assumed to be undertaken and completed in the year prior to commercial operation.

With no contributions from distributed and utility-scale solar, future impacts associated with the 25% RPS are modest and are entirely from offshore wind, as shown in Table 3-31. Construction accounts for 2,914 FTE direct, indirect, and induced jobs, and $476 million in total sales (output) in Maryland in the two years of construction (2020-2022). Between 2021-2030, O&M expenditures on installed capacity create 885 FTE jobs in Maryland and more than $232 million in sales.

Table 3-31. Economic Impacts on Maryland's Economy, 25% RPS

Offshore Wind Impacts	FTE Jobs	Employee Compensation (thous. 2018$)	Output (thous. 2018$)
Construction			
Direct	1,605	$115,620	$274,309
Indirect	513	33,539	86,154
Induced	796	39,655	116,135
TOTAL	**2,914**	**$188,814**	**$476,598**
O&M			
Direct	329	$34,079	$141,108
Indirect	275	18,651	50,280
Induced	281	13,979	40,939
TOTAL	**885**	**$66,709**	**$232,327**

50% RPS Scenario

The 50% RPS contains a 5.5% Tier 1 solar carve-out in 2019 that increases annually until it reaches 14.5% in 2028, where it thereafter remains. The offshore wind carve-out is between 1.4-2.5% between 2019-2024 (as represented by the proposed US Wind and Skipjack projects), followed by requirements of 400 MW of offshore wind by 2026, 800 MW by 2028, and 1,200 MW by 2030.

The cumulative economic impacts of the 50% RPS in terms of construction result in more than 34,000 FTE jobs and $5.4 billion in sales to businesses in Maryland. O&M expenditures are projected to generate more than 4,700 FTE jobs and nearly $811 million in sales. Table 3-32 and Figure 3-53 break down these impacts.

[227] At the time of the PSC Order, the US Wind project was projected to come online in 2020 and the Skipjack Project in late 2022. In conducting the analysis for this report, the online dates for both projects were pushed back one year to account for permitting delays (i.e., US Wind would come online in 2021 while Skipjack would come online in 2023). Skipjack continues to predict that its online date will be 2022, while US Wind has since delayed its projected operating date to 2023.

Table 3-32. Economic Impacts on Maryland's Economy, 50% RPS

		FTE Jobs	Employee Compensation (thous. 2018$)	Output (thous. 2018$)
UTILITY-SCALE SOLAR PV IMPACTS	**Construction**			
	Direct	3,097	$227,885	$473,709
	Indirect	823	53,070	130,979
	Induced	1,498	74,615	218,522
	Subtotal	***5,418***	***$355,570***	***$823,210***
	O&M			
	Direct	854	$44,267	$85,440
	Indirect	126	7,840	19,741
	Induced	278	13,862	40,596
	Subtotal	***1,258***	***$65,968***	***$145,776***
DISTRIBUTED SOLAR PV IMPACTS	**Construction**			
	Direct	7,586	$647,596	$1,253,098
	Indirect	2,943	186,979	427,402
	Induced	4,459	222,210	650,769
	Subtotal	***14,988***	***$1,056,785***	***$2,331,269***
	O&M			
	Direct	1,122	$58,165	$112,266
	Indirect	165	10,301	25,939
	Induced	366	18,214	53,342
	Subtotal	***1,652***	***$86,681***	***$191,548***
OFFSHORE WIND IMPACTS	**Construction**			
	Direct	7,677	$552,972	$1,311,929
	Indirect	2,454	160,408	412,048
	Induced	3,907	189,657	555,437
	Subtotal	***14,038***	***$903,037***	***$2,279,414***
	O&M			
	Direct	671	$69,526	$287,880
	Indirect	560	38,051	102,579
	Induced	573	28,518	83,521
	Subtotal	***1,804***	***$136,095***	***$473,980***
TOTAL IMPACTS	**Construction**			
	Direct	18,360	$1,428,453	$3,038,736
	Indirect	6,219	400,457	970,429
	Induced	9,864	486,482	1,424,728
	TOTAL	**34,444**	**$2,315,392**	**$5,433,893**
	O&M			
	Direct	2,647	$171,958	$485,586
	Indirect	850	56,192	148,259
	Induced	1,217	60,594	177,459
	TOTAL	**4,714**	**$288,744**	**$811,304**

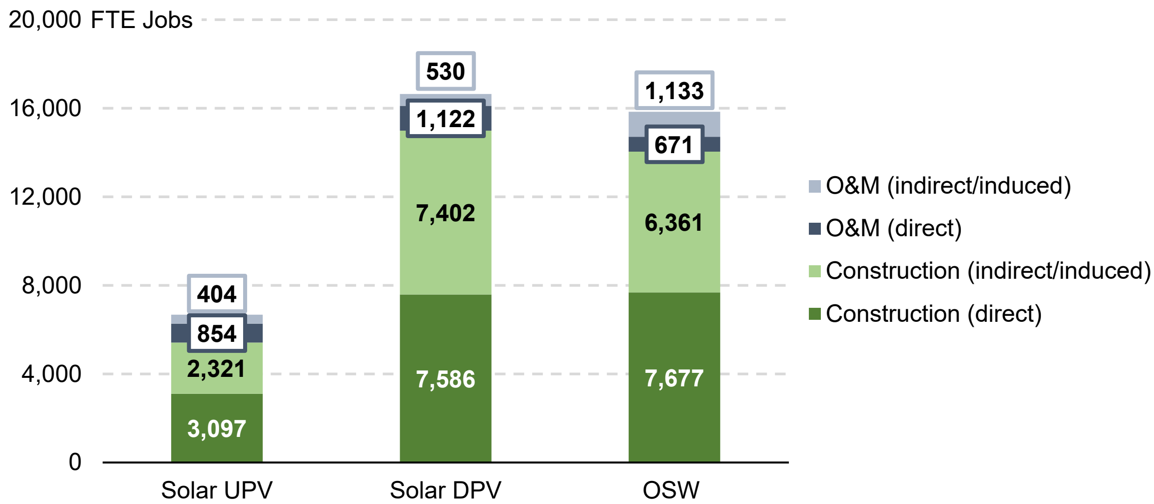

Figure 3-53. Cumulative Full-Time Equivalent Job Creation, by Technology, 50% RPS

Economic impacts associated with the 50% RPS reflect year-over-year generation growth through 2030, in step with annual increases in the Tier 1 solar carve-out and Round 2 requirements for offshore wind. In comparison to the 25% RPS, under which no future construction is attributable to the solar carve-out, solar capacity under the 50% RPS increases by an annual average rate of 14.2% from 2019-2028, after which the solar carve-out requirement is met. O&M expenditures for completed solar installations increase as additional capacity comes online through 2028, before leveling off. For offshore wind, economic impacts from construction accrue irregularly throughout the forecast period, reflecting the US Wind and Skipjack construction in 2020 and 2022, respectively, followed by the three 400-MW Round 2 requirements for which construction begins in 2025, 2027, and 2029. Offshore wind O&M expenditures follow a step function as new capacity is brought online.

Economic benefits from utility-scale solar PV installations attributable to the 50% RPS are concentrated in the construction and service industries, which are the recipients of most of the in-state, construction-related direct expenditures. Although solar PV requires significant expenditures for manufactured components, most of the expenditures are out of state. This gives Maryland a smaller share of overall economic benefits, particularly indirect ones, from utility-scale solar PV development since intermediate supply chain transactions are also assumed to be captured by out-of-state companies. Because the RPS does not drive growth in manufacturing, the solar carve-out generates lower job and household earnings than would otherwise be the case. However, as the *National Solar Jobs Census* suggests, the jobs that do remain in Maryland have compensation levels comparable to those of manufacturing (see Table 3-33).

Table 3-33. Comparison of Solar PV Construction and Manufacturing Jobs

	Installation	Project Development	Manufacturing
Median Wages			
Entry-level	$15/hr	$16/hr	$15/hr
Mid-level	$20	$25	$20
Sr./Supervisor	$30	$38	$30
New Hire Experience and Education Requirements			
With experience (2017)	56%	41%	46%
Percent with bachelor's degree or higher	7%	29%	30%
Percent with vocational or technical	24%	17%	21%
Percent with associate's degree or certification from accredited college	5%	12%	12%

Source: The Solar Foundation, *National Solar Jobs Census*.

Still, the benefits from construction and operation of utility-scale solar PV under the 50% RPS cut across many sectors of the Maryland economy. About 60% of the total construction impact of the RPS in terms of jobs and sales is associated with the initial capital investment by solar developers. Construction, architectural and engineering services, and legal services sectors benefit from this investment (see Figure 3-54). Direct O&M purchases, meanwhile, include various services ranging from landscape maintenance to equipment repair and maintenance. These services represent 60% of the total O&M impact of the RPS on output and nearly 70% of total jobs created. The remaining impacts associated with construction and O&M of both utility-scale PV and distributed PV are distributed throughout the economy from consumption expenditures (induced impacts) and, to a lesser extent, supply chain transactions (indirect impacts), creating jobs across the occupational spectrum.

The distribution of direct, indirect, and induced impacts is slightly different for distributed solar as compared to utility-scale solar. For distributed solar PV construction as a result of the 50% RPS, 50% of jobs and 54% of sales are associated with initial expenditures on goods and services. A small percentage of OCCs to construct distributed PV is allocated to Maryland manufacturing sectors (e.g., fabricated structural metal manufacturing, or other communication and energy wire manufacturing). This allocation does not significantly change how benefits are distributed throughout the state's economy, relative to the benefits of utility-scale PV. Because soft costs make up a greater proportion of distributed PV system costs than utility-scale PV installations, the ranking of industries in terms of jobs created as a result of the 50% RPS slightly differs (see Figure 3-54).[228] The O&M impacts of distributed PV as a result of the 50% RPS, meanwhile, are again skewed toward direct effects, particularly in terms of jobs and earnings. Most of the remaining impact is associated with household consumption.

[228] Construction soft costs are expenses that are not considered direct construction costs, and include costs such as architectural, engineering, financing, and legal fees, plus other pre- and post-construction expenses.

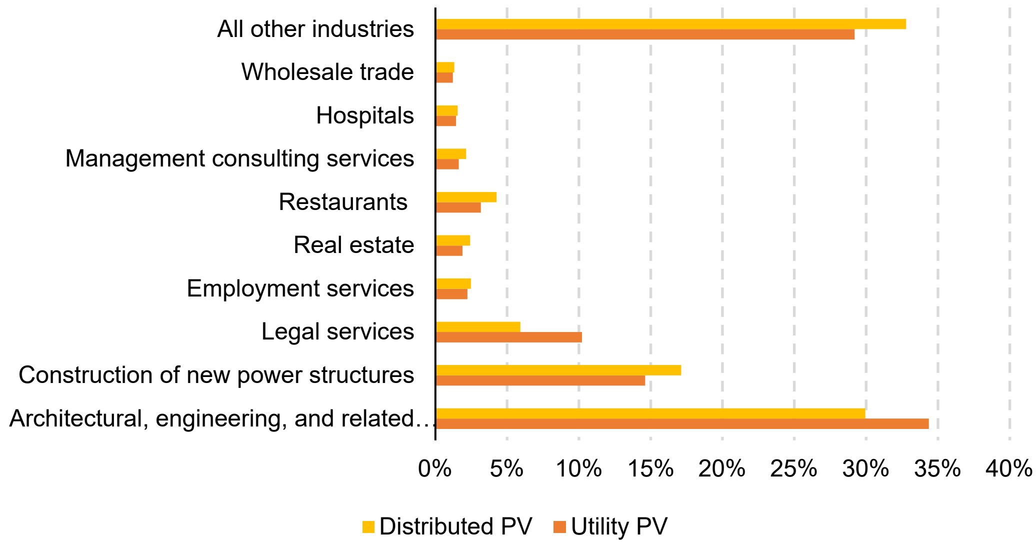

Figure 3-54. Maryland Industries (Percent Full-Time Equivalent Jobs) Benefiting from Solar PV Construction, 50% RPS

For offshore wind construction as a result of the 50% RPS, about 60% of the total economic impact on Maryland is related to direct expenditures. Most direct jobs are in the construction industry, 80% of which are assumed to be filled by Maryland residents (see Figure 3-55). Additional O&M benefits accrue to commercial and industrial machinery repair and maintenance, water transportation, and commercial and industrial machinery equipment rental and leasing sectors, as well as various service industries (see Figure 3-56). Even with assumed investments by Round 1 offshore wind developers in a Maryland steel fabrication plant and the minimum in-state capital expenditure requirements in Maryland PSC Order 88192, the share of in-state manufacturing is small relative to the total manufacturing requirement.

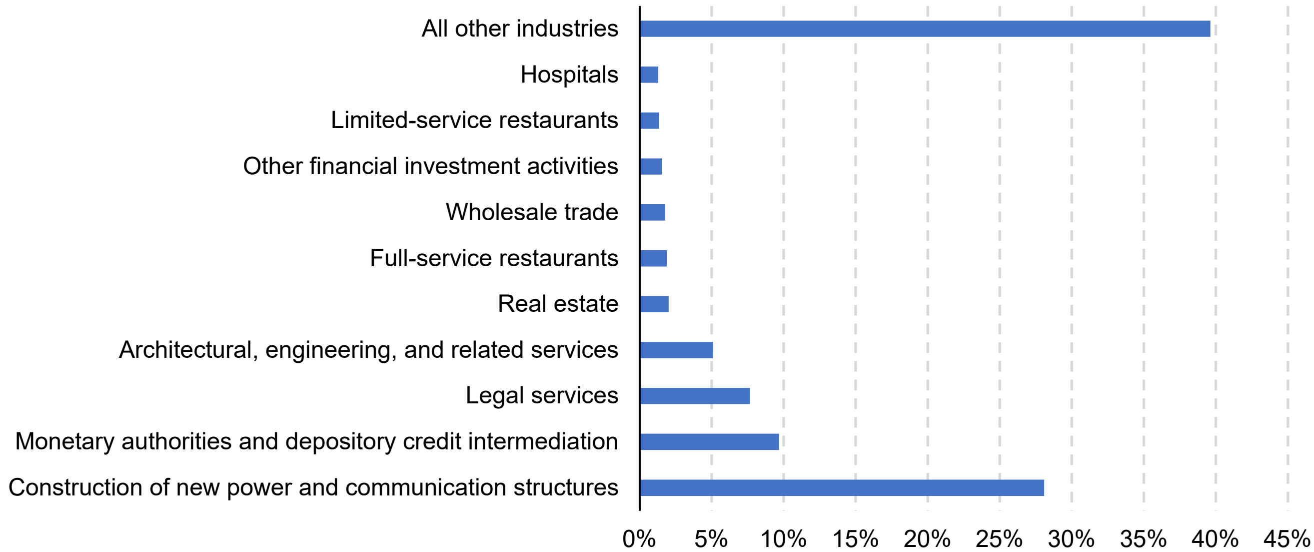

Figure 3-55. Maryland Industries (Percent Full-Time Equivalent Jobs) Benefiting from Offshore Wind Construction, 50% RPS

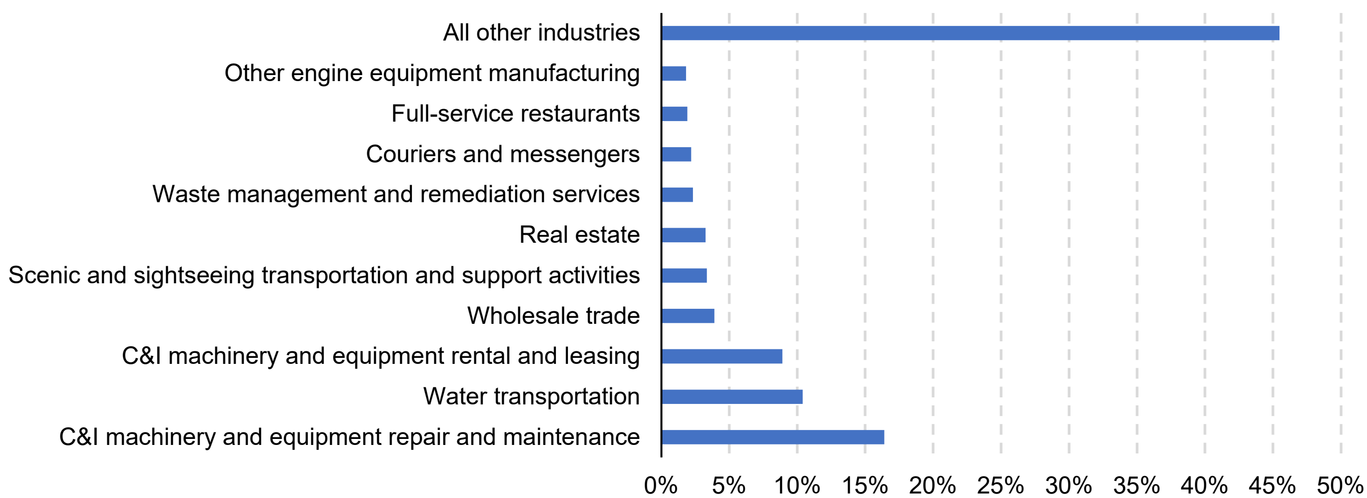

Figure 3-56. Maryland Industries (Percent Full-Time Equivalent Jobs) Benefiting from Offshore Wind O&M, 50% RPS

Supply Chain Limitations and Opportunities for Maryland Solar PV

For solar, NREL estimates that about 60-70% of utility-scale PV installation costs are for hardware (i.e., module, inverter, structural BOS, and electrical BOS), with the balance of costs evenly split between construction and services. For distributed systems, less of the project cost goes to manufactured components while more goes toward services. O&M costs, which include warrantied and non-warrantied parts replacement, monitoring, and property maintenance, are weighted toward services that are usually fulfilled locally. These costs for O&M vary by technology, system size, location, and other factors.

Solar PV systems are constructed of highly recognizable components like solar cells, modules, racking, and inverters, but also hardware such as monitoring devices, cabling, connectors, nuts and bolts, and other manufactured products that knit the system together. Major components, such as modules and inverters, are largely imported. In comparison, there is a greater domestic presence of manufacturers of structural and electrical BOS. During the 12 months ended October 31, 2018, approximately 90% of modules were imported.[229] According to *Solar Power World*, there are 25 domestic solar panel manufacturing facilities,[230] although most of these manufacturers import key components from other countries for assembly in the U.S. or are vertically integrated companies that provide end-to-end services (i.e., design through installation).[231] Nine companies manufacture some or all of their solar panels in the U.S. (see Table 3-34).

Table 3-34. U.S.-Based Companies Involved in Manufacturing Solar PV Panels

Company	Manufacturing Location	Headquarters	Notes
Heliene	Mountain Iron, MN	Canada	
Mission Solar	San Antonio, TX	Texas	
Seraphim	Jackson, MS	China	
Silfab Solar	Bellingham, WA	Canada	
Solaria	Fremont, CA	California	
SolarTech Universal	Riviera Beach, FL	Florida	
SolarWorld Americas	Hillsboro, OR	Germany	In bankruptcy proceedings
SunSpark	Riverside, CA	China	
Tesla/Panasonic	Buffalo, NY	California/Japan	Joint venture

Source: EnergySage, "American-Made Solar Panels," news.energysage.com/u-s-solar-panel-manufacturers-list-american-made-solar-panels/.

Inverters, which convert direct current output from a solar panel into utility frequency alternating current, are an integral component of every solar PV system. Eight companies manufacture inverters domestically, ranging from standalone to grid-tie models,[232] but only three of the leading utility-scale inverter manufacturers are located in the U.S.[233,234] According to the 2017 *National Solar Jobs Census*, U.S. inverter production declined after two major facilities closed at the end of 2016.[235] According to the 2018 *National Solar Jobs Census*, some of these jobs may return under certain conditions. In particular, U.S. Section 301 (Trade Act of 1974) tariffs on Chinese goods could shift inverter manufacturing from China to India, Mexico, and the U.S., particularly if tariffs increase to 25%.[236]

Other solar components are generally categorized as structural BOS and electrical BOS. Structural BOS includes racking, mounting, and tracking systems plus any other materials needed to support the modules. ENF Solar, a consultancy, lists more than 100 solar-

[229] The Solar Foundation, *National Solar Jobs Census 2018*, solarstates.org/#states/solar-jobs/2018.

[230] "U.S. Solar Panel Manufacturers," *Solar Power World*, 2019, solarpowerworldonline.com/u-s-solar-panel-manufacturers/.

[231] EnergySage, "U.S. solar panel manufacturers: a list of American-made solar panels," news.energysage.com/u-s-solar-panel-manufacturers-list-american-made-solar-panels/.

[232] "Global Inverter Manufacturing Locations," *Solar Power World*, solarpowerworldonline.com/global-inverter-manufacturing-locations/.

[233] Wiki-Solar, "Leading utility-scale solar inverter projects," wiki-solar.org/company/inverters/index.html.

[234] ABB acquired GE's inverter business in mid-2018.

[235] The Solar Foundation, *National Solar Jobs Census 2018*, solarstates.org/#states/solar-jobs/2018.

[236] Ibid.

mounting manufacturers in the U.S.[237] Nine U.S. companies manufacture solar-tracking systems.[238] At least two companies selling structural BOS components are located in Maryland.[239] Electrical BOS comprises equipment that transports direct current energy from solar panels through the conversion system that produces alternating current power. Components include conductors, conduits, combiner boxes, disconnects, and monitoring systems. ENF Solar lists 33 solar charge controller manufacturers and 36 solar monitoring system manufacturers in the U.S. Opportunities for manufacturing growth in Maryland from continuing solar PV deployment is probably limited to the structural and electrical BOS supply chains. This is because the solar installers tend to be vertically integrated; that is, they own or control manufacturing, sales, and installation, which limits opportunities for other companies to enter the market. Still, with the increase in Maryland's solar carve-out to 14.5%, the induced demand may attract further BOS manufacturing to Maryland.

Supply Chain Limitations and Opportunities for Maryland Offshore Wind

For offshore wind, NREL estimates between 40-50% of OCCs are for manufactured goods.[240] Approximately one-third of OCCs is for assembly and installation, with the remaining portion covering services and water transportation. According to NREL, more than half of O&M expenditures are for corrective maintenance parts and other machinery, with the balance supporting maintenance construction and miscellaneous services.

Although the majority of onshore wind turbine components (as a fraction of total equipment-related turbine costs) installed in the U.S. are domestically sourced, offshore wind installations require many specialized components that are not currently produced in the United States.[241] Even where facilities serving the U.S. onshore wind market may be capable of manufacturing offshore wind components, logistical concerns primarily related to the long-distance transport of large components may limit their ability to supply the offshore market. Both existing OREC applications (US Wind and Skipjack)[242] to the Maryland PSC allocate significant percentages of construction costs to Maryland, and specifically target investment in a Maryland steel fabrication facility. Apart from these projects, however, there is considerable uncertainty about which industries in Maryland will benefit from offshore wind development.

Because an offshore wind supply chain does not yet exist in the U.S., most economic studies of offshore wind development off the Atlantic coast allocate the majority of in-state capital expenditures to the construction and service industries. These industries have a significant presence in coastal states and have established supply chains. Even in the case of construction and service sectors, however, supply chain constraints may limit the capture of economic benefits. For example, construction of the Block Island wind project, although comprising only five turbines, resulted in shortages of welders in Massachusetts and Rhode

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[237] ENF, "Solar Mounting System Manufacturers from United States," enfsolar.com/directory/component/mounting_system?country=187.

[238] Abhishek Shah, "Solar Tracker Manufacturers (USA, China, India) List and Market – Review of Sale Price and Cost," *Green World Investor*, 2011, updated September 2016, greenworldinvestor.com/2011/07/06/solar-tracker-manufacturers-usachinaindia-list-and-market-review-of-sale-price-and-cost/.

[239] Solar Energy Industries Association, "National Solar Database," seia.org/national-solar-database.

[240] Tyler Stehly, Donna Heimiller and George Scott, *2016 Cost of Wind Energy Review*, National Renewable Energy Laboratory, December 2017, nrel.gov/docs/fy18osti/70363.pdf.

[241] Navigant Consulting Inc., *U.S. Offshore Wind Manufacturing and Supply Chain Development*, prepared for the U.S. Department of Energy, 2013, energy.gov/sites/prod/files/2013/12/f5/us_offshore_wind_supply_chain_and_manufacturing_development.pdf.

[242] Maryland PSC Order No. 88192, Case No. 9431, psc.state.md.us/wp-content/uploads/Order-No.-88192-Case-No.-9431-Offshore-Wind.pdf.

Island. Completing the project required contractors to recruit welders from other states. Another constraint against in-state construction jobs is entry barriers; workers in some trades require additional training before being able to work in an offshore environment.[243]

Most near-term manufacturing opportunities for offshore wind are limited to upstream materials and subcomponents that can be easily transported. Upstream products include scaffolding, coatings, ladders, fastenings, hydraulics, concrete, and electrical components. Table 3-35 identifies some businesses in the mid-Atlantic region that have the potential to support the offshore wind supply chain.[244] Both US Wind and Skipjack are attempting to develop relationships with in-state businesses that traditionally have not participated in energy development projects and markets.

Table 3-35. Existing mid-Atlantic Companies with the Potential to Supply Offshore Wind Components

Industry	MD	DE	NJ	VA	PA
Electronics	**1**	0	3	2	15
Manufacturing & assembly	**17**	0	1	6	17
Installation, construction, materials	**13**	2	1	5	28
Maintenance, logistics, transportation	**16**	0	4	34	6
Services	**6**	2	6	34	4
TOTAL	**53**	**4**	**15**	**81**	**70**

Source: NREL, *Offshore Wind Jobs and Economic Development Impacts in the United States: Four Regional Scenarios*, 2015, nrel.gov/docs/fy15osti/61315.pdf.

Several reports predict future opportunities for suppliers will be greatest in industries responsible for providing foundations and substructures, towers, blade materials, power converters, and transformers.[245] NREL has taken this outlook further by estimating the share of critical offshore wind component manufacturing that could take place in the mid-Atlantic region. These estimates are broken down into three investment scenarios (see Table 3-36).

[243] Bristol Community College, UMass Dartmouth Public Policy Center and Massachusetts Maritime Academy, *2018 Massachusetts Offshore Wind Workforce Assessment*, prepared for the Massachusetts Clean Energy Center, files.masscec.com/2018%20MassCEC%20Workforce%20Study.pdf.

[244] Ross Tyler, "Maryland Prepares Offshore Wind Push," *North American Wind Power*, 2017, issues.nawindpower.com/article/maryland-prepares-offshore-wind-push; S. Tegan, D. Keyser and F. Flores-Espino, *et al.*, *Offshore Winds Jobs and Economic Development Impacts in the United States: Four Regional Scenarios*, National Renewable Energy Laboratory, 2015, nrel.gov/docs/fy15osti/61315.pdf.

[245] Navigant Consulting Inc., *U.S. Offshore Wind Manufacturing and Supply Chain Development*, prepared for the U.S. Department of Energy, 2013, energy.gov/sites/prod/files/2013/12/f5/us_offshore_wind_supply_chain_and_manufacturing_development.pdf; Bristol Community College, UMass Dartmouth Public Policy Center and Massachusetts Maritime Academy, *2018 Massachusetts Offshore Wind Workforce Assessment*, prepared for the Massachusetts Clean Energy Center, files.masscec.com/2018%20MassCEC%20Workforce%20Study.pdf.

Table 3-36. Regional Investment Paths for the Dynamic Components of Offshore Wind in the mid-Atlantic

	Low Investment		Medium Investment		High Investment	
Year:	2020	2030	2020	2030	2020	2030
Deployed capacity (MW)	366	3,196	1,912	7,832	4,100	16,280
Turbine	32%	68%	35%	95%	65%	100%
Blades & towers	13%	71%	25%	95%	30%	95%
Substructures & foundation	11%	30%	20%	50%	30%	85%

Source: NREL, *Offshore Wind Jobs and Economic Development Impacts in the United States: Four Regional Scenarios*, 2015, nrel.gov/docs/fy15osti/61315.pdf.

However, while there exists domestic infrastructure for the manufacture of some offshore wind components (e.g., infrastructure used by offshore oil and gas industry suppliers), a more robust domestic supply chain is unlikely until sufficient demand exists to justify the investment in new, dedicated facilities. This is particularly the case because the offshore wind market faces rapidly changing technologies and continued regulatory uncertainty. Deployment has lagged to date and, as a result, installed offshore wind capacity projections have been consistently pushed into the future and, with it, the development of a domestic offshore wind supply chain. Demand along the Atlantic coast may not be sufficient to attract a wind turbine generator manufacturing facility until the mid-2020s or later.[246,247]

While offshore wind has been slow to develop in the U.S., declining costs and state RPS policies have the potential to leverage development of offshore wind resources and industries.[248] If offshore wind is developed to projected capacities, multiple U.S. ports will need to be improved to support staging and manufacturing operations.[249] In return for Round 1 ORECs, both US Wind and Skipjack are required to invest in a Maryland steel fabrication facility, use a port facility in the greater Baltimore region for marshalling project components, use Ocean City as the O&M port, and invest in upgrades to the Tradepoint Atlantic shipyard. As such, Tradepoint Atlantic has positioned itself to potentially become a hub for offshore wind on the East Coast. This facility has space for offshore wind laydown, manufacturing, and vessel loading.[250] New Jersey is also seen as a leading contender for early offshore wind manufacturing with the announcement in July 2019 of plans to locate a factory for offshore turbine steel foundations in Paulsboro, New Jersey.

High-Manufacturing Scenario

To estimate how an increase in in-state manufacturing content would affect the Maryland economy, a separate, High-Manufacturing scenario was developed on top of the assumptions used for the 50% RPS. This new scenario relies heavily on Navigant and DOE

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[246] Navigant Consulting Inc., *U.S. Offshore Wind Manufacturing and Supply Chain Development*, prepared for the U.S. Department of Energy, 2013, energy.gov/sites/prod/files/2013/12/f5/us_offshore_wind_supply_chain_and_manufacturing_development.pdf.

[247] BVG Associates Ltd., *U.S. Job Creation in Offshore Wind*, prepared for the New York State Energy Research and Development Authority, October 2017, cleanegroup.org/ceg-resources/resource/u-s-job-creation-in-offshore-wind/.

[248] Adam Wilson, "Offshore Wind Ready to Take Off in the United States," S&P Global Market Intelligence, July 2018, spglobal.com/marketintelligence/en/news-insights/research/offshore-wind-ready-to-take-off-in-the-united-states.

[249] C. Elkinton, A. Blatiak and H. Ameen, *Assessment of Ports for Offshore Wind Development in the United States*, Garrad Hassan America, Inc., prepared for the U.S. Department of Energy, 2014, energy.gov/eere/wind/downloads/us-offshore-wind-port-readiness.

[250] Tradepoint Atlantic, "Offshore Wind Factsheet," tradepointatlantic.com/downloads/.

supply chain assumptions for the mid-Atlantic region,[251] but also incorporates the Maryland PSC's in-state investment and sourcing conditions in Order 88192, and accounts for delays in the development of an Atlantic offshore wind market.[252] The High-Manufacturing scenario is framed within a "low-growth" deployment scenario in which an offshore wind market is sufficient to support local manufacturing investment, starting in 2025.

In-state content shares were applied to three of the four IMPLAN manufacturing sectors mapped to NREL construction cost categories (refer to Table 3-25). Fabricated structural metal manufacturing was assumed to remain in the Gulf Coast region at least through 2030.[253] Similar to the 50% RPS, the in-state content share for the construction industry was held at 80% throughout the forecast period. All construction expenditures for services and water transportation were assumed to be fulfilled by Maryland businesses (see Table 3-37). O&M industry shares were not adjusted for the High-Manufacturing scenario.

Table 3-37. In-State Spending Assumptions for Offshore Wind Construction, 50% RPS and High-Manufacturing Scenarios

IMPLAN Industry Sector	Percent of Total OCCs	ORIGINAL ATTRIBUTION TO IN-STATE SOURCES			
		50% RPS	High-Manufacturing		
		All Years	2020	2025	2030
Construction of new power & communication structures	20%	80%	80%	80%	80%
Turbine & turbine generator set units manufacturing	27	0	0	32	41
Power, distribution & specialty transformer manufacturing	10	0	0	15	20
Rolled steel shape manufacturing	8	13	13	13	61
Fabricated structural metal manufacturing	15	0	0	0	0
Architectural, engineering & related services	3	100	100	100	100
Legal services	6	100	100	100	100
Banking	9	100	100	100	100
Insurance carriers	1	100	100	100	100
Water transportation	<1	100	100	100	100

Using steps analogous to those followed for the 50% RPS (refer to Table 3-29), the original in-state spending percentages for OCC expenditures were scaled to arrive at values that would yield a total of 19% in-state spending for 2020, which then rises over the study period to a high of 51% in 2030. Likewise, Maryland's share of total O&M dollars was

[251] Navigant Consulting Inc., *Offshore Wind Market and Economic Analysis*, prepared for the U.S. Department of Energy, 2013, eere.energy.gov/wind/pdfs/offshore_wind_market_and_economic_analysis.pdf; U.S. Department of Energy, "Economic Impacts of Offshore Wind," 2014, nrel.gov/docs/fy14osti/60445.pdf.

[252] These studies originally assumed offshore wind installations ranging from 370 MW to 4,100 MW off the mid-Atlantic coast by 2020.

[253] Navigant's supply chain analysis found significant offshore foundation production serving the offshore oil industry, which could easily transition to offshore wind.

increased to 50% after 2024, under the assumption that a larger offshore wind market would attract more suppliers to service the industry (see Table 3-38).

Table 3-38. Total In-State Content Assumptions for Offshore Wind, 50% RPS and High-Manufacturing Scenarios

	50% RPS		High-Manufacturing		
	2020	All Other Years (2021-2030)	2020	2025	2030
Maryland Share of Total Construction Investment	19%	34%	19%	44%	51%
Maryland Share of Total O&M Expenditures	25%	25%	30%	50%	50%

In the High-Manufacturing scenario, Maryland's greater share of overall construction spending and in-state manufacturing content results in a cumulative 15% increase in jobs and a 25% increase in output over the study period (see Table 3-39 and Figure 3-57 through Figure 3-59). Benefits are distributed throughout the Maryland economy through both indirect impacts, reflecting supply chain growth, and increased household consumption from increased earnings.

Table 3-39. Economic Impacts on Maryland's Economy, High-Manufacturing Scenario

Offshore Wind Impacts	FTE Jobs	Employee Compensation (thous. 2018$)	Output (thous. 2018$)
Construction			
Direct	8,751	$625,832	$1,698,906
Indirect	2,980	197,511	509,770
Induced	4,396	218,987	641,335
TOTAL	**16,127**	**$1,042,330**	**$2,850,011**
O&M			
Direct	1,039	$107,685	$445,882
Indirect	868	58,935	158,878
Induced	887	44,170	129,361
TOTAL	**2,794**	**$210,790**	**$734,121**

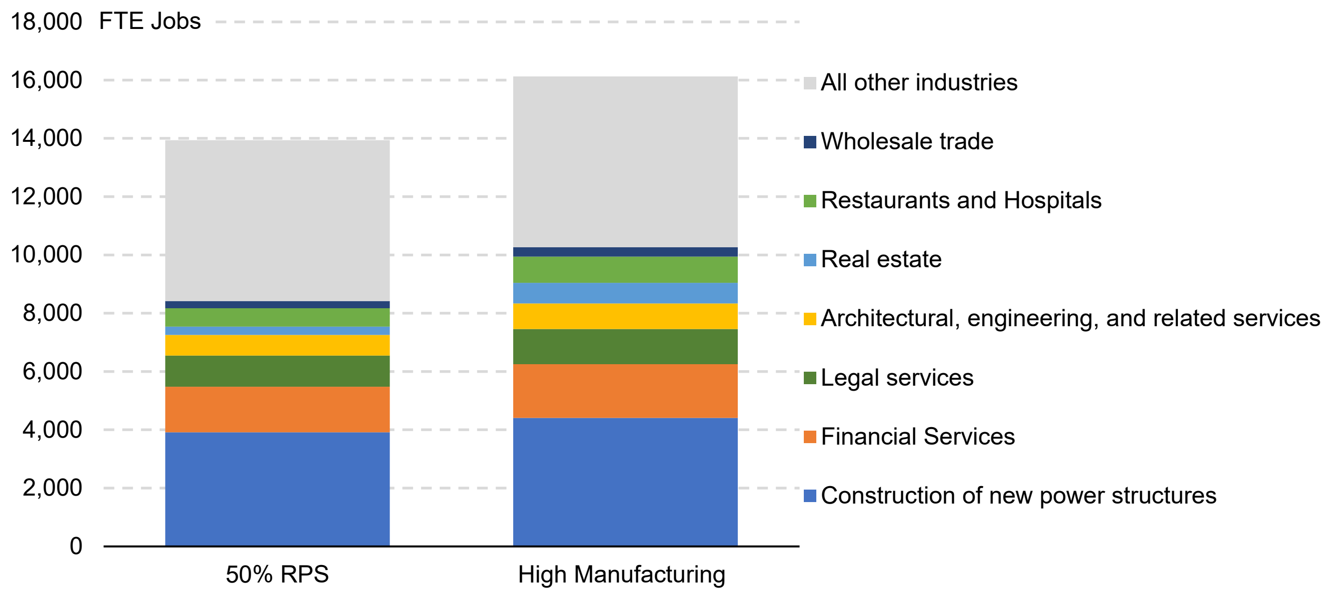

Figure 3-57. Maryland Industries (Full-Time Equivalent Jobs) Benefiting from Offshore Wind Construction, 50% RPS and High-Manufacturing Scenarios

Note: Financial services includes monetary authorities and depository credit intermediation.

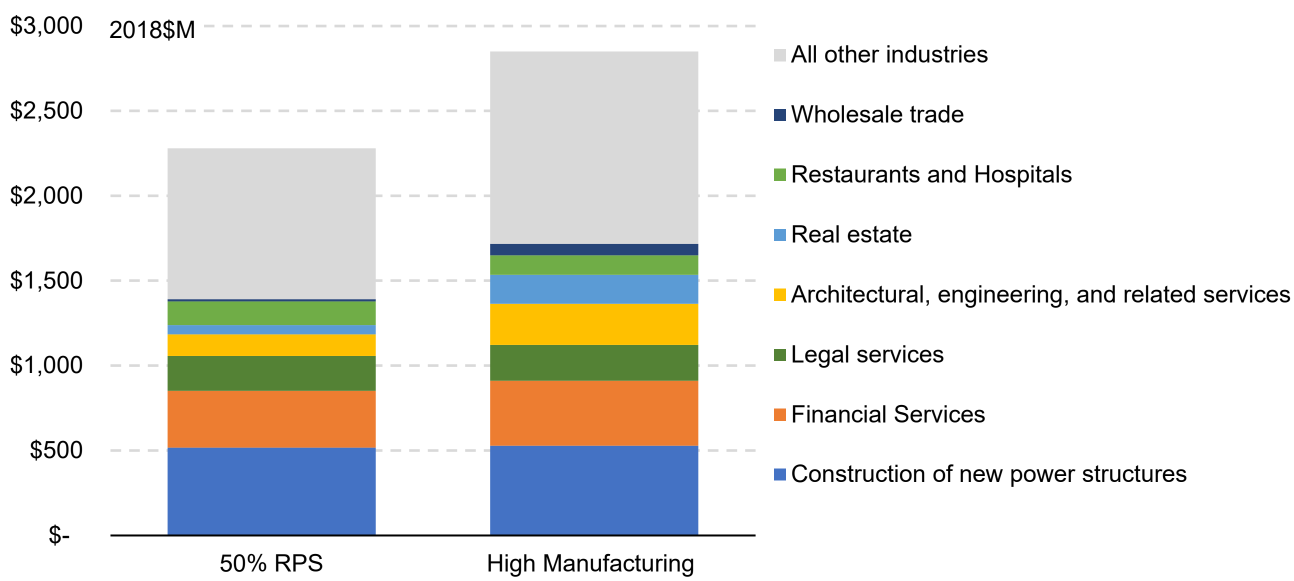

Figure 3-58. Total Output from Offshore Wind Construction, 50% RPS and High-Manufacturing Scenarios

Note: Financial services includes monetary authorities and depository credit intermediation.

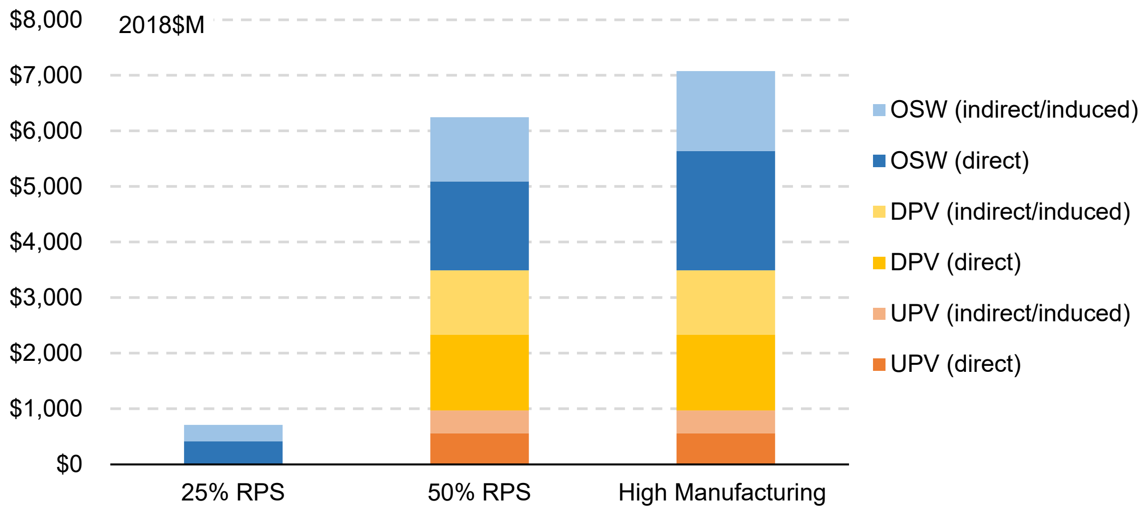

Figure 3-59. Total Output by Technology, 25% RPS, 50% RPS, and High-Manufacturing Scenarios

The High-Manufacturing scenario highlights the opportunities for Maryland's economy from offshore wind development off the Atlantic coast. NREL projections from 2015 suggest that significant development of offshore wind resources can be expected after 2030 (refer to Table 3-36). This could create a market large enough for suppliers to locate more manufacturing facilities close to demand and provide even greater benefits to Maryland.

3.4.8. PJM Scenario

The analysis of economic impacts associated with the Maryland RPS was extended to surrounding states in PJM (PJM scenario) using IMPLAN's regional aggregation capabilities. This required combining the I-O accounts for Delaware, Maryland, New Jersey, Pennsylvania, Virginia, West Virginia, and the District of Columbia into a single-region PJM economy whose final demand could then be adjusted by industry-specific construction and O&M expenditures.[254] The PJM scenario was constructed using the same build-out assumptions as the 50% RPS scenario for Maryland, but with regional (rather than in-state) content factors applied to represent the percentage of total expenditures for a given sector that are spent within the region (rather than solely within Maryland).[255]

[254] Although PJM serves all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia, the PJM scenario seven-state aggregation was used as a proxy for the PJM region for computational convenience under the assumption that most economic benefits of the RPS outside of Maryland would likely be captured by neighboring states.

[255] It is important to understand that the PJM scenario, as specified, does not identify where economic benefits are distributed within the PJM region, nor does Maryland's share of direct impacts remain the same. For example, in the 25% RPS, 50% RPS, and High-Manufacturing scenarios, 100% of UPV construction expenditures on architectural and engineering services are direct impacts on the Maryland economy, while in the PJM scenario, the same 100% is input as a direct impact to the combined multi-state economy that comprises the PJM region in this study. The same is true for sectors where the local content assumption is increased. The concern is not where the greater regional share of construction expenditures is allocated, only that the PJM region receives a greater share than the Maryland-only scenarios because those particular industries appear to have a greater economic presence in the PJM region than in Maryland alone. Also, the PJM scenario estimates economic impacts associated with solar PV and offshore wind construction and operation within Maryland alone. Impacts from renewable energy development outside of Maryland attributable either to RPS requirements in other PJM states or to the Maryland RPS are not considered.

In the absence of useful data on the capacity of industries within the PJM region to supply components to solar and offshore wind developers, local content percentages for construction expenditures were based on the industry output within the region, excluding Maryland, relative to U.S. domestic output for that industry using IMPLAN's 2016 IO accounts. These regional content percentages were then added to Maryland content percentages used in the 50% RPS to arrive at total content assumptions for the PJM region as a whole. For example, in the 50% RPS, 2% of distributed PV construction expenditures on fabricated structural metal manufacturing were assumed to be captured by firms located in Maryland, whereas the PJM scenario assumed that 11% would be captured by firms located within the PJM region. The additional 9% is based on the percentage of output by the industry in the PJM region, excluding Maryland (i.e., $2.7 billion), relative to U.S. domestic output (i.e., $29.1 billion). For offshore wind, the total construction expenditure share captured by PJM was assumed to be 25% of total construction expenditures to the PJM region between 2019-2021, and 40% from 2022-2030 (as compared to Maryland's 19% and 34% allocations during the analogous periods of the 50% RPS). As with the 50% RPS and High-Manufacturing scenarios, regional content by industry was scaled to yield these total values (see Table 3-40 and Table 3-41).

Table 3-40. In-State and Regional Spending Shares for Solar PV Construction, Maryland 50% RPS and PJM Scenarios

IMPLAN Industry Sector	MARYLAND 50% RPS SCENARIO		PJM SCENARIO	
	Distributed PV	Utility PV	Distributed PV	Utility PV
Construction of new power & communication structures	100%	100%	100%	100%
Semiconductor & related device manufacturing	0	0	2	2
Power, distribution & specialty transformer manufacturing	0	0	11	11
Fabricated structural metal manufacturing	2	0	11	9
Other communication & energy wire manufacturing	2	0	10	8
Architectural & engineering services	100	100	100	100
Legal services	100	100	100	100

Table 3-41. In-State and Regional Spending Shares for Offshore Wind Construction, Maryland 50% RPS and PJM Scenarios, 2022-2030

IMPLAN Industry Sector	MARYLAND 50% RPS SCENARIO			PJM SCENARIO		
	Percent of Total OCCs	Original Attribution to In-State Sources	Scaled Attribution to In-State Sources[1]	Percent of Total OCCs	Original Attribution to Regional Sources	Scaled Attribution to Regional Sources
Construction of new power & communication structures	20%	80%	15%	20%	90%	17%
Turbine & turbine generator set units manufacturing	27	0	0	27	5	1
Power, distribution & specialty transformer manufacturing	10	0	0	10	11	1
Rolled steel shape manufacturing	8	13	1	8	21	2
Fabricated structural metal manufacturing	15	0	0	15	0	0
Architectural, engineering & related services	3	100	3	3	100	3
Legal services	6	100	6	6	100	6
Banking	9	100	8	9	100	9
Insurance carriers	1	100	1	1	100	1
Water transportation	<1	100	<1	<1	100	<1
TOTAL	**100%**	-	**34%**	**100%**	-	**40%**

O&M expenditures for utility and distributed PV were assumed to be 100% local in the 50% RPS scenario for Maryland and remained so for the PJM scenario. In line with total construction expenditure adjustments, the PJM share of total O&M expenditures for offshore wind was increased to 35% in the PJM scenario compared to Maryland's 30% in the 50% RPS scenario (see Table 3-42).

Table 3-42. In-State and Regional Spending Shares for Offshore Wind O&M, Maryland 50% RPS and PJM Scenarios

IMPLAN Industry Sector	MARYLAND 50% RPS SCENARIO			PJM SCENARIO		
	Percent of Total OCCs	Original Attribution to In-state Sources	Scaled Attribution to In-State Sources	Percent of Total OCCs	Original Attribution to Regional Sources	Scaled Attribution to Regional Sources
Water transportation	23%	100%	15%	23%	100%	17%
Commercial & industrial machinery & equipment rental and leasing	12	100	7	12	100	9
Commercial & industrial machinery & equipment repair & maintenance	7	100	5	7	100	6
Other engine & equipment manufacturing	5	100	3	5	100	4
Turbine & turbine generator set units manufacturing	53	0	0	53	0	0
TOTAL	**100%**	**-**	**30 %**	**100%**	-	**35%**

In the PJM scenario, the region's greater share of manufacturing content results in a cumulative 13% increase in jobs and a 23% increase in output attributable to construction expenditures over the study period and similar increases in O&M expenditures (see Table 3-43 and Figure 3-60). Total jobs from the initial round of construction expenditures (direct jobs) over the forecast period are actually lower in the PJM scenario, primarily due to fewer construction jobs in utility-scale PV and distributed PV installations, which is attributable to higher labor costs PJM-wide relative to Maryland. For offshore wind, construction jobs in the PJM scenario are higher than in the 50% RPS (Maryland-only) scenario because regional content assumptions for the construction expenditures are higher. As noted earlier, offshore wind developers of the Maryland WEA are expected to recruit workers from both nearby states and overseas to fill trade skills not available in-state. Benefits are distributed throughout the PJM economy through both indirect impacts, reflecting supply chain growth, and increased household consumption from increased earnings. Indirect impacts make up a slightly higher proportion of total impacts due to higher regional manufacturing content in the PJM scenario, which results in greater inter-industry activity. The PJM region benefits from O&M expenditures on the additional renewable energy capacity in Maryland in response to a greater overall regional content share than was assumed for Maryland alone in the 50% RPS scenario.

Table 3-43. Economic Impacts on PJM's Economy, PJM Scenario

		FTE Jobs	Employee Compensation (thous. 2018$)	Output (thous. 2018$)
UTILITY-SCALE SOLAR PV IMPACTS	**Construction**			
	Direct	2,993	$236,456	$525,419
	Indirect	1,005	70,071	179,510
	Induced	1,985	103,407	301,403
	Subtotal	***5,983***	***$409,934***	***$1,006,332***
	O&M			
	Direct	800	$46,692	$85,440
	Indirect	138	9,433	23,855
	Induced	364	18,937	55,198
	Subtotal	***1,302***	***$75,062***	***$164,493***
DISTRIBUTED SOLAR PV IMPACTS	**Construction**			
	Direct	7,399	$657,212	$1,311,968
	Indirect	3,310	228,277	529,505
	Induced	5,746	299,399	872,712
	Subtotal	***16,455***	***$1,184,888***	***$2,714,185***
	O&M			
	Direct	1,051	$61,353	$112,266
	Indirect	181	12,395	31,345
	Induced	478	24,884	72,529
	Subtotal	***1,710***	***$98,632***	***$216,140***
OFFSHORE WIND IMPACTS	**Construction**			
	Direct	8,069	$618,067	$1,560,687
	Indirect	3,012	210,036	567,390
	Induced	5,368	279,625	815,044
	Subtotal	***16,449***	***$1,107,728***	***$2,943,121***
	O&M			
	Direct	760	$80,141	$335,860
	Indirect	749	55,596	153,496
	Induced	879	45,802	133,501
	Subtotal	***2,388***	***$181,539***	***$622,857***
TOTAL IMPACTS	**Construction**			
	Direct	18,461	$1,511,735	$3,398,074
	Indirect	7,327	508,384	1,276,405
	Induced	13,099	682,431	1,989,159
	TOTAL	**38,887**	**$2,702,550**	**$6,663,638**
	O&M			
	Direct	2,611	$188,186	$533,566
	Indirect	1,068	77,424	208,696
	Induced	1,721	89,623	261,228
	TOTAL	**5,400**	**$355,233**	**$1,003,490**

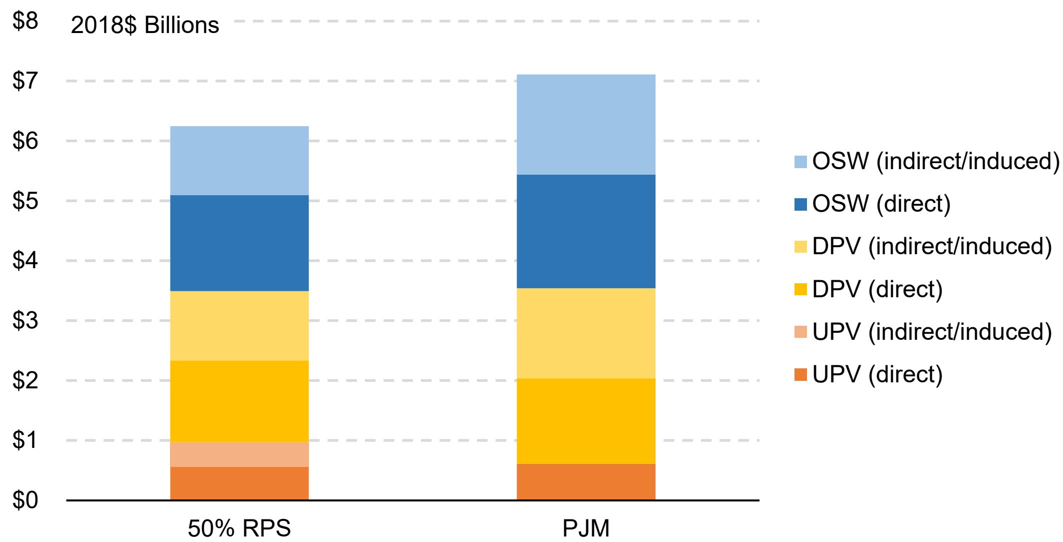

Figure 3-60. Total Output by Technology, Maryland 50% RPS and PJM Scenarios

The results indicate that the PJM region as a whole (or as represented here) will benefit from Maryland's 50% RPS, particularly from construction and O&M expenditures on goods and services that cannot be procured in Maryland due to product availability, established business relationships, or other factors. However, supply chain development potential in the PJM region is similar to Maryland's. This adds uncertainty regarding how the economic benefits will be distributed, and where the opportunities for capturing these benefits lie.

This study has already noted that opportunities for supply chain growth in Maryland from solar PV investment are limited, and the same can be said for the PJM region. No solar panel manufacturing facilities are located in the region, for example, and the majority of solar companies doing business there are installers serving local rather than regional markets. The additional regional shares of manufacturing in the PJM scenario are based on sector definitions, of which the solar PV supply chain is only a very small part. This suggests that estimates of economic benefits gained by other PJM states from solar PV investment in Maryland may be overstated, and that supply chain investment opportunities are no more likely to develop in the PJM region than in Maryland.

Maryland has targeted rolled steel shape manufacturing (for turbine towers) and port infrastructure improvements to kick-start its offshore wind supply chain, while New Jersey is seen as a leading contender for early offshore wind manufacturing with the announcement of plans to locate a factory for offshore turbine steel foundations in Paulsboro.[256] While both investments are at least initially intended to supply offshore wind development requirements in their respective states, expansion is likely if the Atlantic offshore wind market takes off, potentially attracting other industries in the supply chain which may lead to the creation of onshore hubs.

[256] Karl-Erik Stromsta, "Orsted and Germany's EEW Plan Offshore Wind Factory in New Jersey," *Greentech Media*, July 2019, greentechmedia.com/articles/read/orsted-and-germanys-eew-plan-offshore-wind-factory-in-new-jersey?utm_medium=email&utm_source=Daily&utm_campaign=GTMDaily#gs.om3f12.

3.5. Future Ratepayer Impacts in Maryland

The RECs plus ACP costs approach, described earlier in the section on tracking REC and SREC prices (Section 2.4 "Ratepayer Impacts"), is also utilized to estimate future rate impacts of the Maryland RPS. These estimates are a function of four separate components: (1) projected electricity sales; (2) RPS requirements; (3) forecasted REC costs (less rebates applicable to offshore wind); and (4) anticipated ACP costs and usage. The subsequent discussion in this section of the final report reviews each of these separate elements and, as applicable, summarizes the approach to determining estimates in each category. Thereafter, this section combines these elements to develop both total cost and cost-per-kWh calculations of the expected future ratepayer impacts of the Maryland RPS, both in aggregate and for different customer classes. Two main sets of estimates were developed. The first set of estimates was made in December 2018, and they assume that the 25% Maryland RPS (in effect at the time) would remain in place through 2030. A second set of estimates was made in July 2019 to account for the 50% Maryland RPS implemented following the enactment of SB 516 in May 2019. Note that the impact of Tier 2 requirements was excluded from this analysis due to the impending expiration of the Tier 2 category at the end of 2021.

Key findings from analysis of the 25% RPS include:

- ACPs are expected to remain a minimal portion of RPS compliance costs through 2030.
- The Maryland PSC-approved OREC rate—$131.93/MWh (2012$) levelized over a 20-year contract term, or $115.96/MWh on average (weighted, nominal dollars) after refunding revenues from capacity and energy—for the planned US Wind and Skipjack offshore wind projects will be more costly than the rate for all other renewable energy resources used for Maryland RPS compliance.
- SRECs and non-carve-out Tier 1 RECs are estimated to add between 0.128-0.194 cents/kWh to retail electric rates from 2019-2030. This rate impact increases by an additional 0.169-0.295 cents/kWh when also including OREC costs.
- Average costs from the Maryland RPS are estimated to equal approximately $14, $86, $416, and $1,304 per year, respectively, for residential, commercial, IPL, and industrial customers in 2019.[257] These costs are projected to increase, respectively, to approximately $43, $282, $2,473, and $4,119 per year by 2030, inclusive of OREC costs.
- The rate impact of SRECs and non-carve-out Tier 1 RECs remains relatively flat through 2030, ranging between 1.0-1.4% of total retail bills. Including ORECs, the rate impact of the Maryland RPS peaks at 3.4% in 2023. This compares to a maximum impact to-date of 1.8% of retail bills.

Key findings from analysis of the 50% RPS include:

- The overall rate impacts of the Tier 1 non-carve-out requirement increase only modestly from the 25% RPS to the 50% RPS. This is because, after accounting for estimated offshore wind production, the Tier 1 non-carve-out requirement only

[257] Customer class definitions vary by utility, but are presented herein based on aggregate class totals used by the Maryland PSC in its 2018-2027 *Ten-Year Plan* for electric utilities in the state. For example, Pepco has no industrial customers since it does not have an industrial tariff. BGE has an industrial tariff, but it includes all customers of a certain size. As a result, BGE customers like the National Security Agency, Fort Meade, and Johns Hopkins are classified as industrial customers.

increases by 4.1%, from 22.5% in 2020 under the 25% RPS to 26.6% in 2027 under the 50% RPS.

- Based on recent project bids along the East Coast, prices for future offshore wind projects are estimated to fall from an average, weighted nominal price of $115.96/MWh to as low as $46.23/MWh for ORECs alone. Despite this drop, the weighted price of ORECs will still exceed the combined cost of SRECs and Tier 1 non-carve-out RECs.
- The solar ACP, which was revised downward as part of Ch. 757, is expected to fall below projected SREC prices when the ACP reaches $35/MWh in 2025. From 2025-2030, solar carve-out compliance is expected to be met through ACPs or SRECs delivered at the capped price.
- SRECs, non-carve-out Tier 1 RECs, and solar ACPs are estimated to add between 0.377-0.572 cents/kWh to retail electric rates, on average, from 2019-2030. This rate impact increases by as much as 0.789 cents/kWh in 2030 when including OREC costs at the assumed weighted-average rate of $69.11/MWh.
- Average costs from the Maryland RPS are estimated to equal approximately $41, $255, $422, and $3,846 per year, respectively, for residential, commercial, IPL, and industrial customers in 2019. These costs are projected to increase, respectively, to approximately $115, $754, $6,705, and $10,998 per year by 2030, inclusive of OREC costs.
- The rate impact of Tier 1 non-carve-out RECs remains relatively flat through 2030, ranging between 0.7-1.3% of total retail bills. The rate impact of SRECs increases to as high as 3.1% of total retail bills in 2021, then decreases to as low as 1.8% in 2030 as a result of declining SREC prices and then a falling ACP. Including ORECs, the rate impact of the Maryland RPS peaks at 7.6% in 2030. This compares to a maximum impact of 3.4% of retail bills under the 25% RPS.

These results are sensitive to the assumptions used, including reliance on public spot market REC prices, the assumption that REC and SREC prices grow at the rate of inflation in 2023 and onwards, and the exclusion of potential cost savings due to federal or state offshore wind incentive programs. An alternative scenario that evaluates the effect of reduced non-carve-out Tier 1 REC, SREC, and OREC costs on ratepayers is considered at the end of this section.

3.5.1. Energy Sales Assumptions

Projections of aggregate energy sales, net of DSM, were taken from the Maryland PSC's 2018-2027 *Ten-Year Plan*.[258] In the *Ten-Year Plan*, Maryland utilities project a compound annual growth rate (CAGR) of approximately -1.0% from 2018-2027. Table 3-44 reflects the PSC's reported estimates of energy sales, net of DSM, through 2027. It also includes equivalent projections for Maryland's electric cooperatives, Choptank Electric Cooperative (Choptank) and the Southern Maryland Electric Cooperative (SMECO), as well as total energy sales less electric cooperative sales. The combined CAGR of -1.0% was used to extrapolate to 2030 for the overall energy sales estimate, and a CAGR of 0.4% was used for just the electric cooperative energy sales estimates. The sales projections in the *Ten-Year*

[258] Public Service Commission of Maryland, *Ten-Year Plan (2018-2027) of Electric Companies in Maryland*, December 2018, psc.state.md.us/wp-content/uploads/Ten-Year-Plan-2018-2027-FINAL.pdf.

Plan are generally consistent with PJM's load forecasts for each of its utility territories.[259] Although PJM's utility regions cross state and utility boundaries, and are therefore not directly comparable, PJM also shows declining or low load growth in and around Maryland. The same underlying energy sales forecasts were applied when developing the 25% RPS and 50% RPS estimates, although the calculations differ between each case (as discussed below).

Table 3-44. Maryland Energy Sales Forecast, Net of Demand-Side Management (MWh)

Year	Overall Energy Sales	Electric Cooperative Sales	Energy Sales Less Electric Cooperatives
2019	59,432,000	4,555,000	54,877,000
2020	58,967,000	4,572,000	54,395,000
2021	58,282,000	4,575,000	53,707,000
2022	57,618,000	4,589,000	53,029,000
2023	57,092,000	4,607,000	52,485,000
2024	56,649,000	4,624,000	52,025,000
2025	56,017,000	4,642,000	51,375,000
2026	55,496,000	4,671,000	50,825,000
2027	54,994,000	4,705,000	50,289,000
2028	54,466,000	4,724,000	49,742,000
2029	53,943,000	4,743,000	49,200,000
2030	53,425,000	4,763,000	48,663,000

Source: Maryland PSC 2018-2027 *Ten-Year Plan*, Appendix Table 2(a)(ii).

Note: 2028-2030 data are extrapolated using the CAGR from the preceding period (2018-2027), as reported by the Maryland PSC.

3.5.2. RPS Obligations Assumptions

The number of RECs and SRECs an LSE must retire in order to meet its RPS compliance obligation is a function of three things: total retail sale, the legislatively established renewable percentage requirement, and, for the 50% RPS, whether or not the customer is served by an electric cooperative. Under the 25% RPS, the renewable percentage requirement peaks at 25% in 2020, inclusive of the 2.5% solar carve-out. Thereafter, the Tier 1 non-carve-out percentage requirement varies due to the addition of offshore wind resources under the offshore wind carve-out. As of July 2019, the Maryland PSC has approved the issuance of ORECs for two offshore wind projects: the 248-MW US Wind project and the 120-MW Skipjack Project (collectively, "Round 1" projects).[260] For purposes of estimating future production, both Round 1 projects are assumed to come online by January 1 of the projected starting year and to operate at the capacity factors identified in

[259] PJM Resource Adequacy Planning Department, *PJM Load Forecast Report – January 2017*, pjm.com/-/media/library/reports-notices/load-forecast/2017-load-forecast-report.ashx?la=en.

[260] Maryland Public Service Commission, "Maryland PSC Awards ORECS to Two Offshore Wind Developers," 2017, psc.state.md.us/wp-content/uploads/PSC-Awards-ORECs-to-US-Wind-Skipjack.pdf. At the time of the PSC Order, the US Wind project was projected to come online in 2021 and the Skipjack Project by 2023, and these dates were used in preparing the analysis in this report. US Wind has since delayed its projected operating date to 2023.

each project's application.[261] Table 3-45 breaks down Maryland's overall RPS obligations under the 25% RPS by resource category from 2019-2030. The actual offshore wind and non-carve-out Tier 1 percentages will fluctuate on an annual basis depending on offshore wind production.

Table 3-45. Maryland RPS Tier 1 Obligations, 25% RPS (Percent of Retail Sales)

Year	Non-Carve-out RECs[1]	SRECs[2]	ORECs[3]
2019	18.45%	1.95%	0%
2020	22.5	2.5	0
2021	20.9	2.5	1.6
2022	20.9	2.5	1.6
2023	20.1	2.5	2.4
2024	20.1	2.5	2.4
2025	20.1	2.5	2.4
2026	20.0	2.5	2.5
2027	20.0	2.5	2.5
2028	20.0	2.5	2.5
2029	20.0	2.5	2.5
2030	20.0	2.5	2.5

[1] As of 2020, equal to 25% less the percentage contribution from the Tier 1 solar and offshore wind carve-outs.

[2] Set by Maryland RPS legislation.

[3] Calculated by assuming a capacity factor of 42.1% for the 248-MW US Wind project and 43.3% for the 120-MW Skipjack project. The percentage obligation is determined by dividing estimated output by estimated retail electric sales from the PSC 10-year forecast. The total percent is capped at 2.5%.

Under the 50% RPS, the renewable percentage requirement peaks at 50% in 2030, inclusive of the 14.5% solar carve-out, production from Round 1 offshore wind projects, and production from additional offshore wind projects ("Round 2" projects). For electric cooperative customers, the solar carve-out instead peaks at 2.5% in 2020.[262] Rather than specify percentage requirements or limits for Round 2 projects, Ch. 757 required at least 400 MW of additional offshore wind capacity to enter service by 2026, 2028, and 2030, respectively. The only exception to this is a cap on the use of ORECs at 10% of retail energy sales in 2025. For purposes of estimating future production, these requirements are assumed to be met at the required level in each target year and then converted to energy

[261] Levitan & Associates, Inc., *Evaluation and Comparison of US Wind and Skipjack Proposed Offshore Wind Project Applications*, prepared for the Maryland Public Service Commission, 2017, levitan.com/wp-content/uploads/2018/05/Levitan-Associates-Inc.-Evaluation-and-Comparison.-Revised-Public-Version.-Case-No.-9431.-ML-214140.pdf.

[262] The 2019 solar carve-out is assumed to equal 5.5% for both electric cooperative and non-electric cooperative customers because Ch. 757 does not specify a lower requirement.

using a capacity factor of 45%.[263] Newer offshore wind turbines may have higher capacity factors.[264]

Table 3-46 breaks down Maryland's higher RPS requirements under the 50% RPS. It includes separate requirements for electric cooperative customers, who face lower SREC obligations but higher non-carve-out REC requirements. Note that for 2019 and 2020, the 50% RPS Tier 1 non-carve-out requirement falls below that of the 25% RPS. This occurs because the increased solar carve-out for the 50% RPS absorbs a higher percentage share of the overall requirement.

Table 3-46. Maryland RPS Tier 1 Obligations, 50% RPS (Percent of Retail Sales)

	NON-ELECTRIC COOPERATIVE CUSTOMERS			ELECTRIC COOPERATIVE CUSTOMERS		
Year	Non-Carve-out RECs[1]	SRECs	ORECs[2]	Non-Carve-out RECs[1]	SRECs	ORECs[2]
2019	15.2%	5.5%	0%	15.2%	5.5%	0%
2020	22.0	6.0	0	25.5	2.5	0
2021	21.7	7.5	1.6	26.7	2.5	1.6
2022	23.0	8.5	1.6	29.0	2.5	1.6
2023	23.5	9.5	2.4	30.5	2.5	2.4
2024	24.8	10.5	2.4	32.8	2.5	2.4
2025	26.1	11.5	2.4	35.1	2.5	2.4
2026	24.7	12.5	5.3	34.7	2.5	5.3
2027	26.6	13.5	5.4	37.6	2.5	5.4
2028	24.7	14.5	8.3	36.7	2.5	8.3
2029	26.6	14.5	8.4	38.6	2.5	8.4
2030	24.1	14.5	11.4	36.1	2.5	11.4

[1] Calculated by subtracting the Tier 1 solar and offshore wind carve-outs from the legislatively set requirement.

[2] The percentage of future RECs provided by offshore wind will fluctuate on an annual basis depending on total MWh output and retail energy sales. The estimates presented in this table are based on the expected OREC output of both existing Round 1 projects (refer to *Table 3-45*) and prospective Round 2 projects. Round 2 OREC estimates assume 400 MW of additional capacity enters service in 2026, 2028, and 2030 as required by Ch. 757, and that all Round 2 facilities have a capacity factor of 45%. Total OREC generation is relative to projected Maryland energy sales, net demand-side management (refer to "Overall Energy Sales," *Table 3-44*).

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[263] Forty-five percent is the approximate middle point for NREL's estimates for this period, which range from 30-60% depending on the scenario. *See:* atb.nrel.gov/electricity/2018/index.html?t=ow.

[264] For example, recent trade press articles indicate that Ørsted, the owner of the Skipjack project, will contract with GE Renewable Energy for new turbine technology that is currently being tested. These turbines are estimated to have a 63% capacity factor. For more information, *see:* Iulia Gheorghiu, "Orsted taps GE for 50% more efficient turbines in New Jersey, Maryland offshore wind projects," *Utility Dive*, September 23, 2019, utilitydive.com/news/orsted-taps-ge-for-50-more-efficient-turbines-in-new-jersey-maryland-offs/563475/. Although newer turbines may result in higher capacity factor offshore wind facilities, the estimates provided in the final report assume that the Maryland PSC will not substantially increase the number of ORECs it allows due to considerations like ratepayer impact, as discussed in Section 3.5.3, "Comparing Renewable Energy Growth in Maryland with States in PJM."

3.5.3. REC, SREC, and OREC Costs Assumptions

As discussed earlier in the final report, REC prices depend on a complex array of supply and demand conditions. Although RECs can only be retired for RPS compliance in a single state, they can be procured from a broader market in most cases. In Maryland, this market includes the pool of renewable energy resources supplying power within or into PJM. The effect of Maryland's RPS policies, therefore, depends on its aggregate impact on REC availability throughout PJM. Multiple organizations provide market data related to REC sales in PJM, including not only current-year REC prices but also REC prices for future years. Future REC prices, however, are usually reported only a few years forward since the market begins to lose liquidity for REC products much further out in time.

Several simplifying assumptions are made for the purposes of estimating expected REC costs. First, existing REC forward prices are utilized as the best available estimate of REC prices during the years for which these data are available. REC forward prices emerge from surveys of market trading and can therefore be thought of as the market's best approximation of REC prices during the traded years. Although publicly available forward prices data do not reflect the terms, conditions, and pricing of private bilateral agreements, the two sets of data points—public futures and private contracts—are expected to converge over time as the same underlying market fundamentals apply to both private and public transactions. The two can therefore be assumed to be (1) similar in terms of price magnitude (i.e., relatively close prices); and (2) move in the same direction over time (i.e., follow the same trend). REC forward prices as of December 21, 2018 and July 12, 2019 were used for the 25% and 50% RPS estimates, respectively. In each case, the REC forward prices go forward three years, beyond which there is insufficient liquidity to estimate prices. Note that these future prices reflect point-in-time estimates of REC costs, rather than averages of annual RPS compliance costs. This approach reflects the most up-to-date estimates of future changes in REC prices. It may, however, overstate or understate near-term costs if existing contracts carry forward below-market or above-market contract rates, respectively.

Second, beyond the years for which REC forward prices are available, REC prices are projected to remain constant in real-dollar terms; that is, REC prices are assumed to increase at the projected rate of inflation. This approach is consistent with the expectation that changing future market conditions will counterbalance one another—at least to some extent. For example, increased demand due to more stringent RPS requirements will put upward pressure on REC prices, while increased supply due to the declining costs of renewable capacity will provide downward pressure. REC forward prices are drawn from proprietary Marex Spectrometer data. These data are specific to Maryland RECs and are subdivided into Tier 1 RECs and SRECs. Projected inflation rates are drawn from the "Long Range Consensus U.S. Economic Projections" for the Consumer Price Index (CPI) from *Blue Chip Economic Indicators* (*Blue Chip*), which are up to date as of March 2019.

Special assumptions are made for ORECs. Given the nascent state of offshore wind in the U.S. and PJM, there is no established market for ORECs. Instead, all Maryland ORECs must be approved through regulated proceedings overseen by the Maryland PSC. Additionally, market revenues received by offshore wind facilities from the sale of energy, capacity, and ancillary services are rebated to customers. Thus, the true price of unbundled ORECs is equal to the contracted OREC rate less estimated market revenues.

Rebates to customers are determined and processed in accordance with regulations outlined in COMAR 20.61.06 that address offshore wind applications, market participation, and invoicing requirements, among other relevant rules.[265] All transactions related to Maryland offshore wind facilities are directed to an escrow account that is managed by an independent administrator. The administrator is responsible for processing all OREC invoices as well as holding the "proceeds from those sales that are associated with the ORECs" and "from the sale of that project's electricity service attributes associated with those ORECs" in trust.[266] These revenues are transferred to LSEs "in accordance with the relative market share of those companies (in megawatt hours)," less payments to the offshore wind operator for amounts due from OREC invoices (plus a small reserve).[267] LSEs that receive market revenues are then responsible for refunding or crediting customers within 90 days of receipt. No refund or credit approaches have been proposed or approved by the PSC to date.

Prior to Ch. 757, OREC prices were subject to three constraints during Maryland PSC review and approval: (1) a maximum carve-out for ORECs of 2.5% of retail sales; (2) an OREC cost ceiling set at 1.5% of total commercial and industrial (C&I) consumer bills, and an additional cost of $1.50 (2012$) per month for residential customers with 1,000 kWh of monthly usage; and (3) an OREC price maximum of $190/MWh (2012$).[268] Following Ch. 757, these constraints were revised to (1) a maximum carve-out for ORECs of 2.5% of retail sales in 2019 and 2020; (2) a maximum carve-out for ORECs of 10% of retail sales in 2025; and (3) an OREC cost ceiling set at 0.9% of total C&I consumer bills, and an additional cost of $0.88 (2018$) per month for residential customers with 1,000 kWh of monthly usage. The Maryland PSC relied on its consultant, Levitan & Associates, to assess each proposal's compliance with these price constraints.[269] Levitan & Associates, in turn, considered three principal factors when developing net rate impact estimates: the gross OREC price; the value of energy, capacity, and RECs from each facility; and the reduction in market prices as a result of production.[270]

The Maryland PSC ultimately approved issuing ORECs for both Round 1 offshore facilities and found that both projects met all of the OREC cost containment principles in effect prior to Ch. 757.[271] The final order established an OREC price schedule for both facilities "equivalent to a levelized price of $131.93 per OREC (2012$) using a 1.0% price escalator" over a 20-year contract. Both Skipjack and US Wind published their revised OREC price schedules (in nominal dollars) shortly after the PSC's final order.[272] Table 3-47 shows the

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[265] COMAR 20.61.06. Offshore Wind, mdrules.elaws.us/comar/20.61.06.

[266] COMAR 20.61.06.12. Payment of PJM Revenues and Trust for Benefit of Ratepayers, mdrules.elaws.us/comar/20.61.06.12.

[267] COMAR 20.61.06.11. Invoicing of OREC Purchasers and Administrator's Responsibilities, mdrules.elaws.us/comar/20.61.06.11.

[268] Maryland General Assembly, "Maryland Offshore Wind Act of 2013," 2013 session, mgaleg.maryland.gov/2013RS/fnotes/bil_0006/hb0226.pdf.

[269] Note that the price constraints assessed during the PSC review process only applied to the project applications. That is, changing market conditions that may cause OREC rates to exceed these price constraints following approval have no bearing on project compliance.

[270] Levitan & Associates, Inc., *Evaluation and Comparison of US Wind and Skipjack Proposed Offshore Wind Project Applications*, prepared for the Maryland Public Service Commission, 2017, levitan.com/wp-content/uploads/2018/05/Levitan-Associates-Inc.-Evaluation-and-Comparison.-Revised-Public-Version.-Case-No.-9431.-ML-214140.pdf.

[271] Maryland PSC Order No. 88192, Case No. 9431, psc.state.md.us/wp-content/uploads/Order-No.-88192-Case-No.-9431-Offshore-Wind.pdf.

[272] Skipjack Offshore Wind Energy, LLC, Letter accepting approval on Order No. 88192, Case No. 9431, webapp.psc.state.md.us/newIntranet/Casenum/NewIndex3_VOpenFile.cfm?filepath=//Coldfusion/Casenum/9400-9499/9431/Item_122\SkipjackLetterofAcceptance.PDF; US Wind, Inc. - Notice of Acceptance of Conditions, Case No. 9431, webapp.psc.state.md.us/newIntranet/Casenum/NewIndex3_VOpenFile.cfm?FilePath=//Cold fusion/Casenum/9400-9499/9431/\123.pdf.

estimated nominal price of ORECs from Skipjack and US Wind after netting out expected market revenues. Market revenues were calculated using estimated energy and capacity prices, as is consistent with the strategy used by Levitan & Associates.[273]

Table 3-47. Round 1 Offshore Wind OREC Costs (Nominal $/MWh)

	APPROVED PRICE SCHEDULE[1]		ESTIMATED ENERGY REBATE[2]		ESTIMATED CAPACITY REBATE[3]		ESTIMATED OREC PRICE	
Year	US Wind	Skipjack	US Wind	Skipjack	US Wind	Skipjack	US Wind	Skipjack
2021	$166.70		$28.18		$30.91		$107.61	
2022	168.37		27.86		29.65		110.86	
2023	170.05	$171.30	27.73	$27.73	30.31	$14.66	112.01	$128.90
2024	171.75	173.01	28.20	28.20	30.97	14.99	112.57	129.82
2025	173.47	174.74	28.76	28.76	31.65	15.32	113.06	130.67
2026	175.20	176.49	29.48	29.48	32.35	15.65	113.37	131.36
2027	176.96	178.26	30.35	30.35	36.88	16.00	109.74	131.91
2028	178.72	180.04	31.15	31.15	37.69	16.35	109.88	132.54
2029	180.51	181.84	31.84	31.84	38.52	22.11	110.15	127.89
2030	182.32	183.66	32.54	32.54	39.36	22.59	110.41	128.53

[1] Nominal dollar price schedule as published by each developer following approval by the Maryland PSC in Order No. 88192.

[2] Based on 2021-2028 around-the-clock forward prices from PJM's DPL trading point. Prices thereafter increase by 2.2% per year based on consensus estimates of change in the CPI sourced from *Blue Chip* as of March 2019.

[3] Based on Delivery Years (DY) 2018/2019 – 2021/2022 Base Residual Auction (BRA) clearing prices for PJM's DPL South region. Prices thereafter increase by 2.2% per year based on consensus estimates of change in the CPI sourced from *Blue Chip* as of March 2019. Note that multi-year prices are weighted by number of months to develop single year estimates.

Given the high degree of uncertainty regarding future energy and capacity prices, new net rate impact estimates were developed rather than relying on Levitan & Associates projections, which utilize data from as early as 2014. This report did not, however, replicate the production cost modeling used by Levitan & Associates. Instead, several simplifying assumptions were made for estimation purposes. First, forward energy prices from PJM's DPL pricing point were used as a stand-in for the price of energy at the actual energy delivery points of each project.[274] Second, the separate data series for on-peak and off-peak energy prices were combined into a single, time-weighted, average price based on 46.5% on-peak hours and 53.5% off-peak hours (i.e., around-the-clock weighting).[275] Third, capacity prices were based on the latest available PJM resource clearing price auction results for the DPL South zone, which includes the proposed receipt points for both Round 1 projects. Capacity prices were subsequently adjusted using the same "crediting"

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[273] Other potential sources of revenue, such as ancillary services, are uncommon for intermittent sources of power, such as wind generation. Thus, these revenues are assumed to be small and are not included.

[274] Prices are not adjusted for the basis differential between the index, which is a relatively liquid trading point, and the actual delivery points. Additionally, no adjustment is made to account for the impact of injecting a significant amount of power into a specific portion of the grid. The impact of offshore wind on wholesale prices is separately addressed below.

[275] In contrast to onshore wind, which produces a higher share of power during off-peak periods (i.e., at night), offshore wind produces a high portion of power during the day. Because there is limited data available on production patterns for offshore wind along the Atlantic Coast, the around-the-clock average is used instead of an alternative weighting method. *Source:* U.S. Department of Energy, "Top 10 Things You Didn't Know About Offshore Wind Energy," August 12, 2019, energy.gov/eere/wind/articles/top-10-things-you-didn-t-know-about-offshore-wind-energy.

assumptions used by Levitan & Associates; both projects receive 26% of capacity revenues during their first six years of operation, with US Wind receiving 29% and Skipjack receiving 34.4% thereafter. Finally, no ancillary services revenues were assumed, as is consistent with the Levitan & Associates analysis.

Energy price data were sourced from OTC Global Holdings for the period 2020-2028 (prices as of August 5, 2019) using Standard & Poor's (S&P) Global Market Intelligence. Data for 2029-2030 were estimated by extrapolating the 2028 estimated price forward by two years using the aforementioned *Blue Chip* rate of inflation. Because there is considerable uncertainty regarding future capacity markets, this report did not develop more robust demand curve forecasts or assess location-specific dynamics when estimating future capacity prices. Rather, like the energy prices described above, capacity prices are assumed to increase at the rate of inflation beyond 2022, the last year with capacity price data from PJM's most recent auction.

As of 2019, Maryland law requires the PSC to accept applications for Round 2 offshore wind projects on or after January 1, 2020.[276] For purposes of estimating OREC costs in the 50% RPS, this analysis assumes that prices will continue to decline as projected by NREL.[277] Although actual prices will vary by project, the winning bids from several recent offshore wind project auctions in other Northeast states can serve as a stand-in for future Maryland OREC costs. For the projects that enter service in 2026 and 2028, this analysis assumes a nominal, unbundled OREC price of $60/MWh as compared to the average, weighted nominal price of $115.96/MWh for Round 1 projects. This value is based on the winning bid from Ørsted to develop a 400-MW project off the coast of Rhode Island by 2024. Ørsted will provide both ORECs and energy for 20 years at a levelized, nominal price of $98/MWh.[278] The OREC portion was separated out by removing estimated energy costs, in this case assumed to be $38/MWh.[279]

For the projects that enter service in 2030, this analysis assumes a nominal OREC price of $46.23/MWh. This assumption is based on the winning bids from Avangrid and Copenhagen Infrastructure Partners (CIP) to build two 400-MW projects off the coast of Massachusetts, one by 2022 and the other by 2023.[280] Avangrid and CIP will provide both ORECs and energy for 20 years at a combined, levelized, nominal price of $84.23/MWh. Estimated energy costs were removed using the same assumed energy cost as the Ørsted Rhode Island project. The above winning bids (Ørsted at $98/MWh and Avangrid/CIP at $84.23/MWh) are slightly higher but otherwise consistent with estimated pricing for offshore wind projects in the European market. Offshore wind prices from bids in Europe for projects commencing commercial operation in the early- to mid-2020s are between $76-$88/MWh

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[276] Maryland General Assembly, SB 516, "Clean Energy Jobs," 2019 session, mgaleg.maryland.gov/2019RS/chapters_noln/Ch_757_sb0516E.pdf.

[277] National Renewable Energy Laboratory, Annual Technology Baseline, "Offshore Wind," 2018, atb.nrel.gov/electricity/2018/index.html?t=ow.

[278] Institute for Energy Economics and Financial Analysis, "Rhode Island offshore wind project to cost less than 10 cents per kilowatt-hour," February 2019, ieefa.org/rhode-island-offshore-wind-project-to-cost-less-than-10-cents-per-kilowatt-hour/.

[279] Several simplifying assumptions were made to estimate energy prices. First, ISO-NE's Rhode Island Hub and Southeastern Massachusetts Hub were used as a stand-in for the actual delivery points of each project. Second, these separate data series were combined into a single, time-weighted, average price based on 46.5% on-peak hours and 53.5% off-peak hours. Finally, a levelized energy price of $38/MWh was selected based on futures ranging from $37-$39/MWh. These data were sourced from OTC Global Holdings for the period 2020-2028 (prices as of August 2, 2019) using S&P Global Market Intelligence.

[280] Philipp Beiter, Paul Spitsen, Walter Musial and Eric Lantz, *The Vineyard Wind Power Purchase Agreement: Insights for Estimating Costs of U.S. Offshore Wind Projects*, National Renewable Energy Laboratory, February 2019, nrel.gov/docs/fy19osti/72981.pdf.

after adjusting for transmission costs and contract length.[281] These prices are both assumed to meet the net rate impact requirements of Ch. 757.[282]

Table 3-48 presents the expected REC, SREC, and OREC prices for 2019-2030 under the 25% RPS. The OREC figures represent the weighted price of unbundled ORECs, as derived using the separate Skipjack and US Wind prices in Table 3-47. Table 3-49 presents equivalent estimates for the 50% RPS. Note that the OREC costs in Table 3-49 are presented as a weighted average of all expected offshore wind production, including Round 1 and Round 2 projects. For the 50% RPS, this price remains above the assumed rate for new offshore wind projects due to the ongoing cost of past, higher-cost projects.

Table 3-48. Estimated Maryland RPS Tier 1 REC, SREC, and OREC Costs, Not Reflecting Alternative Compliance Payments, 25% RPS ($/MWh)

Year	Non-Carve-out RECs[1]	SRECs[1]	ORECs[2]
2019	$5.83	$10.50	
2020	6.00	11.50	
2021	6.40	12.50	$107.61
2022	6.54	12.78	110.86
2023	6.68	13.06	117.62
2024	6.83	13.34	118.30
2025	6.98	13.64	118.91
2026	7.14	13.94	119.35
2027	7.29	14.24	117.11
2028	7.45	14.56	117.41
2029	7.62	14.88	116.05
2030	7.78	15.20	116.43

[1] 2019-2021 REC and SREC prices derived from Marex Spectrometer futures as of December 2018. Prices thereafter increase by 2.2% per year based on consensus estimates of change in the CPI sourced from *Blue Chip* as of March 2019.

[2] Equal to the weighted nominal price of unbundled Skipjack and US Wind ORECs as listed in *Table 3-47*.

[281] Philipp Beiter, Paul Spitsen, Walter Musial and Eric Lantz, *The Vineyard Wind Power Purchase Agreement: Insights for Estimating Costs of U.S. Offshore Wind Projects*, National Renewable Energy Laboratory, February 2019, nrel.gov/docs/fy19osti/72981.pdf.

[282] Due to time and resource constraints, a more comprehensive assessment of the cost-benefits or rate impacts of these hypothetical Round 2 offshore wind projects subject to the rules, requirements, and caps laid out in Ch. 757 was not conducted. As a rule of thumb, however, it is assumed that the 48% to 67% drop in OREC costs from Round 1 to Round 2 for assumed future offshore wind projects is sufficient to meet the approximately 40% drop in the rate impact caps for residential, commercial, and industrial customers.

Table 3-49. Estimated Maryland RPS Tier 1 REC, SREC, and OREC Costs, Not Reflecting Alternative Compliance Payments, 50% RPS ($/MWh)

Year	Non-Carve-out RECs[1]	SRECs[1]	ORECs[2]
2019	$6.00	$52.00	
2020	6.13	57.50	
2021	6.35	55.00	$107.61
2022	6.85	37.50	110.86
2023	7.00	38.33	117.62
2024	7.15	39.17	118.30
2025	7.31	40.03	118.91
2026	7.47	40.91	87.59
2027	7.64	41.81	86.55
2028	7.81	42.73	77.38
2029	7.98	43.67	76.97
2030	8.15	44.63	69.11

[1] 2019-2022 REC and SREC prices derived from Marex Spectrometer futures as of July 2019. Prices thereafter increase by 2.2% per year based on consensus estimates of change in CPI sourced from *Blue Chip* as of March 2019.

[2] Equal to estimated cost for Round 1 projects (refer to *Table 3-48*) and the weighted average of Round 1 projects and Round 2 projects beginning in 2026. Round 2 project OREC prices are assumed to equal $60 for new capacity online in 2026 and 2028, and $46.23 for new capacity online in 2030.

Note that the OREC prices presented in Table 3-48 and Table 3-49 above may not match the actual prices imposed by Round 1 or Round 2 projects because Maryland law obligates offshore wind developers to pass on cost savings realized in advance of development. More specifically, projects "shall deduct 80% of the value of the state or federal grants, rebates, tax credits, loan guarantees and other similar benefits received" in advance of operation.[283] In the absence of more complete information about available incentives, which are subject to change depending on when each facility commences construction and operation, the simplifying assumption was made to exclude these potential financial benefits and incentives from the estimated costs in Table 3-48 and Table 3-49. Potential cost reductions, however, are explored in a separate scenario outlined in Section 3.5.7, "Alternative Scenarios."

3.5.4. Alternative Compliance Payment Costs and Usage Assumptions

ACPs are a substitute for RECs that function, in effect, as a price ceiling. RECs are the predominant method by which LSEs meet their RPS obligations. This can be expected to continue to be the case up until the time that REC prices come close to, or are in excess of,

[283] COMAR 20.61.06.13. Value to Ratepayers of State or Federal Funds and Benefits, mdrules.elaws.us/comar/20.61.06.13.

the ACP. At this point, an LSE will pay the ACP instead of purchasing RECs in order to minimize the overall cost of compliance. In Maryland, the ACP schedule is set by statute. To date, ACPs have made up a negligible amount of Maryland RPS compliance costs. This is especially the case in the last five years, as documented earlier in Subsection 2.4.1, "Availability of Renewable Energy at Affordable and Reasonable Rates." Under the above assumptions for the 25% RPS, REC and SREC prices were expected to remain well below the previous ACP levels, which were set at $37.50/MWh for Tier 1 non-carve-out RECs and as low as $50/MWh for Tier 1 SRECs. Consequently, ACPs are expected to remain a minimal part of overall Maryland RPS compliance costs. ACPs do not apply to the portion of load served by ORECs; rather, OREC costs are controlled based on the price constraints outlined above in Subsection 3.5.3. All customers pay for ORECs at the PSC approved rate, once the projects are operational.

ACP levels also remain well above the Tier 1 non-carve-out REC prices under the 50% RPS, which sets ACP prices as low as $22.35/MWh. SREC prices, however, are projected to intersect with the revised solar ACP. Table 3-50 presents the solar ACP from 2019-2030 for the 50% RPS alongside estimated SREC prices for the same period. The ACP is expected to supplant SRECs as the prevailing price in 2025, when the solar ACP is $35/MWh and SREC prices are approximately $40/MWh. Thereafter, the ACP remains below expected SREC prices and therefore serves as a price ceiling. The gap between SRECs and the solar ACP is greatest in 2030. From 2025-2030, when the ACP is below the expected SREC price, LSEs will meet their SREC obligations either through ACPs or, as available, by purchasing SRECs that are priced equal to or lower than the cap.

Table 3-50. Solar Carve-out Alternative Compliance Payments, 50% RPS ($/MWh)

Year	ACP	Estimated SREC Price[1]
2019	$100	$52.00
2020	100	57.50
2021	80	55.00
2022	60	37.50
2023	45	38.33
2024	40	39.17
2025	35	40.03
2026	30	40.91
2027	25	41.81
2028	25	42.73
2029	22.5	43.67
2030	22.35	44.63

[1] Refer to *Table 3-49.*

One exception to the above ACP outcomes is in the case of IPL customers, for which an ACP of $2.00/MWh applies rather than the above rates. Given the lower ACP cost, LSEs of IPL customers have sometimes paid the ACP rather than procure RECs. For example, LSEs of IPL customers faced an obligation of 25,116 Tier 1 RECs in 2017, and they opted to meet this requirement entirely through ACPs, at a total cost of $50,232.[284] These LSEs are expected to continue to do so going forward insofar as Tier 1 REC costs are forecast to remain above $2.00/MWh. However, the IPL class is a small share of total Maryland electric demand and contributes less than 0.3% of Maryland's RPS obligation. Thus, ACP costs are expected to be very low relative to aggregate RPS compliance costs and a *de minimis* portion of future ratepayer impacts under both the 25% RPS and 50% RPS. Additionally, the introduction of ORECs will alter ACP costs for IPL customers; the ACP for IPL customers declines by 50%, or to $1/MWh, in the first year that an OREC obligation applies, and then falls to $0/MWh thereafter for any year the net OREC rate impact exceeds $1.65/MWh (2012$). Based on the approved levelized cost of ORECs, this condition will essentially eliminate IPL obligation for Tier 1 RECs by reducing the ACP to zero. It will also further diminish the use of ACPs. IPL customers are addressed further in the following discussion of rate impacts by customer class.

3.5.5. Estimated Rate Impacts

Using the above assumptions to derive an estimated cost of the 25% RPS entails two steps: (1) multiply the RPS percentage requirement [*Table 3-45* or *Table 3-46*] by the projected energy sales ["Overall Energy Sales," *Table 3-44*] to determine the number of RECs required; and (2) multiply the number of RECs required by the average REC price [*Table 3-48* or *Table 3-49*] or ACP [*Table 3-50*], whichever price is lower. For example, the estimated Tier 1 non-carve-out cost for 2020 under the 25% RPS equals $79,605,000 (i.e., 58,967,000 MWh * 22.5% * $6.00/MWh). Step one of this process is modified slightly for the 50% RPS. To determine the number of RECs required in this case:

- Multiply electric cooperative RPS percentage requirements ["Electric Cooperative Customers," *Table 3-46*] by projected electric cooperative energy sales ["Electric Cooperative Sales," *Table 3-44*];
- Multiply non-electric cooperative RPS percentage requirements ["Non-Electric Cooperative Customers," *Table 3-46*] by the projected non-electric cooperative energy sales ["Energy Sales Less Electric Cooperatives," *Table 3-44*]; and
- Sum the preceding estimates.

Step Two is the same for the 50% RPS except for using revised average REC price figures [*Table 3-49*]. For example, the estimated non-carve-out Tier 1 cost for 2020 under the 50% RPS equals $80,504,000 (i.e., [(54,395,000 MWh * 22.0%)+(4,572,000 MWh * 25.5%)] * $6.13/MWh).

Estimated overall electricity costs can also be calculated for comparison purposes by multiplying total sales ["Overall Energy Sales," *Table 3-44*] by the average end-use rate for all sectors, which is provided below in Table 3-51. For example, the estimated total energy sales costs for 2020 equal $7,018,300,000 (i.e., 58,967,000 MWh * $119.02/MWh).

The data in Table 3-51 are based on Edison Electric Institute (EEI) data for *Typical Bills and Average Rates* as adjusted using EIA's *Annual Energy Outlook 2019* (AEO 2019). EEI collects utility-reported, indicative retail rate information broken down by customer class, as well as aggregated across sectors, on a semi-annual basis. The aggregated numbers provide the basis for calculating the baseline, 2018, average retail rate. Given year-over-year variability in rates due to weather and other factors, this analysis used an average of the

[284] Public Service Commission of Maryland, *Renewable Energy Portfolio Standard Report*, November 2018, psc.state.md.us/wp-content/uploads/FINAL-Renewable-Energy-Portfolio-Standard-Report-with-data-for-CY-2017.pdf.

rates for two 12-month periods: one ending June 30, 2018 and the other ending December 31, 2018. To estimate rates going forward, this analysis uses information from AEO 2019, which includes projected end-use prices for customers in the ReliabilityFirst Corporation (RFC) East region. RFC-East includes most of PJM, including Maryland. Although not perfectly representative of Maryland-specific rates, these numbers do capture price trends and are representative of how Maryland rates are expected to change over time. The 2018 average retail rate based on EEI data was adjusted on an annual basis using the projected power price growth rate for all sectors from AEO 2019.

Table 3-51. Estimated Retail Electricity Prices, All Sectors Average (Nominal $/MWh)

Year	All Sectors Avg.
2019	$125.14
2020	119.02
2021	125.71
2022	128.82
2023	132.88
2024	142.37
2025	148.05
2026	153.24
2027	157.69
2028	162.25
2029	166.29
2030	170.40

Note: Developed using data from the EEI *Typical Bills and Average Rates* report and the EIA *Annual Energy Outlook 2019* report.

Table 3-52 provides a summary of estimated future RPS costs from Tier 1 non-carve-out RECs, SRECs, and ORECs in comparison to total power costs, assuming the 25% RPS remained in effect. Table 3-53 provides the equivalent information assuming the 50% RPS. Note that other estimated cost impacts of the Maryland RPS, such as wholesale market energy and capacity price changes or integration costs, are not reviewed in this chapter. However, these impacts are generally estimated to be small (see Subsection 2.4.2, "NREL and LBNL Research").[285] As a result, the "Estimated Total Cost of Electricity" column is held constant in Table 3-52 and Table 3-53.

[285] Additionally, because Maryland is a relatively small member of PJM, the renewable generation catalyzed by the Maryland RPS has a reduced impact on wholesale energy prices in PJM. For example, modeling conducted for the 2016 LTER (see Subsection 3.3.1, "Renewable Capacity Addition Assumptions in the 2016 LTER") concluded that energy prices were almost identical under a 25% RPS, a 35% RPS, or a 50% RPS in Maryland. For the same reason, RPS requirements in Maryland caused only minor fluctuations in capacity prices in PJM. Levitan & Associates identified a small combined energy and capacity price effect of less than $2.00/MWh (levelized 2012$).

Table 3-52. Maryland RPS Estimated Cost – Tier 1, 25% RPS (Nominal $Millions)

Year	Estimated Total Cost of Electricity[1]	RPS Share of Total Costs	NON-CARVE-OUT		SOLAR CARVE-OUT		OFFSHORE WIND CARVE-OUT	
			Est. Cost[2]	Share of Total Cost	Est. Cost[3]	Share of Total Cost	Est. Cost[4]	Share of Total Cost
2019	$7,437.4	1.0%	$63.9	0.9%	$12.2	0.2%	-	-
2020	7,018.3	1.4	79.6	1.1	17.0	0.2	-	-
2021	7,326.7	2.7	78.1	1.1	18.2	0.2	$98.4	1.3%
2022	7,422.6	2.7	78.8	1.1	18.4	0.2	101.4	1.4
2023	7,586.6	3.4	76.7	1.0	18.6	0.2	161.1	2.1
2024	8,065.4	3.2	77.7	1.0	18.9	0.2	162.1	2.0
2025	8,293.2	3.1	78.4	0.9	19.1	0.2	162.9	2.0
2026	8,504.5	3.1	79.3	0.9	19.3	0.2	163.5	1.9
2027	8,671.9	3.0	80.3	0.9	19.6	0.2	160.4	1.8
2028	8,837.0	3.0	81.2	0.9	19.8	0.2	159.9	1.8
2029	8,970.3	2.9	82.2	0.9	20.1	0.2	156.5	1.7
2030	9,103.7	2.8	83.2	0.9	20.3	0.2	155.5	1.7

[1] Calculated by multiplying all sectors average rate [*Table 3-51*] by energy sales forecast [*Table 3-44]*.

[2] Calculated by multiplying Tier 1 RPS obligation [*Table 3-45*] by energy sales forecast [*Table 3-44*] and then by estimated REC cost [*Table 3-48*].

[3] Calculated by multiplying Solar RPS obligation [Table *3-45*] by energy sales forecast [*Table 3-44*] and then by estimated SREC cost [*Table 3-48*].

[4] Calculated by multiplying the estimated Offshore Wind output of currently approved projects [*Table 3-45*] by the Maryland PSC established rate [*Table 3-48*].

Table 3-53. Maryland RPS Estimated Cost – Tier 1, 50% RPS (Nominal $Millions)

Year	Estimated Total Cost of Electricity[1]	RPS Share of Total Costs	NON-CARVE-OUT Est. Cost[2]	NON-CARVE-OUT Share of Total Cost	SOLAR CARVE-OUT Est. Cost[3]	SOLAR CARVE-OUT Share of Total Cost	OFFSHORE WIND CARVE-OUT Est. Cost[4]	OFFSHORE WIND CARVE-OUT Share of Total Cost
2019	$7,437.4	3.0%	$54.2	0.7%	$170.0	2.3%	-	-
2020	7,018.3	3.9	80.5	1.1	194.2	2.8	-	-
2021	7,326.7	5.6	81.9	1.1	227.8	3.1	$98.4	1.3%
2022	7,422.6	5.0	92.7	1.2	173.3	2.3	101.4	1.4
2023	7,586.6	6.0	96.2	1.3	195.5	2.6	161.1	2.1
2024	8,065.4	6.0	103.1	1.3	218.5	2.7	162.1	2.0
2025	8,293.2	5.8	109.8	1.3	210.8	2.5	162.9	2.0
2026	8,504.5	6.6	105.9	1.2	194.1	2.3	258.1	3.0
2027	8,671.9	6.3	115.8	1.3	172.7	2.0	255.0	2.9
2028	8,837.0	7.3	109.4	1.2	183.3	2.1	350.0	4.0
2029	8,970.3	7.0	119.1	1.3	163.2	1.8	348.2	3.9
2030	9,103.7	7.6	109.6	1.2	160.4	1.8	421.6	4.6

[1] Calculated by multiplying all sectors average rate [*Table 3-51*] by energy sales forecast [*Table 3-44*].

[2] Calculated by multiplying the electric cooperative and non-electric cooperative Tier 1 RPS obligations [*Table 3-46*] by the electric cooperative and non-electric cooperative energy sales forecasts [*Table 3-44*], respectively, adding them together, and then multiplying by estimated REC cost [*Table 3-49*].

[3] Calculated by multiplying the electric cooperative and non-electric cooperative Solar RPS obligations [*Table 3-46*] by the electric cooperative and non-electric cooperative energy sales forecasts [*Table 3-44*], respectively, adding them together, and then multiplying by estimated SREC cost [*Table 3-49*] or solar ACP [*Table 3-50*].

[4] Calculated by multiplying the estimated offshore wind output of currently approved and prospective projects [*Table 3-46*] by the estimated weighted average rate [*Table 3-49*].

For the 25% RPS, as shown in Table 3-52, total RPS costs from the Tier 1 non-carve-out and solar carve-out requirements are expected to increase from 2019 to 2020 as the RPS reaches its peak requirement, and then remain relatively constant thereafter. The minor drop, in 2023, of Tier 1 non-carve-out costs as a share of total costs stems from the offsetting effect of ORECs, which supplant a portion of the Tier 1 non-carve-out REC requirement. At the Maryland PSC-approved rate, ORECs will immediately become the largest contributor to RPS compliance costs when the first project enters service. OREC costs decline slightly from 2027-2030 as a result of increasing market revenue (i.e., higher rebates) as well as reaching the previously applicable OREC cap, which limits the allowable OREC expenditure during the affected years.[286]

For the 50% RPS, as shown in Table 3-53, Tier 1 non-carve-out costs increase through 2025, then remain relatively flat thereafter. Solar carve-out costs, meanwhile, peak in 2021 before the solar ACP supplants SREC costs. Offshore wind costs increase incrementally throughout the period as additional projects enter service. Offshore wind becomes the largest contributor to overall costs (surpassing solar) in 2026, when the initial 400 MW of Round 2 projects are expected to commence operations. The total, combined RPS cost is highest in 2030 when all offshore wind capacity additions are in service. All RPS costs are

[286] The degree to which offshore wind production from the US Wind and Skipjack projects exceeds the 2.5% is small, beginning at 8.13 GWh in 2028 and increasing to 34.15 GWh by 2030. Although production beyond the 2.5% OREC limit is allowable, additional offshore generation must settle at Tier 1 non-carve-out market rates.

higher under the 50% RPS as compared to the 25% RPS, but expected costs increase most for solar and offshore wind due to the higher carve-outs.

On a cost-per-kWh basis, Tier 1 non-carve-out RECs and SRECs are estimated to add between 0.128-0.194 cents/kWh to all Maryland electric sales from 2019-2030 under the 25% RPS, and between 0.377-0.572 cents/kWh under the 50% RPS. This cost impact increases by an additional 0.169-0.295/kWh and 0.169-0.789 cents/kWh for the 25% RPS and 50% RPS, respectively, when also including Tier 1 OREC costs. These impact estimates are calculated by dividing the total RPS expenditure for RECs [*Table 3-52* or *Table 3-53*] by total energy sales [*Table 3-44*]. Figure 3-61 graphs the change in estimated REC, SREC, and OREC costs over time for the 25% RPS. Figure 3-62 graphs the equivalent change for the 50% RPS. These average costs are neither distributed evenly among all customers nor proportionate in terms of impact, as discussed below.

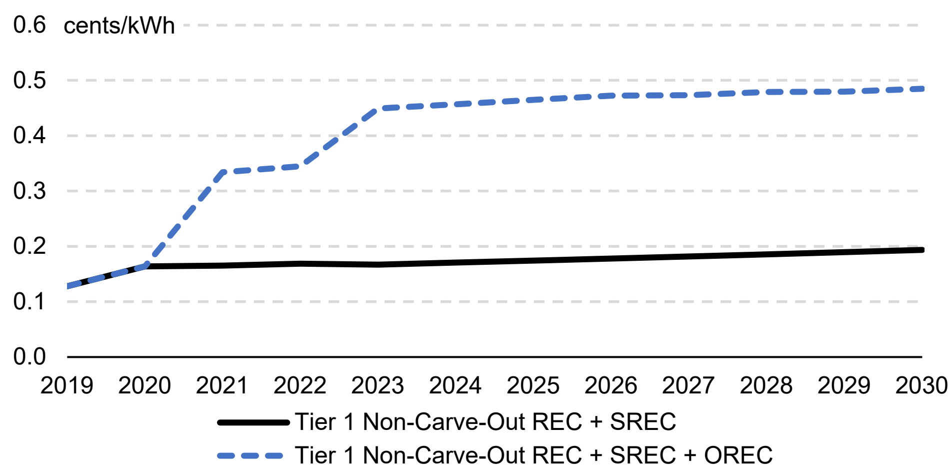

Figure 3-61. Estimated Costs of Tier 1 Non-Carve-out RECs, SRECs, and ORECs, 25% RPS

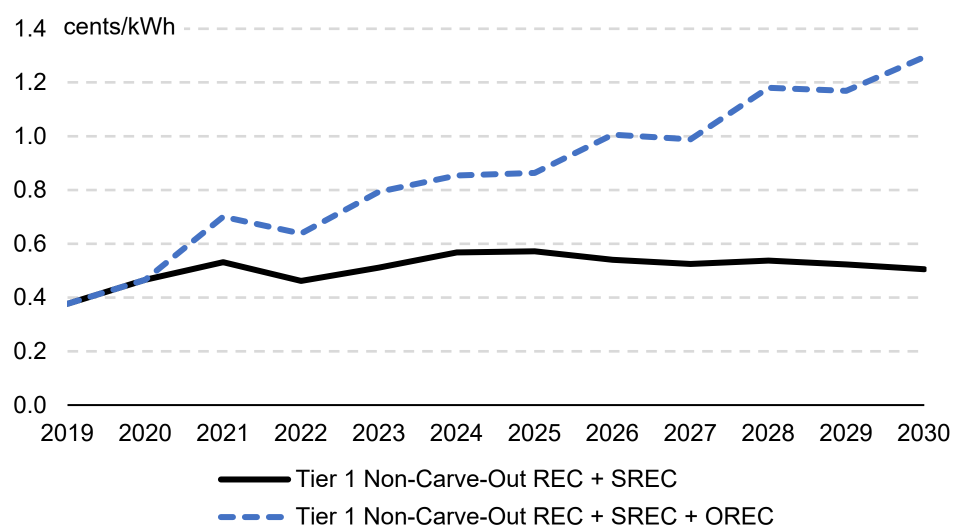

Figure 3-62. Estimated Costs of Tier 1 Non-Carve-out RECs, SRECs, and ORECs, 50% RPS

3.5.6. Estimated Rate Impacts by Customer Class

The Maryland PSC's *Ten-Year Plans* include a breakdown of energy sales and number of customers by customer class for the previous calendar year, as well as forecasted customer counts for future years. This information can be used to identify the approximate share of overall energy sales from each customer class, as well as estimated average consumption per consumer during future years (assuming each class's share of overall sales remains constant). Table 3-54 shows energy sales data in Maryland for 2017.

Table 3-54. Maryland Energy Sales and Customer Count, by Customer Class, 2017

	Residential	Commercial	Industrial
Energy Sales by Customer Class (GWh)	25,665	16,751	15,924
Share of Total	*43%*	*28%*	*27%*
Customer Class Count	2,322,145	246,400	15,291
Average Consumption per Customer, per Month (kWh)	921	5,665	86,783

Source: Maryland PSC 2018-2027 *Ten-Year Plan*, Appendix Tables 1(b)(i) and (b)(ii).

Note: The table excludes "Other" and "Resale" customers. The Industrial class is inclusive of IPL customers, which consumed approximately 25.1 GWh in 2017.

The subsequent figures visualize the average additional cost per customer imposed by the Maryland RPS on a monthly basis. Figure 3-63 through Figure 3-66 show results for the 25% RPS and Figure 3-67 through Figure 3-70 show results for the 50% RPS. Note again that the methodology for estimating cost impacts excludes positive or negative externalities associated with state RPS policies, such as any price suppression impacts of renewable energy or any incremental transmission costs.

Future energy sales are apportioned between customer classes using the same distribution that applied in CY 2017: 42.9% residential sales, 28.0% commercial sales, and 26.6% industrial sales, with the residual applicable to other customer types or resale. Since sales is a primary determinant of RPS compliance costs, the above cost totals [*Table 3-52* or *Table 3-53*] can also be split between customer classes using the same distribution. For example, in 2020, under the 25% RPS, residential customers were responsible for approximately $34,100,000 (i.e., 42.9% * $79,600,000) in Tier 1 non-carve-out costs, and approximately $7,300,000 (i.e., 42.9% * $17,000,000) in Tier 1 solar carve-out costs. The combined Tier 1 non-carve-out and solar carve-out costs ($41,400,000) can be further divided by the forecasted number of residential customers in 2020 (2,372,980) to provide an average annual cost of the RPS per customer, equal in this case to $17.44 (or $1.45 per customer, on average, per month in 2020).

Figure 3-63 tracks residential costs over time for the 25% RPS. In 2019, the Maryland RPS is estimated to add approximately $13.86 per year to residential customer bills in terms of Tier 1 non-carve-out REC and SREC costs. This amount increases to $17.23/yr by 2030, a 24% change. Including ORECs, costs by 2030 increase to $43.12/yr.

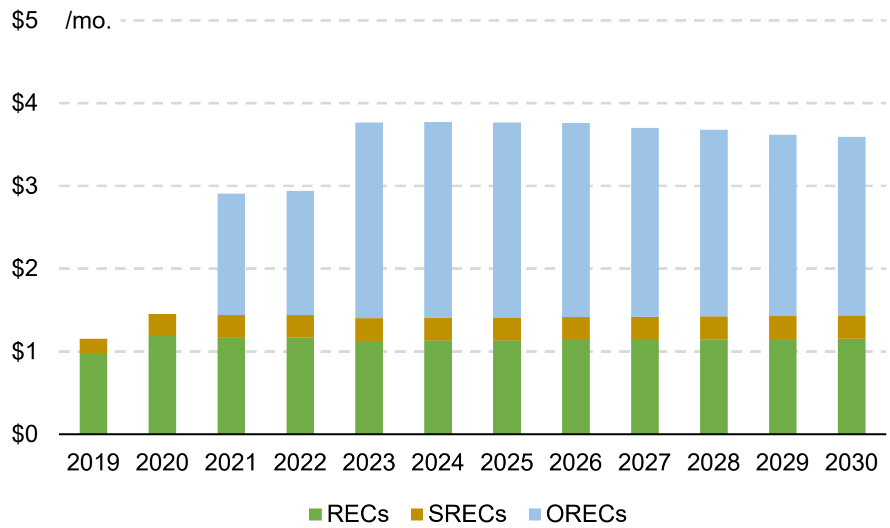

Figure 3-63. Estimated Average Monthly RPS Compliance Costs for Maryland Residential Customers, 25% RPS

Figure 3-64 tracks commercial costs over time for the 25% RPS and follows a similar trend to the residential class. In 2019, the Maryland RPS is estimated to add approximately $86.35 per year to commercial customer bills in terms of Tier 1 non-carve-out REC and SREC costs. This amount increases to $112.85 by 2030, a 31% change. Including ORECs, costs by 2030 increase to $282.43 per year.

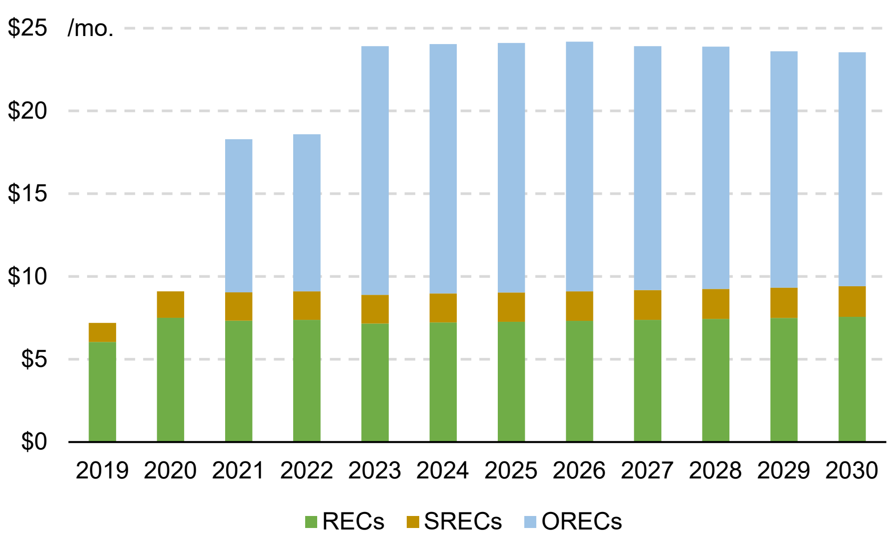

Figure 3-64. Estimated Average Monthly RPS Compliance Costs for Maryland Commercial Customers, 25% RPS

Figure 3-65 and Figure 3-66 track industrial costs over time for the 25% RPS. Two separate figures are necessary in order to distinguish IPL customers, which are eligible for a reduced ACP, from other industrial customers. The discounted ACP, in effect, allows IPL customers to bypass most RPS compliance costs. As a result, the annual RPS cost in 2019 for IPL customers is approximately $415.97 despite significant usage. RPS compliance costs, however, are expected to increase during the forecast period. In accordance with the OREC provisions of the RPS, the Tier 1 non-carve-out REC and SREC portion of costs for IPL customers are halved in 2021 and eliminated in 2022, assuming OREC obligations begin in 2021. Meanwhile, IPL customers face the same OREC obligations as other customers. As a result, the overall cost (inclusive of ORECs) increases by 495% from 2019-2030, reaching $2,473.37 per year, on average, in 2030. Figure 3-65 tracks estimated IPL costs over time.

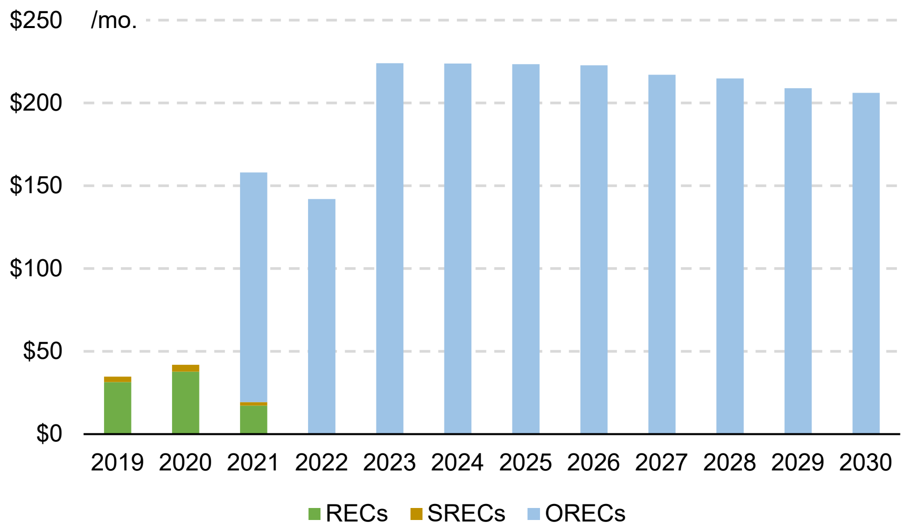

Figure 3-65. Estimated Average Monthly RPS Compliance Costs for Industrial Process Load Customers, 25% RPS

Figure 3-66 shows costs over time for non-IPL industrial customers and follows trends that are consistent with the other classes under the 25% RPS. In 2019, the Maryland RPS is estimated to add approximately $1,304.45 per year to industrial customer bills in terms of Tier 1 non-carve-out REC and SREC costs. This amount increases to $1,645.93 by 2030, a 26% change. Including ORECs, costs by 2030 increase to $4,119.30 per year.

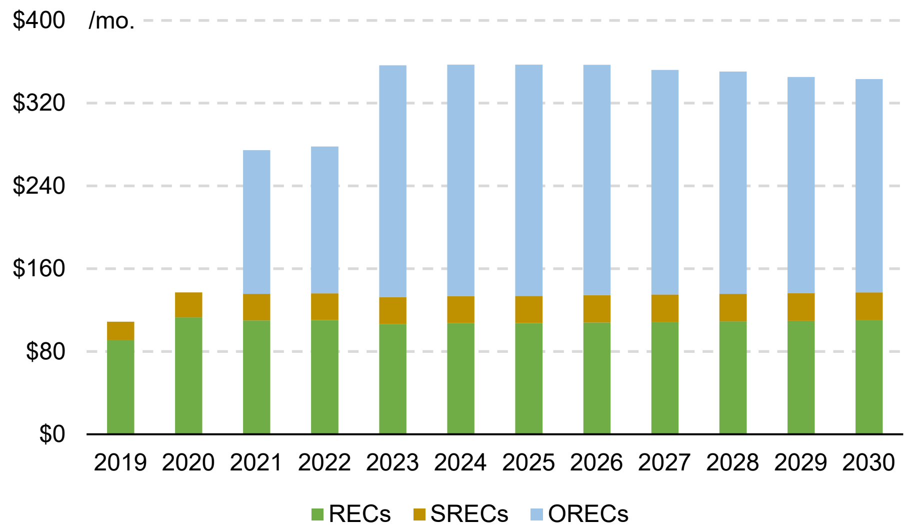

Figure 3-66. Estimated Average Monthly RPS Compliance Costs for Non-Industrial Process Load Industrial Customers, 25% RPS

The most notable way in which the above estimates change for the 50% RPS is that the costs of the solar and offshore wind carve-out increase. Figure 3-67 tracks residential costs over time under the 50% RPS and plots them alongside the 25% RPS results for comparison purposes. In 2019, the Maryland RPS is estimated to add approximately $40.85 per year to residential customer bills in terms of Tier 1 non-carve-out REC and SREC costs. This amount increases to $44.93/yr by 2030, a 10% change. Including ORECs, costs by 2030 increase to $115.11/yr.

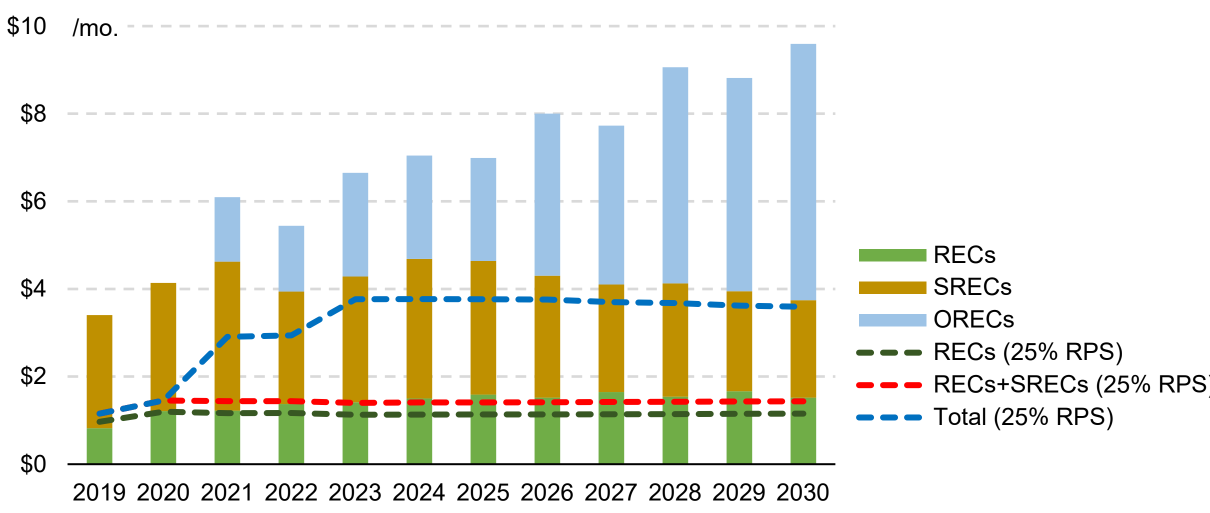

Figure 3-67. Estimated Average Monthly RPS Compliance Costs for Maryland Residential Customers, 50% RPS

Figure 3-68 tracks commercial costs over time for the 50% RPS. In 2019, the Maryland RPS is estimated to add approximately $254.56 per year to commercial customer bills in terms of Tier 1 non-carve-out REC and SREC costs. This amount increases to $294.34 by 2030, a 16% change. Including ORECs, costs by 2030 increase to $754.02 per year.

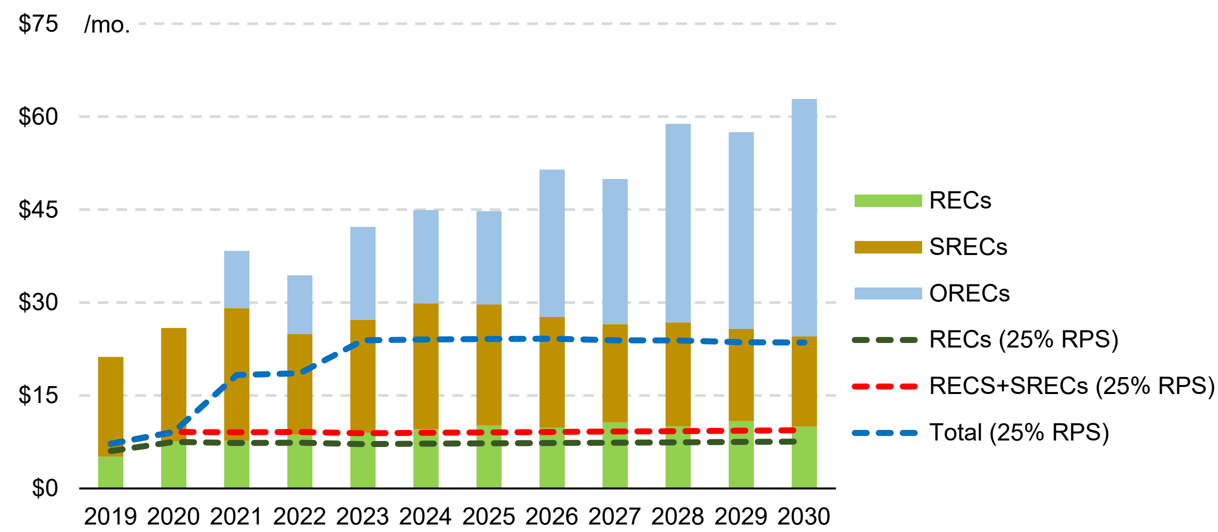

Figure 3-68. Estimated Average Monthly RPS Compliance Costs for Maryland Commercial Customers, 50% RPS

Figure 3-69 and Figure 3-70 track industrial costs over time for the 50% RPS. The annual RPS cost in 2019 for IPL customers is approximately $422.09. RPS compliance costs thereafter increase according to the same conditions affecting IPL customers under the 25% RPS. As a result, IPL costs increase by 1,488% from 2019-2030, reaching $6,704.57 per year, on average, in 2030. Figure 3-69 tracks estimated IPL costs over time.

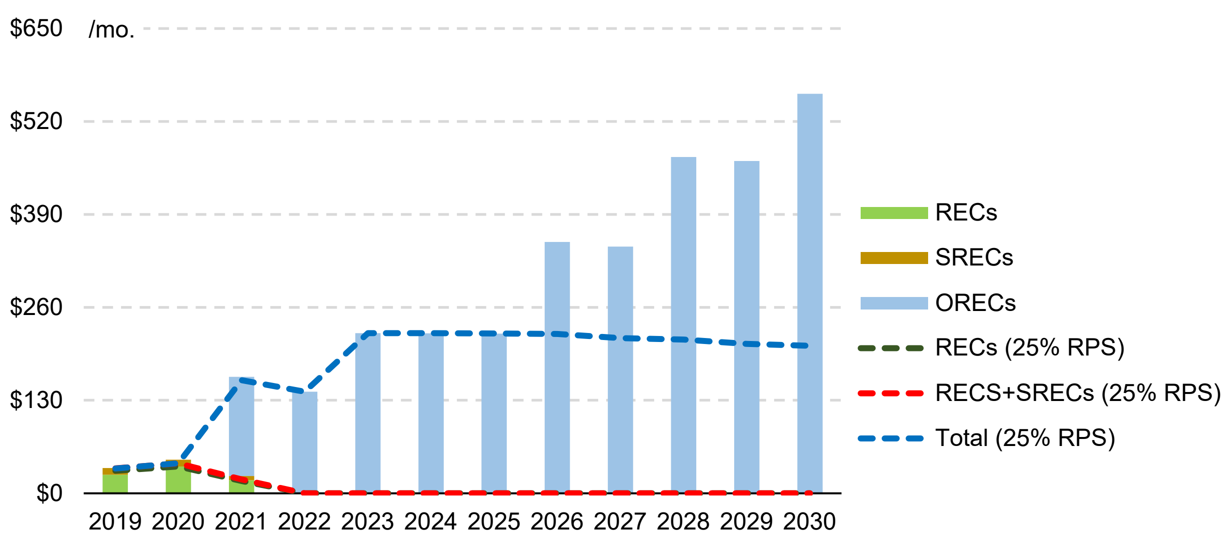

Figure 3-69. Estimated Average Monthly RPS Compliance Costs for Industrial Process Load Customers, 50% RPS

Figure 3-70 shows costs over time for non-IPL industrial customers under the 50% RPS. In 2019, the Maryland RPS is estimated to add approximately $3,845.66 per year to industrial customer bills in terms of Tier 1 non-carve-out REC and SREC costs. This amount increases to $4,293.12 by 2030, a 12% change. Including ORECs, costs by 2030 increase to $10,997.69 per year.

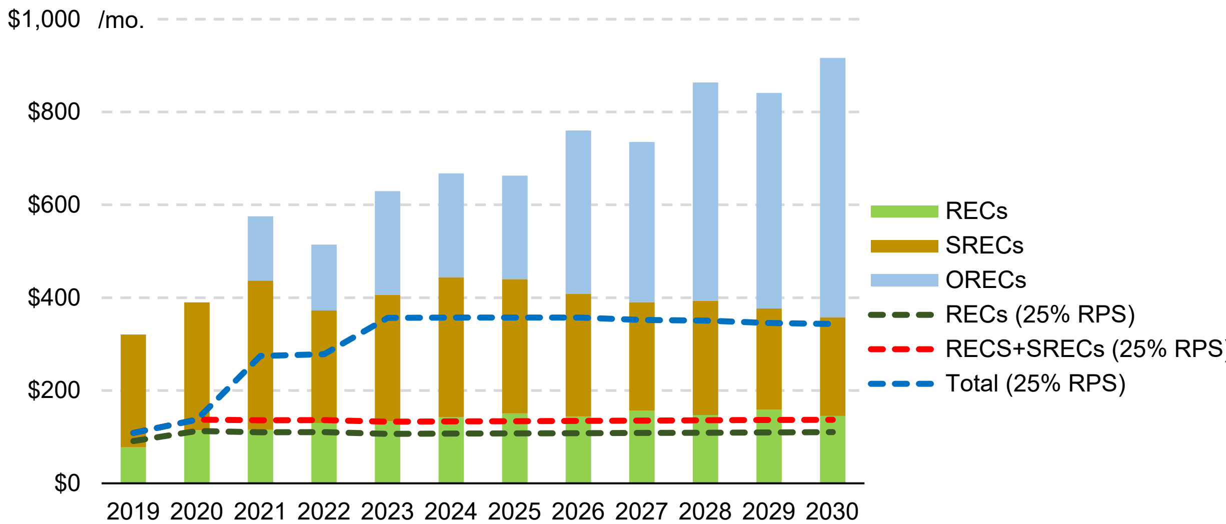

Figure 3-70. Estimated Average Monthly RPS Compliance Costs for Non-Industrial Process Load Industrial Customers, 50% RPS

3.5.7. Alternative Scenarios

The above ratepayer impact assessment is sensitive to the assumptions used, meaning changes in any underlying assumption will alter the findings. To highlight this sensitivity, an additional scenario was created to illustrate the potential impact of reduced REC, SREC, and OREC costs. This "Low-Price" scenario adopts the 50% RPS assumptions with the following adjustments:

1. REC and SREC price estimates from 2019-2022 will remain equal to Marex Spectrometer futures as of July 2019.
2. SREC prices will fall by 32% from 2023-2025. Thereafter, prices will increase each year based on the consensus CPI estimates sourced from *Blue Chip* as of March 2019.
3. REC prices will remain constant at 2022 levels from 2023-2030.
4. Round 1 OREC prices will equal approximately the midway point between the Maryland PSC approved nominal schedule (less estimated market revenues) and the estimated OREC cost for the Ørsted Rhode Island project approved in 2019 ($60/MWh).
5. All Round 2 OREC prices will equal the estimated OREC cost for the Avangrid and CIP Massachusetts projects approved in 2019 ($46.23/MWh).

These changes continue to assume that futures are the best available estimate of near-term REC and SREC costs. The decline in SREC prices from 2023-2025 reflects a continuation of the year-over-year decline in SREC costs estimated by futures markets from 2021-2022. This decrease in costs ends when SREC prices reach $11.89/MWh, which is comparable to estimated SREC costs under the 25% RPS. The assumption that REC prices remain flat at 2022 levels is consistent with recent Tier 1 non-carve-out REC price history, with RECs generally ranging from $6-$7/MWh as of fall 2019 when this analysis was performed. Lowering the OREC price for Round 1 projects reflects the possibility that some portion of the ongoing declines in OREC costs reflected in other recently approved projects will be passed on to Maryland consumers. In particular, developers are required to deduct 80% of the value of cost savings from credits, grants, and other similar incentives. It also reflects potential cost savings in the form of increased energy and capacity rebates if Round 1 offshore wind projects utilize newer and more advanced turbines and therefore produce more energy at a higher capacity factor.[287] Lowering the OREC price for Round 2 projects reflects revised assumptions about the pace of cost declines for Maryland offshore wind projects. Table 3-55 shows the revised estimated REC, SREC, and OREC costs based on the above assumptions. Table 3-56 identifies the estimated cost of this scenario, including RPS costs as a share of total retail costs.

Table 3-55. Estimated Maryland RPS Tier 1 REC, SREC, and OREC Costs, 50% RPS, Low-Price Scenario ($/MWh)

Year	Non-Carve-out RECs[1],[2]	SRECs[1],[3]	ORECs[4]
2019	$6.00	$52.00	
2020	6.13	57.50	
2021	6.35	55.00	$83.81
2022	6.85	37.50	85.43
2023	6.85	25.57	88.81
2024	6.85	17.43	89.15
2025	6.85	11.89	89.45
2026	6.85	12.15	66.42
2027	6.85	12.41	65.90
2028	6.85	12.69	59.09
2029	6.85	12.97	58.88
2030	6.85	13.25	55.65

[1] 2019-2022 REC and SREC prices derived from Marex Spectrometer futures as of July 2019.

[2] 2023-2030 REC prices held constant at 2022 levels.

[3] 2023-2025 SREC prices fall by 31.8% from the preceding year. 2026-2030 SREC prices increase by 2.2% from the preceding year based on consensus estimates of change in the CPI sourced from *Blue Chip* as of March 2019.

[4] Equal to the midpoint of Round 1 project costs and the Ørsted Rhode Island OREC price and, beginning in 2026, the weighted average of Round 1 projects and Round 2 projects. All Round 2 ORECs set equal to the Avangrid and CIP Massachusetts OREC price. Refer to *Table 3-48* and *Table 3-49* for original Round 1 and Round 2 OREC price assumptions, respectively.

[287] For the Round 2 projects, it is assumed that a higher capacity factor would have no net impact on OREC prices since potential production would be accounted for by the Maryland PSC when it is setting an OREC price.

Table 3-56. Maryland RPS Estimated Cost – Tier 1, 50% RPS, Low-Price Scenario (Nominal $Millions)

Year	Estimated Total Cost of Energy[1]	RPS Share of Total Costs	NON-CARVE-OUT		SOLAR CARVE-OUT		OFFSHORE WIND CARVE-OUT	
			Est. Cost[2]	Share of Total Cost	Est. Cost[3]	Share of Total Cost	Est. Cost[4]	Share of Total Cost
2019	$7,437.4	3.0%	$54.2	0.7%	$170.0	2.3%		
2020	7,018.3	3.9	80.5	1.1	194.2	2.8		
2021	7,326.7	5.3	81.9	1.1	227.8	3.1	$76.7	1.0%
2022	7,422.6	4.6	92.7	1.2	173.3	2.3	78.1	1.1
2023	7,586.6	4.6	94.1	1.2	130.4	1.7	121.7	1.6
2024	8,065.4	3.9	98.7	1.2	97.2	1.2	122.1	1.5
2025	8,293.2	3.6	102.9	1.2	71.6	0.9	122.5	1.5
2026	8,504.5	4.4	97.1	1.1	78.6	0.9	195.7	2.3
2027	8,671.9	4.4	103.9	1.2	85.7	1.0	194.2	2.2
2028	8,837.0	5.2	96.0	1.1	93.0	1.1	267.3	3.0
2029	8,970.3	5.2	102.2	1.1	94.0	1.0	266.3	3.0
2030	9,103.7	5.8	92.1	1.0	95.1	1.0	339.5	3.7

[1] Calculated by multiplying all sectors average rate [*Table 3-51*] by energy sales forecast [*Table 3-44*].

[2] Calculated by multiplying the electric cooperative and non-electric cooperative Tier 1 RPS obligations [*Table 3-46*] by the electric cooperative and non-electric cooperative energy sales forecasts [*Table 3-44*], respectively, adding them together, and then multiplying by estimated REC cost [*Table 3-55*].

[3] Calculated by multiplying the electric cooperative and non-electric cooperative Solar RPS obligations [*Table 3-46*] by the electric cooperative and non-electric cooperative energy sales forecasts [*Table 3-44*], respectively, adding them together, and then multiplying by estimated SREC cost [*Table 3-55*].

[4] Calculated by multiplying the estimated offshore wind output of currently approved and prospective projects [*Table 3-46*] by the estimated weighted average rate [*Table 3-55*].

For the Low-Price scenario, Tier 1 non-carve-out costs do not substantially change from the above 50% RPS estimates. Solar carve-out costs still peak in 2021, before falling through 2025 and only growing moderately thereafter. Tier 1 non-carve-out costs and solar carve-out costs are similar from 2026-2030. No ACPs are required in the Low-Price scenario. OREC costs still increase incrementally throughout the period as additional projects enter service. However, offshore wind now becomes the largest contributor to overall costs (surpassing solar) in 2024, before any Round 2 projects are expected to commence operations. Average costs from the Maryland RPS are estimated to equal approximately $41, $255, $422, and $3,846 per year, respectively, for residential, commercial, IPL, and industrial customers in 2019 under the Low-Price scenario. These costs are projected to increase, respectively, to approximately $88, $574, $5,399, and $8,375 per year by 2030.

4. Assessment of Potential Changes to the Maryland RPS

There are many different ways to configure an RPS, as reflected by the diversity of existing state RPS policies. They illustrate the array of potential options for how Maryland might alter its RPS policies. Ch. 393 calls for a general evaluation of potential changes to the Maryland RPS in order to ensure, or increase, its effectiveness in the future. It also calls for evaluation of specific adjustments, including the effect of removing certain resources from RPS eligibility and the effect of long-term contracts. In many cases, potential changes to the RPS introduce trade-offs in terms of possible outcomes. Ultimately, Maryland policymakers will need to prioritize what they want the Maryland RPS to accomplish and adjust the RPS to best meet those priorities.

This chapter of the final report provides a high-level overview of 11 options for changing the Maryland RPS, followed by a discussion of each option. The analysis technique adopted for this assessment is a variant of the strategic planning technique known as a SWOT analysis. Traditionally, SWOT analysis is used to identify internal and external factors that are important to selling a product or achieving a social objective. The term SWOT is an acronym for the four parameters that are typically considered:

- **S**trengths – the characteristics of a policy that give it an advantage over other options;
- **W**eaknesses – the characteristics that put a policy at a disadvantage relative to other options;
- **O**pportunities – external factors that could make a policy more successful or that could be exploited; and
- **T**hreats – external factors that could make a policy less successful.

Brevity and simplicity are two of the primary reasons that SWOTs are used. They provide an intuitive, table-format summary of the pros and cons of a given course of action. This high-level summary facilitates comparisons among options and provides a basis for further research and discussion. The subsequent analysis has modified the traditional SWOT format by preparing strengths and weaknesses lists for specific policy options and alternatives and a separate, overarching discussion of opportunities and threats. The separate opportunities and threats discussion reflects that the same external factors are likely to influence the success of any action taken by Maryland to promote renewable energy. Additionally, these external factors are presented together since several specific factors could potentially enhance or detract from the success of the Maryland RPS.

After the opportunities and threats section, the strengths and weaknesses of the following options are addressed:

- Maintaining the 50% Tier 1 requirement;
- Adopting a 100% RPS or clean energy standard (CES);
- Maintaining the 14.5% Tier 1 solar carve-out;
- Removing black liquor;
- Providing state support for energy storage;
- Moving hydro from Tier 2 to Tier 1;

- Requiring long-term contracts;
- Creating a Clean Peak Standard;
- Lowering the ACP level;
- Limiting geographic eligibility to within PJM; and
- Instituting ZECs or procurement support for nuclear power.

Note that some of the possible changes to the Maryland RPS, such as the implementation of ZECs, are addressed in greater depth elsewhere in the final report. Additionally, this chapter includes a separate, broader discussion of two potential adjustments: (1) the compliance impacts of removing certain Tier 1-eligible resources; and (2) the costs, benefits, and legal implications of allowing Tier 1 non-carve-out RECs to be sourced from anywhere in the contiguous United States.

4.1. External Opportunities and Threats of Relevance to the Maryland RPS

Several external factors, over which Maryland has limited control, will likely influence the impact of the Maryland RPS. This section summarizes these factors, and their potential impact on five objectives that are relevant to the Maryland RPS:

1. Promoting renewable energy development while keeping electricity affordable for all ratepayers;
2. Lowering the cost of renewable energy generation;
3. Promoting in-state economic development (jobs, spending);
4. Realizing environmental benefits (GHG reductions, public health); and
5. Promoting fuel diversity.

External Factors

- *Technology Innovation* – The costs of certain renewable energy technologies, such as onshore wind and solar PV, have declined markedly in recent years. Going forward, costs may continue to decline, lowering the cost of RPS compliance. Continued improvements in the performance of renewable energy technologies, such as higher capacity factors, would further reduce the costs of RPS compliance. Additionally, the costs of complementary technologies like energy storage are also declining rapidly and combined solar/storage projects are becoming more common. Declining technology costs or increased resource output could both speed up the adoption of renewable energy and reduce costs for consumers.
- *Natural Gas Prices* – Natural gas prices have been at historically low levels over the last few years. In response, reliance on natural gas for electricity generation has risen in Maryland, PJM, and nationwide. Between 2013-2017, for example, the percentage of generation in Maryland from natural gas sources rose 11.7%. This trend will likely continue due to the addition of three natural gas plants in the state in 2018 totaling 2,074 MW of installed capacity.[288] While the RPS can

[288] U.S. Energy Information Administration, "Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860)," December 2018, eia.gov/electricity/data/eia860m/.

help to hedge against rising natural gas costs, it may not produce cost savings if natural gas prices continue to fall.

- *Electricity Demand* – Growth in electricity demand has been very low or near zero, limiting or effectively eliminating the increase in renewable energy capacity that may be required under the Maryland RPS just via growth in demand. PJM forecasts that growth in electricity demand will remain low.[289,290] Should demand for electricity increase unexpectedly, more renewable energy will be needed to meet the Maryland RPS. Unanticipated demand for renewable energy, however, can also increase RPS compliance costs in the short run.

- *Customer Demand for Renewables* – Some customers will voluntarily purchase renewable energy generation or credits to meet internal environmental or other public benefit goals. From 2015-2018, voluntary renewable energy sales certified by Green-e Energy have increased by 13% per year on average.[291] Depending on the supply and demand balance of RECs, increased voluntary demand for renewable energy can drive up REC prices and, therefore, RPS compliance costs. It can also, however, promote the various environment and economic objectives supported by renewable energy.

- *RPS Requirements in Neighboring States* – Because REC markets operate across state lines, policy changes in other states can impact RPS compliance costs in Maryland. In just the last five years (2013-2018), five states in PJM (and the District of Columbia) have enacted changes to their RPS laws (excluding Maryland). New Jersey, Michigan, and D.C. increased their RPS requirements. Illinois created requirements for new solar and wind, and Pennsylvania adjusted its solar carve-out to limit eligibility to in-state solar. Ohio reinstated its CES, after prior legislation made it voluntary for two years, but later capped it at 8.5% by 2026. Again, depending on the supply and demand balance of RECs, changes that increase demand for RECs could tighten the market and increase REC prices. Increased renewable generation in other states, however, can have spillover benefits in Maryland, such as reduced cross-state air pollution.

- *Import Tariffs* – In response to China's subsidization of its PV panel producers, the U.S. enacted a four-year tariff on imported crystalline silicon solar panels in January 2018. Solar panel prices rose in anticipation of the tariff, only to fall to pre-tariff levels when China later slashed its subsidies for solar, creating a global oversupply of solar panels. During this period of cost uncertainty, many U.S. companies hesitated to invest in solar. Wood Mackenzie Power & Renewables, a market research firm, reduced its national forecast for 2018-2022 solar installations by 8% compared to its earlier forecasts in the aftermath of the tariffs.[292] Additionally, steel and aluminum tariffs are projected to increase the LCOE from renewable energy by 3-5%.[293] Despite these headwinds, the amount

[289] PJM Resource Adequacy Planning Department, *PJM Load Forecast Report – January 2019*, pjm.com/-/media/library/reports-notices/load-forecast/2019-load-report.ashx?la=en.

[290] Note that programs to promote EV adoption may increase electricity demand beyond what PJM has forecast.

[291] Center for Resource Solutions, *2018 Green-e Verification Report*, resource-solutions.org/g2018/.

[292] Jim Puzzanghera and Don Lee, "The roiled solar power market shows how Trump's tariffs can disrupt an industry," *Los Angeles Times*, July 2018, latimes.com/business/la-fi-solar-tariffs-20180707-story.html#.

[293] Julia Pyper, "Trump's Steel, Aluminum Tariffs Create 'Another Headache' for Renewables," *Greentech Media*, March 2018, greentechmedia.com/articles/read/steel-aluminum-tariffs-renewables-elon-musk#gs.89S9_3o.

of installed solar capacity grew 6% in 2018 as compared to 2017.[294] Continued imposition of tariffs could affect the costs of renewable energy technologies and, therefore, affect the development of renewable energy and RPS compliance costs.

- *Federal Tax Credits* – Two federal incentives for renewable energy will soon expire: the federal PTC in 2019, although projects meeting Internal Revenue Service (IRS) criteria for beginning construction have several years to be completed; and the federal ITC, which is being phased down/out. The ITC provides a 30% federal tax credit for residential and commercial solar investments. After 2021, the commercial ITC will drop to 10% and the residential credit will end; although, again, projects meeting IRS criteria for commencing construction have until the end of 2023 to be placed into service. When the ITC was extended in 2015, SEIA predicted the move would cause an extra 22 GW of new solar capacity by 2022.[295] Likewise, the American Wind Energy Association (AWEA) credits the PTC with helping wind capacity more than quadruple since 2008.[296] The loss of these federal tax credits could increase the cost of wind, solar, and other ITC-eligible projects used to fulfill the Maryland RPS. Extension of either policy could support continued renewable energy growth.

- *Transmission Capacity in Maryland and PJM* – The hosting capacity of the transmission and distribution system within Maryland and/or the rest of PJM may limit the additions of distributed and utility-scale renewable energy projects, barring investment in new transmission and distribution capacity.

- *Federal Carbon Regulation* – In 2009, the EPA determined that emissions of CO_2 and other long-lived GHGs that build up in the atmosphere endanger the health and welfare of current and future generations by causing climate change and ocean acidification. The endangerment finding requires the EPA to regulate CO_2 emissions. It is possible that the federal government will stringently regulate CO_2 emissions in the future, either by statute or by regulation.

- *Siting Challenges* – Developing generating plants can be challenging as developers must obtain state and local approval to site a project before commencing construction. This process can be costly and time-intensive. Furthermore, while public involvement is both valued and required in the siting process, growing public interest has increased the complexity of siting generation. For example, some stakeholders have expressed concern over the potential loss of farmland from proposed utility-scale solar projects. Siting challenges can add costs or delay potential projects.

- *Changes in PJM's Capacity Market* – In June 2018, the FERC found that PJM's capacity market, known as the Reliability Pricing Model (RPM), was not just and reasonable because it did not adequately account for out-of-market payments to certain preferred generation technologies. FERC instituted a paper hearing for stakeholders to propose alternatives, but ultimately determined that PJM should implement its Minimum Offer Price Rule (MOPR). PJM's MOPR required all LSEs that received a state subsidy to bid into the capacity market at a price that did not include any revenue earned from policy arrangements. Imposing the MOPR

[294] Bloomberg New Energy Finance and the Business Council for Sustainable Energy, "2019 Sustainable Energy in America," February 2019, bcse.org/factbook/.

[295] Solar Energy Industries Association, "Solar ITC Impact Analysis: How an Extension of the Investment Tax Credit Would Affect the Solar Industry," 2015, seia.org/sites/default/files/ITC%20Impact%20Analysis%20Factsheet_Sep2015.pdf.

[296] American Wind Energy Association, "Tax Policy," awea.org/production-tax-credit.

will likely raise the capacity price that affected LSEs can offer, and therefore make these LSEs less competitive in PJM's annual RPM auction.

- Recognizing that customers may pay twice for capacity—once through state programs such as the RPS and once through the PJM RPM—FERC proposed a Fixed Resource Requirement (FRR) Alternative that would permit generation that receives out-of-market payments to opt out of the PJM RPM with a matching amount of load.[297] FERC, however, largely left the details of how this process would work to be filled in by PJM and stakeholders. In October 2018, PJM filed two proposals to FERC, both of which would remove state-subsidized resources, and an accompanying amount of load, from RPM auctions. One proposal would implement a price floor for the remaining capacity in the RPM, while the second includes a higher price for capacity resources to balance out what PJM says are the price-suppressive impacts of removing state-subsidized resources. This price-suppressive impact stems from the fact that less capacity will be needed to meet a lower amount of projected load.[298]
- What FERC will accept for a revised PJM RPM is unclear at this time. It is possible, though, that resources that participate as compliance options for state RPS policies may be considered in receipt of out-of-market payments, and be subject to the MOPR, which could make these resources uncompetitive for the PJM RPM. However, these resources could qualify for FERC's FRR Alternative or a different proposal that FERC designs or accepts from petitioners. Since the details are unknown, it is difficult to project the level of prices that a state-subsidized resource might receive. Not receiving revenues from the PJM RPM or receiving less revenues could mean higher RPS compliance costs if RPS-eligible generators are participating in the PJM RPM.

4.2. Maintaining the 50% Tier 1 Requirement

Over the past few years, several states and the District of Columbia have opted to increase their RPS requirement to 50% renewable energy or higher, as documented in Subsection 2.1.1, "Overview of RPS Policies and Renewable Energy Development." In PJM, this includes both D.C. and New Jersey, which have RPS requirements of 100% and 50%, respectively. In 2017, the Maryland General Assembly increased the RPS from 20% by 2022 to 25% by 2020. In 2019, the General Assembly passed SB 516, which raised the Maryland RPS requirement to 50% by 2030. This SWOT evaluates the expected future impact of the 50% RPS as compared to lower RPS levels.

Statistics in this SWOT are based on the results of the Very High Maryland RPS Scenario in PPRP's most recent LTER (2016), which evaluated a 50% RPS scenario. These statistics can be compared to the LTER Reference Case, which reflects Maryland and federal law as of December 2016, to isolate the potential impacts of a 50% RPS.

The LTER's Very High Maryland RPS Scenario has the following assumptions:

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[297] Federal Energy Regulatory Commission, *Order Rejecting Proposed Tariff Revisions, Granting in Part and Denying in Part Complaint, and Instituting Proceeding Under Section 206 of the Federal Power Act*, 163 FERC ¶ 61,236, June 2018, ferc.gov/CalendarFiles/20180629212349-EL16-49-000.pdf.

[298] Federal Energy Regulatory Commission, Docket Nos. EL16-49-000, ER18-1314-000 and -001, and EL18-178-000, *Initial Submission of PJM Interconnection L.L.C.*, October 2018, pjm.com/-/media/documents/ferc/filings/2018/20181002-capacity-reform-filing-w0172181x8DF47.ashx.

- 50% RPS by 2035, including a 5% solar carve-out, and no changes to RPS policies in other states (e.g., New Jersey increasing its RPS to 50% in 2018 was not modeled.)
- RPS is fulfilled with actual generation, not ACPs.
- New wind capacity is used to fulfill all new (non-solar) RPS requirements; this new capacity is built in a PJM zone that contains Maryland (PJM-SW, PJM-Mid-E, or PJM-APS).
- Load growth in Maryland follows the trends forecasted in the Maryland PSC's 2015-2023 *Ten-Year Plan*, released in 2014, and thereafter is assumed to have a 0.7% CAGR from 2023-2035.
- Load growth in the remaining PJM states is based on applying regional growth rates from the AEO 2015 (Reference Case forecast) to the most recent and available state-level retail sales data.[299]

Although the requirements of the 50% RPS scenario in the LTER are different than what was ultimately adopted in CEJA, the results of the LTER provide some indication of the effect of a 50% RPS. This analysis briefly summarizes the strengths and weaknesses of increasing the Maryland RPS to 50%. Important considerations include: cost, environmental impact, economic impact, and land use.

Strengths

- *Expands renewable energy capacity* – A higher RPS helps increase renewable energy capacity while reducing fossil fuel capacity. For example, the LTER Very High Maryland RPS Scenario modeling resulted in: 1,100 MW of additional in-state solar PV; 6,700 MW of additional wind in PJM; and 1 GW less natural gas capacity added in PJM's Mid-E region, which encompasses parts of Delaware, Maryland, and New Jersey, all by 2035. Additionally, more renewable energy resources in PJM and Maryland can reduce both in-state and cross-state emissions.
- *Diversifies Maryland's power portfolio* – A higher RPS supports both existing and new renewable energy generation from a variety of sources. This generation displaces power production from traditional, fossil fuel sources and, as a result, reduces the exposure Marylanders face to fuel price volatility from resources like coal and gas.
- *Increases in-state energy production* – Expanding the RPS potentially increases in-state renewable energy generation. The LTER Very High Maryland RPS Scenario resulted in 6% more renewable energy generated in Maryland and a 26,000-GWh decrease in net electricity imports by 2035. These numbers are likely to be even higher as a result of the large carve-outs in Ch. 757.
- *Jobs and other economic benefits* – Input-output modeling conducted for this project estimated a combined direct and indirect impact of 34,344 FTE construction jobs and 4,674 FTE O&M jobs in solar and offshore wind as a result of increasing the RPS over the period 2019-2030.

[299] Maryland Department of Natural Resources, Power Plant Research Program, *Long-Term Electricity Report for Maryland*, 2016, dnr.maryland.gov/pprp/Documents/LTER-December-2016.pdf.

- *Local and state government tax revenue* – The jobs and economic activity created by all segments of the renewable energy industry, including distributed and utility-scale renewable generation, add to local and state tax revenues.

- *Possible investments in rural and environmental justice communities* – New renewable energy projects under a 50% RPS could help: (1) diversify rural income streams; (2) promote jobs and career pipelines in underserved communities; and (3) reduce the impacts of carbon, air, and water pollution in environmental justice communities.

Weaknesses

- *Many RECs likely to come from outside Maryland* – Historically, over 75% of Tier 1 non-carve-out RECs have come from out-of-state resources. This undermines the potential local economic benefits of expanding the RPS.

- *Additional costs* – The 50% RPS will come at an additional cost, as more RECs and SRECs will have to be procured to meet the higher RPS requirements. Additionally, an increase in demand for renewable energy as a result of the increased RPS could result in short-term increases in REC and SREC prices as supply catches up to demand. A spike in SREC spot market costs as reported in Marex Spectrometer in April 2019 illustrates this potential cost.

- *Little impact on in-state emissions* – In the LTER Very High Maryland RPS Scenario, raising the RPS had limited impact on Maryland emissions, and associated environmental and public health impacts, because in-state and out-of-state coal and natural gas plants continue to generate for the PJM-wide market. Also, as noted previously in the report, sources with emissions profiles are eligible for the Maryland RPS.

- *Land-use concerns* – Localities govern many land use decisions in Maryland. If localities determine that renewables are not compatible with agricultural land use, the level of renewable deployments in Maryland may be limited. These restrictions could impose additional costs and interfere with Maryland's ability to source renewable energy from in-state. See the Solar SWOT below for additional discussion.

- *There are other approaches to increasing renewables* – In addition to state RPS policies, other policy mechanisms in both the U.S. and worldwide have been effective in increasing renewable energy development, such as feed-in tariffs, long-term contracts, and tax incentives.

4.3. Adopting a 100% RPS or CES

To date, eight states, the District of Columbia, and Puerto Rico have adopted a 100% RPS or CES requirement (or goal). These include the D.C. RPS (by 2032); the Nevada CES (by 2040); the New York CES (by 2040); the California CES (by 2045); the Hawaii RPS (by 2045); the New Mexico CES (by 2045); the Washington CES (by 2045); the Maine RPS (by 2050); the New Jersey CES (by 2050); and the Puerto Rico RPS (by 2050). Several additional states, including Maryland, Colorado, Connecticut, Florida, Illinois, Iowa, Massachusetts, Minnesota, North Carolina, Pennsylvania, Virginia, and Wisconsin have considered 100% RPS or CES legislation. CES policies generally include other carbon-free resources that are often excluded from being eligible for state RPS policies such as large hydro and nuclear power, and often build on RPS policies.

Establishing an RPS or CES at 100% serves multiple purposes, including stimulating high levels of renewable energy deployment, spurring renewable energy jobs and economic development, and supporting decarbonization of the electric power grid. It also has other impacts, such as the loss of employment at fossil-fuel generation plants. As is the case for all RPS/CES policies regardless of the percentage level, the relative costs and benefits depend, in part, on policy design. This SWOT explores some of the key considerations related to 100% RPS/CES design as well as strengths and weaknesses of the potential policy.

In 2019, the Maryland General Assembly passed SB 516, which requires a supplemental study be submitted by January 1, 2024 to assess the overall costs and benefits of a 100% RPS. SB 516 also requires a separate report regarding the role of nuclear power in the Maryland RPS. Many of the potential impacts of a 100% RPS or CES are similar to the impacts anticipated for a 50% RPS/CES. Since no state has achieved a 100% RPS/CES goal yet, existing projections about the potential impact are largely based on prospective modeling or theoretical explanations. Although these estimates are useful, they do not always generalize across states.

What follows is a brief review of existing commentary, framed as strengths and weaknesses, regarding the prospective impact of 100% RPS/CES policies. Similar to the SWOT on the 50% RPS, important considerations include: cost, environmental impact, economic impact, and land use. However, the analysis presented below is incremental to the impacts of a 50% RPS. The commentary reviewed in this SWOT represents a potential research agenda for Maryland's 100% RPS/CES study; further research is needed to assess the strengths and weaknesses of a 100% RPS or CES in Maryland's specific context.

Strengths

- *Further expands renewable energy* – A 100% RPS or CES would support increased renewable energy and/or carbon-free capacity and, in the process, promote accompanying economic development, employment, and environmental benefits.
- *Reduces fuel price risks* – A 100% RPS or CES reduces the exposure Marylanders face to fuel price volatility from conventional fossil-fuel resources like coal and gas. They would not, however, be eliminated insofar as Maryland participates in the multi-state PJM market and fossil fuel generation remains a part of the PJM system mix.
- *Further increases in-state energy production* – Implementing a 100% RPS or CES potentially increases in-state renewable energy generation, particularly from solar and offshore wind, which are subject to carve-outs. In addition to supporting these resources, a 100% CES potentially also promotes the continued operation of in-state nuclear assets. More in-state generation provides corresponding in-state environmental and economic benefits, such as reduced air emissions and local government tax revenue.
- *Predictable reliability impacts in certain conditions* – PJM has reported it can incorporate up to 30% wind and solar without impacting grid reliability, although additional ancillary services and transmission would be required. A 100% RPS in Maryland would not raise wind and solar generation in PJM above 30%, assuming other states do not also implement 100% RPS policies.
- *Lower long-run power costs* – Many renewable energy resources, such as wind and solar, are zero marginal cost and therefore cheaper to operate on an ongoing

basis than many fossil-fuel alternatives. In the long run, replacing conventional power sources with renewables may decrease wholesale power costs.

- *Flexible and politically feasible* – RPS and CES policies are adaptable and can serve multiple different policy objectives, depending on design. Consequently, RPS and CES policies have emerged as one of the leading state strategies to address climate change.

Weaknesses

- *Limited in-state benefits* – A large percentage of Tier 1 non-carve-out RECs could come from out-of-state resources, as is the case with the current Maryland RPS. This undermines potential local benefits of expanding the RPS.
- *Short-term costs* – A 100% RPS/CES would likely impose higher costs in the short run, depending on stringency (e.g., more/fewer eligible technologies), as more RECs and SRECs would have to be procured to meet the higher renewable or clean energy requirements.
- *Land use concerns* – High penetration of renewable energy resources may displace other productive land uses, which could have unintended second- or third-order consequences. For example, displaced farmland could lead to increased agricultural production outside of Maryland and higher prices for feedstock and some foods. These consequences, however, are short term as markets equilibrate and find an optimal balance of renewable energy deployment and other land uses.
- *Uncertain reliability impacts if other states in PJM also adopt 100% RPS policies* – Very high levels of penetration of variable renewable energy generation could prompt PJM to procure more ancillary services such as regulation, and likely necessitate significant changes in PJM's system operations and planning. Additionally, high renewable penetration in PJM could create a need for the commercialization of more flexible resources such as long-duration storage.
- *Additional new transmission and distribution may be required* – Depending on how much new renewable energy or clean energy capacity is required, new transmission or distribution lines or upgrades may be required.
- *Job losses and displacement* – High CES/RPS requirements would support certain low-carbon resources at the expense of conventional sources. Job losses may occur as a result of the closure of displaced resources. That, in turn, could cause Maryland to incur costs for retraining the workers at power plants that close.
- *Stranded costs* – Maryland ratepayers may be on the hook for stranded cost recovery if power plants are retired prematurely or PPAs are canceled before their expiration date.

4.4. Maintaining the 14.5% Tier 1 Solar Carve-out

Maryland is one of 15 states (plus the District of Columbia) to establish a solar or DG carve-out.[300,301] Maryland first enacted a Tier 1 carve-out for solar energy in 2007 and subsequently amended it in 2010, 2012, 2017, and 2019. The most recent changes—

[300] Includes DC, DE, IL, MA, MD, MN, MO, NC, NH, NJ, NM, NV, OH, OR, PA, and VT.

[301] Galen Barbose, *U.S. Renewables Portfolio Standards – 2019 Annual Status Update*, Lawrence Berkeley National Laboratory, July 2019 presentation, emp.lbl.gov/publications/us-renewables-portfolio-standards-2.

enacted following the passage of SB 516—increased the solar carve-out requirement to 14.5% by 2028. Maryland's current solar carve-out is the largest in the United States. This SWOT considers the strengths and weaknesses of the current, high solar carve-out as compared to lower levels.

The resources eligible for Maryland's solar carve-out include solar water-heating systems constructed on or after June 1, 2011, solar PV systems, and solar thermal systems, all of which must be connected to a distribution grid serving Maryland to qualify for the carve-out. LSEs may demonstrate compliance using SRECs obtained via contract, purchase, or self-generation. The ACP for solar resources in Maryland is currently higher than Tier 1 non-carve-out resources; the ACP for solar is $100/MWh as of 2019 and 2020, while the Tier 1 non-carve-out resource ACP is $30/MWh. However, SREC prices are lower than the ACP, with spot market prices ranging between $6.50-$14/MWh in 2018.[302] Although SREC prices spiked to as high as $48.75/MWh at the start of April 2019 (corresponding with the passage of SB 516), prices are still below the 2020 solar ACP of $100/MWh.

Currently, all SRECs retired to meet Maryland's solar carve-out are from in-state solar resources. Within PJM, Maryland is third to New Jersey and North Carolina in terms of installed solar capacity.[303] Solar makes up almost 50% of Maryland's renewable energy capacity as of 2018. SEIA estimates that in 2018 Maryland employed 4,515 persons in solar-related jobs, and it was home to as many as 240 solar-related companies, including manufacturers, installers, and developers.[304]

The current next highest solar carve-out in nearby states is the District of Columbia's 10% requirement by 2041. Table 4-1 lists the solar carve-out provisions in other PJM states with an RPS for comparison purposes. Although solar comprises a small share of the total Maryland RPS requirement, it contributes a higher share of the RPS compliance costs. In the latest Maryland PSC RPS report, SRECs accounted for $21.3 million of the $72 million in total RPS compliance costs in 2017 (29.6%), even though they only accounted for 7.7% of the Maryland REC demand.[305]

Proponents of the higher solar carve-out cite the benefits of local job creation and continued expansion of solar in Maryland. Opponents see the increased solar carve-out as costly and inefficient as compared to procuring power from existing, non-renewable energy sources. This analysis briefly summarizes the strengths and weaknesses of the current, 14.5% solar carve-out. Important considerations include: compliance costs, in-state renewable energy development, land use, and economic development.

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[302] SREC prices sourced from Marex Spectrometer, *Spectrometer U.S. Environmental*.

[303] According to the *2018 State of the Market Report for PJM*, New Jersey has 2,591.5 MW and North Carolina has 1,348.9 MW of combined utility-scale and distributed solar, as compared to 1,082.6 MW in Maryland.

[304] Solar Energy Industries Association, "Maryland Solar," seia.org/state-solar-policy/maryland-solar.

[305] Public Service Commission of Maryland, *Renewable Energy Portfolio Standard Report*, November 2018, psc.state.md.us/wp-content/uploads/FINAL-Renewable-Energy-Portfolio-Standard-Report-with-data-for-CY-2017.pdf.

Table 4-1. Altering the Maryland RPS Solar Carve-out SWOT: Solar Carve-out Provisions in Other States in PJM, as of July 2019

State	Overall Requirements[1]	Solar Carve-out
MD	**50% by 2030**	**Solar: 14.5% by 2028**
DE	25% by 2025-2026	Solar PV: 3.5% by 2025-2026
DC	100% by 2032	Solar: 10% by 2041
IL	25% by 2025-2026	Solar PV: 6% of annual requirement beginning in 2015-2016 and continuing until 2025-2026
NC	12.5% by 2021 for IOUs; 10% by 2018 for co-ops and munis	Solar: 0.2% by 2018
NJ	21% by 2021; 35% by 2025; 50% by 2030	Solar electric: 5.1% by 2021; begins declining in 2024 and thereafter to 1.1% by 2033
OH	8.5% by 2026	Solar: 0.5% by 2026
PA	18.5% by 2020-2021	Solar PV: 0.5% by 2020-2021

[1] The listed requirements are inclusive of alternative energy portfolio standards and multiple tiers of resources.

Strengths

- *In-state renewable development* – The increased solar carve-out will support in-state renewable energy development with accompanying benefits including local jobs, property taxes, and other economic benefits.
- *Additional solar market development* – Current solar carve-out policies in Maryland and other states are credited with creating a competitive market for solar development, which, in turn, has led to reductions in both the soft and hard costs of solar generation.[306] The expanded carve-out could again spur further cost reductions.
- *Costs may not increase* – Maryland had over 20 solar projects in various stages of seeking approval from the Maryland PSC as of 2018.[307] Increasing the solar carve-out in 2019 will likely provide a market signal for more of those projects to commence construction, increasing supply in concordance with increased demand.

Weaknesses

- *May increase compliance costs* – SRECs are historically more expensive than Tier 1 non-carve-out RECs. Increased demand for SRECs may stall or reverse recent declines in SREC prices. This is evidenced by the spike in spot market prices for SRECs after the passage of SB 516. Additionally, increased SREC requirements will reduce the level of excess solar capacity that is available for use serving general REC requirements, potentially leading to higher overall REC prices.

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[306] Ran Fu, David Feldman and Robert Margolis, *et al.*, *U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017*, National Renewable Energy Laboratory, 2017, nrel.gov/docs/fy17osti/68925.pdf.

[307] Bob Sadzinski, "Lessons Learned from Past Solar CPCN Cases," presentation before the Power Plant Research Advisory Committee, June 2018, dnr.maryland.gov/pprp/Documents/PPRAC-4-Lessons-Learned-presentation.pdf.

- *Reduced competitive pressure on solar* – Increased solar demand may undercut the current supply-side pressure to reduce soft and hard costs for solar.
- *Land use concerns* – Opposition has been expressed to some utility-scale solar projects due to concerns over the loss of farmland. The 2016 LTER estimated that 2.2% of the Eastern Shore's prime agriculture farmland would be required to meet a 5% solar carve-out if all of the PV needed were located on such land. This is a high-end estimate that ignores existing PV capacity, future distributed solar installations, and other potential sites such as landfills.[308] Land impacts will be higher, however, with a 14.5% carve-out.
- *May introduce interstate commerce concerns* – Maryland's solar carve-out previously comprised only a small percentage of its RPS obligation. The larger requirement, which favors in-state resources, might be construed as economically protectionist.[309]

4.5. Removing Black Liquor as an Eligible Resource

Black liquor is an industrial byproduct derived from the process of converting wood into paper pulp. One prominent use for this byproduct is as an electricity source; burning black liquor in recovery boilers produces steam that can be used to generate electricity. This process also allows paper manufacturers to recover other chemical byproducts for reuse.

Black liquor is classified as "biomass" under the Maryland RPS, and electricity produced from burning black liquor qualifies for Tier 1 RECs.[310] Proponents of maintaining black liquor as an eligible Tier 1 resource argue that burning black liquor to produce energy is an efficient process since it recycles a byproduct of the paper mill process. Proponents also note that the paper mills replenish the fuel stock by replanting trees. Opponents of the eligibility of black liquor argue that black liquor is not clean energy, as it emits as much CO_2 as a coal plant. Opponents also argue that a significant amount of the black liquor credits are subsidizing out-of-state paper mills.

Historically, black liquor RECs were used to satisfy a significant portion of the Maryland RPS requirements. In 2008, black liquor RECs satisfied approximately 38% of the Maryland RPS.[311] This share has declined in recent years. In 2017, black liquor RECs satisfied approximately 24% of the Maryland RPS Tier 1 non-carve-out requirement. All but one of the 11 facilities that provided black liquor RECs in 2017 are from out of state. Moreover, over 90% of the black liquor RECs used for complying with the Maryland RPS come from out

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[308] Maryland Department of Natural Resources, Power Plant Research Program, *Long-Term Electricity Report for Maryland*, 2016, dnr.maryland.gov/pprp/Documents/LTER-December-2016.pdf.

[309] Carolyn Elefant and Edward Holt, *The Commerce Clause and Implications for State Renewable Portfolio Standard Programs*, Clean Energy States Alliance, 2011, cesa.org/webinars/states-advancing-rps-webinar-the-commerce-clause-and-implications-for-state-rps-programs/; Anne Havemann, "Surviving the Commerce Clause: How Maryland Can Square Its Renewable Energy Laws with the Federal Constitution," *Maryland Law Review*, 71(3), 2012, digitalcommons.law.umaryland.edu/mlr/vol71/iss3/6; Joel Mack, Natasha Gianvecchio, Marc Campopiano and Suzanne Logan, "All RECs Are Local: How In-State Generation Requirements Adversely Affect Development of a Robust REC Market," *The Electricity Journal*, 24(4), 2011, sciencedirect.com/science/article/pii/S1040619011000996.

[310] As stated in Annotated Code of Maryland, PUA § 7–701, one applicable fuel source under the RPS is "(i) waste material that is segregated from inorganic waste material and is derived from sources including: 1. Except for old growth timber, any of the following forest-related resources*:* A. mill residue, except sawdust and wood shavings."

[311] Maryland Public Service Commission, *Renewable Energy Portfolio Standard Report of 2010*, psc.state.md.us/wp-content/uploads/MD-RPS-2010-Annual-Report.pdf.

of state.[312] Historically, the main in-state beneficiary of revenues from the sale of black liquor RECs was the Luke Mill paper facility. Luke Mill closed on June 30, 2019.[313] After the closure of Luke Mill, this percentage of black liquor RECs from in-state is likely to decline to zero.

This analysis briefly summarizes the strengths and weaknesses of removing black liquor from the list of eligible resources under the Maryland RPS. Important considerations include: impact on Maryland RPS compliance, available alternatives, impact on Tier 1 REC prices, subsidies, economic considerations, and the location and availability of RPS-eligible resources.

Strengths

- *Provides opportunities for other resources for the Maryland RPS*– Eliminating a resource that satisfies a significant portion of the RPS would essentially increase the Maryland RPS without increasing the percentage. This occurs because other eligible resources would be used to fill the void.
- *Makes the Maryland RPS more compatible with other state RPS policies in PJM* – Pennsylvania and Maryland are currently the only states, along with the District of Columbia, in PJM that certify black liquor. Pennsylvania limits eligible black liquor facilities to those located within Pennsylvania. As of the 2017 compliance year, black liquor in D.C. was reclassified from a Tier 1 facility to a Tier 2 facility. Tier 2 is eliminated in D.C. as of the end of 2019.
- *Reduces subsidies for resources that emit air pollution* – Black liquor contributes to SO_2, arsenic, and GHG emissions. Eliminating black liquor could result in the Maryland RPS favoring non-combustion, non-emission technologies, such as solar and wind, to meet demand.
- *No long-term impact on REC prices* – While prices may increase slightly in the near term as markets adjust, they will eventually fall and stabilize as other qualified resources enter the market in order to meet RPS requirements.
- *Avoids subsidizing out-of-state paper mill plants* – More than 90% of black liquor RECs used for complying with the Maryland RPS in 2017 came from out of state. This percentage will likely increase to 100% following the closure of the Luke Mill paper facility in June 2019. Maintaining black liquor as an eligible technology essentially subsidizes paper mills in other states with minimal direct, in-state economic benefit.

Weaknesses

- *Undermines potential return of paper industry to Maryland* – Although there is no indication that Maryland is a prospective site for future industrial paper mill facilities, the return of the paper industry to the state would provide a variety of economic benefits. Continued support for black liquor would provide a financial incentive for new paper facilities in Maryland, especially if the RPS requirement is adjusted to favor in-state sources (of which there are currently none).

[312] Public Service Commission of Maryland, *Renewable Energy Portfolio Standard Report*, November 2018, psc.state.md.us/wp-content/uploads/FINAL-Renewable-Energy-Portfolio-Standard-Report-with-data-for-CY-2017.pdf.

[313] CBS Baltimore, "Hundreds To Lose Jobs After Luke Paper Mill Closing In Western Maryland," April 2019, baltimore.cbslocal.com/2019/04/30/luke-paper-mill-closing-western-maryland/.

- *Eliminates a carbon-neutral source* – Biomass is considered by some to be a carbon-neutral resource, as it captures the energy value of the CO_2 that would be released into the atmosphere anyway from natural decomposition and avoids additional methane production from landfilling. Methane is 25 times more potent than CO_2 as a GHG.
- *Increases REC prices under certain conditions* – Few states qualify black liquor as an eligible REC provider and, as a result, black liquor RECs that would no longer qualify for the Maryland RPS would need to be replaced with other RECs. An increase in demand for other Tier 1 non-carve-out RECs could increase REC prices slightly in the near term. This is unlikely to occur, however, unless overall REC demand also increases (e.g., higher state RPS requirements) or multiple major resources lose their RPS eligibility at once (e.g., MSW, BFG, and others).

4.6. Providing State Support for Energy Storage

System flexibility is defined as the grid's ability to accommodate both predictable and unpredictable imbalances between supply and demand.[314] Higher amounts of wind and solar drive the need for additional system flexibility. As the penetration of variable resources grows in a region, their impact on the grid becomes more noticeable, sometimes causing overall generation to ramp up and down more steeply on second-to-second, daily, and seasonal time scales. Two such resources, wind and solar, jointly represented just 2.9% of generation in PJM in 2018,[315] and about 4.2% in Maryland in 2018.[316] This low penetration, combined with PJM's large footprint, suggests that wind and solar do not present a major challenge to system flexibility, and are unlikely to do so in the near future.

Numerous resources can enhance system flexibility, including: fast-responding gas plants; power electronics that regulate wind and solar output; smart-devices that adjust their consumption in response to programming or price signals; and energy storage devices such as flywheels, water heaters, and batteries.[317]

This SWOT focuses on energy storage, which has the potential to provide a range of services that may help increase the affordability, reliability, and sustainability of electricity in Maryland. It draws from Section 7.1, "System Flexibility and Energy Storage" which provides further summary and discussion of the potential applications for energy storage. Note that aggregation software can be used to coordinate BTM storage resources, so that they can provide bulk energy and/or distribution system services. Also note that energy storage devices must often provide multiple services, staggered over time, to be cost-effective.

In recent years, dramatic reductions in the cost of batteries and improvements in aggregation software have begun to open new applications for energy storage. In its 2018

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[314] Eric Gimon, "Flexibility, Not Resilience, Is the Key to Wholesale Electricity Market Reform," *Greentech Media*, 2017, greentechmedia.com/articles/read/flexibility-is-the-key-to-wholesale-electricity-market-reform#gs.hhjlo5E.

[315] Monitoring Analytics, LLC, *2017 State of the Market Report for PJM*, March 2018, monitoringanalytics.com/reports/PJM_state_of_the_Market/2017/2017-som-pjm-sec3.pdf.

[316] Note that 2018 EIA figures are preliminary. *Source:* U.S. Energy Information Administration, Electricity Data Brower, "Net Generation for All Sectors, annual," eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=vtvv&geo=00000008&sec=g&linechart=ELEC.GEN.ALL-MD-99.A&columnchart=ELEC.GEN.ALL-MD-99.A&map=ELEC.GEN.ALL-MD-99.A&freq=A&ctype=linechart&ltype=pin&rtype=s&pin=&rse=0&maptype=0.

[317] Eric Gimon, "Flexibility, Not Resilience, Is the Key to Wholesale Electricity Market Reform," *Greentech Media*, October 2017, greentechmedia.com/articles/read/flexibility-is-the-key-to-wholesale-electricity-market-reform#gs.hhjlo5E.

report on energy storage in Maryland, PPRP identified 12 key barriers to storage, some at the PJM level,[318] and some at the state level. The latter barriers include: system and financing costs; concern over whether Maryland's regulated distribution utilities should be allowed to participate in PJM markets; rate designs that mask the real-time cost of energy; questions about the level of utility review needed for BTM storage; limited mechanisms for paying storage owners to avoid distribution system costs; a lack of protocols for dispatching BTM storage to provide services to the grid; and opaque distribution system planning processes.[319] These barriers have led some stakeholders to call for subsidies for energy storage or set a target for energy storage.

Proponents of state-level subsidies and related supports for energy storage cite the long-term environmental and economic benefits of helping to expand the market for storage and increase in-state understanding of how to best utilize it. Opponents cite the risk of increasing emissions in the short term and the costs imposed by subsidies. Energy storage can contribute to increased emissions both because some energy is lost during charging and discharging (resulting in increased generation) and because charging storage during PJM's lowest-cost hours may increase demand for power produced by resources like coal. The MEA launched a first-in-the-nation pilot program in July 2019 to try to address some of these questions.

This analysis briefly summarizes the strengths and weaknesses of adding state-level subsidies, either by including storage in the RPS, creating a standalone storage target, or developing storage incentives. Important considerations include:

- Policy design (adding energy storage as a separate tier or carve-out or adding energy storage power as an eligible technology to the Maryland RPS);
- Defining ratepayer protections and/or cost caps;
- Potential impacts on competitive electric power markets;
- Possible changes to the PJM RPM (PJM's capacity market) that may affect policy support or subsidies to renewables or other specific technologies;
- Impact on the Maryland RPS overall if energy storage is added as an eligible technology; and
- Ensuring flexibility in case market conditions change, thereby altering which applications of storage are most valuable.

Strengths/Weaknesses – Inclusion in the RPS, with or without a Storage Carve-out

- *Emissions* [strength] – RPS regulations could require that storage be charged by renewable energy resources. This reduces the risk of storage increasing CO_2 emissions, which could occur both because some energy is always lost during

[318] In February 2018, the FERC took steps to give storage greater access to wholesale markets. FERC Order No. 841 compels PJM and other RTOs/ISOs to revise their market rules to facilitate the participation of energy storage resources in their energy, ancillary service, and capacity markets.

[319] Maryland Department of Natural Resources, Power Plant Research Program, *Energy Storage in Maryland: Policy and regulatory options for promoting energy storage and its benefits*, 2018, dnr.maryland.gov/pprp/Documents/Energy-Storage-In-Maryland.pdf.

charging/discharging and because charging may increase production during low-cost periods when coal generation predominates.

- *Inflexibility* [weakness] – The RPS may not be a suitable policy for storage because of its focus on generation output (i.e., MWh). Unlike renewable energy resources, the value of storage lies not in simply providing energy to the grid, but in strategically meeting grid needs at certain times and locations. Flexibility is generally better supported through a capacity-based (i.e., $/MW) incentive rather than an energy-based (i.e., $/MWh) incentive.

- *Costs to ratepayers* [weakness] – Any additional costs to procure storage would be passed on to ratepayers in ways similar to the pass-through of other RPS compliance costs.

Strengths/Weaknesses – Standalone Storage Target

- *Flexibility* [strength] – A target would provide more flexibility to deploy storage in a variety of applications. A target can also still be designed to require storage charged by renewable energy, if desired.

- *Emissions* [weakness] – Using storage systems charged by non-renewable energy resources may increase GHG emissions, for the reasons stated above.

- *Costs to ratepayers* [weakness] – LSE costs to procure storage would be passed on to ratepayers.

Strengths/Weaknesses – Storage Incentives

- *Flexibility* [strength] – Storage incentives provide maximum flexibility in terms of how energy storage is used and for what applications. Incentives could be tied to performance of any desired activity (e.g., flattening peak demand) and can incentivize the use of renewable energy resources for charging purposes.

- *Results* [weakness] – Incentives cannot guarantee specific levels of storage deployment or usage, as is the case with targets or requirements.

- *Costs to taxpayers* [weakness] – Depending on the incentive design, the costs of supporting storage are borne by taxpayers through reduced tax receipts, reallocation of tax revenues from other sources, or increased taxes (i.e., as a source of new funds).

Strengths/Weaknesses – All Forms of Support

- *Jobs/economic development* [strength] – Supporting storage could also promote in-state storage resources, with associated jobs in storage project development and deployment.

- *Potential avoided costs* [strength] – As with EmPOWER Maryland projects, it may be possible to identify and support multi-use storage projects with costs that are lower than the system-wide cost savings they would otherwise realize.

- *Unclear need* [weakness] – Given that wind and solar provide a relatively low percentage of total generation in Maryland and in PJM, it is unclear whether storage benefits to the grid would outweigh their costs in the near term. Cost-benefit modeling would provide insight.

- *Safety concerns* [weakness] – The risk of possible battery fires is a concern. New York City released guidelines for the deployment of batteries in 2018, and other states are considering similar regulations.[320]

- *Decommissioning concerns* [weakness] – Standards for battery decommissioning, including the disposal or recycling of chemical components, have yet to become well-established.

4.7. Moving Hydro from Tier 2 to Tier 1

Hydropower has a long history in Maryland as a source of renewable energy generation. According to EIA, as of 2018, large hydro plants in Maryland produced 2,829 GWh, or 6.4%, of the state's net generation.[321] Along with waste-to-energy and poultry litter, hydro (excluding pumped storage) was classified as a Tier 2 resource when the RPS was enacted in 2004, while hydro projects of less than 30 MW capacity were considered a Tier 1 resource. By 2013, the Maryland General Assembly had reclassified waste-to-energy and poultry litter as Tier 1 resources, leaving hydro as the lone Tier 2 resource.

In 2017, Tier 2 RECs accounted for approximately 16% of the total retired RECs for Maryland RPS compliance.[322] Approximately 66% of these RECs came from out-of-state hydro generation, with the majority from North Carolina.[323] Following the passage of SB 516, the Tier 2 classification is scheduled to expire at the end of 2020. Given the prospective phase-out of the Tier 2 resource requirement, some have suggested reclassifying hydro, regardless of MW of capacity, as a Tier 1 resource in order to continue supporting hydro resources.

Several states in PJM allow hydro as an eligible technology for RPS policies, albeit with varying eligibility requirements. Like Maryland, New Jersey renewables are divided into Tier 1 and Tier 2 (referred to as Class 1 and Class 2), with Tier 1 including hydro resources less than 3 MW in capacity and Tier 2 containing hydro resources between 3 MW to less than 30 MW in capacity. Pennsylvania, on the other hand, classifies hydro resources as Tier 1 if less than or equal to 21 MW in capacity, and as Tier 2 if greater than 21 MW, including pumped storage. Hydro greater than 30 MW is accepted as a Tier 1 RPS eligible resource in Illinois and Michigan, and as a Tier 2 RPS eligible resource in the District of Columbia. The hydro facilities must be existing (i.e., not newly constructed or expanded) to qualify for the Illinois, Michigan, and D.C. RPS policies. Run-of-the-river hydro systems on the Ohio River greater than 40 MW are also accepted as a Tier 1 RPS eligible resource in Ohio.[324]

Changing the qualifying status of hydro to Tier 1 would give hydro resources access to higher-priced Tier 1 RECs. Tier 2 spot market REC prices in Maryland, on average, are over 90% less than Tier 1 REC prices in Maryland as of April 2019.[325] Low electric wholesale prices have also put increased pressure on generation resources, including hydro. In the

[320] Mark Chediak, "Boom in giant batteries hits another roadblock: Cities' fear of fire," *Los Angeles Times*, May 2018, latimes.com/business/la-fi-battery-fire-20180518-story.html#.

[321] U.S. Energy Information Administration, "Net generation, United States, all sectors, monthly," October 2018, eia.gov/electricity/data/browser/.

[322] Public Service Commission of Maryland, *Renewable Energy Portfolio Standard Report*, November 2018, psc.state.md.us/wp-content/uploads/FINAL-Renewable-Energy-Portfolio-Standard-Report-with-data-for-CY-2017.pdf.

[323] Ibid.

[324] PJM Environmental Information Services, "Comparison of Renewable Portfolio Standards (RPS) Programs in PJM States," June 2018, pjm-eis.com/-/media/pjm-eis/documents/rps-comparison.ashx?la=en.

[325] Marex Spectrometer, *Spectrometer U.S. Environmental*, August 2018.

face of these market conditions, some hydro companies argue that the reclassification of hydro as a Tier 1 resource is necessary to avoid shutting down hydro projects.

In addition to supporting hydro resources in the face of a less favorable wholesale market environment, access to Tier 1 RECs would also support ongoing O&M, mitigation, and relicensing costs. Potential relicensing costs, which apply when it is time to renew a hydro license with the FERC or state authorities, may include significant facility upgrades, such as the addition of fish ladders, as well as changes to how hydro plants operate, such as management of environmental mitigation activities. Mitigation activities include managing sediment levels, the amount of dissolved oxygen in the water, and other water quality issues.

Supporters of moving hydro to Tier 1 point to potential environmental and economic benefits from sustaining an existing renewable energy resource. Opponents argue that the reclassification of hydro as a Tier 1 resource would allow hydro generation to undercut other resources in Tier 1 REC markets, reducing the support that could be provided to the development of new renewable energy projects. Opponents also question whether existing hydro projects need financial support and contend that making hydro eligible for Tier 1 would provide an unnecessary financial windfall for large hydro companies. Finally, some opponents note that large hydro generation can have detrimental land use, wildlife, and life-cycle emissions impacts and should not receive the same level of incentives as other renewable energy resources as a result.[326]

This analysis briefly summarizes the strengths and weaknesses of altering the qualification status of large hydro. Important considerations include: environmental and economic impacts, REC prices, and the prospects for other renewable energy technologies.

Strengths

- *Increases the supply of Maryland Tier 1 resources to meet RPS requirements* – Making hydro an eligible Tier 1 resource helps avoid or shrink a possible supply gap between the Tier 1 requirement and available Tier 1 resources that is projected over parts of the next decade under a 50% RPS scenario, according to the interim report.
- *Maintains an existing renewable energy technology* – Supports a renewable energy resource that already exists and ensures that Maryland continues its progress toward meeting state environmental goals.
- *Supports baseload, flexible renewable energy resources* – Hydro can serve as an all-hours, baseload resource or as a flexible resource that can be adjusted in response to the needs of grid operators. Hydro can also serve as a black start resource to restore an electric power station or power grid without relying on the transmission network to do so.
- *Incentivizes possible investment in hydro plants* – Access to higher Tier 1 REC prices could encourage investment in updating aging units, as well as supporting investments that may be needed in order to relicense existing hydro projects.
- *Could lower Tier 1 RPS compliance costs to ratepayers* – Ratepayers could realize savings if RECs from hydro projects are sold at a lower price than prevailing Tier 1 REC prices, thereby driving down compliance costs.

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[326] Union of Concerned Scientists, "Environmental Impacts of Hydroelectric Power," ucsusa.org/clean_energy/our-energy-choices/renewable-energy/environmental-impacts-hydroelectric-power.html.

Weaknesses

- *Subsidization of older plants and decreased incentive to develop new resources* – The large hydro resources currently in operation are old, which affects O&M costs as well as efficiency. Subsidizing existing hydro projects occurs in place of financing other, modern types of renewable generation. Additionally, the increased supply for Tier 1 non-carve-out RECs would likely suppress Tier 1 REC prices in the near term, further disincentivizing the development of new renewable energy resources. This shift in resources can undermine fuel diversity.
- *Possible windfall for hydro companies* – Although requiring more O&M, older hydro projects are generally low-cost resources and can operate even in the absence of RPS support. Allowing access to Tier 1 REC prices that are much higher than Tier 2 REC prices could be an economic windfall for owners of hydro projects.
- *Supports facilities with potential negative environmental impacts* – In certain conditions, vegetation and soil erosion as a result of hydro operations can release CO_2 and methane, both of which are harmful. Additionally, hydro dams can be disruptive to surrounding ecosystems and wildlife. Other renewable energy resources could potentially provide the same level of output without these detrimental impacts.

4.8. Requiring Long-Term Contracts

Many renewable energy policy experts contend that long-term contracts are key to successfully developing renewable energy projects because these projects are capital-intensive and most of the costs are incurred up front before the project begins operation. One benefit of a long-term contract with a creditworthy entity is that it makes financing easier to obtain. This arrangement is typically available in utility-regulated markets. In restructured markets, long-term contracts are more difficult to secure as LSEs face uncertainty over projected load and are reluctant to enter into long-term contracts for fear of being financially exposed to a power plant that is uncompetitive relative to market prices, and perhaps lose customers as a result. Contracts in restructured markets tend to be quite short, generally two to three years. Maryland restructured its electricity sector in 1999.

LSEs in restructured markets often rely on short-term purchases of RECs to satisfy state RPS requirements. REC prices can be quite volatile in the short term, as evidenced by sharp decreases in non-carve-out Tier 1 REC and SREC prices in Maryland between 2016-2018, as well as a spike in SREC prices in April 2019. To minimize this price volatility and to overcome financing obstacles for renewable energy, some states have instituted long-term contracting requirements, ranging between 10-20 years, for PPAs with renewable energy generators for purposes of RPS compliance. California requires IOUs to procure 65% of renewable energy capacity from long-term contracts by 2021.[327] Connecticut may acquire up to 4,250 GWh of renewable energy per year under long-term contracts. Rhode Island has negotiated long-term contracts with several renewable energy projects. In 2015 and 2016, Connecticut, Massachusetts, and Rhode Island jointly pursued a three-state Clean Energy RFP, resulting in contracts awarded to 460 MW of renewable capacity. Massachusetts is requiring utilities to negotiate long-term contracts for 1,600 MW of wind by June 2027,

[327] North Carolina Clean Energy Technology Center, DSIRE, "California Renewables Portfolio Standard," programs.dsireusa.org/system/program/detail/840.

3,200 MW by 2035, and to enter into additional long-term contracts for 9.45 TWh of clean energy generation by the end of 2022.[328]

During the 2018 Maryland legislative session, a bill was introduced that, if it had passed, would have required Maryland SOS providers (i.e., distribution utilities) to procure at least 25% of their RPS requirements through a competitive bidding process for long-term contracts lasting at least 10 years and up to 20 years. These contracts would be for the bundled output of renewable energy facilities, including RECs and electricity. Under this proposed arrangement, distribution utilities would submit contracts to the Maryland PSC, and the PSC would review and approve contracts if they are cost-effective as compared to the long-term projection of renewable energy costs. Supporters of the bill asserted that long-term renewable energy contracts can hedge against rising fossil fuel prices and save ratepayers money. Supporters also argued that electricity prices are historically low and can only increase, making now a good time to enter into these arrangements. Distribution utilities and competitive LSEs argued that long-term contracts could result in customers paying higher electricity prices. Furthermore, opponents stated that procuring long-term contracts would conflict with some of the goals of energy deregulation in Maryland, which separated distribution utilities from the generation business.[329]

Whether the long-term contracts result in cost savings for ratepayers depends on the contract price as compared to what would have otherwise been charged. Several factors could impact electricity prices, such as prices of fossil fuels, changes to state and/or federal laws, or technological changes.

The strengths and weaknesses of using long-term contracts to satisfy the Maryland RPS are discussed below. Important considerations include prices, project development, administrative burden, and risk preference.

Strengths

- *Price certainty* – Long-term contracts provide predictability and price certainty, which can hedge against volatility in wholesale prices.
- *Lowers risk for developers* – Requiring long-term contracts as part of the RPS lowers revenue risk for developers and allows them to obtain financing at a lower cost. In turn, the lower financing costs can be passed along to ratepayers through reduced project costs and power prices.
- *New renewable energy projects* – Generation projects that were previously infeasible could potentially be built within Maryland as a result of the added guarantees and support provided by long-term contracts.
- *Economic benefits, including local jobs and taxes* – Increasing development of new renewable energy as a result of long-term contracts increases state and local tax revenues, creates temporary and full-time jobs, and may encourage renewable energy businesses to be located and registered within the state. In

[328] Synapse Energy Economics, Inc. and Sustainable Energy Advantage, LLC, *An Analysis of the Massachusetts Renewable Portfolio Standard*, prepared for the New England Clean Energy Council in partnership with Mass Energy, 2017, necec.org/files/necec/PDFS/An%20Analysis%20of%20the%20Massachusetts%20Renewable%20Portfolio%20Standard.pdf.

[329] Hearing on HB 967 Ratepayer Reduction for Renewable Energy Act before the Maryland General Assembly Economic Matters, March 2018.

turn, investment in renewable energy industries in the state can indirectly benefit other, unrelated local businesses and household incomes.

- *Health and environmental benefits* – Renewable energy projects built within the state or in surrounding states would increase health and environmental benefits for Maryland residents. The environmental benefits include decreased air emissions, water pollution, and GHG emissions.

- *Increases fuel mix diversity* – The development of new renewable energy projects as a result of the long-term contract requirement has the potential to diversify the fuel mix in PJM, assuming the share of long-term contracts remains at a modest level.

Weaknesses

- *Renewable energy projects may be built in surrounding states* – Projects can be built in surrounding states in PJM, or outside of PJM if located in an adjacent control area and the power is delivered into PJM. As a result, not all long-term contracts will be for projects built in Maryland, reducing local economic and environmental benefits.

- *Administrative burden* – Should the PSC have to review and approve contracts, such a process could be time-consuming and therefore delay project development.

- *Uncertainty of long-term contracts as compared to market prices* – The price of electricity under the long-term contracts may be higher or lower than market prices over time. If higher, the long-term contracts could cost ratepayers more than if the energy was procured on the open market or through the SOS process.

- *Possible decline in number of LSEs* – If LSEs are required to enter into long-term renewable energy contracts, they may see the investment as too risky and exit the market. Long-term contracts do not fit most business models of LSEs since it is difficult to hedge when energy markets are illiquid beyond three years and capacity markets are settled on a three-year forward basis. Alternatively, if distribution utilities enter into long-term contracts on behalf of all LSEs in Maryland, this would decrease the portion of load served by competitive supply. This, in turn, would disincentivize LSEs from participating in Maryland's retail choice market. In either scenario, a decrease in the number of LSEs in Maryland would potentially reduce the competitiveness of retail electric supply prices and the variety of retail supply options.

- *Risk of departing load and/or stranded assets* – If a long-term contract is above market in costs and affects customer electricity rates, customers of distribution utilities may depart for other electric providers. This sets up a possible "death spiral" for distribution utilities whereby if enough customers leave, then distribution utilities must raise rates to recover their operations costs. This, in turn, may lead to more customers departing, additional rate increases, and so forth.

4.9. Creating a Clean Peak Standard

Among the newest innovations in state RPS policies is the creation of the Clean Peak Standard (CPS). Whereas most state RPS policies set requirements based on the share of retail supply (MWh) generated by renewable energy resources, regardless of the time of day it is generated, a CPS designates a portion of system peak demand (MW) that must be met by renewable energy sources. CPS compliance is measured based on a renewable energy resource's generation during a designated peak period, and participating resources are compensated using a new, tradeable clean peak certificate (CPC) equal to 1 MWh of eligible generation during the designated peak period. Utilities are required to show a designated number of tradeable CPCs that they either generate themselves or obtain via contract or purchase. Only a handful of states have considered CPS policies to date, and only one policy (in Massachusetts) is fully in effect as of April 2019. The CPS is intended to complement, not replace, the RPS, and may be implemented via an RPS carve-out, a time-of-delivery multiplier, or a new, parallel target. Appendix I outlines additional policy considerations regarding CPS implementation.

The CPS was first identified as a potential next step in the evolution of the RPS in a December 2016 white paper for Arizona's Residential Utility Consumer Office.[330] As the white paper notes, each additional unit of new renewable energy capacity added to a grid provides diminishing returns, such that the capacity value of wind or solar decreases with more wind or solar generation. This is especially true when considering the time of day that renewables typically produce energy; solar production peaks in the afternoon, and wind production is higher at night, on average.

Massachusetts enacted a CPS in August 2018, becoming the first state to do so.[331] The CPS allows qualified energy storage, qualified renewables, and demand response to receive CPCs in exchange for providing power during year-round seasonal peaks. The actual level of the CPS was initially set at zero by regulators in the Massachusetts Department of Energy Resources (DOER). The CPS took effect on January 1, 2019, and it must increase by no less than 0.25% per year up to a yet-to-be-determined target. Policymakers in Arizona and New York are also considering CPS proposals, and the California Legislature approved a related proposal in September 2017 that directs utilities to identify carbon-free alternatives to natural gas for meeting peak demand needs when preparing integrated resource plans at least once every five years.

Proponents of a CPS view the policy as a way to increase the value of incremental renewable energy capacity and to tailor the RPS to meet grid needs. Proponents also see the policy as a means of replacing conventional thermal sources for serving peak demand. Opponents see the CPS as a costly and inefficient alternative to existing ramping resources and ancillary service markets. This analysis briefly summarizes the strengths and weaknesses of implementing a CPS in addition to or as part of the Maryland RPS. Important considerations include influence on renewable energy development, economic outcomes, environmental impacts, effect on REC prices, and administrative requirements.

Strengths

- *Potentially reduces emissions during peak periods* – CPS resources would displace existing peaking power plants and fast-ramping resources, usually natural gas, and replace their output using low-emission alternatives, depending on what resources qualify for the CPS.

[330] Strategen Consulting, "Evolving the RPS: A Clean Peak Standard for a Smarter Renewable Future," on behalf of Arizona's Residential Utility Consumer Office, 2016, strategen.com/new-blog/2016/12/1/evolving-the-rps-a-clean-peak-standard-for-a-smarter-renewable-future.

[331] Massachusetts General Assembly, *An Act to Advance Clean Energy*, HB 4857, malegislature.gov/Bills/190/H4857.

- *May decrease REC prices* – Existing RPS REC prices may decrease if clean peak certificates provide another, supplementary source of revenue for renewables that can serve both RPS and CPS requirements.

- *Remains flexible over time* – A CPS may adjust over time to meet changing system peak requirements (both in terms of peak demand and peak period). This can help sustain a market for clean-peak technologies and is adaptable to changing grid needs. An RPS, in comparison, will not support more RPS-eligible resources once the target is met, other than to meet incremental load growth.

- *Incentivizes clean energy sources to provide needed grid services* – RPS policies credit generation of energy no matter what time it is generated, thereby providing an incentive to generate regardless of whether energy is needed. In some cases, REC revenues and other incentives encourage power production even when prices are negative. A CPS, in comparison, encourages full utilization of existing or new clean resources to address peak demand requirements, or the citing of resources that can meet peak needs. Clean peak resources can also help ease steep up and down ramping, as well as encourage renewable production during peak demand periods when curtailment is less likely.

- *Supports more "dispatchable" clean energy resources and new technologies* – RPS policies have benefitted wind and solar resources more than other renewable energy technologies. A CPS might assist clean energy resources, such as biomass, that have more consistent, controllable output. In addition to the renewable energy resources included in the existing RPS, a CPS also provides a way for policymakers to incentivize qualified energy storage (i.e., charged by renewable energy resources) and demand response.

Weaknesses

- *New CPC costs* – In addition to REC costs, the CPS would create a new CPC. These certificates would impose a cost, and the outlay may not flow to Maryland resources. Additionally, the lack of an existing CPC market in PJM would create uncertainty and perhaps short-term pricing volatility as resource supply and demand equilibrate. For these reasons, CPS advocates recommend adopting a small but gradually increasing CPS to start.

- *Addresses an issue that does not yet exist in Maryland* – Maryland is served by PJM, which offers a wide array of ancillary services that are priced in a competitive market. These resources can address ramping needs in a low-cost manner, reducing the need for a CPS in the first place.

- *More complicated than a traditional RPS* – There are several ways to identify a peak period or measure a resource's contribution during a peak. These factors create implementation challenges, reduce certainty for developers, and create additional oversight requirements. They also potentially reduce the policy benefit. For example, a solar resource that is down-ramping in the early evening could technically contribute to peak load and therefore earn a CPC benefit. It would, however, contribute to the need for ramping.[332]

[332] For example, consider a solar generator that down-ramps from 4:00-7:00 p.m. and has an hourly average production of: 4:00-5:00 p.m.: 1 MW; 5:00-6:00 p.m.: 0.5 MW; and 6:00-7:00 p.m.: zero MW. If the CPS rewards generation during a peak period of 4:00-7:00 p.m., the solar resource would technically have contributed 1.5 MW. However, this contribution is counterproductive as it still requires a fast-ramping resource to replace lost

- *Limited impact on energy* – Because the CPS targets demand and energy during a limited number of hours, not net energy, CPS resources may only provide a limited amount of energy on an annual basis and otherwise be minimally utilized.
- *May inadvertently benefit polluting resources* – Absent eligibility requirements, a CPS may support combustion-based technologies, such as biomass, that some stakeholders oppose due to air emissions.
- *Short-term increase in REC prices* – Existing RPS REC prices may increase in the short term if CPS and RPS resources are mutually exclusive insofar as normal RPS resources instead qualify as CPS resources, reducing the supply of RPS resources.

4.10. Lowering the ACP Level

To show compliance with the Maryland RPS, LSEs have two options: retire the appropriate number of RECs in a tracking account or pay an ACP in lieu of submitting RECs. The ACP effectively functions as a cap on the price of RECs. If the cost of a REC exceeds the ACP, LSEs will opt to pay the ACP instead of acquiring the REC. The ACP both bounds the amount of financial support available to prospective renewable energy generators and limits RPS compliance costs that can be passed through to consumers. Given the substantial reductions in cost for some renewable energy technologies, some Maryland stakeholders have suggested lowering the ACP, both to account for these cost improvements and also to further strengthen the cost cap aspects of the ACP.

In Maryland, the ACP as of 2018 was $37.50/MWh for Tier 1 non-carve-out resources and $175/MWh for Tier 1 solar carve-out resources, with the latter eventually scheduled to decline to $50/MWh in 2024. In the 2019 session of the Maryland General Assembly, the legislature passed SB 516, which decreased the ACP to $22.35/MWh for both non-carve-out and solar carve-out resources by 2030, including a gradual step-down in the interim. This SWOT considers the strengths and weaknesses of further reductions to the ACP in the future.

Most states with an RPS use some form of ACP to constrain costs, and the ACP amounts differ from state to state in PJM, including the District of Columbia, ranging from $25/MWh in Delaware for the first deficient year to $50/MWh in D.C. and New Jersey for Tier 1 non-carve-out resources. This variation in ACP levels influences the market price for RECs. LSEs in states with a high ACP are willing to pay more—up to the ACP amount—for RECs, providing an additional impetus to develop more renewable energy resources that meet the applicable state's RPS requirements. In states with a solar carve-out, the ACPs for solar RPS compliance tend to be higher than the ACPs for Tier 1 (or analogous classification) renewable energy, reflecting the higher costs of solar as compared to other Tier 1 technologies (at least at the time when the RPS was enacted).

In Maryland, funds generated from ACPs accrue to the SEIF, overseen by MEA. This fund is intended to provide grants and loans in support of the construction of Tier 1 resources. To date, ACP usage by Maryland LSEs has been minimal.[333] Low load growth and a large increase in the number of new renewable energy projects have resulted in more RECs and SRECs than are needed to meet state RPS requirements. As a result, Tier 1 SREC and REC prices for both solar carve-out and non-carve-out resources, respectively, have plummeted.

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production during the second half of the peak period. The solar resource, in this case, takes CPCs away from resources that could have potentially produced 0.5 MW consistently throughout the peak period.

[333] According to the November 2018 Maryland PSC *Renewable Energy Portfolio Standard Report*, ACPs comprised less than 0.1% of total RPS compliance costs in 2017. These payments were almost entirely made for Tier 1 IPL, which has an ACP of only $2/MWh.

In Maryland, spot market Tier 1 non-carve-out REC prices ranged between $5.00-$7.75/MWh in 2018, down roughly 50% from $12.53/MWh in 2016.[334] SREC prices have fallen even more sharply, from $110.51/MWh in 2016 to between $6.50-$14.00/MWh in 2018 according to spot market price data. Although the passage of SB 516, which increased the Maryland RPS, has caused SREC prices to increase to between $50-$60/MWh, SREC prices are still below the ACP.[335] The complex interrelationships of REC prices, project development, ACP levels, and power supply imports affect Maryland's ability to meet its RPS requirement using either RECs or ACPs going forward.

Proponents of further decreasing the ACP emphasize its benefit as a simple, transparent way to limit the maximum cost of the Maryland RPS. Opponents, on the other hand, see decreasing the ACP as counter to the intent of the RPS insofar as it disincentivizes renewable development. This analysis briefly summarizes the strengths and weaknesses of decreasing the ACP beyond the levels set by SB 516. Important considerations include: cost impact, effect on renewable development, and short- and long-term market signals.

Strengths

- *Controls costs* – The ACP functions as a cost cap on REC prices. Although LSEs have not relied on ACPs in recent years, a lower ACP would reduce compliance costs in the event of ACP use. This might occur if the RPS is increased to 100%, which would increase demand for RECs and potentially raise REC prices. In this scenario, a lower ACP would control costs more than the current ACP level.
- *Mitigates short-term spikes in REC costs* – In the face of uncertain REC availability, an ACP helps LSEs manage costs.
- *Provides additional funding to programs that support renewable energy* – In Maryland, ACPs are routed to the SEIF. To the extent that LSEs use the ACP going forward, this funding can indirectly help renewable energy development through grants, loans, and other funding measures.
- *Limited impact on short-term renewable energy deployment* – REC prices have declined considerably in the past few years and are currently below the ACP, even after Ch. 757 increased the RPS percentage requirements and reduced the ACP.

Weaknesses

- *Difficult to set an appropriate ACP level* – The market for RECs is difficult to forecast going forward and, as a result, it is unclear what an appropriate ACP level would be if the goal is to ensure that the ACP is high enough that LSEs focus on securing RECs rather than paying the ACP.
- *Reduces long-term incentive to develop renewables, especially in Maryland* – A lower ACP would discourage additional renewable energy development should REC costs reach equilibrium with the ACP. Renewable energy development would instead shift to markets with higher REC prices. In the case of the solar carve-out, solar development would move out of Maryland and into states with higher SREC prices.

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[334] Marex Spectrometer, *Spectrometer U.S. Environmental*, September 2018.

[335] Ibid. (current figures). Historical figures from: Public Service Commission of Maryland, *Renewable Energy Portfolio Standard Report*, November 2018, psc.state.md.us/wp-content/uploads/FINAL-Renewable-Energy-Portfolio-Standard-Report-with-data-for-CY-2017.pdf.

- *Not responsive to actual market costs* – The ACP acts as a price ceiling and, as a result, undermines the market signal to develop additional renewable energy resources in the event of a REC shortage.

4.11. Limiting Geographic Eligibility to Within PJM

Geographic eligibility (i.e., whether out-of-state resources qualify for a state RPS) is an important consideration when designing and implementing state RPS policies. Restrictive geographic eligibility, such as only including resources within a particular state or bordering states, reduces the available supply of RECs and will likely result in higher REC prices unless there is a surplus of existing RECs to absorb the increased demand. More restrictive geographic eligibility requirements can also concentrate the economic and environmental benefits of the state RPS to a more localized and contained area. Conversely, more lenient geographic eligibility requirements can cause the reverse: RECs are in more plentiful supply and presumably cheaper, but the economic and environmental benefits are spread across more states.

When Maryland enacted its RPS in 2004, the geographic eligibility provisions were quite expansive; RPS-eligible resources could be sourced from within PJM, in a state that is adjacent to PJM, or in a control area adjacent to the PJM region if the electricity is delivered into PJM. In 2008, the Maryland General Assembly changed this provision, limiting the eligibility of out-of-state resources to a control area adjacent to PJM as long as the electricity is delivered into PJM.

A substantial percentage of RECs used to comply with the Maryland RPS come from outside the state (83% of Tier 1 non-carve-out RECs in 2017). A specific policy that limits geographic eligibility to only RPS-eligible resources within PJM or within the state could be challenged as a potential violation of the Dormant Commerce Clause. This clause is generally considered to prohibit state policies that unduly burden or discriminate against out-of-state commerce for economic reasons.

This analysis briefly summarizes the strengths and weaknesses of requiring RPS-eligible generation to be located within the PJM footprint. Important considerations include the location of renewable energy resources, environmental impact, effect on REC prices, economic considerations, and legality.

Strengths

- *Incentivizes renewable energy resources within PJM* – Limiting resource eligibility to within PJM could provide additional impetus for developing new renewable energy power plants in PJM. This development would be spurred by higher REC prices.
- *Potential development of renewable energy projects in Maryland* – Restricting geographic eligibility to within PJM could not only lead to additional development of new renewable energy projects in PJM, but possibly new renewable energy projects within Maryland as well, leading to in-state economic development and benefits.
- *Potential for greater environmental benefits from neighboring states* – An increase in renewable energy power plants being built within PJM may result in environmental benefits, such as a reduction of cross-state air pollution, as the fuel mix displaces pollution-emitting generators with more renewable energy resources.

- *Limited impact on REC prices* – If Maryland is the only state that establishes resource eligibility based on geographic location in PJM, the impact on REC supply would likely be limited, since other states may satisfy their RPS requirements with resources located outside of PJM's footprint.

Weaknesses

- *Potential violation of the Dormant Commerce Clause* – Limiting eligibility of RECs to facilities located within PJM may result in a violation of the Commerce Clause unless the state can prove no non-discriminatory alternatives exist to promote state goals such as environmental protection, diversity of energy supply, and reliability and safety.[336]

- *Potentially higher REC costs* – Limiting eligibility to only states within PJM would reduce the supply of eligible RECs and would presumably increase REC prices until additional RECs are available. This may increase the cost of Maryland RPS compliance for ratepayers.

- *Impact may be modest and may not result in the development of renewable energy projects in Maryland* – Limiting eligible resources to those within PJM does not guarantee development of eligible resources in Maryland. Of the 83% of Tier 1 non-carve-out RECs located outside of Maryland that were used to meet the Maryland RPS in 2017, over 60% came from within PJM.[337] New renewable energy projects that may be developed as a result of this policy could very well come from outside of Maryland.

4.12. Implementing Zero-Emission Credits or Procurement Support for Nuclear Power

The United States has 60 nuclear power plants, consisting of 98 separate reactors, in operation as of August 2018.[338] These plants provide 19.3% of the electricity generation and 53.1% of the zero-carbon generation in the U.S.[339] However, some nuclear plants are financially challenged due to reduced wholesale electricity prices, low growth in electricity demand, and competition from lower-cost generators, particularly natural gas. Within PJM,

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[336] Carolyn Elefant and Edward Holt, *The Commerce Clause and Implications for State Renewable Portfolio Standard Programs*, Clean Energy States Alliance, 2011, cesa.org/webinars/states-advancing-rps-webinar-the-commerce-clause-and-implications-for-state-rps-programs/; Anne Havemann, "Surviving the Commerce Clause: How Maryland Can Square Its Renewable Energy Laws with the Federal Constitution," *Maryland Law Review*, 71(3), 2012, digitalcommons.law.umaryland.edu/mlr/vol71/iss3/6; Joel Mack, Natasha Gianvecchio, Marc Campopiano and Suzanne Logan, "All RECs Are Local: How In-State Generation Requirements Adversely Affect Development of a Robust REC Market," *The Electricity Journal*, 24(4), 2011, sciencedirect.com/science/article/pii/S1040619011000996.

[337] Public Service Commission of Maryland, *Renewable Energy Portfolio Standard Report*, November 2018, psc.state.md.us/wp-content/uploads/FINAL-Renewable-Energy-Portfolio-Standard-Report-with-data-for-CY-2017.pdf.

[338] U.S. Energy Information Administration, "How many nuclear power plants are in the United States, and where are they located?," eia.gov/tools/faqs/faq.php?id=207&t=3; Nuclear Energy Institute, "Nuclear Plants in Regulated and Deregulated States," nei.org/resources/statistics/nuclear-plants-in-regulated-and-deregulated-states.

[339] Includes solar, wind, hydro, biomass and geothermal as zero-carbon generation resources. *Source:* U.S. Energy Information Administration, "What is U.S. electricity generation by energy source?," eia.gov/tools/faqs/faq.php?id=427&t=3.

two nuclear plants with a combined capacity of approximately 2,600 MW are slated to close by 2021.[340,341]

Maryland has one nuclear power plant, Calvert Cliffs, which is jointly owned by Exelon Corporation (Exelon) and Électricité de France and is operated by Exelon. Calvert Cliffs accounted for 33.1% of Maryland's net electricity generation and 72.3% of its emission-free electricity in 2018.[342] The plant, which consists of two reactors with a combined capacity of 1,756 MW, employs 900 workers and pays $22.8 million annually in state and local taxes.[343,344] Calvert Cliffs achieved an average capacity factor of over 97% from 2016-2018.[345]

To date, Exelon has not publicly indicated that Calvert Cliffs faces an imminent threat of closure. Outside of Maryland, however, unfavorable market conditions have drawn the attention of policymakers in other states, with some enacting legislation or regulations with financial mechanisms intended to preserve nuclear plants that are otherwise not economically viable. New York, Illinois, and New Jersey have all implemented ZEC initiatives that require utilities or LSEs to maintain or procure ZECs. Each ZEC represents 1 MWh of generation from a nuclear power plant. ZEC requirements are set either at a specified level or based on a percentage of retail sales. Connecticut also enacted legislation that allows nuclear plants to enter into long-term PPAs guaranteeing a fixed level of revenue. These programs are designed to function separately from the RPS and CES. They can, however, be considered part of a suite of policy tools aimed at encouraging clean energy.

Large-scale nuclear generation has not been included in any state RPS policies to date. The lack of broader adoption is partially due to the concern that, depending on the level of the RPS, including nuclear generation in a state RPS could swamp the market and cause RECs prices to plummet. This, in turn, would sharply reduce or essentially eliminate any need to develop solar, wind, or other renewable energy sources. Additionally, state RPS policies are usually aimed at renewable energy development through the construction of new capacity, whereas the current focus on nuclear energy is forestalling the retirement of existing nuclear power plants.

Proponents of ZECs or subsidies for nuclear power cite the environmental, resilience, and economic benefits of maintaining zero-emission nuclear power. Current and proposed nuclear-support arrangements, however, face concerns regarding interstate commerce, the potentially negative impact of subsidies on electric power markets, and the costs imposed on consumers. This analysis briefly summarizes the strengths and weaknesses of adding

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[340] Planned closures include: Exelon's 805-MW Three Mile Island plant, located in Pennsylvania, by September 2019; and FirstEnergy Solutions Corp.'s (FES's) 1,777-MW Beaver Valley plant, located in Pennsylvania and consisting of two reactors, by October 2021.

[341] Michael Scott, "Nuclear Power Outlook," *Annual Energy Outlook 2018*, U.S. Energy Information Administration, eia.gov/outlooks/aeo/npo.php; Rod Walton, "FirstEnergy Solutions Reluctantly files First Steps to Shutting down Nuclear Plants," *Power Engineering*, power-eng.com/articles/2018/08/firstenergy-solutions-reluctantly-files-first-steps-to-shutting-down-nuclear-plants.html.

[342] U.S. Energy Information Administration, Electricity Data Brower, "Net Generation for All Sectors, annual," eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=vtvv&geo=00000008&sec=g&linechart=ELEC.GEN.ALL-MD-99.A&columnchart=ELEC.GEN.ALL-MD-99.A&map=ELEC.GEN.ALL-MD-99.A&freq=A&ctype=linechart&ltype=pin&rtype=s&pin=&rse=0&maptype=0.

[343] Nuclear Energy Institute, "Fact sheet – Maryland and Nuclear Energy," nei.org/CorporateSite/media/filefolder/resources/fact-sheets/state-fact-sheets/Maryland-State-Fact-Sheet.pdf.

[344] Ibid.

[345] Capacity factor is calculated by comparing total electricity produced compared to the maximum that could be produced assuming all-hours production.

state-level subsidies that support nuclear power either separately or as part of the Maryland RPS. Important considerations include:

- Maryland's ability to achieve GHG reductions and the costs of doing so;
- Policy design (adding nuclear power as a separate tier or carve-out or imposing a PPA requirement);
- Determination of the amount of the subsidy and how it is estimated;
- Defining ratepayer protections and/or cost caps;
- Potential impacts on competitive electric power markets;
- Possible changes to the PJM capacity market; and
- Ensuring flexibility in the event market conditions change.

A forthcoming report on nuclear power in Maryland, as required by Ch. 757, provides additional assessment of policy initiatives and issues related to existing and proposed nuclear power generation in Maryland.

Strengths

- *Retention of economic benefits, including local jobs* – Nuclear generation provides sizeable tax revenue for states with nuclear power plants. Calvert Cliffs employs approximately 900 workers, and it pays approximately $22.8 million in state and local taxes.
- *Carbon-free generation and no air pollution* – The Calvert Cliffs nuclear plant generated approximately 15 TWh in 2018, thereby avoiding the release of almost 10.3 MMT CO_2e.[346] Retiring nuclear would likely be replaced with carbon-emitting sources, which would also result in increased NOx, SO_2, and particulate matter emissions.
- *Helps maintain fuel diversity* – A diverse power portfolio hedges against higher fossil fuel prices should they occur.

Weaknesses

- *Increases ratepayer costs* – The gross cost to ratepayers for the New York ZEC program is $7.6 billion over 12 years, net of benefits. The gross cost of the Illinois ZEC program to ratepayers is an estimated $235 million annually over 10 years. The gross cost of the New Jersey ZEC program to ratepayers will be approximately $300 million per year for an estimated seven to 10 years.
- *Complex and time-consuming* – ZEC requirements can be complicated to administer and implement, requiring detailed filings and reviews of plant operations and costs to ensure ratepayers are paying the minimum amount necessary to preserve existing nuclear power plants, and potentially procurements for ZECs.
- *Age of Calvert Cliffs* – Although the operating license for Calvert Cliffs does not expire until 2034 for Unit 1 and 2036 for Unit 2, commercial nuclear reactors to date have not operated for 50 years or more without being retired. Calvert Cliffs'

[346] Nuclear Energy Institute, "Fact sheet – Maryland and Nuclear Energy," nei.org/CorporateSite/media/filefolder/resources/fact-sheets/state-fact-sheets/Maryland-State-Fact-Sheet.pdf.

two reactors are 41 and 42 years old. Therefore, it is possible that the reactors would retire within the next eight to nine years. If so, Calvert Cliffs would not be available to help Maryland meet its goal of reducing GHG emissions by 2030.

- *Court challenges and Dormant Commerce Clause concerns* – New York and Illinois have faced challenges in federal court regarding ZEC programs, although both were upheld by the U.S. Court of Appeals for the Second Circuit and Seventh Circuit, respectively. It is possible that Maryland could face additional legal challenges should the state adopt a ZEC-type program and could face different court rulings.
- *Public concerns and opposition* – Although U.S. nuclear plants have operated safely for decades, nuclear power accidents have raised public concerns regarding whether nuclear power is safe and raised opposition to nuclear power more generally.
- *Plant is still profitable* – Using forward prices through its RPM capacity market, PJM projects that Calvert Cliffs will be profitable through at least 2021, suggesting subsidies may not be needed.
- *Long-term waste disposal* – No permanent long-term solution to store radioactive waste from nuclear power plants exists. The U.S. Congress designated Yucca Mountain in Nevada to store waste from nuclear power plants. However, the Yucca Mountain site is highly contested and, to date, no long-term disposal facilities have been developed. Fourteen states prohibit building new nuclear plants until the issue of a long-term storage solution for the over 80,000 MT of nuclear waste currently stored at U.S. nuclear plants is resolved.

4.13. Excluding Certain Technologies from the Maryland RPS

This section addresses the question of whether excluding individual technologies from the Maryland RPS could affect the ability of LSEs to meet current and future requirements of the policy.[347] As discussed in Section 1.3, "History of the Maryland RPS" the Maryland RPS has changed several times since its inception in terms of which resources are eligible to meet RPS requirements. Excluding resources, all else equal, reduces the supply of available RECs and increases REC costs. The reverse also applies; that is, adding technologies increases the supply of RECs and decreases REC costs. However, changes to the Maryland RPS do not occur in a vacuum. Maryland accepts RECs from resources located throughout PJM, as well as outside of PJM if the power is transmitted into PJM. Likewise, nine other states in PJM have RPS requirements and also accept RECs from throughout PJM. Although there are differences in resource eligibility among states with an RPS requirement, there are enough eligible resources in common between the states that the market for eligible RECs can be viewed as a PJM-wide market. As a result, the outcome of changing the resources that are eligible for the Maryland RPS emerges from complex, market-level interactions between state requirements.

To unpack this complexity, this section begins with a review of the broader availability of RECs within PJM, as well as Maryland's relative share of PJM-wide REC demand. It also calculates the responsiveness of supply to changes in demand (i.e., the supply elasticity) at several points in recent history. Next, the section isolates individual technologies and identifies the expected impact on the PJM-wide REC market if they are removed from the

[347] Note that the subsequent discussion reviews the effect of eliminating different RPS resources from Maryland RPS eligibility only for the purposes of assessing the implications of the change, or similar adjustment, on REC supplies in PJM. Assessment of the employment, environmental, or other impacts is outside the scope of this section.

Maryland RPS. The section concludes with a recap of the anticipated effect of changes in resource eligibility on Maryland's ability to meet current and future RPS targets. Key findings from this analysis include:

- A relatively broad pool of resources is available to address the Maryland RPS requirement. These resources, which also serve other state RPS policies, collectively generated 37.6 million RECs in 2018 versus a total REC demand in Maryland of 10.9 million. The Maryland RPS requirements amounted to 18.9% of total RECs retired in PJM in 2018.
- REC availability and pricing equilibrate across all of PJM, reducing the effect of changes on any one state RPS policy.
- Black liquor, MSW, land-based wind, and small hydro have the largest impact on Maryland's ability to meet current and future targets. Together, these resources comprised 83.2% of the RECs used to comply with the Maryland RPS in 2018. Excluding other resources would have minimal effect.
- Maryland is the only state in PJM that includes black liquor as an eligible Tier 1 resource besides Pennsylvania, where black liquor facilities must be located in-state to be eligible. Consequently, removing black liquor from the Maryland RPS would decrease the supply of PJM renewable generation. This has the potential to increase REC prices. Black liquor, however, has a relatively small (1.5% of all qualified RECs) and declining market share in PJM and therefore it exerts minimal influence over REC prices or the ability of LSEs to meet RPS requirements.
- Eliminating land-based wind, small hydro or MSW from the Maryland RPS would have limited impact on REC availability because displaced RECs would be absorbed in other states within PJM and replaced by other eligible resources.
- Based on the 50% Maryland RPS scenario from the interim report, eliminating both MSW and black liquor may create short-term supply deficits due to the simultaneous effect of increased demand and reduced supply. This effect, however, only applies in the short run. Additionally, by 2030, excluding these resources will have minimal impact on Maryland's ability to meet its RPS requirements or the overall REC availability and costs in PJM.

4.13.1. Maryland's Position in the PJM REC Market

In 2018, PJM certified over 83.4 million RECs within PJM-GATS from a wide array of renewable generators.[348] Approximately 37.6 million of these RECs, or just over 45%, were eligible for the Maryland RPS.[349] This breaks out into 28.5 million Tier 1 non-carve-out, 1.1 million Tier 1 solar, and 8.1 million Tier 2 eligible RECs. Maryland's actual REC requirements during this period, meanwhile, were just over 10.9 million RECs, inclusive of approximately 8.5 million Tier 1 non-carve-out, 0.8 million Tier 1 solar, and 1.6 million Tier 2 RECs, based on REC retirements tracked in PJM-GATS. The number of Tier 1 non-carve-

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348 Inclusive of all states in PJM (and the District of Columbia) with an RPS except Michigan and North Carolina, both of which track REC retirements outside of PJM-GATS. However, RECs generally flow freely between PJM-GATS and the Michigan and North Carolina tracking systems, known as MIRECs and NC-RETS, respectively. For example, MIRECs identified 299,798 RECs imported from PJM-GATS and 3,035 RECs exported to NC-RETS in 2017-2018 in its latest annual report (*see:* mirecs.org/wp-content/uploads/sites/4/2018/10/MIRECS-2017-Annual-Report-Public-Version.pdf, Tables 7 and 8). *Source:* PJM-GATS, "Number of Certificates by Fuel," gats.pjm-eis.com/GATS2/PublicReports/GATSCertificatesStatistics/Filter.

349 PJM-GATS, "Number of Certificates by Fuel," gats.pjm-eis.com/GATS2/PublicReports/GATSCertificatesStatistics/Filter.

out RECs required for the Maryland RPS comprised just under 30% of the total number of RECs certified as eligible for the Tier 1 non-carve-out category of the Maryland RPS in 2018, and 10.2% of the total RECs (all categories) certified by PJM. For Tier 2, the number of RECs required for complying with the Maryland RPS amounted to 19.6% of Maryland-eligible Tier 2 RECs and 1.9% of the total available RECs in PJM. This suggests that a relatively broad pool of resources is available to address Maryland's REC demand, prior to accounting for other states' REC demands. Excess Maryland RPS eligible Tier 1 non-carve-out and Tier 2 RECs are banked, used to meet other state RPS requirements, or are otherwise retired.

In the case of the Tier 1 solar requirement, the number of potential Maryland RPS eligible Tier 1 SRECs is limited by Maryland's carve-out requirements. Nevertheless, the number of eligible Tier 1 SRECs still exceeded Maryland's estimated RPS requirement in 2018. Excess Tier 1 SRECs are banked or used to meet Tier 1 non-carve-out requirements in other states. These initial data points, including specific Tier categories, are summarized in Table 4-2.

Table 4-2. RECs Certified in PJM and Maryland Compared to Maryland's RECs Requirement, 2018

	Tier 1 Non-Carve-out	Tier 1 Solar	Tier 2	TOTAL
PJM RPS-Eligible RECs				**83,408,686**
Maryland RPS-Eligible RECs	28,485,118	1,069,550	8,074,434	**37,629,102**
% of All PJM RECs	*34.2%*	*1.3%*	*9.7%*	***45.1%***
Maryland RPS Requirement	8,515,665	846,256	1,580,350	**10,942,271**
% of All PJM RECs	*10.2%*	*1.0%*	*1.9%*	***13.1%***
% of MD RECs	*29.9%*	*79.1%*	*19.6%*	***29.1%***

Source: PJM-GATS, "Number of Renewable Certificates by Fuel," gats.pjm-eis.com/gats2/PublicReports/GATSCertificatesStatistics/.

Of the states in PJM that track RECs using PJM-GATS, Maryland's retirements equaled approximately 18.9% of the 57.7 million RECs retired in PJM in 2018, as shown in Table 4-3. The total number of RECs certified by PJM each year is in excess of retirements within PJM.

Table 4-3. RECs Retired in PJM, by State, 2018[1],[2]

State	Tier 1 Solar	Tier 1 Non-Carve-out and RPS Compliance[3]	Tier 2	TOTAL
MD	**846,256**	**8,515,665**	**1,580,350**	**10,942,271**
DE	127,452	688,582	0	**816,034**
DC	67,893	1,684,954	112,592	**1,865,439**
IL	76,109	4,034,884	0	**4,110,993**
NJ	2,357,814	9,166,102	1,758,180	**13,282,096**
OH	200,620	5,124,597	0	**5,325,217**
PA	596,481	9,182,921	11,623,329	**21,402,731**
TOTAL	**4,272,625**	**38,397,705**	**15,074,451**	**57,744,781**

[1] In instances where the reporting year spans multiple years (e.g., June 2017 – May 2018), the later year is used for categorization purposes. *Source:* PJM-GATS, "RPS Retired Certificates for Reporting Year 2018," gats.pjm-eis.com/GATS2/PublicReports/RPSRetiredCertificatesReportingYear/Filter.

[2] Although not included in the table, Michigan and North Carolina data are available from the following *Sources:* Michigan Renewable Energy Certification System Public Reports, mirecs.org/public-reports/; North Carolina Renewable Energy Tracking System, "REC Issuance and Retirements," portal2.ncrets.org/myModule/rpt/myrpt.asp?r=110.

[3] For purposes of this analysis, the term "Tier 1 Non-Carve-out," in terms of REC retirements, will be considered inclusive of the "RPS Compliance" category of states without a "tiers" distribution.

As shown above, Maryland REC retirements and requirements comprise a moderate share of all PJM RECs. To the extent that state RPS policies within PJM are reasonably consistent in terms of resource eligibility, a broad stock of RECs is available to respond to any changes in Maryland RPS requirements with minimal effect on REC prices or overall supply. Additionally, within the PJM REC market, resources displaced from the Maryland RPS can generally supply RECs in other PJM states. This, in turn, puts downward pressure on prices elsewhere that then incentivizes resources to instead support the Maryland RPS to the extent that Maryland REC prices are higher. In other words, REC availability and pricing equilibrate across all of PJM, reducing the effect of changes in any one state's RPS.

Besides the equilibration of existing resources, residual increases in REC prices will also signal to developers that they can potentially earn a return from building additional new, eligible resources. That is, changes in resource eligibility that decrease the total availability of RECs and result in increasing REC prices will incentivize the development of new resources. Equivalently, if generators from outside of PJM find that the economics associated with the sale of power and RECs in PJM are more attractive than they were previously, they can increase the number of RECs available for use to satisfy the RPS requirements of the states within PJM. In both cases, the end result is full compliance with RPS requirements in the long run, up to the point of the ACP (if one exists).

Another way to describe the market response discussed above is that REC supply is thought to be elastic in the long run, meaning capable of responding to price signals and re-equilibrating. It is difficult to develop a full supply curve for PJM-area RECs due to the complexity of the overall REC market and the lack of price transparency. However, it is possible to develop several short-term point elasticities for the supply of Maryland RECs using quantity demanded and price data published by the Maryland PSC. For example, from 2015-2016, the average price of Tier 1 non-carve-out RECs decreased from $13.87 to

$12.52, while the quantity of Tier 1 non-carve-out RECs obligated by the Maryland RPS increased from 6,131,624 to 7,210,870. The resultant point elasticity is 1.81.[350] An elasticity greater than one indicates that supply is more responsive than demand (i.e., elastic) in a specified period. In this case, the high elasticity reflects that the amount of renewable generation increased faster than the increase in RPS requirements from 2015-2016. This increase in supply drove down REC prices.

In comparison, an elasticity less than one would indicate that supply is less responsive than demand (i.e., inelastic), at least in the short term. This is the case from 2014-2015 and from 2016-2017, which have point elasticities of 0.06 and 0.07, respectively. From 2014-2015, prices increased at a greater rate than the increase in quantity demanded. From 2016-2017, prices fell at a faster rate than the decline in quantity demanded. In the latter case, inelastic supply suggests that eligible generators oversupplied RECs in 2017 relative to the quantity demanded. This evidence supports the claim that REC supply is currently more than sufficient to meet RPS targets in the immediate future. Point elasticities are necessarily limited in what they indicate, especially as the REC supply and demand curves shift over time in response to changes in the costs of renewable technologies, state RPS requirements, and more. Nevertheless, they generally suggest that the availability of RECs in PJM has substantially increased, in some years outpacing change in REC demand. Figure 4-1 illustrates the relative change of Maryland Tier 1 non-carve-out REC prices and quantity requirements for the years discussed above.

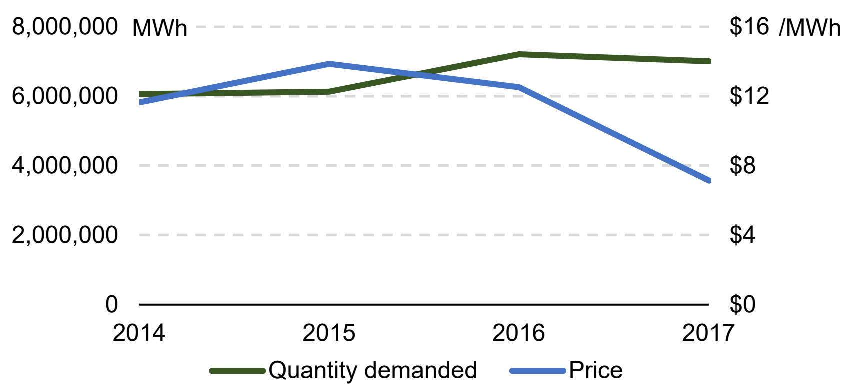

Figure 4-1. Year-over-Year Change in Maryland Tier 1 Non-Carve-out REC Requirements and Prices

Source: Maryland PSC *Renewable Energy Portfolio Standard Reports*.

The Tier 1 non-carve-out eligible resources that have historically seen the greatest use for compliance with the Maryland RPS—black liquor, MSW, land-based wind, and small hydro—

[350] The formula for point elasticity is:

$|(\Delta qd / qd) / (\Delta p / p)|$

where:

"qd" is quantity demanded; and
"p" is price.

The calculation for the point elasticity of changes from 2015 to 2016, for example, is:

$|(\Delta qd / qd) / (\Delta p / p)| =$
$|(1{,}079{,}256 / 6{,}062{,}635) / (-\$1.35 / \$13.87)| =$
$|(0.1760) / (-0.0973)| =$
$|-1.81| =$
$1.81.$

have the largest impact on Maryland's ability to meet current and future targets. For example, these four resources accounted for 83.2% of RECs used to comply with the Maryland RPS in 2018, according to data from PJM-GATS. Relatedly, these resources could also potentially cause the greatest changes in the REC market if removed, both in terms of new resource entry and revised REC flows within the PJM-wide market.[351] BFG, other biogas, geothermal, and agricultural waste resources have been used only in small amounts for compliance. LFG and wood waste have also been used for Maryland RPS compliance in smaller amounts, albeit more consistently over time. Because LFG, wood waste, BFG, other biogas, geothermal, and agricultural waste contribute only minimally to Tier 1 non-carve-out compliance, especially in comparison to the broader pool of PJM renewable energy resources, the implications of these resources no longer being eligible to meet the Maryland Tier 1 non-carve-out RPS requirements would be correspondingly minimal. In other words, the effect on resource availability, Maryland's ability to meet its RPS goals, and REC prices would be small. Table 4-4 quantifies each of these resources' share of Maryland REC retirements as well as their presence among all PJM certified RECs in 2018. The subsequent subsections review in further depth the impact on RPS compliance of removing the major resources listed above.

Table 4-4. PJM RECs Compared to RECs Retired in Maryland, by Fuel Source, 2018

Fuel Source	RECs Retired in Maryland		RECs Available in PJM	
	GWh	%	GWh	%
Agr. Biomass	0.0	0.0%	24.1	0.0%
BFG	-	0.0	575.0	0.9
Black Liquor	1,279.1	11.7	4,273.6	6.8
Geothermal	2.7	0.0	1.9	0.0
Hydro (large and small)	2,621.3	24.0	14,455.7	22.8
LFG	394.5	3.6	3,641.5	5.8
MSW	978.5	8.9	4,284.6	6.8
Other Biogas	87.3	0.8	194.1	0.3
Other Biomass Liquids	-	0.0	13.0	0.0
Solar (incl. Solar Thermal)	846.3	7.7	7,233.8	11.4
Wood Waste	502.8	4.6	3,558.3	5.6
Wind	4,229.8	38.7	25,016.9	39.5
TOTAL	**10,942.3**	-	**63,272.5**	-

Source: PJM-GATS.

Note: PJM's listing of resources is not equivalent to Maryland's listing. The PJM fuel sources are allocated on the basis of similarity. Large and small hydro resources are grouped together because PJM-GATS does not separately distinguish small hydro resources on the basis of size. PJM resources that have never been used for Maryland RPS compliance are excluded.

[351] Eliminating large hydro as a Tier 2 resource is not expected to have any impact because by doing so, Maryland would also eliminate the Tier 2 requirement and corresponding REC obligations.

4.13.2. Excluding Black Liquor

Maryland is the only state in PJM that includes black liquor as an eligible Tier 1 resource besides Pennsylvania, where black liquor facilities must be located in-state to be eligible.[352] As a consequence, if Maryland were to modify the Tier 1 eligibility criteria to exclude black liquor, the impact would be to increase the gap between PJM renewable generation and PJM RPS requirements by the amount of black liquor being used by Maryland as a Tier 1 resource. That is, Maryland would need to replace black liquor with other renewable energy resources from the pool of available resources in PJM (or potentially adjacent to PJM with service into the region) that meet Maryland's eligibility requirements. The displaced black liquor credits would not be available to meet other states' RPS standards, meaning the total supply of available RECs would decrease. As noted earlier, a decrease in the supply of RECs to meet the overall PJM-wide RPS requirements would increase the price of RECs relative to the status quo. However, it would also induce market responses in the form of increased renewable energy project development.

The ultimate price effects of eliminating black liquor eligibility would likely be small, both because the supply of RECs in PJM is in excess of RPS demand and also because black liquor's role in the Maryland RPS is declining. Black liquor has historically been one of the primary resources used for complying with Tier 1 of the Maryland RPS. However, it is not anticipated that additional black liquor resources will go into service going forward; no additional black liquor facilities have been recently developed in PJM and none are listed in the PJM Queue as of January 2019. There has been a steady increase in the number of black liquor RECs used to comply with the Maryland RPS, increasing from 240,282 MWh in 2006 to as high as 1,668,231 MWh in 2017.[353] At the same time, however, black liquor's share of Maryland's Tier 1 requirements peaked at 24% in 2014 and has decreased in the years since as the overall Tier 1 RPS percentages have increased.[354] In 2018, Maryland retired 1,279,124 MWh of RECs from black liquor, equal to approximately 11.7% of all REC retirements.[355] This same trend of declining market share also applies to PJM overall. Black liquor RECs make up a very small portion of this overall market. The black liquor RECs retired in 2018 to meet Maryland RPS requirements accounted for 1.5% of all available RECs tracked by PJM-GATS.

Because black liquor has a relatively small and declining market share, it exerts minimal influence over the PJM-wide REC price (i.e., it is not the marginal resource). The change in Maryland REC prices from altering black liquor resource eligibility is therefore limited to the small degree by which PJM-wide REC prices would increase due to a short-term decrease in REC supply. In summary, it is expected that a reduction of available black liquor RECs can be replaced with minimal short- or long-term effect on REC prices, or Maryland's ability to meet its RPS requirements.

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[352] The District of Columbia RPS counted black liquor as a Tier 1 resource until 2017; it is now classified as a Tier 2 resource. The Tier 2 category will expire after 2019. Delaware has two black liquor facilities that are listed as certified for the state RPS, but those facilities are not represented in the compliance reports for 2016-2017.

[353] Public Service Commission of Maryland, *Renewable Energy Portfolio Standard Reports*, psc.state.md.us/commission-reports/.

[354] Ibid.

[355] PJM-GATS, "RPS Retired Certificates for Reporting Year 2018," gats.pjm-eis.com/GATS2/PublicReports/RPSRetiredCertificatesReportingYear/Filter.

4.13.3. Excluding Onshore Wind

The expected impact of potentially eliminating black liquor is different than the potential effect of eliminating onshore wind power.[356] Because other states in PJM accept RECs sourced from onshore wind power projects as eligible to satisfy Tier 1 requirements, any Tier 1 RECs from onshore wind that are not accepted in Maryland would simply be used by other states in PJM. This would subsequently "free up" Tier 1 RECs from other Maryland-eligible sources (e.g., qualifying biomass, LFG, and small hydro) upon which other states previously relied. In essence, the allocation of RECs from various widely accepted sources would change, but the overall number of RECs available to meet Tier 1 requirements in PJM would not. As a result, there would be no significant changes in the pricing of RECs in PJM, nor would there be any change in the overall gap between the aggregate PJM Tier 1 RPS requirement and the amount of Tier 1 generation coming from PJM.

The replacement effect identified for wind would apply as long as the amount of wind-sourced Tier 1 RECs no longer used by Maryland to meet its RPS requirements is less than the number of Tier 1-eligible RECs available in PJM from other renewable energy resources and used by other states. Alternatively stated, if there are sufficient Tier 1 RECs in PJM sourced from generation other than wind to fully replace the wind-sourced RECs that would no longer be accepted in Maryland following a hypothetical change in the Tier 1 eligibility criteria, then:

- There would be no impact to the REC markets in Maryland or PJM;
- The prices of Tier 1 RECs in PJM and in Maryland would be unaffected;
- There would be no additional incentives to develop new renewable projects in PJM over and above the incentives that existed prior to Maryland's change in Tier 1 eligibility related to wind-sourced generation;
- There would be no additional incentives for generators outside of PJM to increase imports into PJM compared to the import levels that existed prior to Maryland's change in Tier 1 eligibility related to wind-sourced generation; and
- The magnitude of the gap between PJM renewable generation and renewable energy needed to meet RPS requirements would be unchanged.

The amount of energy sourced from wind that Maryland is projected to use to meet its Tier 1 RPS requirement is well below the amount of energy generated in PJM from other (non-wind and non-solar) sources. In 2018, Maryland met approximately 49.7% of its Tier 1 non-carve-out requirement with wind, equal to approximately 4,229.8 GWh of wind generation out of 8,515.7 GWh of total Tier 1 non-carve-out resources retired. Although this is a large share of Maryland's requirement, it comprises about 14.8% of the non-carve-out RECs certified by PJM-GATS as eligible for Tier 1 of the Maryland RPS in 2018.[357]

4.13.4. Excluding Small Hydro

The rescission of Maryland Tier 1 eligibility for small hydro would result in circumstances similar to that of the elimination of onshore wind eligibility. That is, given that other states in PJM allow the use of small hydro to meet their Tier 1 (or equivalent) requirements, the elimination of this resource from the Maryland RPS would have no significant implications for REC prices in Maryland or elsewhere in PJM. Likewise, it would not affect the ability of

[356] As noted earlier, this discussion is for illustration purposes only—no state with an RPS policy, be it in PJM or anywhere else in the country, is considering excluding onshore wind.

[357] *Source:* PJM-GATS.

any of the states in PJM with an RPS to meet their RPS obligations. This is especially the case because small hydro comprises a relatively small share of all Maryland REC retirements; it represented less than 10% in 2018.[358]

4.13.5. Excluding Municipal Solid Waste

The removal of MSW would have an impact measuring somewhere in between black liquor and the more prevalent RPS eligible resources, including wind, solar, and small hydro. In addition to Maryland, MSW is accepted as a Tier 1 RPS eligible resource in Ohio and Michigan, as a Tier 2 RPS eligible resource in Pennsylvania and New Jersey, and as part of Virginia's and Indiana's voluntary renewable energy goal. However, both Maryland and New Jersey require that the MSW resource be connected with the electric distribution system serving each state, respectively. Although the limited eligibility of MSW among states in PJM could reduce the ability to transfer MSW RECs (albeit to a lesser extent than black liquor), the effect of removing MSW from Maryland RPS eligibility in still likely to be small. MSW makes up a smaller share of Maryland's REC retirements (8.9% of all RECs in 2018) and overall PJM-GATS certified renewable generation (1.2% in 2018) than black liquor. MSW also has greater potential to serve RPS requirements in other states than black liquor.

4.13.6. Meeting Current and Future Targets After Excluding Resources

The above characterization of the PJM market is consistent with the interim report, which indicates that Maryland can meet, or come very close to meeting, its current and future RPS requirements, both at the previously applicable 25% by 2020 level and at the 50% by 2030 level (using interim report assumptions for this scenario). These projections are prior to accounting for banked resources, which can help erase short-term deficits, and market-responsiveness. The interim report also suggests that Maryland can meet these requirements in the absence of resource types like black liquor. Table 4-5 compares projected net available resources (i.e., expected renewable energy generation minus the expected renewable energy requirement) under each scenario (i.e., 25% Maryland RPS, and the 50% RPS with an expanded solar and offshore wind carve-out). Both cases assume no change in other state RPS policies through 2030. Additionally, the growth rate of renewable energy capacity in PJM is held constant except for offshore wind.[359]

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[358] Ibid.

[359] *See:* Section 3.1, "Meeting Existing and Future Targets" and Appendix F, "Assumptions for the Interim Report" for further explanation of the assumptions made in the interim report, as applicable to this subsection.

Table 4-5. Comparison of Net Available Renewable Energy Resources in PJM, Current Maryland RPS and a 50% Maryland RPS (GWh)

	Renewable Energy Resource	2018	2019	2020	2025	2030
PROJECTED RPS REQUIREMENTS IN MD AND PJM[1]	**Maryland (25% RPS)**					
	Tier 1 Solar	916	1,189	1,528	1,543	1,559
	Tier 1 Non-Carve-out	8,730	11,249	13,753	12,669	12,797
	ORECs	-	-	-	1,369	1,369
	PJM (includes Maryland)					
	Tier 1 Solar	5,095	6,457	7,509	8,530	7,025
	Tier 1 Non-Carve-out and RPS Compliance	49,354	57,206	64,798	93,763	110,428
	ORECs	-	-	-	1,369	1,369
	COMBINED (incl. carve-outs) [A]	**54,449**	**63,663**	**72,307**	**103,662**	**118,822**
PROJECTED RPS REQUIREMENTS IN MD AND PJM ASSUMING 50% MARYLAND RPS[2]	**Maryland (50% RPS)**					
	Tier 1 Solar	916	3,353	3,667	7,100	9,042
	Tier 1 Non-Carve-out	8,730	11,097	11,919	11,422	15,902
	ORECs	-	1,524	1,528	6,174	6,236
	PJM (includes Maryland)					
	Tier 1 Solar	5,095	8,621	9,648	14,087	14,508
	Tier 1 Non-Carve-out and RPS Compliance	49,354	57,054	62,964	92,516	113,533
	ORECs	-	1,524	1,528	6,174	6,236
	COMBINED (incl. carve-outs) [B]	**54,449**	**67,199**	**74,140**	**112,777**	**134,277**
PROJECTED RENEWABLE GENERATION IN PJM	Solar	13,065	16,255	19,445	39,111	78,666
	Wind	27,553	29,776	31,999	37,556	43,113
	Offshore Wind (25% MD RPS)	-	-	-	1,369	1,369
	Offshore Wind (50% MD RPS)	-	1,524	1,528	6,174	6,236
	Hydro	10,756	10,874	10,992	11,583	12,175
	Qualifying Biomass	2,888	2,925	2,961	3,145	3,329
	Methane	4,026	4,146	4,267	4,869	5,471
	Other	5,842	5,842	5,842	5,842	5,842
	COMBINED (25% MD RPS) [C]	**64,130**	**69,818**	**75,506**	**103,475**	**149,965**
	COMBINED (50% MD RPS) [D]	**64,130**	**71,342**	**77,034**	**108,280**	**154,832**
NET AVAILABLE RESOURCES[3]	**25% MD RPS [C - A]**	**9,681**	**6,155**	**3,199**	**-187**	**31,143**
	50% MD RPS [D - B]	**9,681**	**4,143**	**2,894**	**-4,497**	**20,555**

Note: All inputs based on data from the interim report. As a result, estimates for 2018 and 2019 may not match 2018 and 2019 actuals. Excludes Tier 2 requirements.

[1] Assumes 25% Maryland RPS with 2.5% solar and 2.5% offshore wind carve-outs.

[2] Assumes 50% Maryland RPS with 14.5% solar and 10% offshore wind carve-outs, and that all other state RPS policies remain unchanged.

[3] Represents non-solar-carve-out Tier 1 RPS requirements in PJM compared to projected available PJM renewable energy generation, inclusive of offshore wind and excess solar (i.e., solar generation in excess of solar carve-out requirements).

The “Other” category of PJM generation resources in Table 4-5 includes both MSW and black liquor generation (as well as a small amount of geothermal and other miscellaneous resources). As discussed above, these resources are not expected to grow over the next decade, as also indicated by the static amount of projected “Other” generation through 2030. Under the 25% and the 50% Maryland RPS scenarios, the “Other” category prevents a deficit in the amount of available resources as soon as 2019 and 2020, respectively. By 2030, however, the exclusion of MSW and black liquor has minimal impact on RPS compliance across the entirety of PJM because of the surplus of net available resources. Thus, in the long run, excluding these resources has minimal impact on Maryland’s ability to meet its RPS requirements or on overall REC availability and costs in PJM

4.14. Allowing Tier 1 RECs from Anywhere in the Contiguous United States

This section evaluates the costs, benefits, and legal implications of allowing Tier 1 non-carve-out RECs to be sourced from anywhere in or off the coast of the contiguous United States, rather than requiring that such RECs come from generators located in PJM or a control area that is adjacent to PJM.[360] Throughout the following discussion, this change is referred to as “removing geographic restrictions.”

For the purposes of estimating the impacts of removing geographic restrictions, this analysis assumes Maryland has the entirety of renewable energy generation in the contiguous U.S. available as a source of RECs, but that many of these resources are already committed or otherwise unavailable. Most renewable energy generation serves either the compliance market or the voluntary market. The compliance market includes sales from new and existing renewables that are used to meet state RPS obligations. The voluntary market includes sales used for utility green pricing, utility renewable contracts, unbundled RECs, competitive LSEs, community choice aggregations, PPAs, and community solar.[361] Utilities also purchase additional RECs outside of these markets and above RPS requirements. Additionally, some RECs are available, but they are intentionally banked for future RPS compliance years. The totality of renewable energy sales (excluding large hydro) in these markets was approximately 424 million MWh in 2017.[362]

Much of this 424 million MWh is unavailable to Maryland LSEs, as it represents generation from existing PPAs, community solar projects, utility contracts, or other sales of renewable energy generation that already contractually designate a buyer of the generation and/or RECs. By design, most RPS compliance markets require renewable energy generation to come from a more limited pool of resources (e.g., within the same regional market or state) than the voluntary market. This restriction of supply increases prices as compared to the voluntary market. With the notable exception of Texas,[363] unbundled REC costs are higher

[360] The Maryland CEJA directed PPRP to conduct “an assessment of the costs, benefits and any legal or other implications of allowing the location anywhere in or off the coast of the contiguous United States of Tier 1 renewable sources that are currently required to be located in the PJM region or in a control area that is adjacent to the PJM region, if the electricity is delivered into the PJM region.” After deliberating with PPRP staff and PPRP/MEA legal counsel, there is not thought to be any legal concerns with allowing RECs for the Maryland RPS to be sourced from anywhere in or off the coast of the contiguous United States. Therefore, this issue will not be addressed further.

[361] For an additional description, *see:* Eric O’Shaughnessy, Jenny Heeter and Jenny Sauer, *Status and Trends in the U.S. Voluntary Green Power Market (2017 Data)*, October 2018, National Renewable Energy Laboratory, nrel.gov/docs/fy19osti/72204.pdf.

[362] Ibid.

[363] Texas RECs are approximately equal to the price of unbundled RECs in voluntary markets. This is because Texas has far surpassed its RPS, has strong wind resources, and has previously developed transmission infrastructure to

in compliance markets than in the voluntary market.[364] Thus, if Maryland removed its geographic restrictions, then the state's LSEs would most likely purchase unbundled RECs from the voluntary market. This market represented 51.7 million RECs in 2017.[365]

Approximately two-thirds of unbundled voluntary RECs came from three states in 2017: Texas (31%), Oklahoma (26%), and Kansas (8%). In all three states, wind is the predominant source of RECs. Further, from mid-2018 to mid-2019, the average price of voluntary RECs from wind generation nationwide was within one cent of the average price for voluntary RECs from all technologies, further suggesting the predominance of wind as a source of unbundled RECs.[366] Thus, this analysis assumes that, by removing geographic restrictions, Maryland would replace its existing Tier 1 non-carve-out resources with wind RECs from the South-Central region. Key findings from this section include:

- Unbundled RECs in voluntary markets usually retail for $1/MWh or less. From 2012-2017, removing geographic restrictions for Tier 1 non-carve-out RECs would have lowered Maryland RPS compliance costs by between approximately $311-$328 million. Unbundled voluntary REC prices are likely to remain low because supply growth continues to outpace demand growth, as gauged using the price elasticity of supply.

- Removing geographic restrictions would likely shift all non-carve-out renewable energy resource development attributable to the Maryland RPS to locations outside of PJM. Likewise, economic development would also shift outside of PJM, as would the economic benefits of these activities.

- If Maryland only procured voluntary RECs from wind, local air quality would no longer be influenced by the Maryland RPS. From 2012-2017, removing geographic restrictions is estimated to increase total CO_2 emissions in PJM by 13.9 million short tons. The impact on SO_2 and NOx emissions is more ambiguous and depends on whether emitting resources that currently qualify for the Maryland RPS continue to operate if geographic eligibility restrictions were removed.

- The cost reductions provided by accepting RECs from anywhere comes at the expense of local and regional economic, environmental, and resource development benefits, as applicable.

4.14.1. Costs

From 2012-2017, the average cost of Tier 1 non-carve-out RECs retired for the Maryland RPS ranged from $3.19-$13.87, as identified in Table 4-6. By contrast, unbundled RECs in voluntary markets usually retail for $1/MWh or less, as shown in Figure 4-2. Thus, LSEs in Maryland could conceivably reduce their RPS compliance costs if restrictions on geographic eligibility in the Maryland RPS were removed. Table 4-6 shows a range for the estimated annual cost savings that Maryland would have realized by using unbundled voluntary RECs rather than geographically restricted Tier 1 non-carve-out RECs for the years 2012-2017. These estimates assume an annual average price of between $0.50-$1.00/MWh. Over the six-year period shown, the use of unbundled voluntary RECs would have lowered Maryland

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connect windy areas with load centers. All of these factors contribute to very low wind generation costs and high wind generation availability in Texas. As a result, Texas is the largest source of renewable energy production in the United States and often provides the marginal renewable resource in voluntary markets.

[364] Eric O'Shaughnessy, Jenny Heeter and Jenny Sauer, *Status and Trends in the U.S. Voluntary Green Power Market (2017 Data)*, National Renewable Energy Laboratory, October 2018, nrel.gov/docs/fy19osti/72204.pdf.

[365] Ibid.; excludes Alaska and Hawaii.

[366] Based on data from Spectron (2019).

RPS compliance costs by between approximately $311-$328 million. This is equal to a 90-95% reduction in Tier 1 non-carve-out RPS compliance costs over the same time period.

Table 4-6. Estimated Cost Savings from Eliminating Geographic Restrictions for Tier 1 Non-Carve-out RECs in the Maryland RPS, 2012-2017

Year	Avg. Tier 1 Non-Carve-out Price for MD LSEs ($/MWh)	MD Tier 1 Non-Carve-out REC Retirements	Estimated Savings by Using Unbundled Voluntary RECs $0.50/MWh	Estimated Savings by Using Unbundled Voluntary RECs $1.00/MWh
2012	$3.19	3,907,136	$10,510,196	$8,556,628
2013	7.70	4,873,572	35,089,718	32,652,932
2014	11.64	6,062,186	67,532,752	64,501,659
2015	13.87	6,135,152	82,026,982	78,959,406
2016	12.53	7,216,439	86,813,761	83,205,542
2017	7.14	7,017,686	46,597,435	43,088,592
TOTAL Savings			**$328,470,844**	**$310,964,759**

Source: Average REC prices sourced from Maryland PSC *Renewable Energy Portfolio Standard Reports*. Tier 1 non-carve-out REC retirements are sourced from the same reports, as well as PJM-GATS.

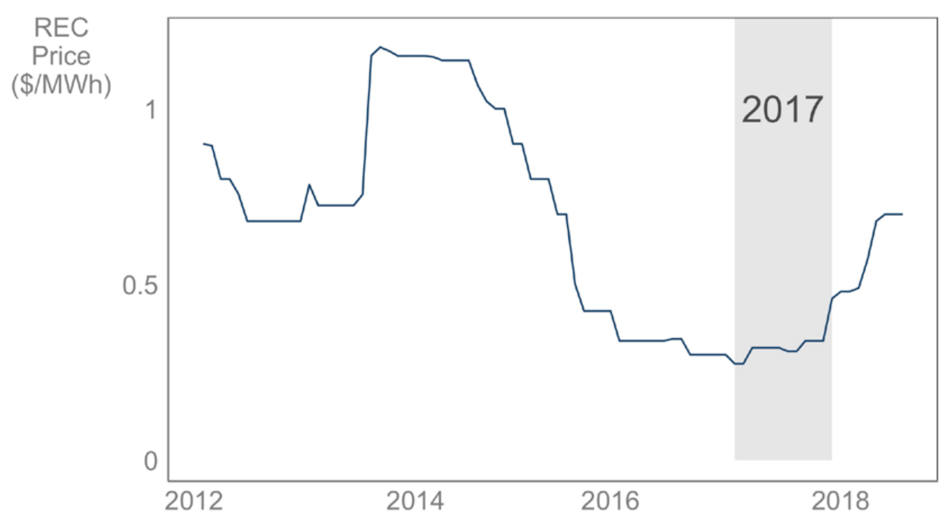

Figure 4-2. Unbundled Voluntary REC Prices, January 2012 – August 2018

Source: NREL, *Status and Trends in the U.S. Voluntary Green Power Market: 2017 Data*, 2018, nrel.gov/docs/fy19osti/72204.pdf.

The savings presented in Table 4-6 assume that unbundled voluntary REC prices would not change following an increase in demand caused by Maryland shifting its Tier 1 non-carve-out REC requirement to the unbundled voluntary REC market. One way to gauge whether this is the case is to evaluate the price elasticity of supply, meaning the responsiveness of supply (i.e., the number of unbundled voluntary RECs sold) to changes in its price (i.e., the unbundled voluntary REC price). Texas REC prices were used as a proxy for unbundled voluntary REC prices due to the lack of readily available national unbundled REC data, as well as the close correlation of the two data series. Texas is the largest source of renewable energy production in the United States and often provides the marginal renewable energy resource in voluntary markets. Figure 4-3 shows changes in Texas REC prices as compared to unbundled voluntary REC sales from 2012-2017. As apparent in this graph, prices have continued to fall despite an increase in unbundled voluntary RECs sold.

The point elasticities for 2012-2017 are consistently less than one.[367] An elasticity less than one indicates that supply is less responsive than demand (i.e., inelastic), which suggests that eligible generators oversupplied RECs relative to the quantity demand. This evidence supports the claim that REC supply is currently more than sufficient to meet RPS targets in the immediate future. Visually, this is also evident in Figure 4-3 insofar as prices continue to fall despite an increase in unbundled voluntary REC demand.[368] Assuming that supply growth continues to outpace demand growth, unbundled voluntary REC prices are likely to remain low.

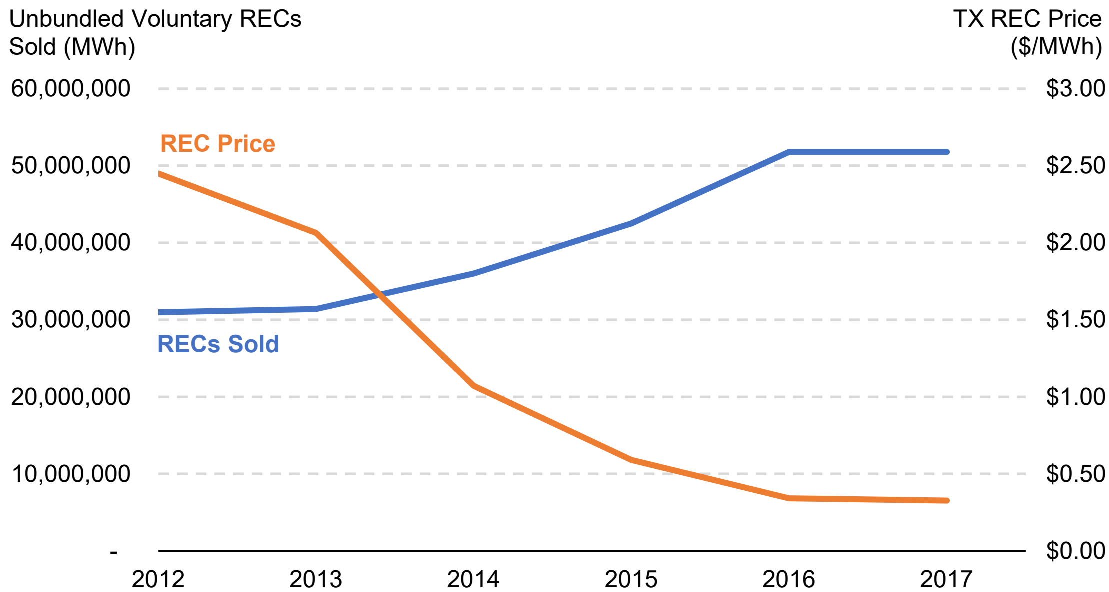

Figure 4-3. Unbundled Voluntary REC Sales Compared to Texas REC Prices, 2012-2017

Source: TX REC prices from S&P; REC Sales from NREL's *Status and Trends in the U.S. Voluntary Green Power Market* (2012-2017).

4.14.2. Renewable Energy Development

The Tier 1 non-carve-out requirement of the Maryland RPS has contributed to the creation of new renewable energy projects throughout PJM and in neighboring states, as well as sustained Tier 1-eligible plants that began operation before 2004 (see Section 2.1, "Deployment of Renewable Energy" and Section 2.6, "Influence of Past Changes to the Maryland RPS"). From 2012-2017, Maryland retired 5,604,963 in-state Tier 1 non-carve-out RECs and 29,596,347 RECs from out-of-state Tier 1 non-carve-out resources for an overall total of 35,201,310 RECs. The Maryland RPS is unlikely to have played a similar role in Maryland, PJM, and surrounding states without geographic restrictions because prices in

[367] The formula for point elasticity is |(Δqd / qd) / (Δp / p)|, where "qd" is quantity demanded and "p" is price.

[368] Note that by 2012, Texas had already surpassed its RPS requirement of 10,000 MW of renewable energy capacity by 2025, only including wind generators. Thus, the Texas RPS requirements are not a major contributor to REC demand.

these regions generally exceed prices in other portions of the national market, as discussed above.

Some of the RECs retired for the Maryland RPS are from resources that, absent Maryland RECs, are still likely to have been developed with the support of other state RPS policies and their REC payments. However, removing Maryland REC demand has the net effect of decreasing REC demand throughout the PJM-wide REC market, thereby putting downward pressure on REC prices. Reduced REC prices will act to discourage development of new renewable energy projects. Thus, as much as 35 million MWh of renewable energy generation in the greater PJM region from 2012-2017 may not have existed had Maryland removed geographic restrictions.

Whether the Maryland RPS could influence renewable energy development in voluntary markets after removing geographic restrictions is an open question. One method to assess this question is to compare the relative size of the market for Tier 1 non-carve-out RECs in PJM and the market for unbundled voluntary RECs, as shown in Table 4-7. In 2017, the Maryland RPS was responsible for 29% of the Tier 1 non-carve-out RECs retired in PJM. By comparison, the Maryland RPS would have been responsible for 12% of the unbundled voluntary RECs retired in 2017, inclusive of a small number of unbundled voluntary RECs from PJM. Thus, although the Maryland RPS could potentially support renewable energy development in voluntary markets if geographic restrictions were removed, this influence is less pronounced.

Table 4-7. Comparison of Tier 1 Non-Carve-out REC Retirements: Maryland RPS Compliance, All RPS Requirements in PJM, and the Unbundled Voluntary REC Market, 2017

	PJM Tier 1 Non-Carve-out Market[1]	National Unbundled Voluntary Market
RECs Retired	24,149,583	51,744,000
Maryland Tier 1 Non-Carve-out RPS Requirement	7,017,686	7,017,686
% of Market	*29%*	*12%*

Sources: PJM GATS, "RPS Retired Certificates for Reporting Year 2017;" PJM GATS, "MD - RPS Retired Certificates for Reporting Year 2017;" NREL, *Status and Trends in the U.S. Voluntary Green Power Market: 2017 Data*.

[1] In instances where the reporting year is not a calendar year (e.g., June 2017 – May 2018), the later year is used for categorization purposes.

In the coming years, Maryland's influence in the unbundled voluntary REC market will likely shrink because growth in the state's Tier 1 non-carve-out requirement is likely to be outpaced by growth in the unbundled voluntary REC market. Between 2012-2017, the number of unbundled voluntary RECs sold grew by 11.2% per year, on average. Maryland's Tier 1 non-carve-out requirement, meanwhile, is expected to grow substantially between 2019-2020, but by only 1% per year, on average, between 2020-2030.[369] To the extent Maryland does influence renewable energy development, it would likely support continued renewable energy development in the markets that are already prevalent sources of unbundled voluntary REC sales (i.e., Texas and Oklahoma). This is because the renewable energy resources (e.g., wind speed and solar quality) are stronger than in Maryland and development costs are also lower.

[369] This is inclusive of decreased Tier 1 non-carve-out requirements in some years as a result of solar carve-out and offshore wind carve-out requirements. See *Table 1-2* for Maryland's current percentage of renewable energy required by category and year through 2030.

4.14.3. Air Emissions

Although some voluntary RECs also have an emissions profile, wind resources are likely to predominate unbundled voluntary REC purchases. Local air quality in Maryland would not directly benefit from these resources due to their location outside of PJM. The transboundary impacts of resources in Texas, Oklahoma, and Kansas on the mid-Atlantic region, including Maryland, are thought to be very low.[370] Rather, Maryland air quality will continue to depend on the emission content of both in-state generation and nearby, out-of-state generation that produces cross-state emissions (e.g., upwind emissions in Pennsylvania).

Table 4-8, which is based on data presented in Section 2.2, "Environment" calculates the PJM-wide carbon content impact from 2012-2017 of Maryland removing geographic restrictions. Assuming the resources supported by the Maryland RPS are replaced by resources that emit at the PJM average emission level for CO_2, PJM generators would have emitted an additional 13.9 million short tons of CO_2 from 2012-2017 as a result of this change. The degree to which these additional CO_2 emissions would impact Maryland depends on the location of the generators and their generator-specific CO_2 emissions.

Table 4-8. Total CO_2 Emissions in PJM with and without Maryland RPS Resources

Year	Net PJM Generation[1] (GWh)	Avg. PJM Emissions[1] (lbs/MWh)	CO_2 Emissions (short tons)	Avg. PJM Emissions, Excluding MD RPS[2] (lbs/MWh)	CO_2 Emissions, Excluding MD RPS (short tons)	Change in CO_2 Emissions (short tons)
2012	790,090	1,092,000	431,389,140	1,095,369	432,719,963	1,330,823
2013	799,842	1,112,000	444,712,152	1,117,723	447,000,740	2,288,588
2014	807,987	1,108,000	447,624,798	1,113,875	449,998,242	2,373,444
2015	786,699	1,014,000	398,856,393	1,020,180	401,287,247	2,430,854
2016	812,536	992,000	403,017,856	997,638	405,308,328	2,290,472
2017	808,230	948,000	383,101,020	955,852	386,274,186	3,173,166
TOTAL	**4,805,384**		**2,508,701,359**		**2,522,588,706**	**13,887,347**

[1] Data reproduced from *Table 2-7*.

[2] Data reproduced from *Table 2-11*.

As compared to carbon content, it is less clear to what extent eliminating geographic restrictions would affect SO_2 and NOx emissions in Maryland. As discussed in Section 2.2.6, "SO2 and NOx Emission Changes as a Result of the Maryland RPS," the Maryland RPS supports some eligible resources that emit SO_2 and NOx emissions. If Maryland-based LSEs ceased purchasing these RECs, they might instead be sold to meet the RPS compliance requirements of other states, all the while continuing to emit.[371] On the other hand, these resources might also retire and be replaced with additional energy imports or alternative in-state resources that emit less SO_2 and NOx.

[370] Brian Sergi, Inês Azevedo, Steve J. Davis and Nick Muller, *Transboundary health damages of air pollution in the U.S.*, 2019, Working Paper.

[371] Note that Maryland is the only state in PJM that allows out-of-state black liquor as a Tier 1 resource, making it more likely that black liquor resources will retire, as discussed in Section 4.13, "Excluding Certain Technologies from the Maryland RPS."

4.14.4. Economic Development

Due to the lower cost of voluntary RECs, removing geographic restrictions on Tier 1 non-carve-out RECs would likely end the use of Tier 1 non-carve-out RECs from in-state plants for Maryland RPS compliance. (According to estimates from NREL, there were no unbundled voluntary RECs produced in Maryland in 2017.[372]) Therefore, the Maryland RPS would no longer support generation by in-state, non-carve-out Tier 1-eligible plants, nor any economic activity associated with this generation. This economic development would instead shift elsewhere. On a historical basis, this would have likely resulted in the retirement of some generators that produce RECs used for the Maryland RPS, as discussed above. Additionally, this shift would likely hinder future in-state economic development. In the near term, however, this change is unlikely to disadvantage existing resources so long as they qualify for other state RPS policies in PJM. Additionally, the Maryland RPS carve-outs for solar and offshore wind are assumed to be unchanged.

[372] Eric O'Shaughnessy, Jenny Heeter and Jenny Sauer, *Status and Trends in the U.S. Voluntary Green Power Market (2017 Data)*, National Renewable Energy Laboratory, October 2018, nrel.gov/docs/fy19osti/72204.pdf, Table A-2.

5. LONG-TERM CONTRACTS FOR RENEWABLE ENERGY

Many states use long-term contracts (LTCs) to meet at least a portion of their RPS requirements. This chapter addresses the key issues associated with Maryland's potential reliance on LTCs to satisfy the state's RPS requirements and also quantifies the cost implications for customers if Maryland were to employ LTCs for renewable energy or RECs/SRECs in the future. The cost impacts associated with reliance on LTCs are highly dependent on the specifics of the arrangements (e.g., the percentage of the RPS to be met with LTCs, the segment of customers that would be affected by the contracts, and the nature of the product to be procured), as well as such factors as the future prices of energy, RECs, and SRECs. Because of the uncertainties surrounding assessment of the future costs and benefits related to use of LTCs, several scenarios were developed for this analysis based on alternative financial assumptions (which importantly affect the life-cycle costs of renewable energy project development), alternative market prices for RECs and SRECs, and differing portions of the overall RPS to be met through LTCs. Additionally, alternative calculations were made based on whether the contemplated LTCs would apply to SOS customers alone (i.e., the costs of the LTCs would be bypassable) or whether the costs would be shared by all customers (i.e., non-bypassable).

This analysis contemplates three different LTC requirement regimes: 15%, 25%, and 40%. These percentages represent the proportion of the Maryland RPS requirement that would be met through the use of LTCs. Under each of these regimes, two types of recovery mechanisms are addressed: either a non-bypassable charge to all customers or a charge to SOS customers only that would be bypassable though opting out of SOS and arranging for generation through a competitive LSE. This study found that under the range of financial and market assumptions considered, reliance on LTCs tended to result in higher costs than meeting RPS requirements through sequential short-term contacts over 20 years. For some of the scenarios considered, the extra costs associated with use of LTCs were *de minimis*. For other scenarios, cost impacts were larger but in all cases below $4.00 per month (net present value [NPV], 2021$) considering both Tier 1 non-carve-out and solar carve-out requirements combined based on typical residential usage of 1,000 kWh per month. The range of quantitative impacts is summarized below:

- All of the scenarios examined resulted in a net cost to consumers; that is, costs on an NPV basis were estimated to be higher with reliance on LTCs for a portion of the RPS requirement than if LTCs were not used.
- The cost impacts related to satisfying a fixed percentage of the RPS requirement for Tier 1 non-carve-out were higher than the analogous cost impacts for satisfying the same percentage of Tier 1 solar. This is due to the greater amount (in percentage terms and, correspondingly, in absolute terms) of the Tier 1 non-carve-out requirement relative to the Tier 1 solar carve-out requirement.
- In the lowest-cost scenario, characterized by high REC/SREC prices and low financing costs, the monthly cost impacts for a typical residential customer were below $0.50 for all years of the analysis period (through 2040) for all percentage requirements (15%, 25%, and 40%) for Tier 1 non-carve-out, and below $0.15/month for the Tier 1 solar carve-out.
- For the highest-cost scenario, characterized by low REC/SREC prices and high financing costs, and using LTCs to meet 40% of the RPS requirement, the monthly cost impacts for a typical residential customer were between $1.70-$2.25/month for all years of the analysis period for Tier 1 non-carve-out, and between $0.65-

$1.20/month for the Tier 1 solar carve-out. The monthly impacts for the lower-percentage scenarios (15% and 25%) were proportionally lower.

In addition to the quantitative analysis, certain key qualitative issues related to LTCs are addressed in this chapter. The principal findings and conclusions resulting from the qualitative analysis are:

- Numerous other states use LTCs to meet RPS requirements to varying degrees. In general, most of these states use LTCs for the purchase of RECs and SRECs, unbundled from energy.
- Whether for unbundled RECs/SRECs or bundled (RECs or SRECs plus energy), most of the other states using LTCs rely on the electric distribution companies (EDCs) to conduct the competitive solicitations and enter into the LTCs. Two states (Illinois and New York) rely on state power agencies to conduct the solicitations and enter into contracts.
- The costs/benefits of LTCs for renewable energy or RECs/SRECs in other states are generally allocated to all electric customers rather than to just SOS customers.
- Restricting the allocation of costs/benefits of LTCs for renewable energy or REC/SECs to SOS customers only could result in market distortions that could cause customer migration into or out of SOS.
    - If the LTCs entail higher-than-market prices, customer migration out of SOS could entail remaining SOS customers bearing higher and higher costs as the SOS customer base declines.
    - If the LTCs entail lower-than-market prices, customers may migrate away from competitive service and into SOS, thereby adversely affecting the development and maintenance of the competitive retail electric market.
- The potentially adverse impacts of LTCs to SOS customers can be mitigated by allocating the costs/benefits to all electric customers (or all customers within a class, e.g., residential customers), or by limiting LTCs to a small percentage of the overall RPS requirement. If a state restricts LTCs to a small percentage of the overall RPS requirement, the benefits of LTCs associated with price hedging and renewable energy industry support would also be reduced.

5.1. Overview of Long-Term Contracts

LTCs for the purchase of either standalone RECs or RECs bundled with energy and capacity provide certain advantages.[373] LTCs for renewable energy are particularly important for states that have restructured their electric utility industry. For states that have retained vertically integrated electric utilities, the utility can construct and own renewable energy projects, or enter into LTCs for energy and RECs. Under restructuring, utilities are typically precluded from owning generation assets and can engage in the sale of generation only under specific circumstances. Furthermore, competitive LSEs are unwilling to incur long-term power or REC commitments, given the uncertainty of future load service obligations. Consequently, compliance with state RPS requirements generally takes the form of short-

[373] Revenue from the sale of ancillary services can also provide a revenue stream for generation resources, though this does not typically represent a significant source of revenue for renewable energy projects, particularly solar and wind resources given their intermittent nature and inability to be dispatched. Consequently, revenues associated with the sale of ancillary services are ignored in this chapter for ease of exposition.

term REC purchases that are not likely to drive the development of new renewable energy projects.

There are numerous variations on how LTCs with renewable energy developers can be structured, including the duration of the contracts, the products being purchased (RECs, SRECs, or energy with RECs or SRECs), the entity acting as the purchaser (e.g., a state power authority or an EDC), the timing of the procurements, and the total amount of LTCs relative to the RPS requirement. Certain approaches may offer benefits not available through other means, or entail risks not incurred by relying on alternative approaches. Additionally, decisions regarding the desirability of LTCs, and the specific nature of the contracts, cannot be made without consideration of current market conditions regarding not only interest rates (which affect the overall cost of renewable energy projects), but also energy prices, which can help define the up-side and down-side risk faced by the purchaser, as discussed later in this chapter. The following section addresses the benefits and risks of LTCs for renewable energy, including a discussion of the benefits and risks associated with LTCs for RECs alone or for a bundled product. The next section examines qualitative factors that should be taken into account when considering whether to adopt LTCs. The next section quantifies, to the extent possible, the cost differential for Maryland consumers resulting from LTCs compared to sequential short-term market purchases. The final section highlights the conclusions emerging from the analysis.

Maryland's consideration of the potential costs/benefits of LTCs would be unnecessary if there were a long-term forward market for energy, capacity, and RECs. If such a market existed, renewable project developers would be able to hedge short-term market prices using long-term forwards. No liquid long-term markets exist, however. Forward markets for energy are liquid only extending out approximately three to four years. The capacity auctions in PJM are for the third year ahead, so capacity prices are known three years forward. RECs markets, like the energy markets, are liquid for three to five years out, but not longer than that, and bid and offered REC prices are generally not reported for more than two to three years into the future. Because no long-term forward markets exist, renewable project developers can only lock in prices for project outputs using long-term, bilateral contracts.

5.2. Benefits and Risks of Long-Term Contracts

The benefits of LTCs, either for standalone RECs or for a bundled product, entail potentially reduced costs to consumers, a method of hedging future costs, and possibly more projects getting developed than would be the case otherwise. The possibly reduced costs to consumers stem from the lower financing costs to renewable energy project developers, due to the reduced risk inherent in the project revenue stream. The reasons for this are associated with the nature of renewable energy projects and the kinds of risks that project developers face in the market. Those risks, in large part, determine the ability of project developers to obtain third-party financing and the cost of that financing.

The costs of renewable energy projects, particularly solar and wind projects, are virtually all related to project construction (materials and land acquisition); only a very small proportion of costs are related to O&M. While virtually all electric generation plants entail significant upfront capital costs, renewable energy plants—particularly solar and wind plants—differ from natural gas plants, for example, since a substantial portion of total costs for a natural gas plant is related to fuel. If natural gas costs increase, market costs for electricity will also increase since natural gas is the marginal fuel for most hours in PJM.[374] Similarly, if market prices for electricity decline, the cause will likely be the declines in natural gas prices. Consequently, a natural gas plant is automatically hedged, to a degree. This means that a natural gas plant does not face the same degree of risk of exposure to a decline in market prices as does a wind or solar facility. As a result, LTCs may be more important for the development of renewable energy projects than for projects that incur significant fuel costs.

One of the risks to buyers is that an LTC will be more costly than other options over the course of the contract term. Specifically, the risk is that spot market purchases of energy, combined with RECs during the term of the contract, would be less costly than the contract entered into, or that a similar LTC entered into in the future would be less costly than one entered into today. Given market uncertainties, the concern over this risk is warranted, though certain factors should be recognized to put this risk into perspective.

First, the risk can be mitigated (though not eliminated) by staggering the purchases of the LTCs over a period of time. This approach is made easier when the amount of renewable energy required under the relevant RPS increases over time, meaning only a portion of the total amount of LTCs needs to be purchased in any one year.

Second, it should be recognized that market prices for electricity are low relative to prices over the past 10 to 15 years. This is largely attributable to the low cost of natural gas. While market prices of electricity could decline further, the degree to which they may decline is much less than the degree to which they may increase. This suggests that, at least for the electricity price component of LTCs, it is not expected that market prices in the future would be much less than the portion of the contract price that is related to the price of energy (rather than RECs). To the extent that current and short-term future energy prices are used to evaluate the competitive bids of renewable energy developers, currently observed market prices for energy would provide some discipline to potential purchasers in selecting suppliers.

It is important to note, however, that under a competitive solicitation for long-term renewable energy supply, offerors will not tie bids to market prices for electricity, but rather base bids on the cost of project development and the cost of O&M over the contract period. Project development costs would include materials, installation, site acquisition and preparation, and licensing costs. O&M costs would include both variable and fixed O&M costs. In addition, the costs of project decommissioning would need to be reflected in the cost proposal.[375] This means that the potential for lower costs for similar contracts in future years will be dictated largely by potential declines in the cost of project construction, in combination with legislative and regulatory changes over the course of the contract period. From 2010-2017, the costs of both solar project installations and wind power projects (i.e., the LCOE) declined significantly. Solar costs declined by 80% and wind power project costs declined by 63%.[376] Other factors equal, it should be anticipated that the costs of LTCs for renewable energy will decline in future years relative to the costs of such contracts today.

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[374] The spot market price of energy is set each hour by the marginal plant, that is, the last plant dispatched to meet load requirements in that hour. In PJM, the marginal plant tends to be fueled by natural gas. In 2018, natural gas was the marginal fuel in approximately 60% of the hours of the year.

[375] The State of Maryland requires solar and wind power project developers to identify decommissioning costs when applying to the Maryland PSC for a Certificate of Public Convenience and Necessity (CPCN). Before construction may begin, the applicant must enter into financial arrangements to accommodate adequate funds to return the site to its original condition in the event that the developer sells the project to another party, or in the worst case, abandons the project prior to decommissioning.

[376] *See: Lazard's Levelized Cost of Energy Analysis: Version 11.0*, 2017, lazard.com/media/450337/lazard-levelized-cost-of-energy-version-110.pdf.

Under the Public Utility Regulatory Policies Act (PURPA), Maryland electric utilities and electric ratepayers, as well as utilities and ratepayers in some other states, faced higher-than-market prices for power purchases under LTCs with qualifying facilities (QFs). Under PURPA, an IOU was required to purchase the output of a QF (as defined in PURPA and which included certain categories of renewable energy projects) at the utility's avoided cost. The contract price, therefore, did not relate to the total cost of production from a specific renewable energy project, but rather to the cost that would be avoided by the utility through reliance on the power produced by the QF at the time the contract was entered into. In some states, the estimates of avoided costs were well in excess of the costs that were ultimately realized, meaning QF suppliers earned significant economic rents (i.e., excess profits) over the duration of these LTCs. These costs were ultimately borne by ratepayers. Having faced the adverse economic consequences associated with high-priced QF contracts, it is not unreasonable for there to be a reluctance to revisit that experience in the form of LTCs for renewable energy.

That said, there are important differences between the QF contracts entered into in the 1970s and 1980s, and the LTCs for renewable energy envisioned herein. For example, Maryland would have much greater control over the amount and timing of the contracts, as well as the terms of the contracts. Additionally, the price basis for the contracts would be the actual project costs (i.e., bid prices) as described above rather than estimated avoided generation costs. This means that any "excess" cost to the purchaser that could be argued to exist in future years, that is, the lower cost of a similar LTC entered into at a later time, would not be attributable to economic rents, but rather simply reflect changes in the economic landscape associated with project development and certain other related factors.

Maryland's adoption of an RPS reflects the recognition that all-in renewable energy generation costs are expected to exceed the cost of conventional fossil fuel generation. The RPS is designed to provide renewable energy generators with an additional stream of revenue in the form of RECs that would be paid by all of Maryland's retail electric customers. As such, the state was aware of, and has implicitly agreed to, costs for renewable energy that are over and above market power prices, at least in the short term. This recognized relationship between renewable energy costs and market power costs fundamentally differs from the expectations surrounding the avoided cost methodology employed for the calculation of price under the QF contracts, which was based on the expectation of indifference between the QF contracts and generation by the relevant utility. Consequently, although LTC costs could be higher in the early years of the contract period relative to the costs of a new contract in the later years of the contract period, and although the potential exists for the incurrence of above-market costs for all of, or at least some portion of, the term over which the contract would run, the conceptual reasons underlying the cost deviations differ importantly between QF contracts and the LTCs discussed in this chapter.

5.3. Qualitative Analysis

As noted previously in this chapter, there are significant uncertainties surrounding the forecasted economic factors relied upon in the quantitative analysis, such as RECs prices, energy prices, and future renewable energy project capital costs and performance characteristics. There are also uncertainties surrounding the regulatory backdrop affecting REC prices (and also energy prices) in PJM. For example, if Pennsylvania were to increase its Alternative Energy Portfolio Standard (AEPS), REC prices in Maryland would be affected, along with those in New Jersey, the District of Columbia, and Delaware. REC prices would also be affected if a state in PJM with an existing RPS requirement freezes its requirement at a lower level than originally imposed by statute, as Ohio did. Together, all these factors could erode the robustness of any quantitative projections of Maryland REC prices, with or without the exercise of utility- or state-sponsored LTCs for RECs, or for bundled energy and RECs.

This section addresses qualitative issues surrounding the potential of Maryland facilitating the implementation of LTCs, either directly through a state organization or indirectly through the EDCs. Additionally, this section addresses other non-quantitative issues such as the advantages and disadvantages of using a state government organization to enter into LTCs or reliance on the EDCs, the duration of the contracts, the level of contracted load relative to overall RPS requirements, timing issues, and what other states have done recently regarding LTCs.

5.3.1. Contracting Entity

Maryland could either enter into LTCs directly or direct the EDCs to enter into LTCs for the purchase of RECs or bundled energy. If the state opts to enter into LTCs directly, it could do so by relying on an existing state organization or, in the alternative, by creating a state power authority. Existing state organizations that could fulfill this function include MEA or Maryland Environmental Service (MES). Alternatively, Maryland could create a power authority similar to the Illinois Power Agency (IPA) or the New York State Energy Research and Development Authority (NYSERDA). One issue that Maryland would need to recognize is ensuring that the long-term payment obligations under the contracts do not adversely affect the state's borrowing ability or favorable bond rating.

The various states that have entered into long-term renewable energy/RECs arrangements have done so under a variety of constructs. Table 5-1 shows the variations that characterize these arrangements.

Table 5-1. Long-Term Renewable Energy Contract Arrangements, Select Sample of States

State	Contracting Organization	Product Purchased	Duration of Contract(s)	Notes
CA	Electric utility solicitations, with CA PUC oversight	Primarily bundled energy and RECs[1]	10 years or more	
CT	EDCs' (Eversource & United Illuminating) competitive solicitations, with CT Dept. of Energy and Environmental Protection oversight	Zero-emission RECs (ZRECs) up to 1 MW; low-emission RECs (LRECs) up to 2 MW; zero-carbon greater than 2 MW (solar limited to 20 MW)	ZREC and LREC: 15 years; zero-carbon: between 3-10 years	
DE	DPL solicitation administered by Delaware Sustainable Energy Utility, with DE PSC oversight	SRECs	20 years	
IL	Illinois Power Agency via competitive procurement method	RECs	15 years for REC contracts (past LTCs varied from 5-20 years)	Beginning 6/1/2017, RPS-eligible load changed from just default service customers to all retail customers
MA	EDCs' and MA Dept. of Energy Resources' competitive solicitations, with MA Dept. of Public Utilities oversight	Unbundled RECs and generation. Distribution companies can sell excess and credit proceeds to customers[2]	15-20 years	Solicitations may be coordinated and issued with other New England states, or entities designated by those states (see: MA Chapter 188: An Act to Promote Energy Diversity)
MI	EDCs' competitive solicitations, with MI PSC oversight	RECs from approved PPAs and RECs-only contracts	Ranges from 5-20 years, with majority 15-20 years	
NH	Utilities' (except municipalities) competitive solicitations, with NH PUC and Site Evaluation Committee oversight	Energy and/or unbundled RECs	Not defined	
NJ	EDCs' competitive solicitations, with NJ Board of Public Utilities oversight	RECs and SRECs	Not defined	
NY	NYSERDA	RECs	Generally, 20 years; 50 years for hydro projects; limited to the life of the project	
PA	EDCs' competitive procurement processes and bilateral contracts (small-scale solar), with PA PUC oversight	Energy and attributes such as Alternative Energy Credits (AECs) and SRECs from large- and small-scale projects	5-20 years	PA Act 213 (2004) does not provide specific contract terms for AECs
RI	EDCs' solicitations, with RI PUC oversight	Energy and RECs (capacity available separately on a voluntary basis) for projects greater than 20 MW but less than 200 MW[3]	10-15 years; longer than 15 years subject to PUC approval	Pricing must be less than the forecasted market price of energy and RECs over the term of the contract

[1] Sixty-five percent of RPS requirement beginning 2021-2024.

[2] 1,600 MW (offshore wind) by June 30, 2027 (individual RFPs for not less than 400 MW); 9.45 million MWh (solar, onshore wind, and hydro) by December 31, 2022; and can be paired with energy storage.

[3] 90 MW per year, of which 3 MW must be solar or PV in-state.

As noted above, Maryland could also opt to require its EDCs to enter into contracts with third-party renewable energy developers in a manner similar to that in which the state handles the power generation from the Competitive Power Ventures (CPV) St. Charles Energy Center.[377] In both instances, the contracting party is the distribution utility, which collects revenues to recover the power costs through a non-bypassable charge. In the case of RECs procured under LTCs, it would be much simpler to recover the costs only from SOS customers (i.e., a bypassable charge) as part of the utility's obligation to meet the state RPS requirement. If that were the case, competitive LSEs would not need to back out the RECs procured under LTCs by the EDC from their RPS obligations. Rather, the RECs procured under the LTC would be used to meet the RPS obligations for SOS service and SOS customers. The implications of these alternative contracting avenues are discussed below. Note that many of the decision points that Maryland would need to address are interrelated. For example, the selection of a contracting entity, or whether the charge to recover procurement costs would be bypassable or non-bypassable, is much less important if the proportion of RPS obligation procured under LTCs is smaller rather than larger (for example, less than 10% versus 40%).

5.3.2. Product to be Procured

There are two key categories of options that define the product to be procured under LTCs. These include:

1. Whether the energy (and capacity) will be bundled with the RECs or the RECs will be purchased on a standalone basis, with the developer arranging for the sale of the energy (and capacity and ancillary services, if applicable) separately, outside the LTC; and
2. The specific types of renewable energy to be procured, such as the resource, vintage, size, and location of renewable projects.

Both of these options are discussed further below.

Bundled/Unbundled RECs

If the LTC is strictly for the purchase of RECs without the associated energy, capacity, and ancillaries, the effect is the placement of a significant portion of the market risk onto the renewable project developer, rather than having that risk be borne by the state or by its ratepayers. In essence, the burden of finding a third party to purchase the energy on a long-term basis in order to supplement the firm revenue stream associated with the RECs purchase would fall on the developer.[378] Long-term purchases made by state organizations typically occur under RECs-only arrangements (refer to Table 5-1). For example, NYSERDA conducted its third annual procurement of Tier 1 RECs, with purchase levels set to meet New York's goal of 50% renewable energy by 2030. Similarly, the purchases made by the IPA are for RECs only.

If the purpose of the long-term purchase is for Maryland to hedge a portion of its RPS costs, and at the same time provide a hedging mechanism to wholesale renewable power providers for the portion of total revenues related to the sale of RECs, the RECs-only approach can be seen to provide such benefits. However, the benefits from the developer's

[377] These arrangements are structured as contracts for differences.

[378] It is generally not necessary for a renewable project developer to have 100% of the project output locked into a firm price over the life of the project (or the life of the project financing). However, a significant portion of the output is typically required to be committed at a known price adequate to service the debt in order to obtain project financing.

risk reduction, and the corresponding reduction in financing costs, would be decreased. The resultant risk to the state from paying what may ultimately be out-of-market energy prices, which would become evident in future years, would be eliminated under a RECs-only LTC. With declines in the installation costs of solar and wind energy projects, it can be anticipated that over time, the energy price component of bundled long-term projects, as well as the RECs component, would be able to be characterized as "above market."

Product Characteristics

The specific products to be procured under an LTC for renewable energy generation using a competitive procurement vehicle can, in large part, reflect the state's objectives from both a resource development perspective as well as from the perspective of economic development benefits. For example, if the goal is to spur the development of new renewable energy projects, the solicitation can be restricted to new renewable energy projects, or projects with online dates near the time of the solicitation issuance. If only certain types of renewable or clean technologies are desired, such as solar or wind, the solicitation can specify that. In this way, the state could avoid providing the basis for augmentation of technologies that may be seen as less desirable, for example, with respect to land use or emissions characteristics. As an example, the solicitation issued by NYSERDA in spring 2019 specified projects that came online (or that will come online) after 2015.[379]

Specifying the minimum size of an eligible project could affect the price, since smaller projects generally entail higher development costs on a per-kW basis, but it would also affect the costs associated with selecting the winning bidders and administering the contract post-award. It is simply less administratively burdensome to deal with one 20-MW project than 10 2-MW projects, other factors being equal. Specifying a maximum project size is a mechanism that can help ensure a greater degree of competition in the solicitation process and at the same time help facilitate wider geographic distribution of winning projects. Rhode Island, for example, specifies a maximum project size of 200 MW (and a minimum size of 20 MW for projects other than solar, which may be smaller).[380]

One of the more difficult issues to address is maximizing the amount of in-state benefits from renewable energy project development. New renewable energy projects under LTCs that are procured competitively and are required to be located within Maryland would serve to maximize the state's ability to garner employment, income (direct, indirect, and induced), and tax benefits, rather than having those benefits accrue to other states. Maryland, however, is limited in its ability to require renewable energy projects to be located within Maryland without violating the Dormant Commerce Clause. A 2017 federal court ruling upheld Connecticut's ability to specify that renewable energy purchased under LTCs be connected to the Northeast grid and hence be able to deliver energy into Connecticut. The court, however, did not rule that Connecticut could require renewable energy to emanate from projects located within the state.[381]

A second and related issue concerns wholesale market impacts. The ruling mentioned above clarified that the type of contracts at issue in the Connecticut procurements—renewable energy provided under LTCs between Connecticut utilities and developers at a specified price—did not intrude upon the FERC's authority to set wholesale electricity rates under the Federal Power Act. The Connecticut ruling recognized that the procurement entailed only a

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[379] *See:* NYSERDA RFP No. RESRFP19-1, available at nyserda.ny.gov/.

[380] Refer to *Table 5-1*.

[381] U.S. Court of Appeals for the Second Circuit, *Allco Finance Limited v. Klee*, *et al.*, Docket Nos. 16-2946 and 16-2949, June 2017, statepowerproject.files.wordpress.com/2014/03/2nd-ct-decision-062817.pdf.

very slight indirect impact on wholesale prices and did not warrant the conclusion that the Connecticut approach impeded FERC's authority.

The Maryland RPS requires that generation from eligible resources be located within PJM or by a source that transmits its generation into PJM.[382] Whether a competitive solicitation for an LTC for RECs alone, or a bundled product that includes RECs, can be restricted to only projects located in Maryland is fundamentally a legal question, which is beyond the scope of this analysis.

5.3.3. Contract Duration

LTCs for renewable energy resources, either as a bundled product or as RECs-only, need to be of sufficiently long duration so as to allow project developers to recover a substantial portion of capital costs over the contract period at prices that are reasonably reflective of the market.[383] Prices approximating market prices are needed to avoid unnecessary variability in the price of electricity to retail customers and also to avoid the potential of inducing customers to act in such a way as to avoid the contract costs. In general, solar and wind projects can be expected to be effectively operational over a period of 20 years or longer; consequently, 20 years (approximately) should represent the maximum duration of an LTC (bundled or unbundled) for the provision of renewable energy resources. Since performance risk is typically placed on the project owner, extending the long-term supply contract for a period of longer than 20 years places risks on the supplier, which potentially could be manifested in higher rates over the course of the contract period.[384]

The longer the duration of the contract, however, the greater the degree of market risk placed on the purchaser. Regardless of the skill of the purchaser in forecasting market prices for energy and RECs, projections 10 to 20 years into the future must be viewed as more speculative than shorter-term price projections. The purchaser, therefore, incurs a higher risk that the prices contracted for when the contract was entered into may be significantly higher than market prices in the later years of the contract term.

Virtually all states that have entered into long-term, fixed-price contracts for either bundled (energy plus RECs) or unbundled RECs have specified contract terms of up to 20 years. While this entails greater potential that the contract price will be out-of-market in future years, the potential benefits of relatively long contract durations have been viewed as more important. Specifically, these benefits include: lower prices due to reduced risk on the part of the supplier and the longer period over which the project would be able to recover costs; enhanced opportunities for project financing; and more stable retail prices that incorporate the LTC impacts. The implications of a longer-term contract, however, also depend on the segment of retail customers that are ultimately responsible for paying for the contract, as well as the percentage of the RPS requirement that is met through the contract. Both of these factors are addressed below.

[382] Prior to 2011, Maryland's geographic eligibility requirement included allowance for generation in states adjacent to PJM. The enactment of HB 375 in 2008 modified the geographic eligibility requirement to eliminate "adjacent-state" eligibility.

[383] A project developer would be able to recover full capital costs under a short-term contract if the prices were high enough.

[384] LTCs are generally written as providing a specified price per kWh generated or delivered. If the contract term exceeds the expected life of the project, the project owner would face the risk of being unable to earn revenues from generation over some portion of the contract period.

5.3.4. Responsible Customers

Recovery of the costs of LTCs can be either bypassable or non-bypassable. Under a non-bypassable arrangement, all ratepayers from designated customer classes (e.g., residential and small commercial customers) would be credited for a portion of the procurement and be billed the associated costs, regardless of whether the customer receives competitive generation service or receives SOS from the EDC. This arrangement would neither benefit nor disadvantage either category of customer relative to the other, other factors being equal. A similar approach is employed by the EDCs with respect to the allocation of costs associated with the offshore wind Maryland RPS Tier 1 carve-out requirement.

The alternative approach is to restrict the applicability of LTCs to SOS customers, as was contemplated in Maryland SB 391, which was introduced in the 2018 Maryland General Assembly session but was not enacted into law. If enacted, the bill would have facilitated the purchase of LTCs by the EDCs for 25% of the RPS requirement for SOS customers. Customers receiving electric generation service from a competitive LSE would not be directly affected by the LTCs, as the contracts would directly affect only the costs of SOS.

Adverse market consequences of LTCs could occur in two ways. First, if the prices associated with the LTCs exceed comparable market costs at any time during the contract period, SOS customers would have incentive to leave SOS and procure power from a competitive electric generation suppler. This would leave fewer SOS customers from which to collect the out-of-market costs, thus imposing greater burden on those customers remaining on SOS. If more and more customers leave SOS in response to increasingly out-of-market costs, the resulting burden on the remaining SOS customers would also increase.

The other adverse market consequence would arise if LTC prices fell below comparable market costs during the contract period. This circumstance would make it difficult for competitive LSEs to be able to offer a competitive price to both existing and potential customers; hence, the LSEs could be disadvantaged in the retail service market.

These potentially adverse impacts could be reduced through limitations or constraints on the degree to which LTCs are used to meet SOS power supply requirements.

5.3.5. Reliance on LTCs for SOS Supply

The adverse impacts associated with out-of-market pricing for LTCs, either higher- or lower-than-market prices, would increase with increasing amounts of the SOS supply portfolio made up of LTCs. Additionally, if only RECs were purchased under LTCs rather than the underlying renewable energy supply, potential adverse impacts associated with the contracts would also be reduced, other factors held constant.

SB 391 contemplated that 25% of the RPS requirement for SOS would be purchased under LTCs. With a 50% RPS requirement, the 25% limitation would effectively reduce the percentage of the supply portfolio made up of LTCs to 12.5%.[385] Under these conditions, even with a market price deviation of 30%, that is, LTCs being priced either 30% above or below the short-term market prices, the impact on consumer bills would amount to less than 4% of the energy-related portion of the SOS bill.[386] Capacity costs, ancillary services costs, customer costs, and transmission/distribution costs would not be affected. Note that

[385] It should be noted that the 12.5% figure would be further reduced by the amount of the offshore wind carve-out.

[386] The 30% price deviation is multiplied by the 50% RPS requirement and the 25% limitation on the proportion of the RPS requirement met through long-term contracts (i.e., 30% market price deviation * 50% RPS * 25% LTC obligation = 3.75%).

a smaller percentage of the SOS portfolio being supplied through LTCs, while limiting the degree to which SOS customers might be exposed to higher-than-market prices and the degree to which competitive LSEs could be disadvantaged, also limits the degree to which SOS customers could benefit from the price hedges provided through LTCs.

If the costs of the LTCs were equally applicable to SOS customers and customers taking competitive generation service, that is, the LTC costs (and benefits) were non-bypassable, the issues related to potential adverse consequences from out-of-market prices would not result. Consequently, no additional load risk would be put onto competitive LSEs, and SOS customers would not be burdened with the potential that a higher and higher level of total costs related to LTCs would need to be shouldered.

5.4. Quantitative Analysis

To estimate the rate impacts of requiring LTCs to procure renewable energy under the Maryland RPS, other states' estimates serve as a useful guide. Such states compare the cost of the LTCs to some "counterfactual" scenario construct, that is, the cost of resources that would have been procured but for the LTCs. The cost of the counterfactual resources is estimated differently across states. Some states use the wholesale power market prices to estimate this cost while other states, like California, use the all-in cost of a combined cycle gas turbine (CCGT). In many restructured states, the counterfactual resources are compared to wholesale electricity prices.

The analysis conducted herein is designed to address the question of whether LTCs for renewable energy will likely result in either higher or lower costs to Maryland consumers and the potential magnitude of those cost differentials. Certain fundamental assumptions about how LTCs would be structured need to be examined and defined since the structure can affect cost estimates. Each of the key elements of the contract structure are addressed below.

The results of the quantitative analysis are dependent on the assumptions relied upon. These assumptions include forecasted energy prices, REC and SREC prices, capacity prices, financing costs, capital costs, tax regulations, capacity factors, and other elements. To assess a range of potential outcomes, alternative assumptions regarding future REC and SREC prices are relied upon as well as alternative financing costs. While the results provide reasonable high value and low value alternatives to account for uncertainty, the range of outcomes does not exhaust all possible values, since actual future impacts of LTCs on consumer costs could be affected by influences not directly addressed in this analysis.

5.4.1. Contracting Entity

There are two potential purchasers: either a state government entity or the EDC. While private entities other than the regulated EDCs may opt to enter into LTCs for renewable energy, the state cannot compel them to do so. If a state government organization such as MEA or a to-be-created Maryland Power Authority (similar to the power authorities in Illinois and New York) were to enter into LTCs for renewable power, the EDCs (or all LSEs serving retail customers in Maryland) could be required to purchase a *pro rata* share of the energy procured through the LTCs.

If the EDCs operating in Maryland were to be required to enter into LTCs for renewable power, the energy procured under those contracts could either be earmarked for SOS customers or allocated to all electric customers. For purposes of this analysis, the contracting entity has no meaningful impact on the result; hence, either a state entity (existing or new) or the EDC can act as the purchaser. It is assumed that the costs of the contracts would be allocated on a non-bypassable basis.[387]

5.4.2. Product to be Procured

For purposes of the quantitative analysis, the product assumed to be procured under LTCs would be bundled energy, RECs, and any associated capacity. Contract terms would entail firm fixed prices for all of the output, or a significant portion of the output of the specified renewable energy project. The firm fixed prices could either be a levelized price or a base-year price subject to fixed escalation. For purposes of this analysis, the distinction is not important.

Fundamentally, this analysis develops a proxy for the cost (price) of energy, capacity, and RECs under a PPA, and compares those estimated values to what would otherwise be available in the market under arrangements that do not contemplate long-term renewable energy PPAs over the assumed contract period of 20 years. Comparison of the two cost streams defines the net benefits or costs.

5.4.3. Forecasting Market Conditions

As stated previously, this study begins by estimating market prices for energy, capacity, and RECs. These steps are necessary to assess revenue streams absent LTCs. Each is discussed below.

Energy Costs

To forecast energy costs, this study first compares historical hourly prices provided by PJM to estimated hourly output provided by NREL and PVWatts to create an output-weighted index to apply to monthly average forward prices.[388] The hourly energy outputs for onshore wind and utility-scale solar are based on hypothetical projects located in Maryland (western Maryland for wind and eastern Maryland for solar). Then, this output-weighted index is applied to the on-peak and off-peak weighted average forward prices. Consideration of separate on- and off-peak prices is necessary because the generation profiles of solar and onshore wind differ significantly. Solar energy is generated predominantly during on-peak periods. In contrast, onshore wind energy is generated predominantly during off-peak periods.

Average monthly on- and off-peak energy forward prices at the PJM Western Hub were used for 2019, 2020, and 2021, as provided by S&P Global Market Intelligence. These average forward prices are projected over a 25-year period (the assumed project life) using a nominal market price escalator of 0.36% based on the real CAGR in generation price provided by EIA's *Annual Energy Outlook* for the RFC-East region over the same period.

Capacity Costs

Electricity generators in PJM are eligible to receive capacity payments based on their successful participation in PJM's annual capacity auction. PJM, however, treats wind and solar resources differently from resources such as steam plants due to the variable nature of

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[387] The issues related to the designation of the purchasing entity, and the customers ultimately receiving the renewable energy purchased under the LTCs and incurring the corresponding costs have been discussed previously in this chapter. These issues relate to risk, potential adverse impacts on competitive LSEs, and potential adverse impacts on SOS/default service customers.

[388] PVWatts is a program developed by NREL to estimate the energy production and cost of energy of grid-connected PV energy systems, by location. *See:* pvwatts.NREL.gov.

wind and solar projects. Specifically, the installed capacity of wind and solar resources is adjusted downward to account for its variability. The amount of solar or wind capacity, denoted in MW, that can be bid into the capacity auctions for any specific project is the capacity that "…can reliably contribute during summer peak hours."[389] PJM bases the adjustment on the most recent three years of actual data available from the specific project. For immature projects that have not been operational for three years, the available data for the project are relied upon, with the Class Average Capacity Factor relied on for the years for which project-specific data are not available.[390] The Class Average Capacity Factors effective June 1, 2017 (the most recent data available) are as follows:[391]

- Wind power located in mountainous terrain: 14.7%
- Wind power located in open/flat terrain: 17.6%
- Solar ground-mounted fixed panel: 42%
- Solar ground-mounted tracking panel: 60%
- Solar other than ground-mounted: 38%[392]

In the absence of project-specific data, these percentages would be multiplied by the project's installed capacity to determine the capacity available for participation in the capacity auction. For purposes of this analysis, the 14.7% capacity factor associated with wind power located in mountainous terrain and the 60% capacity factor for solar (ground-mounted tracking panel projects) were relied upon.

The revenue accruing to the project in any year would be the adjusted MW capacity multiplied by the market-clearing capacity price as determined by the PJM capacity auction, held three years in advance of the relevant delivery year (DY). To determine the amount of revenue available to the project over the life of the project, therefore, the capacity (MW) needs to be known (or approximated) as well as the projected capacity price over the project life. The capacity price is determined in the market by the interplay of demand (based on the projected PJM annual peak plus an added amount for reliability, which is generally about 15%) and supply (the amount of MW bid into the market at various prices). The intersection of the administratively determined demand curve and the market-driven supply curve, in combination with PJM's administrative rules, provides the market-clearing capacity price.

The forecast of capacity prices is uncertain because the amount of supply that will be bid into the market each year, the price related to each of the capacity bids, and the amount of capacity required is uncertain. Regulatory factors, new plant construction, power plant retirements, and the location of future power plants and transmission facilities affect the market's clearing prices. Because of these factors, accurately forecasting capacity prices has proven to be difficult. Therefore, for purposes of developing capacity prices to help quantify the power supply cost impacts from LTCs, this study relied on actual capacity prices for the

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[389] PJM Interconnection, LLC, *PJM Manual 21: Rules and Procedures for Determination of Generating Capability*, May 2019, pjm.com/-/media/documents/manuals/m21.ashx, Appendix B.

[390] Ibid.

[391] When this analysis was conducted, PJM was in the process of changing its methodology to calculate the capacity value of wind and solar, and the specifics of the new methodology that was adopted were not yet available. *See:* pjm.com/-/media/committees-groups/subcommittees/irs/20190313/20190313-item-05-calculation-of-capacity-values-for-wind-and-solar-capacity-resources.ashx.

[392] PJM Interconnection, LLC, "Class Average Capacity Factors – Wind and Solar Resources, effective June 1, 2017," pjm.com/planning/resource-adequacy-planning/resource-reports-info.aspx.

years for which those prices are available, that is, through DY 2021/2022, with those prices held constant (in real terms) for the remainder of the analysis period.

This study estimates the annual capacity credit revenue for a Tier 1 project by first assuming that it receives the PJM-assigned class average capacity factor (60% for a ground-mounted tracking panel solar project and 14.7% for wind in mountainous terrain). This class average is then multiplied by the project manufacturer's net maximum capacity, which is the output rating less the energy required to operate all auxiliary equipment and control systems.

The capacity value is then multiplied by the resource clearing price to estimate the annual capacity revenue. Since the capacity clearing price is PJM delivery zone-specific, the study uses the DY 2021/2022 PJM Base Residual Auction (BRA) Resource Clearing Price (RCP) in the Pepco area of $140 per MW-day for wind and $165.73/MW-day for a ground-mounted tracking solar array in either the DPL or Eastern Mid-Atlantic Area Council (EMAAC) areas, since these values are known.[393] The known capacity values, by relevant Maryland delivery zone, are shown in Table 5-2.

Table 5-2. PJM Base Residual Auction Resource Clearing Prices ($/MW-day)

Locational Deliverability Area	Delivery Year			
	2018/19[1]	2019/20[2]	2020/21[3]	2021/22[4]
PJM	$164.77	$100.00	$76.53	$140.00
BGE	164.77	100.30	86.04	200.30
DPL-South	225.42	119.77	187.87	165.73
EMAAC	225.42	119.77	187.87	165.73
Pepco	164.77	100.00	86.04	140.00

[1] PJM 2018/2019 RPM Base Residual Auction Results, pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2018-2019-base-residual-auction-report.ashx. *See also:* Maryland PSC 2017-2026 *Ten-Year Plan*.

[2] Ibid. (2019/2020), pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2019-2020-base-residual-auction-report.ashx.

[3] Ibid. (2020/2021), pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-report.ashx.

[4] Ibid. (2021/2022) pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx.

It is assumed that the capacity prices will grow at the forecasted rate of inflation, measured by the Gross Domestic Product (GDP) price index, projected at 2.1%.[394]

Since this analysis examines the impact of LTCs on the price of renewable energy resources to Maryland retail consumers, the differential between developer revenues (which will match consumer costs) with and without LTCs is considered. For completeness, it should be noted that the availability of LTCs entered into by either the State of Maryland or the state's EDCs could have the effect of marginally increasing the amount of renewable energy projects developed. To that extent, such contracts could affect the supply of resources eligible to bid

[393] The Pepco delivery area, rather than the BGE delivery area, was relied on because although capacity prices in these two areas are the same through the 2021/2022 Planning Year, in that Planning Year, the BGE price is higher than all of the other areas in Maryland. The Pepco area was selected in lieu of the BGE area to avoid a potential forecasting bias.

[394] *Blue Chip Economic Indicators*, Vol. 44, No. 3, March 10, 2019.

into the PJM capacity auctions and hence affect the ultimate capacity price. The impacts on clearing price, however, would be *de minimis*, if anything. Consequently, this consideration is ignored for purposes of this analysis.

An additional factor that warrants mention is that the FERC is currently evaluating proposals offered by PJM to modify its capacity market in response to directives made by FERC. PJM's proposals are designed to neutralize capacity market distortions associated with out-of-market subsidies paid to certain types of generating facilities, including certain renewable generating facilities with "subsidies" in the form of RECs. Nuclear generating facilities receiving ZECs are also addressed. As of this writing, FERC has not issued an order in the proceeding indicating which PJM proposal will be adopted or what modifications to the proposed mechanisms should be implemented.

REC/SREC Prices

This study considers two sets of REC/SREC price scenarios: low-price scenarios using the REC/SREC forecasted prices for 2021, and high-price scenarios employing the ACPs, which act as price caps. The REC/SREC forward prices employed in the low-price scenarios are provided by Spectrometer and S&P and are assumed to increase annually by the projected inflation rate of 2.1%. The projected REC/SREC prices for the low-price scenarios are shown in Table 5-3.

Table 5-3. Maryland REC/SREC Price Forecast (nominal $/MWh)

Year	Tier 1 REC	Tier 1 SREC
2018	$5.40	$10.00
2019	5.65	10.50
2020	5.95	11.50
2021	6.10	12.50
2022	6.23	12.76
2023	6.36	13.03
2024	6.49	13.30
2025	6.63	13.58
2026	6.77	13.87
2027	6.91	14.16
2028	7.06	14.46
2029	7.20	14.76
2030	7.35	15.07
2031	7.51	15.39
2032	7.67	15.71
2033	7.83	16.04
2034	7.99	16.38
2035	8.16	16.72
2036	8.33	17.07
2037	8.51	17.43
2038	8.68	17.80
2039	8.87	18.17
2040	9.05	18.55

For the REC/SREC high-price scenarios, the ACPs set in the Maryland CEJA were applied.[395] The 2019 and 2020 ACP for Tier 1 non-carve-out RECs ($30.00) is used and decreases after 2023 to a final level of $22.35 in 2030, and all years thereafter. The ACP for Tier 1 solar is set at $80 per SREC in 2021 and decreases in the following years to a final level of $22.35/REC in 2030, and all years thereafter. These ACPs are shown in Table 5-4.

[395] *See:* Clean Energy Jobs Act (SB 516), passed April 8, 2019, legiscan.com/MD/comments/SB516/2019.

Table 5-4. Maryland Alternative Compliance Payment Schedule (Ch. 757) (Nominal $/MWh)

Compliance Year	Tier 1 Non-Solar	Tier 1 Solar
2019	$30.00	$100.00
2020	30.00	100.00
2021	30.00	80.00
2022	30.00	60.00
2023	30.00	45.00
2024	27.50	40.00
2025	25.00	35.00
2026	24.75	30.00
2027	24.50	25.00
2028	22.50	25.00
2029	22.50	22.50
2030+	22.35	22.35

5.4.4. Long-Term Contract Price Estimate

The NREL 2018 ATB provides estimates of the LCOE across resource types.[396] The ATB estimates reflect the cost of an electricity generation plant from the perspective of a utility or other investor, and uses different sensitivities reflecting different financial assumptions, technology changes over time, tax policy changes, and alternative tariff scenarios.[397] The ATB LCOE estimates show onshore wind costs of between $20-$170/MWh. Utility-scale PV costs (on a levelized basis) are estimated to be between $40-$100/MWh, derived assuming a capital cost recovery period of 30 years for alternative sets of assumptions.

This study derives the PPA price by estimating the cost of producing electricity using renewable energy resources in Maryland rather than relying on historical project-specific data, which are generally confidential. Using assumed OCCs, O&M costs, production output estimates, financing costs, and available tax incentives, this study estimates an LCOE and the corresponding PPA price. This estimated PPA price is compared to the market energy price (plus the cost of the RECs and the relevant capacity cost) to derive the potential economic benefit or cost of LTCs for renewable energy relative to the cost of sequential short-term market energy purchases (again including the cost of the RECs and the relevant capacity cost) over the life of the PPA term.

This analysis assumes a typical project size and productivity for onshore wind and utility-scale solar. Biomass and offshore wind are excluded from the analysis based on either provisions in the Maryland RPS or characteristics unique to the resource. In the case of offshore wind, the Maryland RPS already contemplates that the resource would be developed through an LTC with terms and prices approved by the Maryland PSC. Biomass has costs that are highly dependent on the specific biomass fuel being contemplated (e.g., switchgrass, wood waste). As a result, the estimated levelized costs of biomass would be

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[396] *See:* National Renewable Energy Laboratory, Annual Technology Baseline, atb.nrel.gov/.

[397] National Renewable Energy Laboratory, Annual Technology Baseline, "Guidelines for Using ATB Data," atb.nrel.gov/electricity/user-guidance.html.

highly uncertain and would not be useful for assessing the potential cost reductions (or cost increases) to consumers associated with LTCs.

A project's capacity factor is the ratio of actual energy output over a defined period of time, typically a year, to the energy output at rated capacity over the same time period. Based on interviews with industry experts, a typical utility-scale solar project capacity of 20 MW and a capacity factor of 25% were assumed. For onshore wind, a project size of 50 MW and a capacity factor of 35% were assumed.

System Output Degradation

Solar projects experience annual degradation in their ability to produce energy. For example, an NREL 2002 study estimated a degradation rate of 0.71% per year.[398] The same report lists initial degradation rates as high as 2.5% per year. More recently, NREL again studied the degradation rate for PV systems and found a mean degradation rate of 0.8% and a median of 0.5% per year.[399] For the current analysis, a first-year degradation rate of 2% was assumed for PV projects, which declines to 0.8% in following years.[400] It was also assumed that the electricity production from onshore wind resources degrades by 0.5% per year.

Capital Costs of Renewable Energy Projects

To estimate the LCOE and the PPA price, this analysis assumes a generic facility's OCCs and O&M costs. Specific OCCs include civil and structural engineering costs, mechanical equipment supply and installation, electrical instrumentation, indirect project costs, and owner costs such as feasibility and engineering studies and permitting/legal fees.[401] By way of example, NREL's 2018 ATB provides capital costs for utility-scale solar projects, such as OCCs of $1,754/kW, fixed O&M costs of $14/kW-year, and no variable O&M costs. The 2018 ATB also estimates an LCOE for solar for five locations across the United States, with Chicago (the closest of these locations geographically to Maryland) having an LCOE of $79/MWh.

For more region-specific capital and O&M costs, EIA provides key data and assumptions used in its AEO annual report. AEO 2018 includes a series of cost and performance data for new generating projects, such as the OCCs of renewable energy projects. Although other costs, such as variable and fixed O&M costs, are similar across the U.S., construction costs vary across regions due to variability in weather, availability of land, proximity to infrastructure, and other factors. AEO 2018 assumes a weighted-average total OCCs for onshore wind across the U.S. of $1,657/kW and $2,105/kW for solar PV with tracking. These costs are reported to be higher for areas in which parts of Maryland lie, such as those within the RFC-East – DPL and RFC-West – Potomac Edison areas,[402] where total OCCs for onshore wind in 2017 were $2,132/kW and $1,817/kW, respectively.[403] The Maryland-

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[398] C.R. Osterwald, A. Anderberg, S. Rummel and L. Ottoson, *Degradation Analysis of Weathered Crystalline-Silicon PV Modules*, National Renewable Energy Laboratory, 2002, nrel.gov/docs/fy02osti/31455.pdf.

[399] Dick Jordan and Sarah Kurtz, *Photovoltaic Degradation Rates – An Analytical Review*, National Renewable Energy Laboratory, 2012, nrel.gov/docs/fy12osti/51664.pdf.

[400] *See also* Sunpower's website for an explanation of PV system degradation: businessfeed.sunpower.com/articles/what-to-know-about-commercial-solar-panel-degradation.

[401] U.S. Energy Information Administration, *Capital Cost Estimates for Utility Scale Electricity Generating Plants*, 2016, eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf.

[402] *See:* U.S. Energy Information Administration, "Electricity Market Module Regions," eia.gov/outlooks/aeo/pdf/nerc_map.pdf.

[403] U.S. Energy Information Administration, "Cost and Performance Characteristics of New Generating Technologies," *Annual Energy Outlook 2018*, February 2018, Tables 8.2 and 8.3.

specific total OCCs for solar PV with tracking range from $2,020/kW to $2,333/kW. Such data, however, only reflect averages of a given sample of projects. The average of these costs is used for this study, identified as the average regional OCC in Table 5-5, which also provides a summary of cost data from AEO 2018 relevant to Maryland renewable energy projects.

Table 5-5. Cost of New Generating Technologies in the U.S., 2018 (2017$)

	NATIONWIDE VALUES			REGIONAL OCC VALUES		
Technology	**Total OCC** ($/kW)[1]	**Variable O&M** ($/MWh)	**Fixed O&M** ($/kW-yr)	**RFC-East – DPL** ($/kW)	**RFC-West – Potomac Edison** ($/kW)	**Average Regional OCC** ($/kW)
Onshore Wind	$1,657	$0.00	$47.47	$2,132	$1,817	$1,975
Solar PV – Tracking	$2,105	$0.00	$22.02	$2,333	$2,020	$2,177

Source: EIA, "Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2018," Tables 8.2 and 8.3.

[1] Total OCC includes base OCCs adjusted by project contingency and technological optimism factors.

Economic and Financial Assumptions

This study assumes a long-term inflation rate of 2.1% over the next 10 years and is based on a compilation of projections by major forecasting entities (universities, banks, research institutes, government organizations) as reported in *Blue Chip*.[404] By comparison, NREL's 2018 ATB relies on an inflation rate assumption of 2.5%. A 2.1% annual escalation factor is applied to O&M costs and REC values. For wholesale electricity prices, an increase of 0.36% per year is assumed, in line with the rate projected in AEO 2019 for RFC-East.[405]

The NREL 2018 ATB uses a real (i.e., inflation-adjusted) interest rate on long-term debt of 5.4% and a nominal rate (i.e., one that includes inflation) of 8% across all technologies. This interest rate is significantly higher than current corporate Aaa-rated bond yields and utility long-term bond yields of about 4.01% and 3.95%, respectively.[406] Yields on lower-rated corporate and utility bonds are slightly higher at 4.87% and 4.29%, respectively. According to *Blue Chip*, the yield on Aaa-rated and Baa-rated corporate bonds is expected to remain around 5.1% and 6%, respectively, through the next decade.[407]

Since B-rated bonds reflect a lower credit rating than A-rated bonds, the increase in yield reflects risk, all else equal. According to IHS Markit, most projects in the PJM area are sponsored by merchant generators that face more project risk than regulated utilities.[408] See Figure 5-1 for a comparison of project ownership, by geographic area and ISO/RTO region.

[404] *Blue Chip Economic Indicators*, 44(3), March 2019.

[405] U.S. Energy Information Administration, *Annual Energy Outlook 2019*, January 2019, eia.gov/outlooks/aeo/.

[406] *The Value Line Investment Survey – Selection & Opinion*, Issue 4, Part 2, June 2019.

[407] *Blue Chip Financial Forecasts*, 37(12), December 2018.

[408] James Saeger, "The Cost of Capital for Renewable Generation Capacity Ownership," IHS Markit, presentation at EIA Energy Conference, 2017, eia.gov/conference/2017/pdf/presentations/james_saeger.pdf.

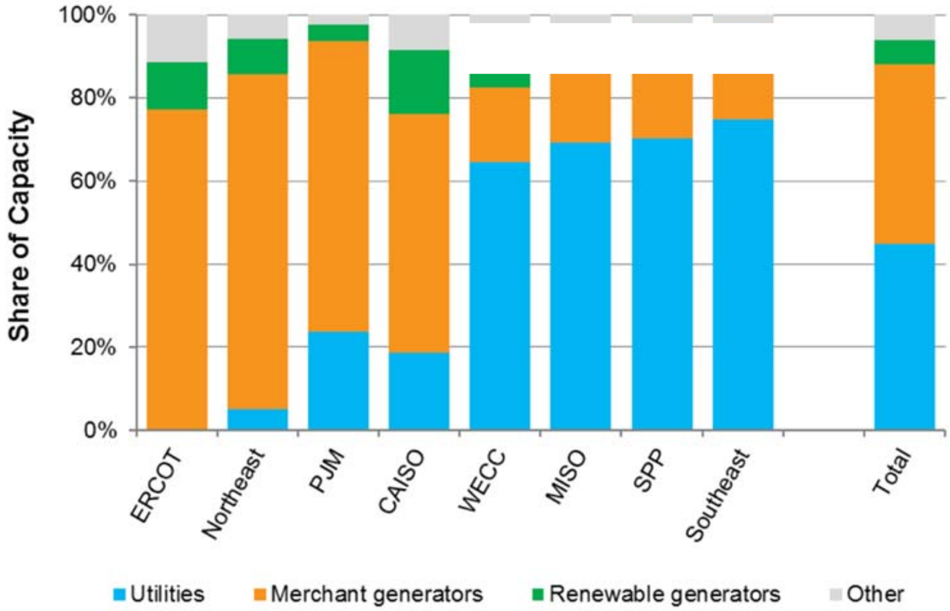

Figure 5-1. Project Ownership Share, by ISO/RTO Type

Source: James Saeger, *The Cost of Capital for Renewable Generation Capacity Ownership*, IHS Markit, presentation at EIA Energy Conference, June 2017.

Since individual renewable projects may be constructed based on a PPA with a utility, the yield associated with lower risk is applied and an ATB rate of 4.5%. To be more conservative, a sensitivity is run using a 6% cost of debt. This rate matches the maximum of the range of the *Blue Chip Financial Forecasts* long-term forecasts for debt costs of 5.1% (corporate Aaa bond yield) and 6% (corporate Baa bond yield).[409]

Weighted Average Cost of Capital and Return on Equity

In a 2017 presentation to EIA, IHS Markit estimated the cost of capital for renewable energy companies. For large utilities with greater than $25 billion in equity market capitalization, the average cost of equity was 7%, 3.4% for debt, and the weighted average cost of capital (WACC) was 5%.[410] For merchant renewable generators, the average cost of equity was 10.6%, debt was 6.1%, and the WACC was 7.3%. The renewable energy companies face these higher costs due to smaller company size and lower leverage. In contrast, larger utilities incur lower financing costs from broader diversification and greater liquidity in capital markets.[411]

A 2017 NREL survey of PV industry professionals paints a complex picture of project financing structures, showing that a tax equity investor faces a higher equity return after it transfers ownership of the tax credits to the developer.[412] A recent update to the NREL study found that the WACC for utility-scale PV lies within a range of 3.2-6.8% with a mid-cost estimate of 6.1%. For a utility-scale project, the cost of equity varies depending on its

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[409] *See: Blue Chip Financial Forecasts*, 37(12), December 2018.

[410] James Saeger, "The Cost of Capital for Renewable Generation Capacity Ownership," IHS Markit, presentation at EIA Energy Conference, 2017, eia.gov/conference/2017/pdf/presentations/james_saeger.pdf.

[411] Ibid.

[412] *See* the following article for a detailed description of this financing model: Keith Martin, "Partnership Flips," Chadbourne *Project Finance Newswire*, April 2017, projectfinance.law/media/1598/pfn_0417.pdf.

source. The mid-cost, after-tax return for equity provided by a tax equity investor (tax equity) is 7.25% "at flip" and 8.3% "after flip", with the term "flip" referring to a point in the transaction when ownership of the tax credits changes.[413] According to the 2017 report, these rates for equity financiers have fallen in recent years as competition among financiers has increased.[414]

An equity sponsor, which is typically the developer of the project, faces a slightly higher return on equity (ROE) of about 8.5%. For a utility-scale project that is financed with 50% debt, the cost of debt is 3.5%. The NREL 2017 study also found that debt costs have remained stable despite increases in the Federal Funds Rate because such increases were expected and were priced into the market.

The financing rates and capital structure assumed in this study will play a key role in the estimated LCOE, as demonstrated by an NREL wind energy study that employs two financing scenarios using a base-case project that holds non-financial parameters constant. The higher-cost financing scenario represents typical rates and capital structure for project-specific financing and employed a sponsor equity internal rate of return (IRR) of 12%, tax equity IRR of 8%, a long-term debt rate of 5%, and a capital structure of 35% debt. The lower-cost financing scenario assumed a debt leverage of 40%, debt rate of 4.5%, and equity IRR ranging from 7% (tax equity) to 10% (sponsor equity). Using NREL's System Advisor Model (SAM), the NREL study yields an LCOE of $51/MWh for the higher-cost scenario and $42/MWh for the lower-cost scenario (see Table 5-7).[415]

Table 5-6. LCOE Comparison of Higher-Cost and Lower-Cost Financing Scenarios, NREL Study

SAM Financial Model Inputs	Higher-Cost Financing Scenario	Lower-Cost Financing Scenario
Sponsor Equity IRR	12%	10%
Tax Equity IRR	8%	7%
Debt Interest Rate	5%	4.5%
Loan Term	15 years	18 years
Debt Percentage	35%	40%
Resulting Nominal LCOE	**$51/MWh**	**$42/MWh**

Source: Paul Schwabe, David Feldman, Jason Fields, and Edward Settle, *Wind Energy Finance in the United States: Current Practice and Opportunities*, NREL, August 2017.

Given the financial cost range provided in the studies summarized above, this study applies a similar high-cost and low-cost financing range. The same financial parameters are used regardless of technology type. The cost of debt range is 4.5-6%, assuming a debt term over the economic life of the project (25 years). The cost of equity range is 7-10%. For both sensitivities, it is assumed that an LTC will be entered into with an electric utility and the financing structure will be 50% debt and 50% equity. As a result, the WACC for the low-cost

[413] David Feldman and Paul Schwabe, *Terms, Trends, and Insights on PV Project Finance in the United States, 2018*, National Renewable Energy Laboratory, November 2018. nrel.gov/docs/fy19osti/72037.pdf.

[414] Ibid., 2017, nrel.gov/docs/fy18osti/70157.pdf.

[415] Paul Schwabe, David Feldman, Jason Fields and Edward Settle, *Wind Energy Finance in the United States: Current Practice and Opportunities*, National Renewable Energy Laboratory, 2017, nrel.gov/docs/fy17osti/68227.pdf.

scenario is approximately 5%, and the high-cost scenario WACC is about 7%. These ranges are broadly consistent with the studies summarized above.

Production Tax Credit and Investment Tax Credit

Under Section 48 of the Internal Revenue Code, renewable energy projects can receive an ITC or PTC.[416] For the purposes of this study, it is assumed that construction begins before December 31, 2021 and the project is placed in service by December 31, 2023, such that solar projects would receive an ITC of 22%. This analysis assumes that wind projects will not receive the tax credit because the ITC for wind is set to expire after December 31, 2019.[417]

Tax Rate

The current corporate tax rate is 21% and the Maryland corporate tax rate is 8.25%.[418] Therefore, this study assumes a combined tax rate of 27.52%.[419]

Depreciation

Since its inception in 1986, the federal Modified Accelerated Cost Recovery System (MACRS) streamlined the tax code system of deducting tangible assets from gross receipts by setting a recovery period of a series of years, setting a method of how depreciation allowances are to be allocated, and establishing the method by which to determine when property is "placed in service."[420]

Under MACRS, most types of solar, geothermal, and wind property qualify for depreciation deductions using a five-year schedule. MACRS is a method of depreciation for tax purposes in which a project owner can recover the cost of investing in renewables through a series of annual tax reductions.[421] There are exceptions, however, for equipment that benefits from other federal incentives. For qualifying solar energy equipment on which an ITC grant is claimed, for example, the owner must reduce the project's depreciable basis by one-half the value of the 30% credit.

Since 2002, renewable project owners have been able to deduct a specified percent of the cost of new assets, while the remaining portion would be deducted under MACRS. President George W. Bush signed the Job Creation and Work Assistance Act of 2002 that set the rate at 30%.[422] The Tax Cuts and Jobs Act of 2017 increased the bonus depreciation from 50% to 100% for qualified projects in place after September 27, 2017 and before January 1,

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[416] Energy.gov, "Tax Credits, Rebates & Savings," energy.gov/savings/business-energy-investment-tax-credit-itc.

[417] IRS Notice 2016-31 allows four years for a qualifying wind project to take the PTC after it begins construction. Therefore, a wind project that begins construction in 2019 has until the end of 2023 to take the PTC, albeit at 40% of the value of the PTC because the PTC began phasing down in 20% increments annually beginning in 2017. Note that future changes or extensions of the PTC and/or ITC could have significant impacts on the cost estimates calculated in this analysis.

[418] *See:* U.S. Congress, Federal Tax Cuts and Jobs Act, passed December 2017, congress.gov/bill/115th-congress/house-bill/1/text. *See also:* commerce.maryland.gov/about/taxes.

[419] Applying the following calculation: combined corporate tax = (21.0% + 8.25%) – (21.0%*8.25%).

[420] *See:* U.S. Partnership for Renewable Energy Finance, "MACRS Depreciation and Renewable Energy Finance," 2014, ourenergypolicy.org/wp-content/uploads/2014/01/MACRSwhitepaper.pdf.

[421] Solar Energy Industries Association, "Depreciation of Solar Energy Property in MACRS," seia.org/initiatives/depreciation-solar-energy-property-macrs.

[422] *See:* U.S. Congress, HR 3090, Job Creation and Worker Assistance Act of 2002, congress.gov/bill/107th-congress/house-bill/3090.

2023.[423] Business taxpayers can write off the cost of acquiring a tangible asset faster through bonus depreciation than under MACRS alone.[424]

Decommissioning Costs

The Annotated Code of Maryland requires that before beginning construction of an electric generating facility with a capacity greater than 2 MW, the developer must obtain from the Maryland PSC either a Certificate of Public Convenience and Necessity (CPCN) or approval of an exemption from the CPCN requirement.[425] The PSC requires, as established through its orders in previous proceedings, that solar project developers applying for PSC certification prepare and submit a decommissioning plan for the project. The decommissioning plan must identify the responsible party (or parties); the estimated costs for decommissioning, dismantling, and disposing of all relevant components including cables, wiring, and foundations; and restoration of the site following decommissioning.[426] Following the PSC's approval of the decommissioning plan, financial guarantees to cover the cost of project decommissioning, consistent with the cost shown in the approved decommissioning plan, must be in place before construction of the project can begin. Those guarantees could take the form of a surety bond, letter of credit from a credit-worthy financial institution, or other acceptable arrangement. The application of these types of instruments can entail an additional cost on the solar developer.

Significant uncertainty exists regarding the cost of decommissioning a solar project 20 years or more into the future. The principal source of uncertainty is related to the salvage value, or the re-use value, of the project components, particularly the solar panels.

For purposes of this analysis, an estimated decommissioning cost for new solar projects in Maryland of $105,000/MW of installed capacity is adopted. The assumption is based on the estimated decommissioning cost for a 20-MW solar project proposed by Maryland Solar, LLC proposed by Maryland Solar, LLC ($2,100,000 total for the project).[427] Note that given the uncertainty associated with decommissioning costs, particularly as it relates to the salvage or re-use value of the solar panels, and the project-specific nature of certain decommissioning costs (e.g., site restoration and economies of scale with respect to equipment removal), a wide range of potentially reasonable values would be available for use in this analysis. Second, and more important, the selection of a value for solar decommissioning will not materially affect the analytical results addressed in this chapter. Decommissioning costs will need to be incurred regardless of whether the solar project is constructed under an LTC arrangement or alternative arrangement. The principal concern of this chapter is the difference in the costs associated with LTC arrangements compared to the alternatives rather than with the absolute value of the project costs.

Maryland does not require similar financial guarantees for decommissioning of other renewable (or non-renewable) energy projects. For example, new wind projects located in Maryland are not required to post a financial guarantee for decommissioning costs that may be incurred at the end of the economic life of the project. As a consequence, the costs

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[423] U.S. Congress, Public Law 115-97, December 2017, congress.gov/115/plaws/publ97/PLAW-115publ97.pdf.

[424] U.S. Partnership for Renewable Energy Finance, "MACRS Depreciation and Renewable Energy Finance," 2014, ourenergypolicy.org/wp-content/uploads/2014/01/MACRSwhitepaper.pdf.

[425] *See:* Annotated Code of Maryland, PUA § 7-207 and § 7-208.

[426] *See:* Comments of the Engineering Division (of the Maryland Public Service Commission Staff) regarding Case Nos. 9464 and 9463, MD Solar 1, LLC and MD Solar 2, LLC, Request for Approval of Decommissioning Plans, October 2018, Mail Log Nos. 222381 and 222382.

[427] Daniel Raimi, *Decommissioning US Power Plants: Decisions, Costs, and Key Issues*, Resources for the Future, 2017, Table 9.

associated with financial guarantees for decommissioning costs for other projects are also assumed to be zero, regardless of whether those projects are located within Maryland or elsewhere.

5.4.5. Modeling the Cost of Renewable Generation

This study imports Maryland-specific cost data for both of the project types (onshore wind and utility-scale solar) into a basic cash flow model to determine the break-even PPA price for a renewable energy contract from a developer's point of view. The cash flow model relied upon herein, with some modifications, is the Cost of Generation model used by the California Energy Commission (CEC) in its Renewable Energy Transmission Initiative (RETI) proceedings. Certain modifications have been effectuated to make the model more applicable to Maryland and to update the model inputs to reflect current market conditions. This model determines the levelized cost of generating power over the life of a typical renewable energy project and solves for the break-even PPA price. It incorporates a series of financial assumptions, such as the ROE, to estimate the "year one" cost of generation. The project must generate just enough income from power sales to obtain the specified return.[428]

Project costs include average OCCs and variable and fixed O&M costs for projects built in Maryland. Also applied is a series of assumptions regarding financing, applicable taxes, and tax incentives, as discussed in the preceding subsection and shown in Table 5-7.

Table 5-7. Project Assumptions for Analysis of Long-Term Contracts

	Onshore Wind	Solar
Project Size	50 MW	20 MW
Capacity Factor	35%	25%
Degradation per Year	0.5%	2.0%, 0.8%
Economic Life	25 years	25 years
Overnight Capital Costs (2017$/kW)	$1,975	$2,177
Variable O&M Costs	$0	$0
Fixed O&M Costs (2017$/MWh)	$47	$22
Decommissioning Costs (2017$)	$0	$105,000
2021/2022 Capacity Credit (nominal$)	$140.00	$165.73
Tax Rate	27.52%	27.52%
Contract Term	20 years	20 years
Federal PTC	0%	0%
Federal ITC	0%	22%

This study also runs a series of sensitivities or scenarios for both solar and wind projects, including a range of financing costs and REC/SREC prices, with details summarized in Table 5-8.

[428] California Energy Commission, *Cost of Generation Model User's Guide Version 2*, 2010, ww2.energy.ca.gov/2010publications/CEC-200-2010-002/.

Table 5-8. Scenario Assumptions for Analysis of Long-Term Contracts

Project Type	Scenario	2021 REC/SREC Price (nominal$)	Cost of Debt	Cost of Equity	Debt Term (years)
Onshore wind	Low Financing Cost, Low REC Price	$6.10	4.6%	7.0%	25
	Low Financing Cost, High REC Price	$30.00	4.6	7.0	25
	High Financing Cost, Low REC Price	$6.10	6.0	10.0	25
	High Financing Cost, High REC Price	$30.00	6.0	10.0	25
Solar	Low Financing Cost, Low SREC Price	$12.50	4.6%	7.0%	25
	Low Financing Cost, High SREC Price	$80.00	4.6	7.0	25
	High Financing Cost, Low SREC Price	$12.50	6.0	10.0	25
	High Financing Cost, High SREC Price	$80.00	6.0	10.0	25

For each scenario, the NPV of a hypothetical project's annual cash flow using the estimated PPA price is compared to an alternative scenario whereby the project owner is selling output into the wholesale market at the market price. The annual present value of net income associated with this alternative income stream is subtracted from the annual NPV of the PPA. The positive values in Table 5-9 (below) under the "NPV of Cost" heading represent the higher per-MWh costs of the PPA relative to sequential short-term market transactions. These figures do not incorporate any environmental or economic development benefits associated with solar and wind.

Table 5-9 shows that the PPA price for an onshore wind project located in Western Maryland ranges from $40.69-$66.03/MWh depending on the assumptions made regarding financing costs and the market value of RECs. The PPA price for a utility-scale solar project located in Eastern Maryland shows a wider range from $39.06-$74.76/MWh under the same assumptions, respectively, relied upon for wind power in Western Maryland.

Table 5-9. Break-Even Power Purchase Agreement Price and Net Present Value Cost of Projects for Analysis of Long-Term Contracts (2021$/MWh)

Project Type	Scenario	2021 PPA Price	NPV of Cost				
			2021	2025	2030	2035	2040
Onshore Wind	Low Financing Cost, Low REC Price	$55.11	$14.73	$13.93	$12.99	$12.11	$11.29
	Low Financing Cost, High REC Price	40.69	4.28	4.05	3.78	3.52	3.28
	High Financing Cost, Low REC Price	66.03	22.65	21.42	19.97	18.62	17.36
	High Financing Cost, High REC Price	50.49	11.39	10.77	10.04	9.36	8.73
Solar	Low Financing Cost, Low SREC Price	$55.50	$13.45	$12.72	$11.86	$11.06	$10.31
	Low Financing Cost, High SREC Price	39.06	1.54	1.45	1.36	1.26	1.18
	High Financing Cost, Low SREC Price	74.76	24.31	22.89	21.23	19.68	18.24
	High Financing Cost, High SREC Price	51.00	10.19	9.64	8.98	8.38	7.81

In the next subsection, the rate impacts of LTCs are estimated by first multiplying the NPV of costs associated with each scenario by the RPS requirements for Tier 1 RECs (for onshore wind) or SRECs (for solar) under the CEJA. Then, a series of sensitivities are examined for different long-term contracting requirements and under varying percentages of RPS compliance achieved though reliance on LTCs.

5.4.6. Rate Impacts

For estimating the ratepayer impacts in Maryland from requiring that electricity suppliers meet a portion of the RPS via LTCs, this study considers three different percentages: 15%, 25%, and 40%. For each of these scenarios, the study also considers whether the cost of meeting such a requirement will be recovered through a non-bypassable charge to all customers or a charge to SOS customers only. In both cases, the rate impact on residential customers is estimated by assuming monthly usage of 1,000 kWh, that is, 1 MWh.

All Retail Ratepayer Impacts

For each of the financing costs and REC/SREC price scenarios discussed previously, the total cost is estimated by assuming any LTC requirement for the Tier 1 non-carve-out will be met with new onshore wind, and that the requirement for the Tier 1 solar carve-out will be met by new utility-scale solar. Thus, the NPV of costs or benefits of each relevant renewable energy resource is multiplied by the Tier 1 non-carve-out and Tier 1 solar minimum required percent of retail sales. This study uses forecasted retail sales in Maryland from 2018-2027 provided in the Maryland PSC's *Ten-Year Plan*.[429] Then, the study uses CAGRs from the *Ten-Year Plan* to estimate annual sales for the remaining life of a 20-year contract beginning in 2021 (2021-2040). For the total RPS obligation, this study multiplies these forecasted annual sales by the RPS requirements established in the CEJA. The resulting RPS requirements are then multiplied by the assumed designated LTC requirement for each of the following scenarios: 15%, 25%, and 40%.

The total costs for Tier 1 non-carve-out and Tier 1 solar for selected years over an assumed 20-year contract period that would be recovered through a non-bypassable charge to all retail customers are shown in Figure 5-2 and Figure 5-3. For both Tier 1 non-carve-out and Tier 1 solar, total costs differ across the four financing and REC price scenarios. The low financing costs and high REC prices scenario (depicted as "Low FC/High REC" in the following figures) yields the lowest total NPV costs, at approximately $13 million for Tier 1 non-carve-out and $1.6 million for Tier 1 solar during the first year (2021) under a 25% LTC requirement, that is, the smallest NPV increment of costs under LTCs over and above costs under sequential short-term market purchases.

Both Figure 5-2 and Figure 5-3 calculate total NPV costs based on total Maryland retail sales adjusted for IPL. The high financing costs and low REC prices scenario (High FC/Low REC) produces the highest total cost differential. For example, under the 25% LTC requirement, customers would pay about $68.6 million for Tier 1 non-carve-out and less than $25.5 million for Tier 1 solar in the first year (2021) of the program.

[429] Public Service Commission of Maryland, *Ten-Year Plan (2018-2027) of Electric Companies in Maryland*, December 2018, psc.state.md.us/wp-content/uploads/Ten-Year-Plan-2018-2027-FINAL.pdf, Appendix Table 2(a)(ii).

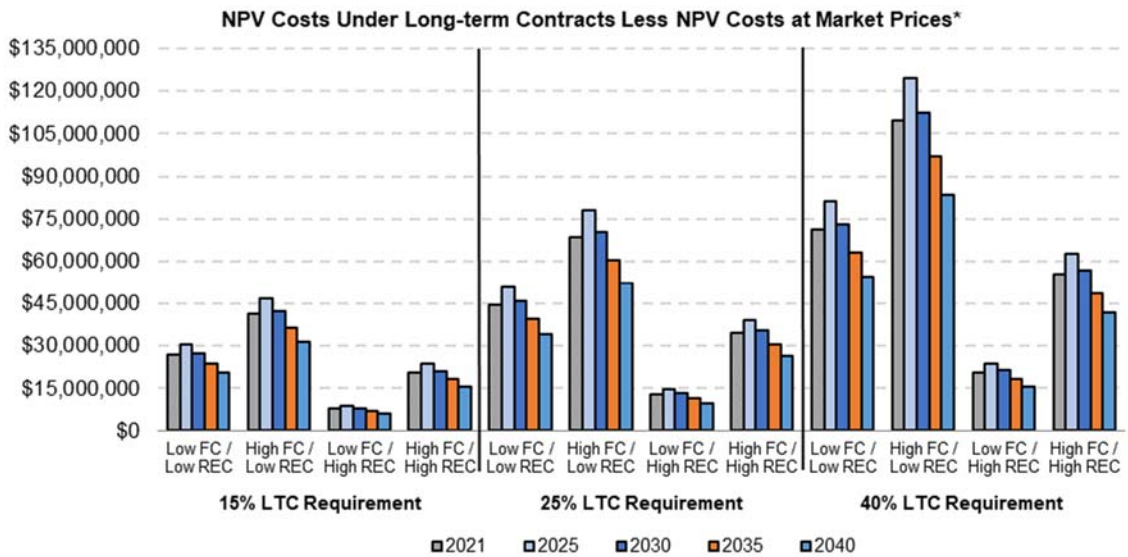

Figure 5-2. Net Present Value Cost Comparison by Total Cost – Tier 1 Non-Carve-out, All Retail Customers (2021$)

*"FC" denotes financing costs; "REC" denotes REC prices.

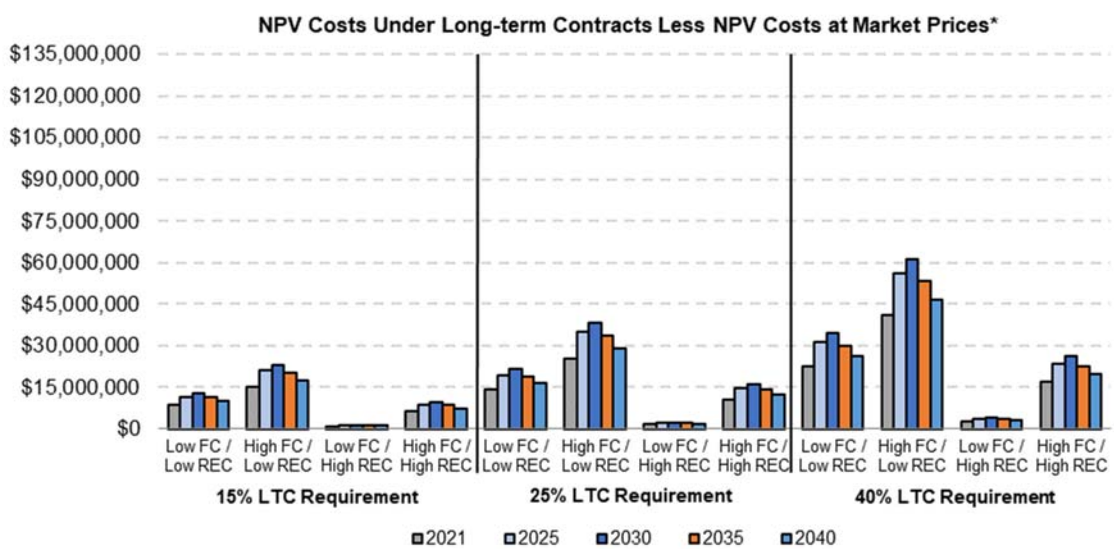

Figure 5-3. Net Present Value Cost Comparison by Total Cost – Tier 1 Solar Carve-out, All Retail Customers (2021$)

*"FC" denotes financing costs; "REC" denotes SREC prices.

Across all scenarios, total costs peak in 2027 and 2029 and decline thereafter as a result of the beginning of the offshore wind carve-out requirements set at 400 MW by 2026, 800 MW by 2028, and 1,200 MW by 2030. Such increases in the offshore wind carve-out, in turn, reduce the requirement for Tier 1 non-carve-out resources. In general, the total costs for the Tier 1 non-carve-out requirement eclipse total costs for Tier 1 solar due to the difference in the RPS requirements between these categories, representing a nearly 3-to-1 ratio.

Dividing the total costs shown above in Figure 5-2 and Figure 5-3 by total retail electricity sales yields annual average costs per MWh, as shown in Figure 5-4 and

Figure 5-5. These figures show that under a 15% LTC regime, the average additional cost for Tier 1 non-carve-out resources under LTCs would hover between $0.13-$0.16/MWh under the Low FC/High REC scenario over the 20-year period. The average cost for Tier 1 solar is lower still at $0.02-$0.03/MWh under the Low FC/High REC scenario.

Under a 25% LTC requirement for the same Low FC/High REC scenario, all customers would pay about $0.22/MWh for Tier 1 non-carve-out contracts and $0.03/MWh for Tier 1 solar contracts during the first year. In the 40% requirement case under the highest-cost scenario (High FC/Low REC), the average cost for Tier 1 non-carve-out contracts peaks at $2.23/MWh in 2025 and falls to $1.77/MWh in 2040. Similarly, the average costs for Tier 1 solar contracts in the same High FC/Low REC scenario peak at $1.16/MWh in 2030 and fall to $0.99/MWh in 2040.

Under the 15% LTC regime, the average cost for Tier 1 non-carve-out resources would be between $0.65-$0.85/MWh using the High FC/Low REC assumptions over the 2021-2040 analysis period. The average additional cost for Tier 1 solar is between $0.25-$0.40/MWh over the same period. Costs under the 40% scenario are proportionally higher.

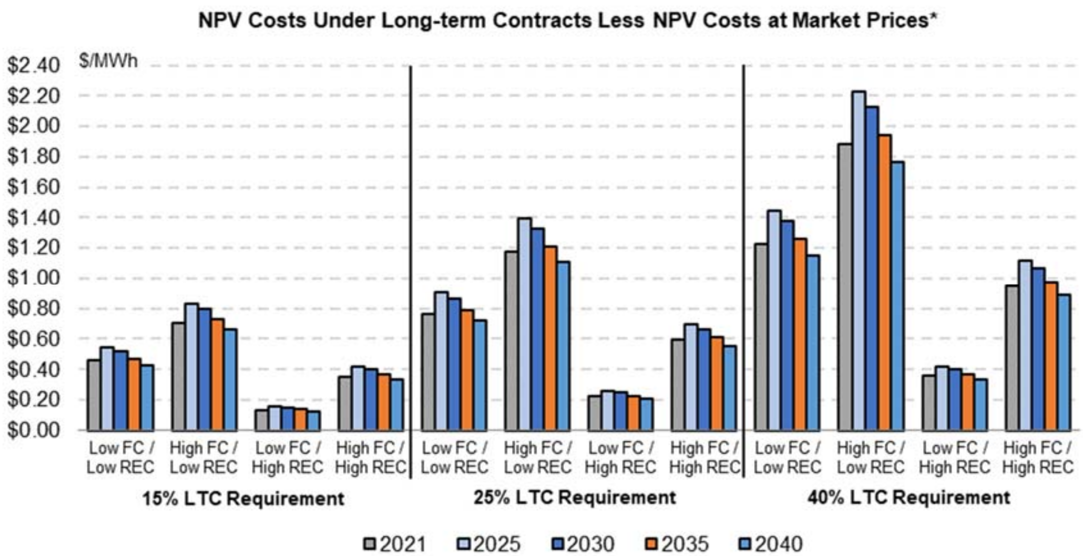

Figure 5-4. Net Present Value Cost Comparison by Average Rate – Tier 1 Non-Carve-out, All Retail Customers (2021$/MWh)

*"FC" denotes financing costs; "REC" denotes REC prices.

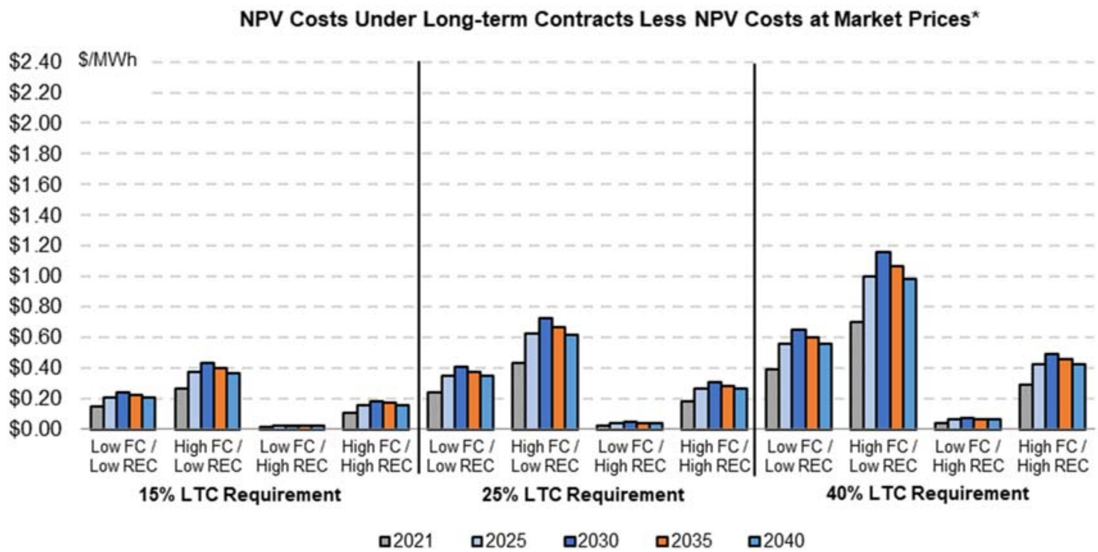

Figure 5-5. Net Present Value Cost Comparison by Average Rate – Tier 1 Solar Carve-out, All Retail Customers (2021$/MWh)

*"FC" denotes financing costs; "REC" denotes SREC prices.

To estimate the ratepayer impact for residential customers, which represents 43% of all electricity sold at retail in Maryland, this study assumes that a typical Maryland residential household uses 1,000 kWh (or 1 MWh) per month. Thus, the residential monthly bill closely matches the average costs presented in the preceding figures. Next, the cost per kWh is divided by the weighted-average residential retail rate in Maryland. This average retail rate is based on total electric revenues, including transmission and distribution costs, divided by electricity sales provided by the EIA's *Annual Electric Power Industry Report: Form EIA-861 2017*.[430] For example, the expected weighted-average residential rate in 2021 is projected to be 14.7 cents/kWh.

Figure 5-6 shows that the 15% Tier 1 non-carve-out LTC requirement would have a 0.09% impact on a typical residential monthly bill in 2021 under the lowest-cost scenario (Low FC/High REC). At 25%, the monthly bill impact under that same scenario would be 0.15% during the first year. In the most extreme case at a 40% LTC requirement under the High FC/Low REC scenario, residential customers would face a 1.28% impact on their monthly bill in 2021 that would increase to 1.76% by 2040.

[430] U.S. Energy Information Administration, *Annual Electric Power Industry Report*, Form EIA-861 detailed data files, eia.gov/electricity/data/eia861/.

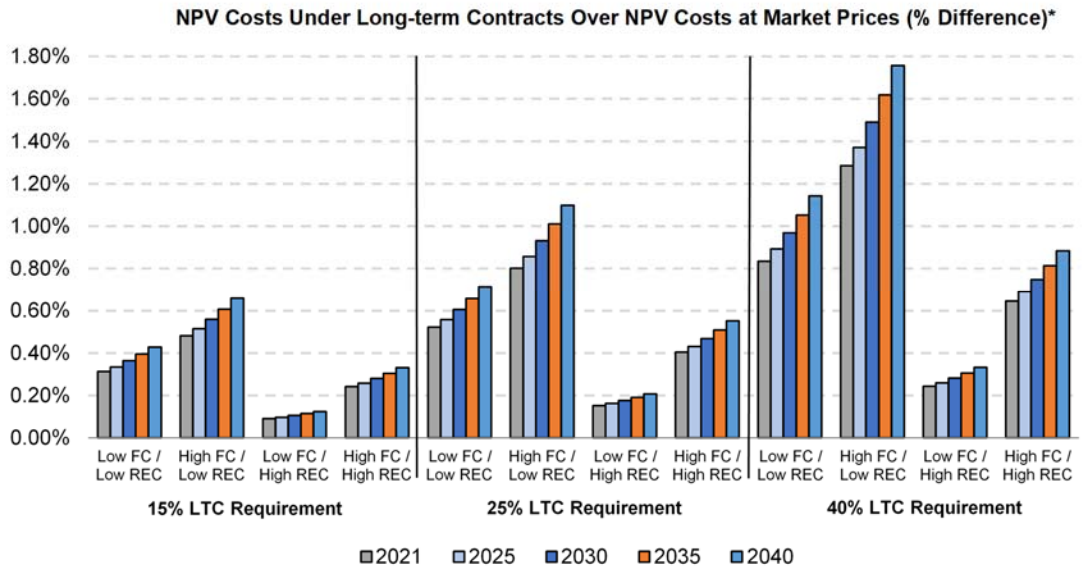

Figure 5-6. Net Present Value Cost Comparison – Tier 1 Non-Carve-out, All Residential Retail Customers (Percent Difference/Monthly Bill)

*"FC" denotes financing costs; "REC" denotes REC prices.

Considering that the Tier 1 solar RPS requirement is a third less than the non-carve-out requirement, the ratepayer impact of an LTC requirement for Tier 1 solar procurements is substantially less, as demonstrated in Figure 5-7. For instance, the monthly bill impact of a 25% LTC for Tier 1 solar projects hovers around 0.02% over the 20-year period under the Low FC/High REC assumptions. The residential rate impacts remain below 0.8% in all years, even under the highest-cost scenario (High FC/Low REC).

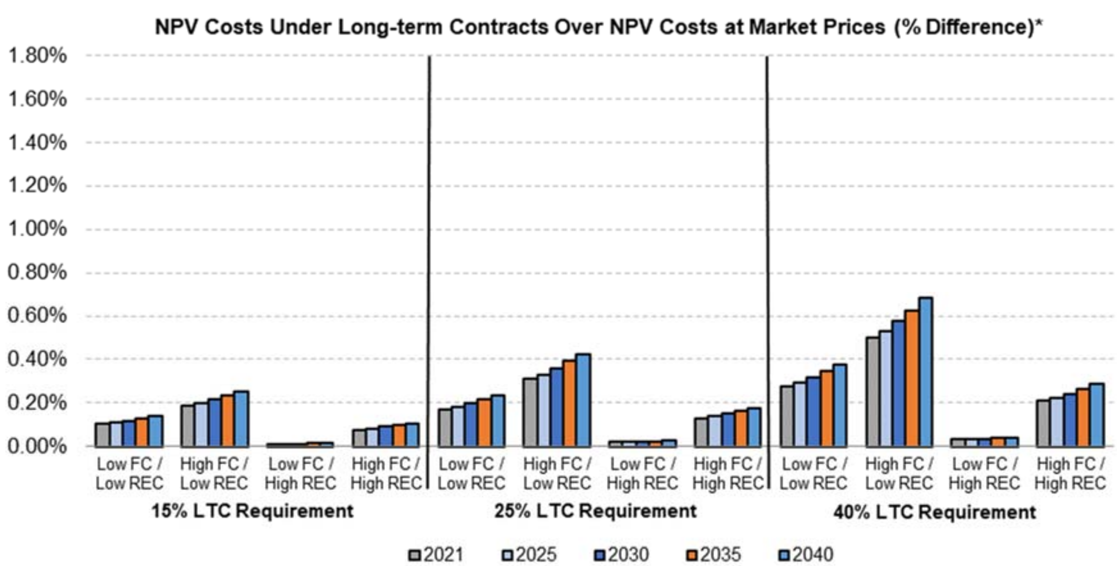

Figure 5-7. Net Present Value Cost Comparison – Tier 1 Solar Carve-out, All Residential Retail Customers (Percent Difference/Monthly Bill)

*"FC" denotes financing costs; "REC" denotes SREC prices.

Standard Offer Service Rate Impacts

This study considers the cost impact if the state legislature were to levy LTC costs only on SOS customers. During its 2018 legislative session, the Maryland General Assembly considered, but did not enact, such a proposal (SB 391) that would have required EDCs to enter into LTCs to meet at least 25% of each year's RPS for electricity provided to SOS customers.

Maryland's electric restructuring law provides for utility procurement of electricity for SOS customers or customers that cannot, or choose not to, switch to competitive supply. Maryland requires that the PSC adopt a procurement process that balances the "best price" (i.e., least cost) with price stability (protection of customers "from excessive price increases").[431] The law requires the electric companies to use a competitive bidding process to procure supply at the lowest cost, and permits PSC-approved bilateral contracts. The bidding process currently entails conducting solicitations twice a year for terms ranging from three to 24 months.

This analysis contemplates an SB 391-type regime in which the costs (or benefits) of an LTC requirement are recovered through a charge or rebate to Maryland's SOS customers only. It is assumed that SOS suppliers presently meet their Maryland RPS obligations with short-term REC/SREC purchases. An LTC requirement would necessitate that the utility, rather than the wholesale SOS suppliers, provide the RECs/SRECs for RPS compliance since the SOS suppliers are providing power under short-term contracts with the utility, that is, contracts not more than two years' duration. Establishing a requirement for an LTC for the wholesale supplier would be an unworkable condition.

For the SOS scenario, this study assumes that LTCs will only be used to meet a portion of Tier 1 RPS requirements. For example, the proposed SB 391 would have required EDCs to enter into LTCs for RECs and electricity generated from certain Tier 1 resources to meet at least 25% of each year's RPS for electricity provided to SOS customers. This study also estimates the costs of a 15% and 40% requirement. Figure 5-8 and Figure 5-9 show the total NPV of an LTC requirement applicable to only SOS supply. The costs shown are those above the costs of sequential short-term purchases over the PPA term.

As shown in Figure 5-8, for the 25% scenario, total added costs for Tier 1 non-carve-out resources assuming the Low FC/High REC scenario would equal approximately $6.1 million in 2021. Under the highest-cost scenario (High FC/Low REC), SOS customers would pay about $32.5 million in additional costs in the first year. As is the case for a non-bypassable charge levied to all customers, total costs fall after reaching a peak in 2027 and 2029.

[431] 2013 Annotated Code of Maryland, PUA § 7-510(c)(4)(ii), Phased implementation of customer choice, law.justia.com/codes/maryland/2013/article-gpu/section-7-510/.

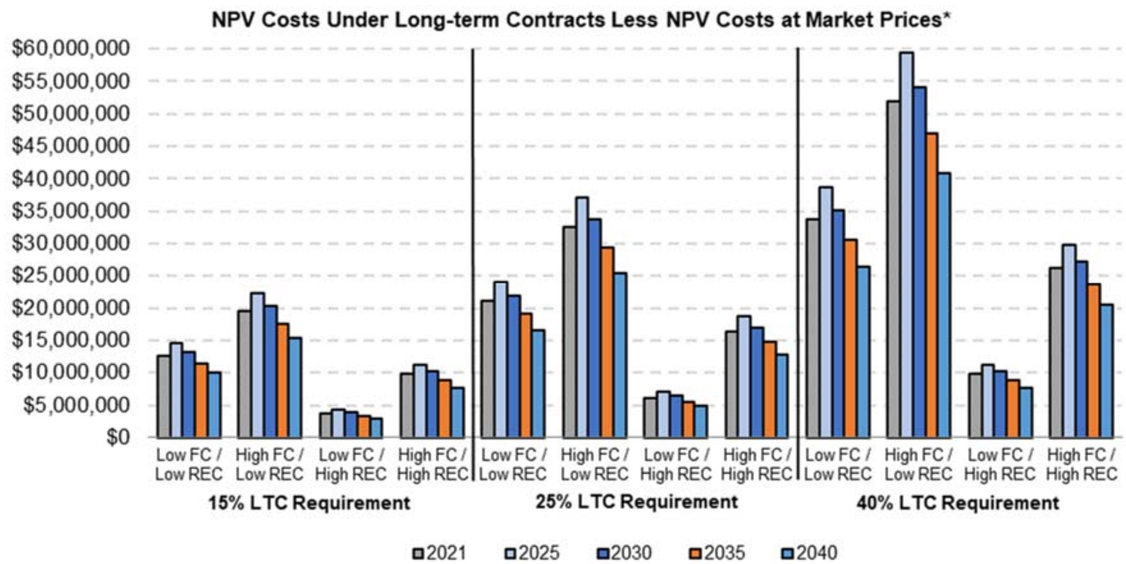

Figure 5-8. Net Present Value Cost Comparison – Tier 1 Non-Carve-out, SOS Customers (2021$)

*"FC" denotes financing costs; "REC" denotes REC prices.

The total costs associated with an LTC requirement for Tier 1 solar are a fraction of the costs for the Tier 1 non-carve-out (see Figure 5-9). For example, under the 25% requirement under the Low FC/High REC scenario, SOS customers would pay approximately $728,000 in the first year (2021).

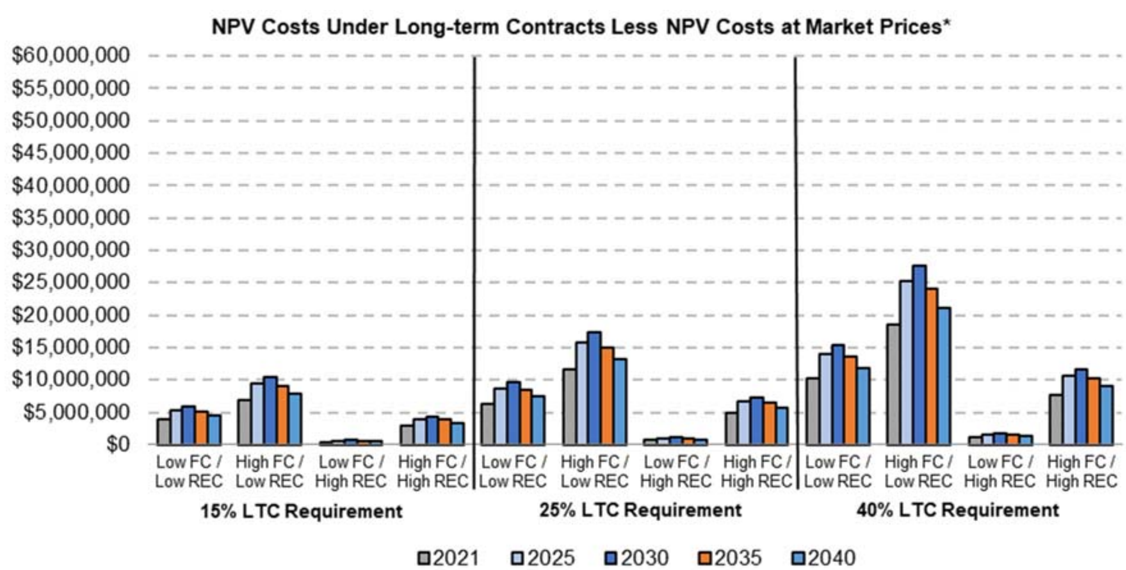

Figure 5-9. Net Present Value Cost Comparison – Tier 1 Solar Carve-out, SOS Customers (2021$)

*"FC" denotes financing costs; "REC" denotes SREC prices.

The average cost profile of an LTC requirement on SOS supply mirrors the average cost for the non-bypassable charge due to the arithmetic of SOS sales in both the numerator and denominator when calculating average costs. Figure 5-10 and Figure 5-11 show the monthly cost impact of a 15%, 25%, and 40% LTC requirement. The figures show, again, that the Low FC/High REC scenario results in the lowest costs for SOS ratepayers at $0.22/MWh for Tier 1 non-carve-out and $0.03/MWh for Tier 1 solar in 2021, assuming a 25% LTC requirement. Since the typical residential household in Maryland consumes about 1 MWh per month, the figures above also represent the added cost per month.

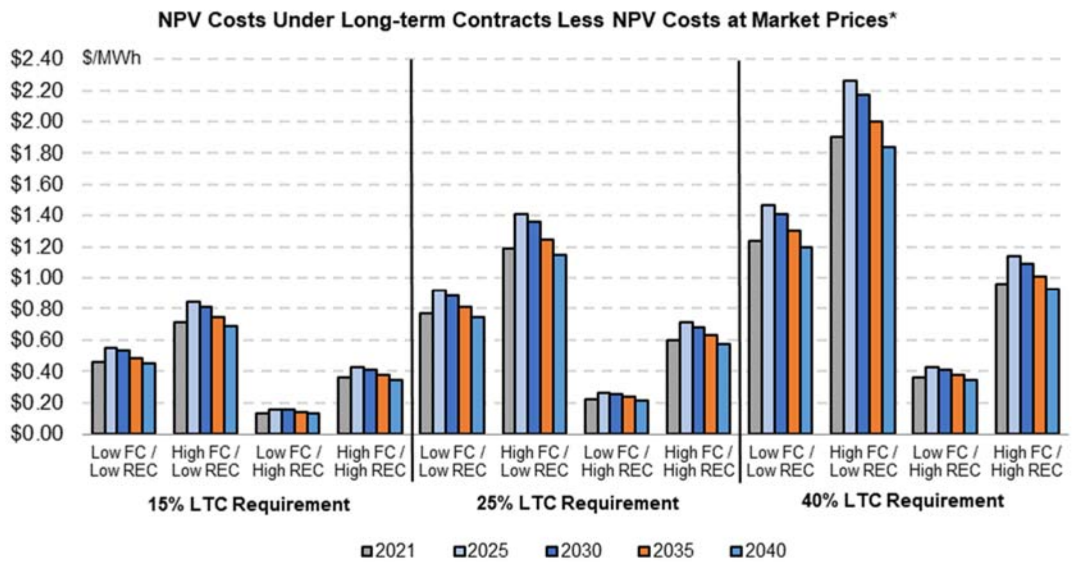

Figure 5-10. Net Present Value Cost Comparison by Average Rate – Tier 1 Non-Carve-out, SOS Customers (2021$/MWh)

*"FC" denotes financing costs; "REC" denotes REC prices.

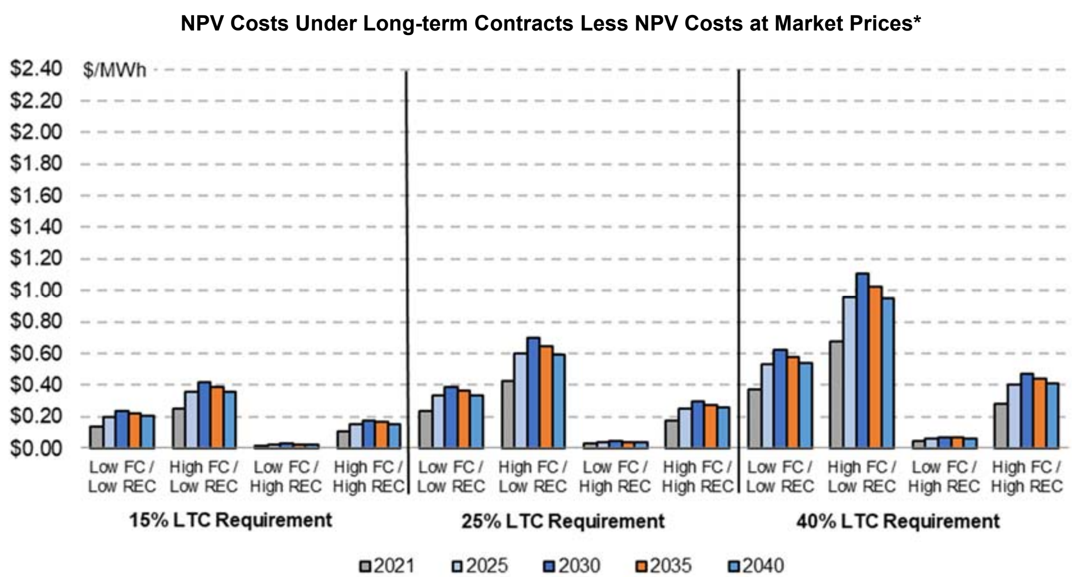

Figure 5-11. Net Present Value Cost Comparison by Average Rate – Tier 1 Solar Carve-out, SOS Customers (2021$/MWh)

*"FC" denotes financing costs; "REC" denotes SREC prices.

As is the case with assuming cost recovery through a non-bypassable charge to residential customers, this study estimates the total bill impact of an LTC requirement for SOS customers. Figure 5-12 and Figure 5-13 show the total bill impact of an LTC requirement as a percent of the weighted average residential rate of about 14.3 cents/kWh in 2021.

As shown in Figure 5-12, the percentage cost increase impact of a 25% LTC requirement for Tier 1 non-carve-out resources on a residential SOS monthly bill is 0.16% in 2021 under the Low FC/High REC scenario, which increases to 0.21% by 2040. In contrast, under the High FC/Low REC scenario, residential SOS customers can expect to pay 0.82% of their total bill in the first year, increasing to 1.13% in 2040.

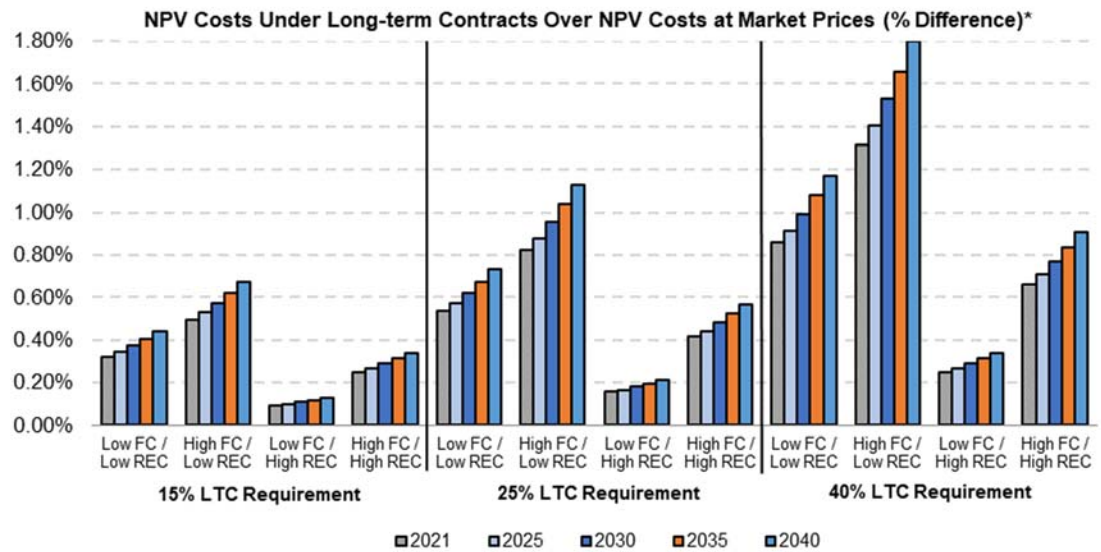

Figure 5-12. Net Present Value Cost Comparison – Tier 1 Non-Carve-out, Residential SOS Customers (Percent Difference/Monthly Bill)

*"FC" denotes financing costs; "REC" denotes REC prices.

For a Tier 1 solar LTC requirement, the residential SOS bill impact is substantially less, reflecting the lower RPS requirement for solar power in general. Figure 5-13 shows that a residential household would pay about 0.02% of their monthly SOS bill under the lowest-cost scenario (Low FC/High REC) with a 25% requirement in 2021. Under the highest-cost scenario (High FC/Low REC) with a 25% requirement, added costs in 2021 would amount to about 0.35%.

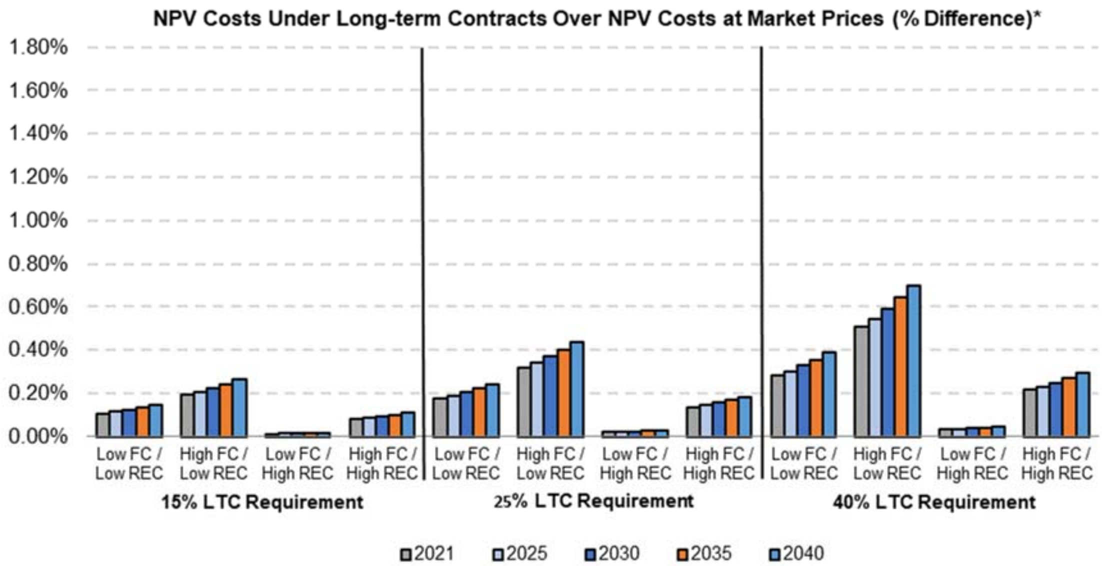

Figure 5-13. Net Present Value Cost Comparison – Tier 1 Solar Carve-out, Residential SOS Customers (Percent Difference/Monthly Bill)

*"FC" denotes financing costs; "REC" denotes SREC prices.

5.5. Impact of Future Conditions

The scenarios defined in this analysis do not exhaust the full spectrum of potential future conditions that could emerge and importantly affect the estimated impacts of Maryland requiring LTCs for LSEs to meet part of their RPS requirements. Examples of future conditions that could affect the benefits and costs of LTCs include:

- Higher-than-expected future increases in the market price of energy, for example, resulting from a greater-than-expected increase in natural gas prices, would serve to increase the benefits of LTCs since the energy purchased under the fixed-price LTCs would be more attractive relative to the market energy prices.
- Larger-than-expected future declines in the market price of energy would serve to decrease the benefits of LTCs since the energy purchased under the fixed-price LTCs would be less attractive relative to the analysis.
- Significant reductions in the capital cost of renewable energy projects in the future would serve to lower the value of future RECs and/or SRECs (other factors held constant) and erode the benefit of LTCs for renewable energy entered into prior to the emergence of the lower capital costs.
- New environmental regulations (e.g., a new carbon tax) would have the likely effect of increasing the future cost of electricity (other factors equal) and hence increase the benefits associated with fixed-price LTCs for renewable energy projects.

These potential future circumstances indicate that the range of results presented herein regarding the cost implications of long-term renewable energy contracts does not define upper and lower bounds of the potential impacts, but rather presents a set of reasonable outcomes associated with reliance on LTCs for the satisfaction of a portion of Maryland's renewable energy requirement.

6. NON-RPS POLICIES TO PROMOTE RENEWABLE ENERGY

In addition to RPS policies, numerous regulatory and market-based tools can be used to promote renewable energy technologies.[432] These either (1) promote renewable energy deployment, primarily by providing financial support to individual projects; or (2) address barriers to renewable energy by reforming market rules and regulatory processes that may indirectly impede renewable energy projects. Figure 6-1 provides an overview of these initiatives.

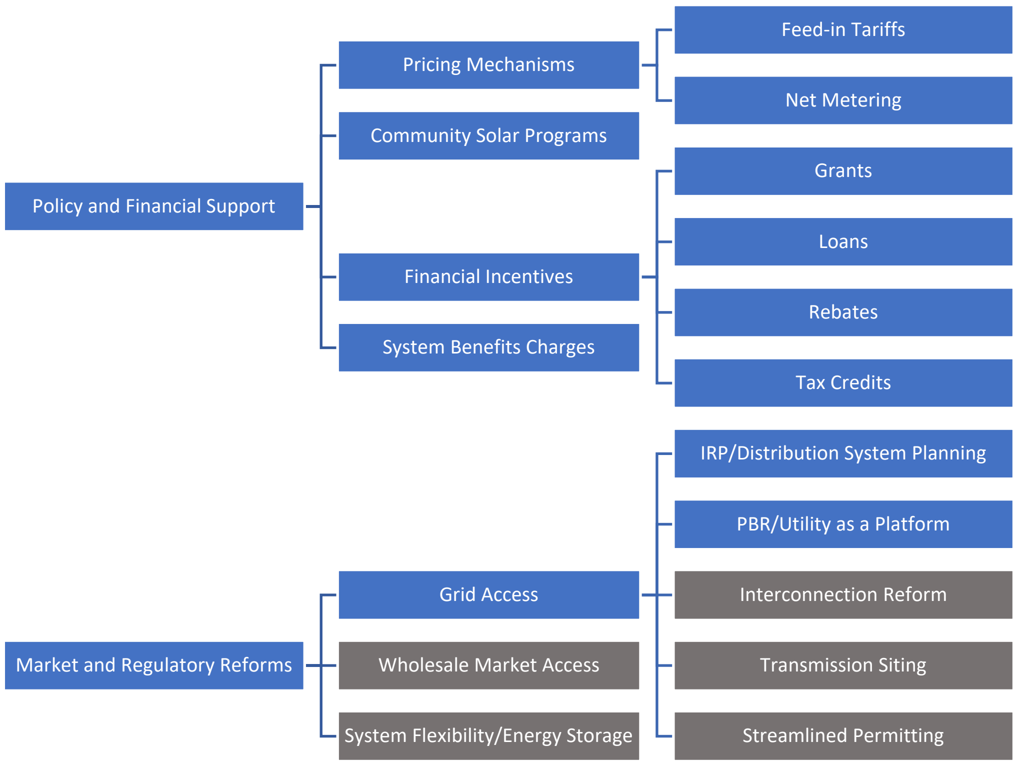

Figure 6-1. Supportive Policies for Renewable Energy in the Power Sector

IRP = integrated resource planning; PBR = performance-based regulation.
Note: Two of the topics shown in gray are addressed elsewhere in the final report: Wholesale Market Access (Appendix J) and Section 7.1, "System Flexibility and Energy Storage." The other three topics shown in gray lie outside the scope of this report. Updating interconnection standards has been a focus of the Maryland PSC's two-year Public Conference 44 on Grid Modernization. Transmission siting lies primarily under PJM's purview, and building permitting lies under the purview of cities and counties throughout the state.

It is difficult to distinguish the incremental impacts of these initiatives (and other related factors) due to the many potential overlaps and interactions among them, as illustrated in Figure 6-2. Instead, these policies and regulatory reforms are typically considered as complementary. For example, the EPA maintains a portal for information on eight types of

[432] Just as the RPS focuses on the power sector, so, too, does this chapter. It is understood that these policies exist within the broader context of policies to promote renewable energy across sectors (i.e., also within the transportation and heating/cooling sectors) and, still more broadly, to curb air and water emissions throughout the economy as a whole.

state policies to support renewable energy.[433] Similarly, in 2018, the International Energy Agency (IEA) co-authored a report titled *Renewable Energy Policies in a Time of Transition*,[434] which highlights 10 types of "key" power sector policies. In a slight variation, a recent policy guide issued by the consulting company Energy Innovation titled *Designing Climate Solutions* recommends the use of RPS laws and a host of "complementary policies" to promote grid flexibility.[435] (The guide also supports the use of cross-sector carbon pricing mechanisms, similar to RGGI in form yet broader in scope.)

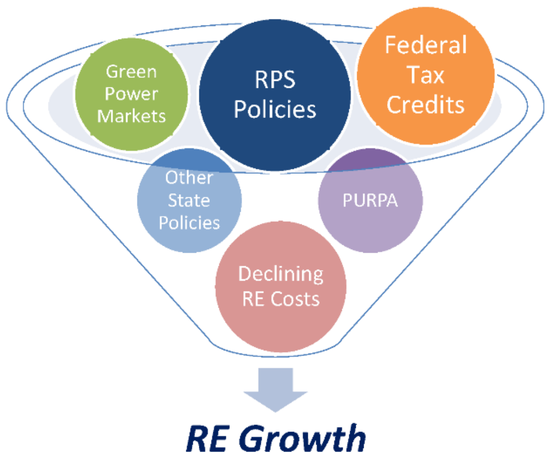

Figure 6-2. Broad Array of Market and Policy Factors Driving Renewable Energy Growth

Source: LBNL, *U.S. Renewables Portfolio Standards – 2019 Annual Status Update*.

In keeping with this precedent, experts who were consulted for this chapter of the final report recommended thinking of the Maryland RPS as the "backbone" of the state's efforts to promote renewable energy resources, and using additional policies to address the gaps that remain despite the RPS. Put another way, the Maryland RPS has been successful at promoting the growth of the lowest-cost renewable energy resources in the region, as well as the technologies eligible for the solar and offshore wind carve-outs. Maryland can (or continue to) use additional policies to pursue related objectives, such as: encouraging non-electric renewable energy technologies such as solar thermal; promoting DG; supporting projects in LMI communities; and minimizing or removing institutional or regulatory impediments to renewable energy.

The following sections of this chapter provide primers on the 10 policies shown in blue above in Figure 6-1 summarizing how they work, their use in other states, their chief advantages and disadvantages, and (if applicable) their history in Maryland. Table 6-1 summarizes the primary strengths and limitations of these policies.

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[433] U.S. Environmental Protection Agency, "State Policies to Support Renewable Energy," epa.gov/statelocalenergy/state-renewable-energy-resources#State%20Policies%20to%20Support%20Renewable%20Energy.

[434] International Renewable Energy Agency, International Energy Agency and Renewable Energy Policy Network for the 21st Century, *Renewable Energy Policies in a Time of Transition*, 2018, irena.org/-/media/Files/IRENA/Agency/Publication/2018/Apr/IRENA_IEA_REN21_Policies_2018.pdf.

[435] Hal Harvey, Robbie Orvis and Jeffrey Rissman, *et al.*, *Designing Climate Solutions*, Energy Innovation Policy & Technology, LLC, energypolicy.solutions/guide/.

Table 6-1. Overview of Non-RPS Policies to Promote Renewable Energy

	Strengths	Limitations
Feed-in Tariffs (FITs)	▪ Provide predictable revenue stream for developers ▪ Can be designed in a myriad of ways to prioritize certain technologies, locations, or applications	▪ Setting the FIT price is challenging and can either be insufficient and not result in much renewable energy development, or be too high and perhaps result in too much renewable energy development
Net Metering	▪ Easy for customers to understand and use existing metering infrastructure	▪ Concerns that ratepayers may cross-subsidize customers with DG systems ▪ Retail rates may not capture the actual value of electricity to the grid in a given time/place
Community Solar	▪ Increases access to solar PV beyond homeowners with suitable roofs or those customers that can afford to purchase and install their own solar system	▪ Customer acquisition costs to attract enough participants to get projects financed and developed can increase subscription rates
Financial Incentives	▪ Can help address the barrier posed by high capital costs and increase the overall affordability of projects	▪ Often provide money before a project is built, rather than rewarding electricity production
- Grants	▪ Can be designed to emphasize certain technologies, applications, customer classes, or geographic areas	▪ Require a continual stream of funding and can be costly to administer, given the need for applicants and administrators to prepare and review applications, respectively
- Loans	▪ Can be self-sustaining, assuming no loan defaults ▪ Likely to underwrite more projects than private banks due to lending mission and familiarity with renewable energy technologies	▪ Risk of loan defaults ▪ Require ongoing loan servicing and monitoring
- Rebates	▪ Simple to develop and administer and can be designed to support different technologies, geographic areas, or customer segments	▪ Challenging to set the "right" rebate level that does not under- or over-support the targeted technology or application
- Tax Incentives	▪ Do not require a direct source of funding or annual appropriations	▪ If an individual or business has no tax liability, can require complex financing arrangements that increase the overall cost of capital
System Benefits Charges	▪ Not dependent on annual state budget appropriations ▪ High degree of flexibility and can support loans, rebates, production incentives, and other policy mechanisms	▪ Disbursements around the state may be disproportionate to contributions, by region ▪ Risk that funds will be re-allocated to the state's general revenue fund
Integrated Resource Planning/ Distribution System Planning	▪ Helps the public gauge whether utility procurement and grid investment plans are conducive to the growth of distributed and utility-scale renewable energy projects	▪ Requires substantial time and effort on the part of utilities, stakeholders, and regulators
Performance-Based Regulation/ Utility as a Platform	▪ Can help to align utility profit motives with state renewable energy deployment goals (among others)	▪ Performance metrics require careful preparation to avoid unintended consequences and implementation takes place over many years ▪ New utility business models are, by definition, untested

Source: Adapted and expanded from irena.org/-/media/Files/IRENA/Agency/Publication/2018/Apr/IRENA_IEA_REN21_Policies_2018.pdf.

6.1. Feed-in Tariffs / Premiums

Feed-in Tariffs (FITs) and Feed-in Premiums (FIPs) are among the most popular mechanisms for increasing renewable energy deployment worldwide, especially for smaller renewable energy projects. As of 2017, 113 countries had some type of FIT in place.[436] FITs provide renewable energy system owners with a long-term (i.e., 15- to 20-year) purchase agreement for electricity at a specific price. FITs are also usually paired with guaranteed grid access and, in some cases, priority dispatch. FITs are essentially the inverse of a renewable purchasing requirement such as an RPS. Under an RPS, a quota of electricity from eligible generation is set, and the market determines the price paid, usually restricted by some combination of legislated cost caps, rate impacts, or ACPs. A FIT sets a technology-specific price, and the market responds with an undefined amount of eligible energy capacity (unless program-wide caps or technology-specific caps are imposed).[437] There are three states with FIT/FIP programs in effect, as shown in Figure 6-3. In states where an RPS is in effect, FITs/FIPs may be used by utilities to fulfill their RPS requirements.

Figure 6-3. States with Feed-in Tariffs or Premiums, Including Utility-Level Programs

Source: NCCETC DSIRE.

The value of a FIT can be based on (1) the levelized cost of a given renewable energy technology, which historically has been the most common basis; (2) a utility's avoided cost of energy plus societal and environmental benefits (e.g., reduced air emissions); (3) resource quality, which takes into account the likely output of a renewable energy system in a specific location; or (4) an auction procurement mechanism, under which a government requests bids for projects from which a utility will ultimately purchase electricity. The primary advantage of auctions is that they introduce competition into the process, which helps to ensure that FITs are not needlessly high. In Europe, there has been a shift to auction-based FITs for large-scale projects, while smaller ones continue to be

[436] Renewable Energy Policy Network for the 21st Century, *Renewables 2018: Global Status Report*, 2018, ren21.net/gsr-2018/.

[437] Charles Kubert and Mark Sinclair, *Distributed Renewable Energy Finance and Policy Toolkit*, Clean Energy States Alliance, 2009, cesa.org/assets/Uploads/CESA-renewableenergy-FinancePolicy-toolkit2009.pdf.

supported through more traditional FITs. The cost of (non-auction) FITs can be also contained by setting caps on participation, establishing procedures to reduce FIT levels on a regular basis over time, and/or ending FITs when a program's funding ends. However, all these mechanisms introduce uncertainty, which can dampen the overall impact of a FIT.[438]

In addition to auctions, some countries have transitioned from FITs to other policy mechanisms such as FIPs that either offer a set premium on top of the market price or a sliding premium based on a set price or "strike price." In the latter case, the premium makes up the difference between the strike price and the market price.

FITs and FIPs tend to be paired with guarantees for grid access and priority dispatch, so that the electricity generated under these contracts has a strong likelihood of being utilized.

6.1.1. Experience with Feed-in Tariffs / Premiums in Other States

Other than perhaps PURPA, which some consider as one of the very first FITs ever enacted, the United States has had limited experience with FITs. Below are two examples of FITs in the U.S.

Since 2011, Northern Indiana Public Service Company (NIPSCO) has offered a FIT for wind, solar, and biomass systems ranging in size from 3 kW – 1 MW. FIT rates vary between $0.0918-$0.2500/kWh depending on the technology, project size, and start date. Highest incentives are for 3- to 10-kW wind projects. The contract length for these FITs is to be no longer than 15 years, with a 2% annual escalator for rates.[439]

In 2012, the Long Island Power Authority (LIPA) (a public-private entity that owns transmission and distribution infrastructure on Long Island) established a Clean Solar Initiative Feed-in Tariff I (FIT I) to interconnect up to 50 MW of distributed PV in its service territory. The program was open to projects between 50 kW and 2,000 kW. Interested applicants submitted a bid price into an auction. The price selected to be paid to accepted applicants was $0.22/kWh. All projects that made the cut were awarded a fixed-price, 20-year PPA with LIPA.[440]

6.1.2. Advantages and Disadvantages of Feed-in Tariffs / Premiums

Advantages

- *Long-term certainty* – FITs (and, to a lesser extent, FIPs) provide a predictable income stream for project owners, which helps to lower the cost of financing and drive rapid deployment.
- *Flexibility* – FITs can be designed in a myriad of ways, and indeed, no two FITs are designed the same because political jurisdictions have different policy objectives. Differences in FIT policy design include eligible resources and technologies; length of contract; adjustment in FIT prices over time; location or application; capacity limits by project, technology, year, or cumulative; and

[438] Sadie Cox and Sean Esterly, *Feed-in Tariffs: Good Practices and Design Considerations*, National Renewable Energy Laboratory, 2016, nrel.gov/docs/fy16osti/65503.pdf.

[439] NIPSCO, "Feed-in Tariff," nipsco.com/our-services/renewable-energy-projects/feed-in-tariff-program.

[440] PSEG Long Island, "Clean Solar Initiative Feed-in Tariff I," psegliny.com/aboutpseglongisland/ratesandtariffs/tariffs/feedintariff1.

resource intensity (e.g., different rates for wind or solar energy depending on the site's resource availability).[441]

Disadvantages

- *Administrative complexity* – The flexibility with FITs noted above can be a disadvantage in that there is a multitude of ways to set a FIT, adding complexity and raising the risk of inadvertent policy outcomes.
- *Risk of over/under-compensation* – The primary challenge with FITs/FIPs is setting appropriate levels of compensation, which should be based on a thorough evaluation of the levelized costs of eligible renewable energy technologies. Ideally, FITs should be updated on a regular basis (e.g., annually) to keep pace with technology advancements and market developments. If FIT/FIP levels are too high, they can lead to excessive developer profits and runaway renewable energy deployment. If FIT/FIP levels too low, they may not drive the desired investment.
- *Risk of non-optimal siting* – By guaranteeing grid access, FIT/FIP policies can lead to less-than-optimal project locations, unless siting considerations are designed in the FIT/FIP.[442] For instance, China's FIT for wind set a higher price for projects that were sited in lower-quality wind resource areas.
- *Potential legal challenges* – In 2017, a U.S. District Court declared that a FIT program in California violated PURPA.[443] The Energy Policy Act of 2005 exempted regions with nondiscriminatory access to competitive power markets from PURPA. In a separate order, FERC instituted a rebuttable presumption that generators larger than 20 MW have access to competitive power markets in PJM, ISO-NE, Midcontinent ISO (MISO), New York ISO (NYISO), and the Electric Reliability Council of Texas (ERCOT), and exempted those RTOs from having to comply with PURPA.[444] As a part of PJM, Maryland is exempt from PURPA.

6.1.3. Maryland's Use of Feed-in Tariffs / Premiums

Maryland has not used FITs or FIPs.

[441] KEMA, Inc, *Exploring Feed-In Tariffs for California: Feed-In Tariff Design and Implementation Issues and Options*, Final Consultation Report, prepared for the California Energy Commission, 2008, energy.ca.gov/2008publications/CEC-300-2008-003/CEC-300-2008-003-F.PDF.

[442] Charles Kubert and Mark Sinclair, *Distributed Renewable Energy Finance and Policy Toolkit*, Clean Energy States Alliance, 2009, cesa.org/assets/Uploads/CESA-renewableenergy-FinancePolicy-toolkit2009.pdf.

[443] Buck Endemann, William Keyser, Molly Suda and Toks Arowojolu, "Federal Court Rejects California Public Utilities Commission's RE-MAT Program as Non-Compliant with PURPA," K&L Gates, 2017, globalpowerlawandpolicy.com/2017/12/federal-court-rejects-california-public-utilities-commissions-re-mat-programs-as-non-compliant-with-purpa/.

[444] New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities, Order No. 688, 2006-2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,233 (2006) (adopting a rebuttable presumption that "small" Qualifying Facilities may not have nondiscriminatory access to markets because of their size and defining "small" as less than 20 MW), order on reh'g, Order No. 688-A, 2006-2007 FERC Stats & Regs., Regs Preambles ¶ 31,250 (2007); *See:* also Revised Regulations Governing Small Power Production and Cogeneration Facilities, Order No. 671, 2006-2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,203, (adopting exemption under PURPA for Qualifying Facilities 20 MW or smaller from sections 205 and 206 of the FPA), order on reh'g, Order No. 671-A, 2006-2007 FERC Stats.& Regs., Regs Preambles ¶ 31,219 (2006).

6.2. Net Metering

Net metering is the measurement of electricity that is net of the energy consumed and produced by a customer-generator during a billing period (e.g., a month). Effectively, net metering permits customers to use the utility grid as if it were a battery storage device, such that any excess energy produced from a generator can be stored. Traditionally, net-metered customers have been compensated for excess generation at their retail rate. Nearly every state has some form of net metering policy, as shown in Figure 6-4. These policies largely came into existence when DG technologies were uneconomic. As distributed PV systems in particular have become increasingly cost-competitive, 48 states (and the District of Columbia) have begun considering or recently adopted alternatives to net metering.[445]

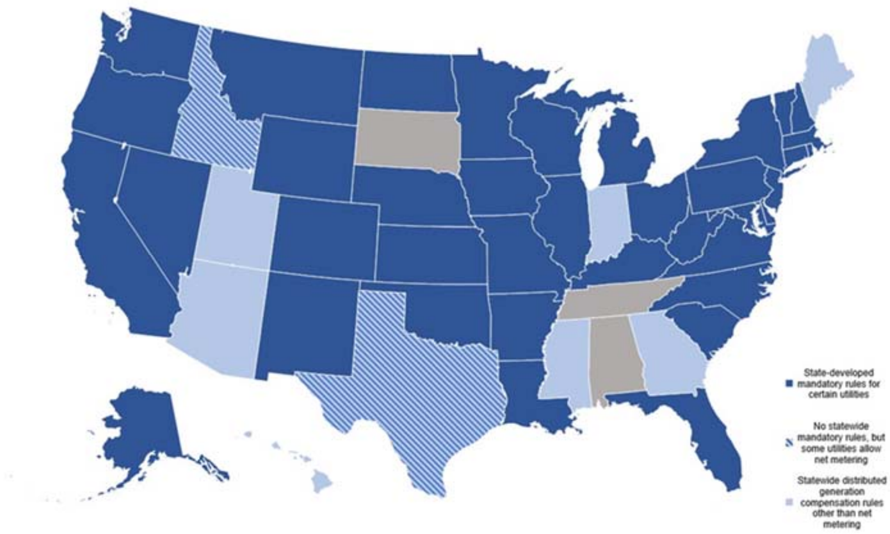

Figure 6-4. States with Net Metering Policies

Source: NCCETC DSIRE.

6.2.1. Experience with Net Metering and Its Alternatives in Other States

Several factors have prompted most states to reevaluate their net metering policies. These factors include: improvements in the economics of DG technologies, especially solar; the resulting uptick in DG capacity; concerns that customers without DG may be subsidizing customers who do; and concerns that customers with DG facilities may not be contributing fully to covering the fixed costs of the electric power system.[446]

Net metering impacts costs and revenues for utilities, distributed energy resource (DER) providers, and individual DER owners. These impacts must be understood, so that any changes made avoid unintended consequences, such as DER "boom" and "bust" cycles.[447]

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[445] Tom Stanton, *Review of State Net Energy Metering and Successor Rate Designs*, National Regulatory Research Institute.

[446] Autumn Proudlove, Brian Lips, David Sarkisian and Achyut Shrestha, *50 States of Solar: Q4 2018 Quarterly Report and 2018 Annual Review*, Executive Summary, North Carolina Clean Energy Technology Center, January 2019, nccleantech.ncsu.edu/wp-content/uploads/2019/01/Q4-18-Exec-Summary-Final.pdf.

[447] Tom Stanton, *Review of State Net Energy Metering and Successor Rate Designs*, National Regulatory Research Institute.

As states look to the future, one of the primary questions under consideration is whether a DER should be compensated based on the value it provides to the grid or the cost (to utilities) that it avoids, or some mix of the two. As of January 2019, 11 states, including Maryland, have completed value-based studies of DERs and 18 are underway.[448] There is wide variation in the categories of benefits and costs included in these studies and their results, which thus far range from 4-30 cents/kWh, with a mean value of 16 cents/kWh.[449]

States have made several types of changes related to DERs, including wholly replacing net metering with a successor rate tariff; increasing fixed charges and/or minimum bills; instituting time-varying rates; imposing or increasing demand charges; and setting a new rate class for customers with DG. Table 6-2 summarizes the types of policy changes under consideration around the country and the states where they have been adopted.

Table 6-2. Distributed Energy Resources Policy Types Recently Adopted by States

Policy Type	Vertically Integrated States/ *Restructured States*
Replacing net metering or initiating a regulatory process to do so	AZ, CA, HI, ID, IN, LA, MI, NV, UT, VT *CT, DC, MA, ME, NY*
Changing credit rates for excess generation	AZ, CA, GA, HI, IN, KS, LA, MT, NC, NH, NV, SC, UT, WI *ME, NY, OH, TX*
Increasing/(decreasing) customer fixed charges	AL, AK, AR, AZ, (CO), FL, HI, ID, IN, KS, KY, MI, MN, MO, ND, NM, NV, OK, SC, SD, TN, WA, WI, WV *(CT), DC, DE, MA, NH, NJ, (NY), OH, PA, RI, TX*
Assigning demand charges or standby charges	AL, AR, AZ, CA, KS, NC, NM, SC, UT *MA, NH*
Creating a separate customer class for DG	IA, ID, KS, MT, NV *TX*
Providing for third-party-owned or utility-owned DG	AZ, FL, GA, LA, MO, NC, NM, SC, UT, VA, VT *DC, NY, RI, TX*
Adding provisions for community solar	CA, CO, HI, MN, NC, OR, VA, VT, WA *CT, DC, DE, IL, MA,* ***MD,*** *ME, NH, NJ, NY, RI*

Source: Adapted from Tom Stanton, *Review of State Net Energy Metering and Successor Rate Designs*, National Regulatory Research Institute.

[448] The Value of Solar Study commissioned by the Maryland PSC is discussed in Subsection 7.2.1, "Estimated Land Use Impacts of Solar PV."

[449] Tom Stanton, *Review of State Net Energy Metering and Successor Rate Designs*, National Regulatory Research Institute.

6.2.2. Advantages and Disadvantages of Net Metering

The advantages and disadvantages summarized below have been alluded to in the preceding discussion.

Advantages

- *Simplicity and surety* – Net metering is easy for customers to understand and provides a guaranteed purchaser for any excess electricity.
- Can rely on existing metering infrastructure.
- *Effectiveness as a market catalyst* – With net metering (among other incentives), the payback period for a well-situated distributed PV unit has been attractively short, throughout the U.S., for many years. This has helped BTM PV gain a foothold in the country.

Disadvantages

- *Possible cost-shifting* – There are concerns that customers without DG facilities are subsidizing those customers with DG facilities. Others counter that DG provides additional benefits to the grid, in terms of resiliency and avoided infrastructure investments, that are not reflected in retail rates.
- *Lack of access* – Net metering is only available to customers that have homes or sites that are suitable for DG systems.

6.2.3. Maryland's Use of Net Metering and Next Steps

Maryland enacted net metering in 1997, with an aggregate limit of 34.7 MW. In 2007, this limit was raised to 1,500 MW, which is equivalent to roughly 10% of peak load in the state as of 2014. Eligible technologies in Maryland include solar, wind, biomass, micro-CHP, fuel cells, and closed conduit hydro generators that are intended primarily to supply a customer's annual energy usage. However, solar systems represent over 99% of net-metered capacity in the state. As of the latest net metering status report (2018) issued by the Maryland PSC, net metering capacity had reached 772 MW, or roughly half the state's capacity limit. Thus, the PSC concluded that no policy changes were necessary at this time. With up to 200 MW of community solar that could come online and the unpredictability in the potential amount of new solar installations, the PSC suggested that policymakers begin considering possible next steps as Maryland gets closer to the 1,500-MW cap.[450]

6.3. Community Solar

Community solar allows customers to own a portion of or purchase the output of a solar project located off-site. These customers may not be able to install their own solar systems on-site because of lack of roof space, an inadequate solar resource, or because they rent or lease their home or business space and do not have the ability to install a solar system. In a community solar program, a utility or third party owns a utility-scale PV array and sells parts of the array's power (kW) or generation (kWh) to multiple subscribers. These subscribers voluntarily pay for their part of the solar project and then receive a credit on their electricity bill for their share of production. This bill credit for generation produced may also include payment for the RECs, depending on how the program is set up. Subscribers

[450] Public Service Commission of Maryland, *Report on the Status of Net Energy Metering in the State of Maryland*, September 2018, psc.state.md.us/wp-content/uploads/FINAL-2018-Net-Metering-Report.pdf.

may pay for their share of the project via an upfront payment or an ongoing monthly payment.[451]

There are four types of community solar models: community group purchasing, off-site shared solar, on-site shared solar, and a community-driven financial model. Community solar installations can be owned by a utility, a special purpose entity (SPE), or a nonprofit organization.[452] Forty-one states (and the District of Columbia) have at least one community solar program, as shown in Figure 6-5. Many state programs require that a portion of the community solar projects be reserved for LMI participants.

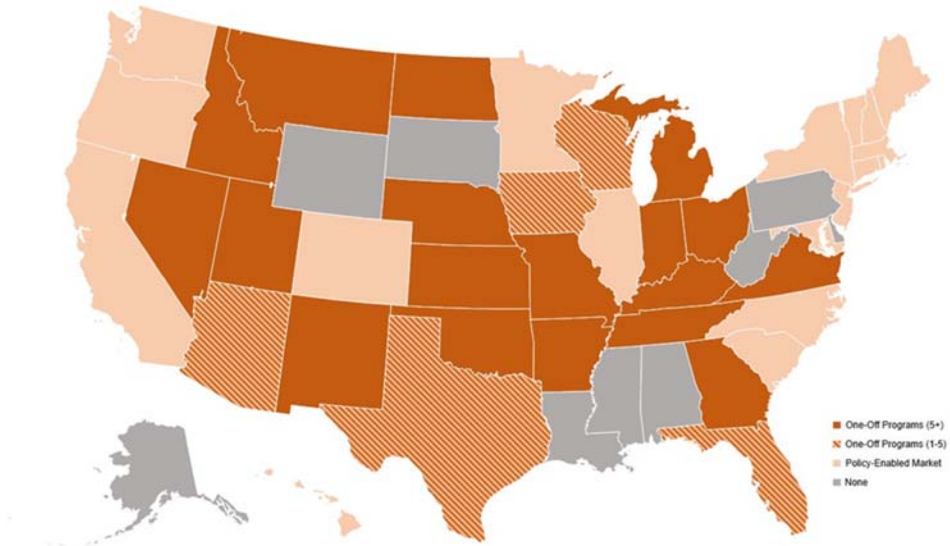

Figure 6-5. States with Community Solar Policies

Source: Wood Mackenzie Power & Renewables, *The Vision for U.S. Community Solar: A Roadmap to 2030*.

Note: One-off programs are initiated voluntarily by a utility, rather than enabled through statewide programs.

6.3.1. Experience with Community Solar in Other States

As of July 2018, installed community solar capacity nationwide totaled 933 MW. Nineteen states (and the District of Columbia) require utilities to offer community solar programs. Another 23 states simply have one-off programs.[453] It is projected that over the next several years, approximately 3 GW of community solar will come online in the country.[454] The largest low-income community solar project in the U.S. is a 30-MW solar project that will service its low-income customers via a bill credit.[455]

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[451] Jenny Heeter, Lori Bird, Eric O'Shaughnessey and Sam Koebrich, *Design and Implementation of Community Solar Programs for Low- and Moderate-Income Customers*, National Renewable Energy Laboratory, December 2018, nrel.gov/docs/fy19osti/71652.pdf.

[452] An SPE is a business entity, consisting of individuals and/or companies, that assists participant-owned community solar projects with tax and finance issues, including fully utilizing the federal solar tax credits.

[453] Wood Mackenzie Power & Renewables, *The Vision for U.S. Community Solar: A Roadmap to 2030*, Executive Summary, July 2018.

[454] Solar Energy Industries Association, "Community Solar," seia.org/initiatives/community-solar.

[455] Imperial Irrigation District, "IID & Citizens commission community solar project dedicated to low-income customers," September 25, 2019, iid.com/Home/Components/News/News/709/30?backlist=%2F.

6.3.2. Advantages and Disadvantages of Community Solar

Advantages

- *Equal access* – Community solar is open to those who are precluded from distributed solar (e.g., renters, homeowners with shaded roofs, or customers that cannot afford to purchase their own solar system). It is estimated that only one-fifth of the population can install distributed solar.[456]
- *Potential decrease in the need for energy assistance* – In the long term, community solar may reduce ratepayer reliance on energy assistance programs.
- *Low bar for entry* – There are typically no upfront costs paid by subscribers since they are not purchasing the system. Although the specifics vary, customers can also take their community solar subscription with them if they move, possibly subject to some constraints such as having to relocate within a utility's service territory. Likewise, subscribers do not have to worry about how long they will reside in a location.
- *Economies of scale* – Even though each participant may have a modest load, their collective demand can support a utility-scale solar project.
- *Siting flexibility* – Projects can be located on-site or off-site and can be sited in a location that maximizes the solar output.

Disadvantages

- *Land use concerns* – As with all utility-scale PV, there are concerns that solar installations will be built on farmlands or diminish the value of nearby sites. Some Maryland counties have established limits on the number and size of community solar projects that can be installed within a geographical location.[457]
- *Long-term commitment* – Some community solar projects require long-term commitments, such as 20- to 25-year subscriptions.
- *Risk of project delays* – A percentage of subscribers must be committed to a community solar project before it is built. If there is difficulty obtaining subscribers, it may prolong the time period before the project is built, or the project may not be built at all. Siting concerns, and related regulatory review processes, can also cause project delays.

6.3.3. Maryland's Use of Community Solar

In 2015, the Maryland General Assembly passed legislation for a three-year community solar pilot program. The program has a statewide cap of 193 MW, of which 60 MW has been

[456] Jason Coughlin, Jennifer Grove and Linda Irvine, *et al.*, *A Guide to Community Solar: Utility, Private, and Nonprofit Project Development*, U.S. Department of Energy – Energy Efficiency & Renewable Energy, November 2018, nrel.gov/docs/fy11osti/49930.pdf.

[457] Scott Dance, "Maryland launches community solar program, creating green energy opportunities—but also potential conflicts," *The Baltimore Sun*, August 2018, baltimoresun.com/news/maryland/environment/bs-md-community-solar-20180802-story.html.

set aside for projects that benefit LMI ratepayers.[458] The Maryland PSC adopted regulations for the community solar pilot program in 2016.

Under the pilot program, each of Maryland's major IOUs is responsible for selecting one or more Subscriber Organizations to build a community solar project in their service territory and present the project to the PSC for approval.[459] A utility customer may subscribe to a portion of the community solar project by either paying an upfront fee and/or by making monthly payments. The utility issues a community solar adjustment to the subscriber for the appropriate amount, and the subscriber still pays supply, delivery, and administrative charges. Any unsubscribed energy from the community solar project is paid for by the IOU.

As of May 2019, 62 interconnection requests for Community Solar projects in Maryland have been given a "reserved" or "accepted" status under the pilot program. This means that the projects have been accepted by one of the participating utilities, but they are not yet in service. Many presumably are still seeking subscribers. Thirty-eight of the projects are in the service territory of BGE, 11 are in Pepco, eight are in Potomac Edison, and five are in DPL. Together, the reserved projects represent 91 MW of capacity. In addition, 0.09 MW of capacity are in service.[460,461]

Also as of May 2019, according to Solar United Neighbors, there are 12 projects in Maryland that are open to subscribers, equating to a total capacity of 27.4 MW.[462] In addition, a 0.022-MW SPE community solar project in University Park, Maryland is fully subscribed. The electricity generated from this project is sold to a church below retail rates, and the net revenues and tax credits are passed to the project's 36 other subscribers.

In addition to community solar projects, MEA commenced the Maryland Community Solar Pilot Program in April 2017, which offers grants/incentives to residential and business customers in Maryland that subscribe to a community solar project within the subscriber's utility service territory.[463] Residential customers who subscribe and apply for the grant may receive an incentive of $80/kW of their subscription. To encourage LMI ratepayers to subscribe, the grant increases to $240/kW.[464] Commercial customers may receive a grant

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458 Maryland Public Service Commission, "Community Solar Pilot Program," psc.state.md.us/electricity/community-solar-pilot-program/.

459 Delmarva Power and Light, "Community Solar," delmarva.com/SmartEnergy/MyGreenPowerConnection/Pages/CommunitySolar.aspx.

460 Values based on the interconnection queues posted by the four participating utilities:

BGE: bge.com/SmartEnergy/MyGreenPowerConnection/Documents/BGE_CSEGS_QUEUE_PilotApplicationList.pdf.

DPL: delmarva.com/MyAccount/MyService/Documents/21119Copy%20of%20CSEGS%20Pilot%20Queue%20Status%20-%20Delmarva%20Year%202%2011%2026%20%202018%20(version%201).pdf.

Pepco: pepco.com/MyAccount/MyService/Documents/32519CSEGS%20Pilot%20Queue%20Status%20-%20Pepco%20Year%201%2008%2010%202017.pdf.

FirstEnergy: firstenergycorp.com/content/dam/feconnect/files/retail/md/community-solar/pe-pilot-queue.pdf.

461 DPL's queue does not use the term "reserved." Projects that are not designated as "Wait Listed" are assumed to be "Reserved."

462 Solar United Neighbors, "Find Subscriptions," cs.solarunitedneighbors.org/states/MD/show.

463 Maryland Energy Administration, "Community Solar," energy.maryland.gov/residential/Pages/Community-Solar.aspx.

464 Ibid.

for $100/kW.[465] In FY 2018, MEA awarded eight community solar grants to projects with a combined capacity of 14.2 MW.[466]

6.4. Grants

Grants provide partial or full funding for specific projects, whether they are energy efficiency, renewable energy, fossil energy, labor training, research and development, or others. Grants are generally issued through competitive solicitations or RFPs, which can be highly structured or left more general and open to encourage innovative project ideas. Grants may also be awarded through reverse auctions to select projects that require the smallest amount of funding.[467] Seventeen states and the District of Columbia provide grants for renewable energy projects, as shown in Figure 6-6.

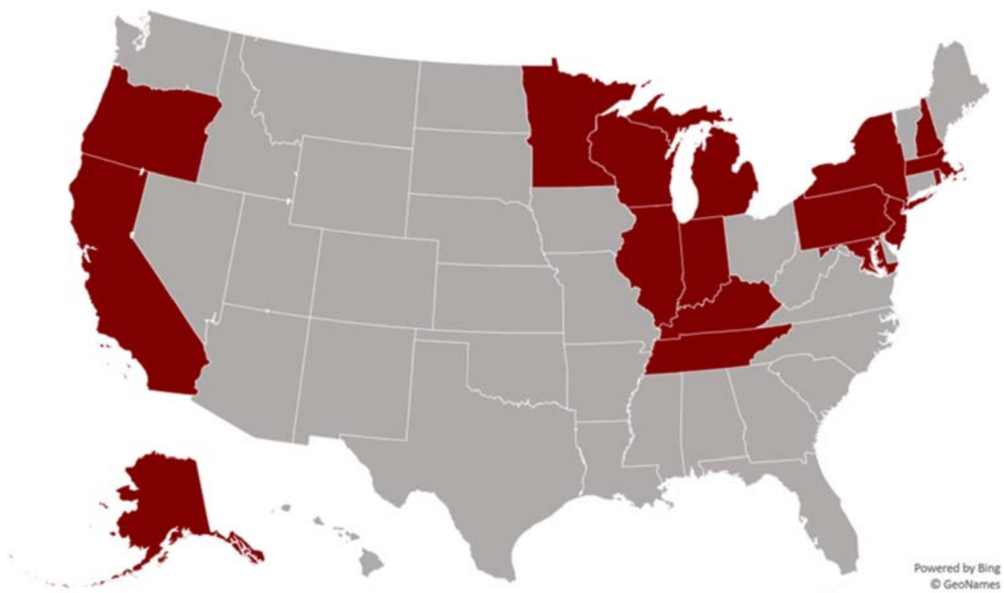

Figure 6-6. States with Grant Programs for Renewable Energy Projects

Source: NCCETC DSIRE.

6.4.1. Experience with Grants in Other States

Collectively, the states shown above underwrite 47 grant-making programs. They are diverse, focusing on a wide range of renewable energy technologies and potential recipients, including private customers, public organizations, nonprofits, farms, and communities. Twelve of the states shown above also have an RPS.[468]

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[465] Ibid.

[466] Maryland Energy Administration, *Maryland Strategic Energy Investment Fund: Report on Fund Activities Fiscal Year 2018*, energy.maryland.gov/Reports/FY18%20SEIF%20Annual%20Report.pdf.

[467] Charles Kubert and Mark Sinclair, *Distributed Renewable Energy Finance and Policy Toolkit*, Clean Energy States Alliance, 2009, cesa.org/assets/Uploads/CESA-renewableenergy-FinancePolicy-toolkit2009.pdf.

[468] North Carolina Clean Energy Technology Center, DSIRE, dsireusa.org. Historically, the federal government provided funding to NCCETC to track state incentives for clean energy. This funding has been discontinued and the database has not been systematically updated since 2016.

6.4.2. Advantages and Disadvantages of Grants

Advantages

- *Addresses upfront costs* – Most of the costs associated with renewable energy projects occur during project development and construction, while project benefits accrue slowly over time.
- *Flexibility* – Grants can be designed to emphasize certain technologies, applications, customer classes, or geographic areas. They can also be used for pilot or demonstration projects, or to support more technologically mature projects.
- *Compatibility* – Grants can be combined with private capital. Grantors can require grantees to secure funding from other sources to preserve grant funds and also to ensure potential grantees have support from other parties.

Disadvantages

- *High administrative costs* – Preparing and/or reviewing grant applications is time-consuming, both for applicants and government agencies.
- *Not self-sustaining* – By definition, grants involve no repayment. Therefore, they require a continual stream of funding, or will be short-lived by design.
- *Imprecision* – The appropriate amount of grant funding can be hard to calibrate; it may be higher than necessary to attract applicants or too small to catalyze the desired activity.
- *Not performance-based* – Because grant money is provided up front, there is little emphasis on the ultimate performance of a project.[469]

6.4.3. Maryland's Use of Grants

Maryland has 12 active grant-making programs that provide funds for renewable energy projects, sometimes in conjunction with energy efficiency or EV projects. (A small portion of this money flows to renewable energy workforce development.) These grantmaking programs are summarized in Table 6-3. In FY 2018, MEA awarded over 2,700 grants through these programs, providing over $12.5 million in support for renewable energy projects and related activity in the state.[470]

MEA's Smart Energy Investment Dashboard provides historical data on $45 million in MEA investments between 2000 and 2014, which can be helpful for understanding long-term trends.[471] MEA's investments supported 13,184 projects with an aggregate total cost of nearly $406 million.[472] Over half the support from MEA flowed to solar PV projects, followed by geothermal and wind projects, as shown in Figure 6-7. Over 60% of funds went to residential projects, as shown in Figure 6-8. On a county basis, funding flowed primarily to

[469] Charles Kubert and Mark Sinclair, *Distributed Renewable Energy Finance and Policy Toolkit*, Clean Energy States Alliance, 2009, cesa.org/assets/Uploads/CESA-renewableenergy-FinancePolicy-toolkit2009.pdf.

[470] Maryland Energy Administration, *Maryland Strategic Energy Investment Fund: Report on Fund Activities Fiscal Year 2018*, energy.maryland.gov/Reports/FY18%20SEIF%20Annual%20Report.pdf.

[471] Data vintages based on email correspondence in October 2019 with Brett Dobelstein, GIS Specialist, Eastern Shore Regional GIS Cooperative (ESRGC).

[472] Maryland Energy Administration Smart Energy Investment Dashboard. Site accessed March 2019. Smart Energy Investment Dashboard is no longer available.

Garrett County, the center of wind activity in the state, and to Maryland's most populous counties, as shown in Figure 6-9.

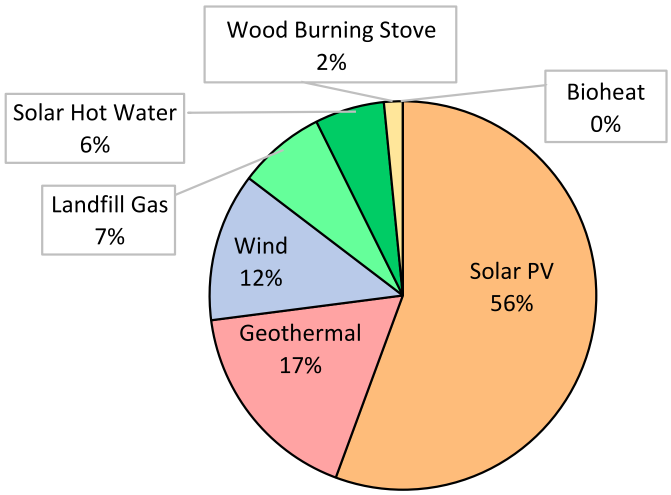

Figure 6-7. Maryland Energy Administration Support for Renewable Energy, by Technology

Source: MEA Smart Energy Investment Dashboard, apps.esrgc.org/dashboards/smartenergy/#renewable.

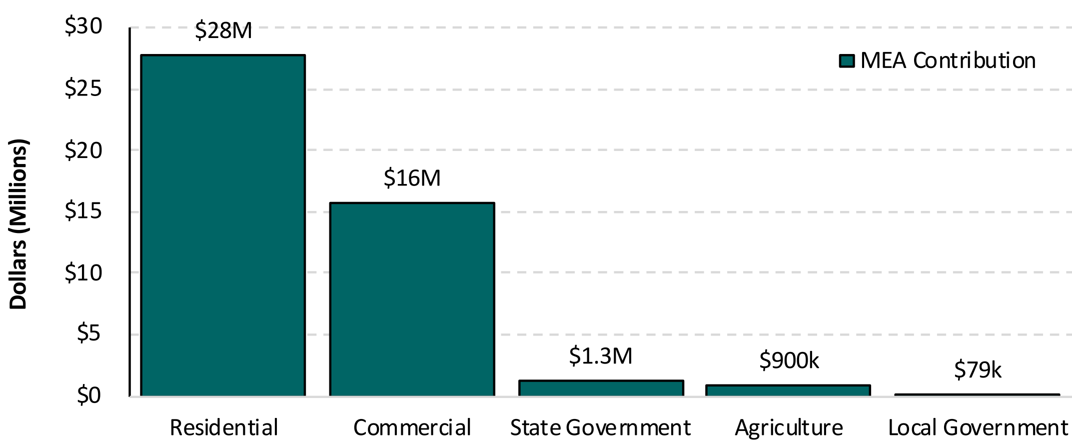

Figure 6-8. MEA Support for Renewable Energy, by Sector

Source: MEA Smart Energy Investment Dashboard, apps.esrgc.org/dashboards/smartenergy/#renewable.

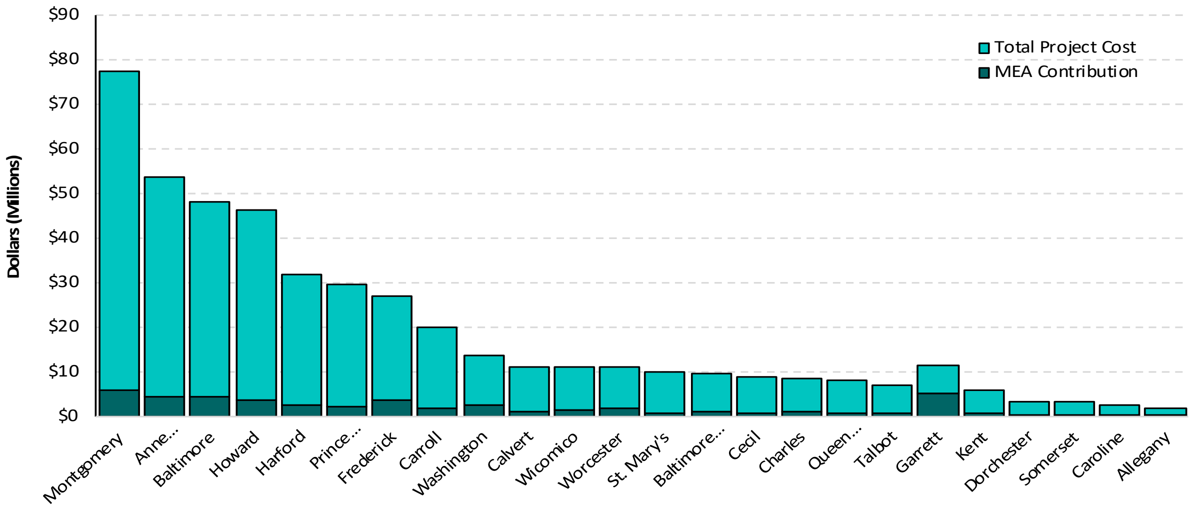

Figure 6-9. Maryland Energy Administration Support for Renewable Energy, by County

Source: MEA Smart Energy Investment Dashboard, apps.esrgc.org/dashboards/smartenergy/#renewable.

Table 6-3. Maryland Grant Programs Focused on Renewable Energy

Name/Description	Beneficiaries	Annual Budget ($M)	Funding Limit	Cost Share Requirement
Clean Energy Grants Program[1,2] Supports the installation of solar PV, solar water heaters, geothermal, wind systems, and clean-burning stoves.	Homeowners, businesses, nonprofits, government entities	Not found	Varies by technology	Not found
Animal Waste to Energy (WTE)[3] Animal WTE projects on either a farm/pilot scale or a community/regional scale.	Businesses, government agencies, nonprofits	Up to $6, FY19	Up to $4 million for projects <2 MW; up to $2 million for projects >2 MW	40%-50%
Community Solar LMI-PPA[4] Community solar projects serving LMI customers, with terms intended to maximize customer savings on electricity costs.	Subscriber organizations that meet thresholds for LMI customer participation	Up to $3, FY19	Up to $500,000	Not found
Resiliency Hub[5] Funding for solar+storage projects to serve as "resiliency hubs" in high-density/LMI neighborhoods.	Solar/microgrid developers	Up to $5, FY19	$1,300/kW	Not found
Parking Lot Solar PV Canopy with EV Charger[6] Grants available for projects >75 kW, paired with at least four EV chargers	Businesses, nonprofits, local governments, state agencies	Not found	$400/kW; up to $200,000	Not found
Community Solar[7] Grants available for customers subscribing to a community solar project.	Businesses, residents	Not found	Varies by applicant category; $80-240/kW	Not found
Wind (Residential and Community)*[8] Wind energy systems serving homeowners or communities *Two programs with joint funding	Residents, businesses, nonprofits, state/local/ municipal governments	$1, FY19	Varies by size; $100,000-$1,000,000	50%
Clean Burning Wood and Pellet Stove[9] Clean-burning stoves that displace electric, fossil fuel heating systems (that do not use natural gas), or old woodstoves.	Homeowners	Not found	Varies by type; $250-$700/ installation	Not found

Table 6-3. (cont.)

Name/Description	Beneficiaries	Annual Budget ($M)	Funding Limit	Cost Share Requirement
Kathleen A.P. Mathias Agricultural Energy Efficiency Program[10] Though focused on energy efficiency, some funds are available for renewable energy projects.	Farms and businesses in the agricultural sector	$0.175, FY19	$60,000	50%
Offshore Wind Business Development Program[11] Funding to defray barrier entry costs for businesses entering the global offshore wind industry.	"Emerging Businesses;" i.e., businesses owned and controlled by individual(s) whose net worth is <$6.5M	$1.2, FY19	$25,000 for market entry; $200,000 for capital investments/ facilities upgrades	50% for capital investments/ facilities upgrades
Offshore Wind Workforce Training Program[12] Training centers that provide instruction on trade skills and safety standards used for offshore wind projects.	Emerging businesses	$0.8, FY19	$200,000	50%
Net Zero Schools[13] Design and construction of three new net zero schools.	School districts with plans for new schools in the BGE territory	$9.0, total	Not found	Not found

Note: All information in this table was sourced from the section of MEA's website devoted to grant opportunities as well as supporting documents posted on individual grant program websites. "Not found" represents information that was not found on MEA's website.

[1] energy.maryland.gov/residential/Pages/incentives/CleanEnergyGrants.aspx.

[2] energy.maryland.gov/business/Pages/incentives/cleanenergygrants.aspx.

[3] energy.maryland.gov/business/Pages/incentives/awe.aspx.

[4] energy.maryland.gov/residential/Pages/CommunitySolarLMI-PPA.aspx.

[5] energy.maryland.gov/Pages/Resiliency-Hub.aspx.

[6] energy.maryland.gov/business/Pages/incentives/PVEVprogram.aspx.

[7] energy.maryland.gov/residential/Pages/Community-Solar.aspx.

[8] energy.maryland.gov/Pages/Info/renewable/windprograms-residential.aspx.

[9] energy.maryland.gov/Residential/Pages/incentives/woodstoves.aspx.

[10] energy.maryland.gov/business/Pages/incentives/mathiasag.aspx.

[11] energy.maryland.gov/Pages/Info/renewable/offshorewindbusinessdevelopment.aspx.

[12] energy.maryland.gov/Pages/Info/renewable/offshorewindworkforce.aspx.

[13] energy.maryland.gov/govt/Pages/MDNetZeroSchools.aspx.

6.5. State Loan Programs

States utilize loan programs to support a variety of activities, including renewable energy and energy efficiency projects. Loan programs reduce the upfront capital costs of projects by spreading out payments over a long time frame, effectively making projects more affordable. Today, the majority of states operate at least one energy loan program, totaling over 200 state loan programs for renewable energy and energy efficiency improvements.[473] There are several types of loan programs that have been offered by states, each with varying eligibility requirements and administrative oversight. Forty-four states and the District of Columbia offer loan programs for renewable energy projects, as shown in Figure 6-10.

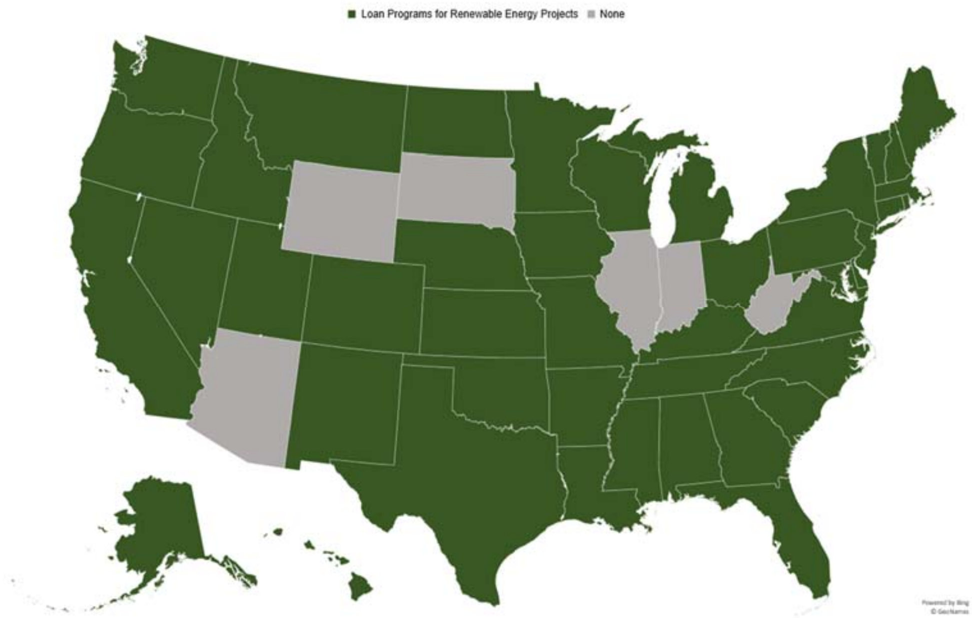

Figure 6-10. States with Loan Programs for Renewable Energy Projects

Sources: NCCETC DSIRE; PACENation, pacenation.us/pace-programs/.

6.5.1. Experience with Loan Programs in Other States

There are several types of programs that states implement to provide loans to property owners for energy projects or to assist in improving commercial loan conditions.

Direct Loans

With direct loans, funds are provided directly to the borrower through an institution, such as a government agency or a green bank.[474] Funding for loans is often allocated from state clean energy funds or through revenues generated from other programs (e.g., RGGI). Other funding allocations come from bond issuances or private capital. As loans are repaid, a program's initial project capital can be reused for new loans. One example of a state direct loan program is Pennsylvania's Renewable Energy Program (REP), which provides loans to component manufacturers of wind and geothermal generation equipment. Up to $40,000 is available for every new job created, with a cap of 50% of the total project cost or $5 million, whichever is less.[475]

[473] North Carolina Clean Energy Technology Center, DSIRE, programs.dsireusa.org/system/program?type=89&.

[474] Charles Kubert and Mark Sinclair, *Distributed Renewable Energy Finance and Policy Toolkit*, Clean Energy States Alliance, 2009, cesa.org/assets/Uploads/CESA-renewableenergy-FinancePolicy-toolkit2009.pdf.

[475] Pennsylvania Department of Community and Economic Development, "Renewable Energy Program (REP) – Geothermal and Wind Projects," dced.pa.gov/programs/renewable-energy-program-rep-geothermal-wind-projects/.

PACE

Property Assessed Clean Energy (PACE) programs allow property owners to make energy efficiency and renewable energy upgrades to their property with loans that are repaid over 15-20 years through an annual assessment and surcharge on their property tax bill. PACE programs are completely voluntary and may cover 100% of project costs. However, state legislation is required to authorize municipalities to create special assessment districts in which PACE financing is available.[476] Projects are generally funded either through bonds (in which a bonding authority issues a bond to raise funds for a project) or direct funding (where a capital provider funds a project directly). The assessment and resulting property tax surcharge are secured by a senior lien on the property that stays with the property regardless of ownership, but gives the taxing authority that places the lien first claim to repayment in the event of foreclosure.

There are 36 states plus the District of Columbia that have passed legislation enabling PACE programs and 20 states that have active programs. Depending on how the enabling legislation is written, PACE can be used for commercial and/or residential properties.[477] A Commercial PACE (C-PACE) program is the most common type of PACE program in the U.S.; approximately 2,000 municipalities across the country have active C-PACE programs as of 2016.[478] Residential PACE (R-PACE) programs are far less widespread. R-PACE-enabling legislation has been passed in 28 states and the District of Columbia; however, only California, Florida, and Missouri currently offer PACE financing to residential customers.[479]

Matching Loans

State governments can match loans from private lenders to encourage renewable energy project development. In this case, the state will administer a share of a loan to a project developer at a low interest rate, and a private lender will provide the remaining loan balance. The state's share of the loan is completely separate from the private lender's, and therefore can offer more flexible repayment terms and interest rates as low as 0%. Unlike direct loan programs, the state and the private lender share underwriting and risk.[480]

The Iowa Alternative Energy Revolving Loan Program (AERLP), administered by the Iowa Energy Center, provides a single low-interest loan with 50% of the total loan at 0% interest and the remainder from matching lender-provided funds at the market interest rate.[481]

Interest Rate Buy-Down

States can assist private lenders in offering below-market interest rate loans by subsidizing the interest rate through a lump-sum payment to the lender called an "interest rate buy-down." This type of subsidy requires far less capital than the principal amount of a loan, and

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[476] Sijia Qiu and Jocelyn Durkay, "PACE Financing," National Conference of State Legislatures, 2016, ncsl.org/research/energy/pace-financing.aspx.

[477] PACENation, "PACE Programs Near You," pacenation.us/pace-programs/.

[478] PACENation, *The Benefits of PACE Financing for Commercial Real Estate Companies*, 2016, pacenation.us/wp-content/uploads/2016/05/The-benefits-of-PACE-for-CRE-FINAL-1.pdf.

[479] PACENation, "PACE Legislation," pacenation.us/pace-legislation/.

[480] Charles Kubert and Mark Sinclair, *Distributed Renewable Energy Finance and Policy Toolkit*, Clean Energy States Alliance, 2009, cesa.org/assets/Uploads/CESA-renewableenergy-FinancePolicy-toolkit2009.pdf.

[481] Iowa Economic Development, "Alternate Energy Revolving Loan Program," iowaeconomicdevelopment.com/energyloans/.

it removes the state from underwriting responsibilities and default risk.[482] However, the capital used for an interest rate buy-down payment is not a revolving fund and therefore is not repaid to the state.

The Massachusetts Clean Energy Center (MassCEC) and the Massachusetts DOER have partnered together to offer the Mass Solar Loan program, which is focused on enabling lower-cost financing for residents interested in purchasing a solar electric system. The loan support includes an interest rate buy-down program for qualifying low-income residents.[483]

Linked Deposits

A linked deposit program allows participating banks to make below-market interest payments on state deposits. In return, the bank then uses the funds from the state deposits to provide low-interest loans to renewable energy projects. The state treasurer can establish these programs without legislation. Linked deposits require limited administrative duties such as monitoring deposits and ensuring that applicants for the renewable energy loans are investing in a qualified project. However, like the interest rate buy-down program, the state does forego the earned interest on the funds that are re-loaned to qualified borrowers.[484]

The Missouri State Treasurer's Office launched the Missouri FIRST Linked Deposit Program for Alternative Energy in March 2018.[485] The program provides low-interest loans to consumers purchasing, installing, or constructing equipment that produces alternative energy, such as solar panels or wind facilities, and businesses that produce alternative energy for either sale or their own use.

6.5.2. Advantages and Disadvantages of Loan Programs

Advantages

- *Improved lending terms* – State loan programs can offer at- or below-market interest rates and longer repayment terms to match the actual energy production and cash flow of the project over time.
- *Low interest rates* – Many state loans can be formulated to include low interest rates, which significantly reduce the interest expenses for borrowers.
- *Sustainability* – If the program is established as a revolving loan fund (RLF), the principal payments for one loan are used to fund subsequent loans, assuming there are no defaults.
- *Provides lender confidence* – State-sponsored loan approvals provide a mark of confidence to other investors or private lenders that could cover the remaining equity gap.
- *Fills lending gap* – A state-sponsored loan program is more likely to approve renewable energy loans than private lenders because the loans are consistent with policy objectives and underwriters are more familiar with the technologies.

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482 Charles Kubert and Mark Sinclair, *Distributed Renewable Energy Finance and Policy Toolkit*, Clean Energy States Alliance, 2009, cesa.org/assets/Uploads/CESA-renewableenergy-FinancePolicy-toolkit2009.pdf.

483 Massachusetts Clean Energy Center, "Mass Solar Loan," masscec.com/get-clean-energy/residential/solar.

484 Charles Kubert and Mark Sinclair, *Distributed Renewable Energy Finance and Policy Toolkit*, Clean Energy States Alliance, 2009, cesa.org/assets/Uploads/CESA-renewableenergy-FinancePolicy-toolkit2009.pdf.

485 Missouri State Treasurer, "MissouriF1rst," treasurer.mo.gov/content/low-interest-loans/alternative-energy.

Disadvantages

- *High capital requirements* – Project loans may need to cover a larger share of the project cost than rebates or grants.
- *Risk of loan defaults* – The loan administrator assumes the risk of loan defaults.
- *Administrative costs* – Loan funds also require ongoing loan servicing and monitoring.
- *Remaining equity gaps* – Loan funds cannot always provide 100% financing to cover all upfront costs.

6.5.3. Maryland's Use of Loan Programs

Maryland runs three statewide loan programs—the Baltimore Energy Initiative Loan Program, the Jane E. Lawton Conservation Loan Program, and the State Agency Loan Program. In addition, the Maryland Commercial PACE program (MD-PACE) began operating in 2015 as a turnkey, open-market, statewide administration program for C-PACE at no cost to jurisdictions that choose to participate. Participants are administered by PACE Financial Servicing, LLC (PFS) and the Maryland Clean Energy Center (MCEC) through a set of standardized rules. There are currently 17 counties in Maryland, including Baltimore City, that have enabled C-PACE programs. Of these, 15 counties have opted into the MD-PACE program and are administered by PFS under a standardized set of rules.[486] Outside of MD-PACE, Montgomery and Prince George's counties operate and administer their own C-PACE programs. Table 6-4 provides a summary of Maryland's loan programs and the two county-led C-PACE programs.

[486] Maryland Commercial PACE, "Where is C-PACE Available in Maryland?," md-pace.com/where-is-pace-in-md/.

Table 6-4. Maryland Loan Programs Focused on Renewable Energy

Program/Description	Program Funding	Eligible Technologies	Loan Details
Baltimore Energy Initiative (BEI) Loan Program[1] ▪ Beneficiaries: Nonprofit and for-profit small businesses ▪ Description: The City of Baltimore provides low-interest loans to finance a wide range of energy measures. ▪ Administrators: Baltimore City Energy Office, The Reinvestment Fund, and Healthy Neighborhoods, Inc.	▪ Source: Customer Investment Fund from Maryland PSC[2] ▪ Budget: Not found[3]	▪ Renewable energy (solar PV, CHP) ▪ Energy efficiency	▪ Term: Up to 15 years ▪ Amount: *Large loans:* $150,000 – $2 million at 3% fixed interest rate *Small loans:* Less than $150,000 at 4% fixed interest rate
Jane E. Lawton Conservation Loan Program[4] ▪ Beneficiaries: Local government, nonprofit organizations, and Maryland businesses ▪ Description: This program provides an opportunity to reduce the beneficiary operating expenses by identifying and installing cost-effective energy conservation improvements. ▪ Agency: MEA	▪ Source: Revolving loan fund ▪ Budget: $850,000 for FY 2019[5]	▪ Renewable energy (solar water heat, geothermal electric, geothermal heat pumps, geothermal direct-use) ▪ Energy efficiency	▪ Term: Up to 10 years ▪ Amount: $50,000 – $500,000 at 2% interest rate compounded annually for FY 2019
State Agency Loan Program (SALP)[6] ▪ Beneficiaries: State government ▪ Description: This program provides loans to state agencies for cost-effective energy efficiency improvements in state facilities. ▪ Agency: MEA	▪ Source: Oil Overcharge Restitution Trust funds, RGGI,[7] ARRA[8] ▪ Budget: $1.7 million for FY 2019[9]	▪ Renewable energy (solar passive, solar water heat, solar space heat, solar PV, wind, geothermal heat pumps, daylighting, solar pool heating) ▪ Energy efficiency	▪ Term: Not found ▪ Amount: $50,000 – $200,000 at 0% interest rate
MD-PACE[10] ▪ Beneficiaries: Commercial property owners ▪ Description: This program assists commercial property owners in accessing financing to make qualifying energy efficiency and clean energy improvements to commercial properties with loans that are repaid through an annual surcharge on the owner's property tax bill. ▪ Agencies: PFS and MCEC	▪ Source: Lenders determined by municipality ▪ Budget: Not found	▪ Renewable energy (solar energy equipment, geothermal energy devices, wind energy systems, water conservation devices) ▪ Energy efficiency	▪ Term: Up to 20 years ▪ Amount: Up to 100% of cost of energy upgrades

Table 6-4. (cont.)

Program/Description	Program Funding	Eligible Technologies	Loan Details
Prince George's County C-PACE[11] ▪ Beneficiaries: Commercial property owners ▪ Description: This program assists commercial property owners in accessing financing to make qualifying energy efficiency and clean energy improvements to commercial properties with loans that are repaid through an annual surcharge on the owner's property tax bill. ▪ Agency: Prince George's County	▪ Source: Various lenders ▪ Budget: Not found	▪ Renewable energy (solar energy equipment, geothermal energy devices, wind energy systems, water conservation devices) ▪ Energy efficiency	▪ Term: Up to 20 years ▪ Amount: At least $25,000 and up to 100% of cost of energy upgrades; no more than 20% of the full cash value of commercial property or 90% when combined with outstanding mortgages
Montgomery County C-PACE[12] ▪ Beneficiaries: Commercial property owners ▪ Description: This program authorizes commercial property owners to make energy efficiency and renewable energy upgrades to their buildings through repayments via a property tax surcharge. ▪ Agencies: Montgomery County and PFS	▪ Source: Greenworks Lending, LLC ▪ Budget: Not found	▪ Renewable energy (solar water heat, solar thermal electric, solar PV, wind, biomass, hydro, geothermal electric, geothermal heat pumps, anaerobic digestion, tidal energy, wave energy, ocean thermal, fuel cells using renewable fuels, geothermal direct-use, biomass system) ▪ Energy efficiency	▪ Term: Up to 20 years ▪ Amount: At least $5,000 and up to 100% of cost of energy upgrades; no more than 20% of the full cash value of commercial property or 90% when combined with outstanding mortgages

[1] Baltimore Energy Initiative Loan Program Guidelines and Instructions, March 2015, reinvestment.com/BEILoans/downloads/BEI%20Loan%20Program%20-%20Application%20Guidelines%20and%20Instructions.pdf.

[2] The Customer Investment Fund (CIF) is a $113.5 million fund created through the 2012 Exelon/BGE merger. The funds are designed to provide BGE customers with energy efficiency and energy assistance programs.

[3] The City of Baltimore is able to use some of the CIF for the BEI program; however, the amount is not disclosed.

[4] energy.maryland.gov/Govt/pages/janeelawton.aspx.

[5] July 1, 2018 – June 30, 2019; dbm.maryland.gov/budget/Documents/operbudget/2019/Proposed/BudgetHighlights.pdf.

[6] energy.maryland.gov/govt/Pages/stateloan.aspx.

[7] The RGGI sets a regional cap or limit on CO_2 emissions that declines by a certain amount annually. Each member state, including Maryland, establishes an emissions budget. States are then permitted to sell allowances equal to one short ton (2,000 lbs) of CO_2 through auctions and then invest the proceeds in energy programs.

[8] The American Recovery and Reinvestment Act of 2009 (ARRA) was an economic stimulus package created by the federal government in 2009 that distributed money to state congressional districts.

[9] dbm.maryland.gov/budget/Documents/operbudget/2019/Proposed/BudgetHighlights.pdf.

[10] md-pace.com/wp-content/uploads/2018/07/MD-PACE-Guidelines-July-2018-Updates.pdf.

[11] fscfirst.com/wp-content/uploads/2018/10/C-PACE-Program-Overview.pdf.

[12] mocopace.wpengine.com/.

6.6. Renewable Energy Rebates

Rebates are utilized by retailers, manufacturers, and governments to incentivize consumers to purchase certain products by refunding a portion of the product cost. State and local governments often administer rebate programs to encourage the installation of renewable energy technologies by reducing capital costs.[487] Thirty states have rebate programs to support the development of renewable energy projects, as shown in see Figure 6-11.[488]

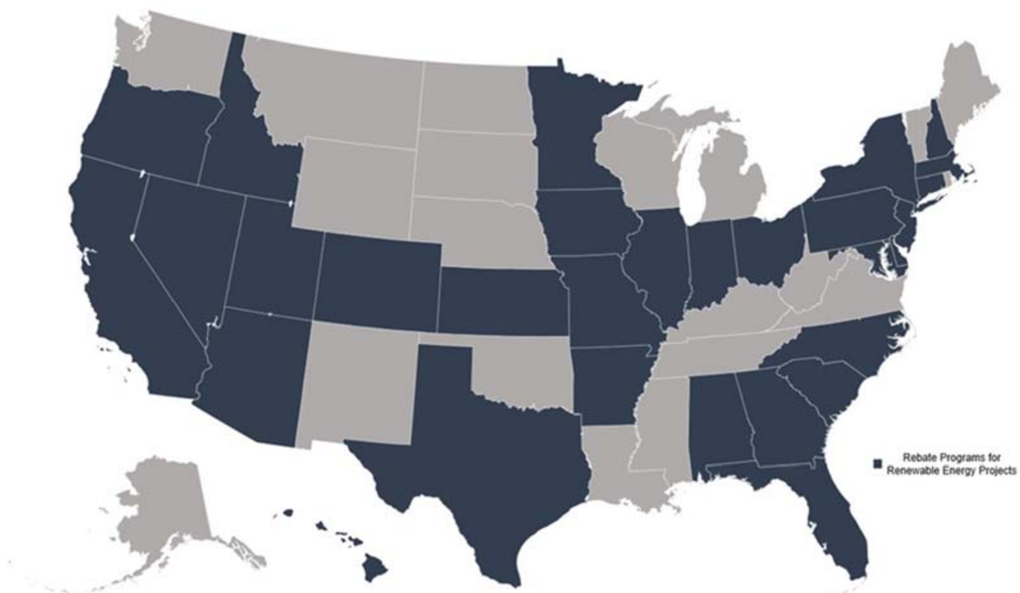

Figure 6-11. States with Rebate Programs for Renewable Energy Projects

Source: NCCETC DSIRE.

Various administrative options exist for renewable energy rebate programs. Such programs are often administered by the state energy agency or public utilities commission. States may, in turn, put the onus on electric utilities to offer rebates, sometimes as part of a larger renewable energy and energy efficiency initiative. In some cases, manufacturers, retailers, and providers of renewable energy systems will offer rebates as incentives to purchase their products. Rebate programs typically are only available for a limited time, ending either when funding has been exhausted or when a certain amount of renewable energy generation has been installed. State agencies often use a Systems Benefit Charge or state energy office program funds to provide rebates. Local agencies also typically use public funds, but they may rely on private funding from a local business. Rebates provided by utilities will typically use a fund consisting of surcharges on customers' bills. State and local rebate programs are generally made available to all consumer sectors (i.e., residential, commercial, industrial, agricultural, government, and nonprofit).

Likewise, design mechanisms for renewable energy rebates vary widely between programs. Generally, a rebate will be provided as a direct cash payment functioning as a retroactive

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[487] Rebate programs for renewable energy generation are often referred to as buy-down programs because they "buy down" the bottom-line cost to purchasers.

[488] North Carolina Clean Energy Technology Center, DSIRE, Maryland Rebate Programs, programs.dsireusa.org/system/program?fromSir=0&state=MD.

discount off the retail price of a renewable energy system.[489] In order to receive payment, project owners must complete an application process in which they confirm project eligibility and provide proof of purchase or installation. Successful applicants will receive payment either during the construction process to reduce the cost of installation or as a lump-sum payment provided upon the completion of the system installation, depending on the design of the program. The rebate value is often based on installed capacity of a renewable energy system, a dollar-per-kilowatt ($/kW) rate.[490] Rebate levels often differ based on a project's size or technology, and rebates may require that projects meet specific performance standards for product components (such as inverters or meters) or overall efficiency.

Rebate programs are sometimes designed to provide payments over time, on a per-kWh basis, as the system produces renewable generation. Like any performance-based incentive (PBI),[491] output-based rebates incentivize production, rather than simply installed capacity. For example, a Minnesota utility, Dakota Electric Association, offers a rebate plan to residential customers that have purchased solar technology equal to $500/kW (with a $4,000 maximum incentive). The rebate amount is not received up front, but rather through a credit on the monthly bill equal to $0.08/kWh produced, up to the full rebate amount or 10 years, whichever occurs first.[492] California's Solar Initiative uses both standard and performance-based rebates. Residential and small business projects are eligible for upfront rebates paid in dollars/watt, while larger commercial, government, and nonprofit projects (i.e., >30 kW) are eligible to receive 60 monthly payments paid in cents/kWh over five years. As the overall number of solar PV installations increase in California, PBI levels decrease.[493]

6.6.1. Experience with Renewable Energy Rebates in Other States

The majority of rebates offered in the states that currently have active rebate programs are for solar PV projects, geothermal heat pumps, or solar water heaters. Rebates for the latter two technologies are provided as part of initiatives aimed at facilitating energy efficiency upgrades to businesses and homes. There are currently at least two rebate programs available for small- or utility-scale wind projects—one in New York and one in Maryland.[494]

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[489] Cash incentives differ from non-cash incentives, such as tax credits and tax exemptions, which lower the cost of goods through reductions in taxes and therefore require tax liability (usually income) and for the taxpayer to collect payment when filing a tax return. Tax rebates provide a direct cash refund, separate from a tax return, equal to a fraction of the amount paid in taxes. However, these programs usually require some type of tax liability and are therefore discussed in Section 6.7, "Tax Incentives for Renewable Energy" along with tax credits and tax exemptions.

[490] Energy efficiency rebates tend to provide a lump-sum payment that is not capacity-based.

[491] *See also:* Section 6.1, "Feed-in Tariffs / Premiums" which are one of the most common forms of PBIs.

[492] Dakota Electric Association, "Solar Installation Rebate," dakotaelectric.com/wp-content/uploads/2018/10/SolarRebate.pdf.

[493] Go Solar California, "California Solar Initiative Rebates," gosolarcalifornia.ca.gov/csi/rebates.php.

[494] North Carolina Clean Energy Technology Center, DSIRE, programs.dsireusa.org/system/program?_ga=2.263538956.1280834457.1554733258-740416452.1546443531.

6.6.2. Advantages and Disadvantages of Renewable Energy Rebates

Advantages

- *Supports market for renewable energy technologies* – Rebates can provide financial support to a large number of projects at the same time, helping to drive market demand and potentially lead to lower installed costs.
- *Adjustable* – Rebates can be adjusted in response to changes in technology costs, government incentives, market conditions, and program goals.
- *Easily tailored* – Rebate programs can be designed to specifically support different sectors (i.e., commercial, residential, industrial, and/ or agricultural); technologies (e.g., solar PV, solar hot water systems, geothermal systems, and small wind turbines); as well as certain geographical regions.
- *Enables market growth* – Rebates provide upfront capital that reduces installed costs, subsequently accelerating return on investment and reducing the financial risks associated with renewable energy projects.
- *Easy to administer* – Once program eligibility, requirements, and budgets are set, rebate programs are relatively simple to oversee.
- *Few limitations on participation* – Unlike grants, rebates do not require system owners to submit a successful proposal for competitive funding. Applicants are only limited by eligibility requirements, such as size and generation specifications, and are considered equitable across income levels.

Disadvantages

- *Risk of "rebate" dependency* – Consumer demand for renewable energy technologies may decrease if rebate programs end or rebate levels decline.
- *Challenges in setting the "right" incentive level* – Potential project owners often differ in what they need from a rebate program to make a renewable energy project viable. This variability in program needs results in rebate programs that that either over- or under-subsidize renewable energy projects.
- *No funding recovery* – Without annual appropriations or replenishment from other sources, rebates consume available funding. Once exhausted, funds are no longer available for rebates to support future renewable energy installations.
- *Not tied to project performance* – Unless explicitly designed to do so, rebates are not tied to how well or how poorly a system performs. The rebate is tied to capacity (i.e., as a $/kW).
- *Limited awareness* – Unless heavily marketed, individuals and businesses interested in purchasing a renewable energy system may be unaware of the existence of rebates. Therefore, the rebate program may not be the primary motivating factor influencing customers to purchase renewable energy systems.
- *Weak incentive for emerging technologies* – Rebate programs are best suited for market-ready, standard technologies. Too high a level of rebate support is

generally needed to move the market for nonstandard and early-stage technologies.[495]

6.6.3. Maryland's Use of Renewable Energy Rebates

Maryland currently has six active rebate programs that include incentives for consumers to purchase geothermal heat pumps. The programs, which are administered by local utilities to fulfill their EmPOWER Maryland requirements, function primarily as energy efficiency rebates and are funded by a variety of sources, including MEA and surcharges on customer bills. The rebates offered are lump-sum cash rebates that are not capacity-based and range from $1,500 to $1,620.[496] Outside of geothermal heat pumps, Maryland does not currently operate any rebate programs for solar, wind, or other renewable generation.

6.7. Tax Incentives for Renewable Energy

Generally, a tax incentive is designed to encourage certain consumer behavior or actions through a reduction in tax liability. Tax incentives for renewable energy systems provide support through directly reducing customer costs. At the state level, these programs are usually administered by state revenue departments or other state agencies. This section reviews three prevalent tax options that states and local governments employ: tax credits, tax exemptions, and tax rebates. Forty-four states and the District of Columbia provide tax incentives for renewable energy projects, as shown in Figure 6-12.

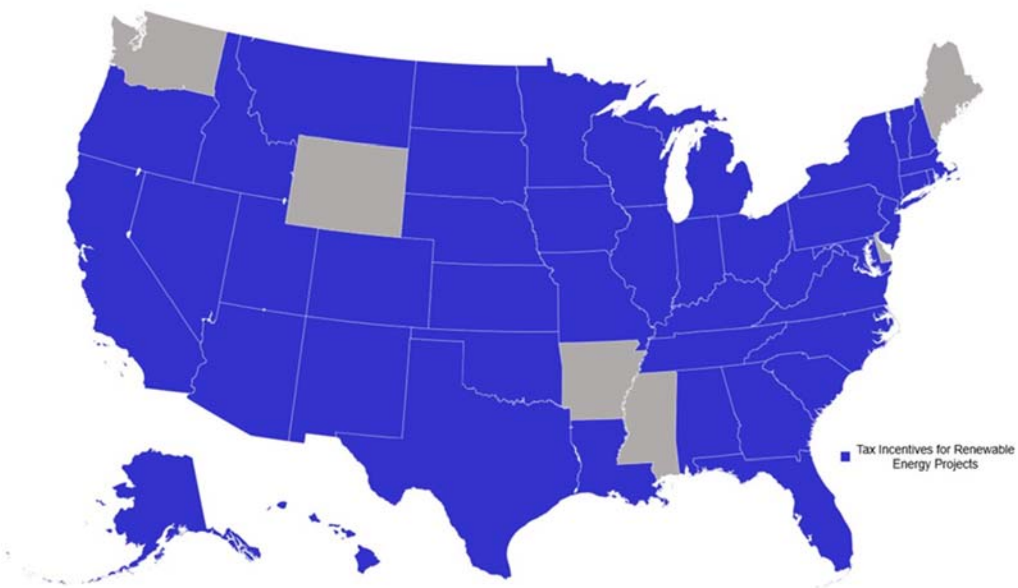

Figure 6-12. States with Tax Incentives for Renewable Energy Projects

Source: NCCETC DSIRE.

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[495] Charles Kubert and Mark Sinclair, *Distributed Renewable Energy Finance and Policy Toolkit*, Clean Energy States Alliance, 2009, cesa.org/assets/Uploads/CESA-renewableenergy-FinancePolicy-toolkit2009.pdf.

[496] North Carolina Clean Energy Technology Center, DSIRE, Maryland Rebate Programs, programs.dsireusa.org/system/program?fromSir=0&state=MD.

6.7.1. Investment and Production Tax Credits

Tax credits are a dollar-for-dollar reduction in actual tax owed to the federal and state government.[497] For example, if a project owner is eligible for a $30,000 tax credit, their tax liability decreases by $30,000. Tax credits can either be refundable or non-refundable. A refundable tax credit allows an individual or business to receive the full amount of credit, even if the credit exceeds their tax liability, with the balance received as a tax refund. A nonrefundable tax credit cannot be used to create a tax refund in the event that the tax credit exceeds tax liability. Tax credit policies vary widely with respect to system and performance provisions. ITCs and PTCs are two of the most common types of tax credits.

Investment Tax Credit

An ITC is a tax incentive for business and personal investment that can be applied to investments in eligible renewable energy technologies. ITCs allow individuals or businesses to deduct a certain percentage of investment costs for an eligible renewable energy project from their state income taxes. ITCs for renewable energy are currently well-established at the federal level for the residential, commercial, agricultural, and industrial sectors. However, more recently, states have begun to implement ITCs to incentivize the development of renewable energy. Maryland does not currently employ any ITCs for renewable energy, but it does have one for energy storage. Further discussion of the ITC as well as a review of active federal and state ITC policies is discussed in Section 6.8, "Investment Tax Credits."

Production Tax Credit

A PTC is based on measured system output (i.e., the amount in kWh of energy generated by an eligible renewable energy project). For example, the FY 2019 federal PTC allows a $0.019/kWh reduction in state income tax liability for electricity produced by wind power.[498] The per-kWh rate of a PTC will usually vary based on the renewable energy technology. Like the ITC, the PTC has long been used by the federal government, but several states have more recently established PTC policies for both personal and corporate income taxes. Maryland does not currently employ any PTCs for renewable energy technologies. Further discussion of the PTC as well as a review of active federal and state PTCs is discussed in in Section 6.9, "Production Tax Credits."

Advantages of ITCs and PTCs

- *Easy to administer* – State ITCs and PTCs do not require an agency to provide oversight duties, a direct source of funding, or annual appropriations.
- *Flexible to market changes* – Tax credit levels can be adjusted to account for the availability of other federal, state, and local incentives as well as changes in market conditions.
- *Promotes investment* – Tax credits result in a direct reduction in an individual's or business' tax liability, thereby enhancing after-tax cash flows.

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[497] Property tax credits can also reduce the amount of local property tax owed in addition to state tax.

[498] Energy.gov, Renewable Electricity Production Tax Credit (PTC), energy.gov/savings/business-energy-investment-tax-credit-itc.

Disadvantages of ITCs and PTCs

- *Insufficient tax liability* – If an individual or business has little or no tax liability, they may not be eligible to receive tax credits and would therefore not be incentivized to develop renewable energy projects. To bypass this barrier, PTCs and ITCs may be structured in a way that allows tax credits to be traded to entities with larger tax liability for investment capital.
- *Impact on state revenue* – State ITCs and PTCs can have a greater-than-anticipated impact on state tax revenues unless they are structured with an annual total credit limit and granted on a first-come, first-served basis.
- *Difficult to combine with other state financing programs* – Other state financing programs, such as upfront rebates, grants, and loans with low interest rates, may reduce the depreciable basis of the project, which is used when calculating one's tax liability. Thus, financing indirectly lowers the ITC and PTC available to a project.

6.7.2. Property Tax Credit

A property tax credit reduces the property tax imposed on structures that utilize renewable energy. Property taxes are collected at both the state and local level; therefore, state property tax credits will either give local governments the option to provide a credit against state and/or local property taxes for eligible renewable energy systems, or offer a blanket credit. A property tax credit can be applied to state and/or local property taxes for residential, commercial, industrial, or agricultural properties. Maryland's active property tax credits are listed in Table 6-5.

Advantage of the Property Tax Credit

- *Flexible to market changes* – As with ITCs and PTCs, property tax credits can be adjusted to account for the availability of other federal, state, and local incentives as well as changes in market conditions.

Disadvantage of the Property Tax Credit

- *Weak incentive* – When taken alone, property tax credits are rarely sufficient to support development of a renewable energy system.

6.7.3. Tax Exemptions

State and local governments use sales tax exemptions and property tax exemptions to make purchasing and installing renewable energy systems more feasible for taxpayers.

Sales Tax Exemptions

A sales tax exemption allows businesses and individuals to be exempt from the state sales tax (or sales and use tax) on the purchase of a renewable energy system, effectively reducing the upfront costs. State sales tax exemptions can apply to both distributed and utility-scale renewable energy systems. There are 26 states, including Maryland, that currently offer state sales tax exemptions on the purchase of renewable energy systems.[499] Maryland's sales tax programs are listed in Table 6-5.

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[499] Charles Kubert and Mark Sinclair, *Distributed Renewable Energy Finance and Policy Toolkit*, Clean Energy States Alliance, 2009, cesa.org/assets/Uploads/CESA-renewableenergy-FinancePolicy-toolkit2009.pdf.

Property Tax Exemptions

A property tax exemption allows businesses and homeowners to exclude the added value of a renewable energy system from the valuation of their property for taxation purposes, making it more feasible for a taxpayer to install renewable energy devices on their property. As with property tax credits, states can give local governments the option to enroll in a property tax exemption program or offer a blanket exemption. These exemptions are typically limited to DG systems and generally do not extend to utility-scale projects. There are 34 states, including Maryland, that currently offer various property tax exemptions or incentives for renewable energy systems.[500] Maryland's property tax programs are listed in Table 6-5.

Advantages of Tax Exemptions

- *Easy to administer* – State or local tax exemption programs do not require agency oversight, a direct source of funding, or annual appropriations.
- *Does not add to the property tax burden* – Installing a renewable energy system would not increase property valuations or real estate taxes for owners.[501]

Disadvantage of Tax Exemptions

- *Weak incentive* – Tax exemptions provide inadequate support to the development of renewable energy systems when taken alone.[502]

6.7.4. Maryland's Use of Tax Incentives

In 1985, Maryland enacted Title 9 of the Maryland Property Tax Code, which gives local governments the option to allow a property tax credit for buildings equipped with a solar or geothermal device that generates electricity to be used in the structure.[503] As of February 2019, four counties in Maryland offer a property tax credit under Title 9. These tax credit programs, as well as Maryland's three other active tax exemption programs, are listed below in Table 6-5.

[500] North Carolina Clean Energy Technology Center, DSIRE, dsireusa.org/.

[501] Charles Kubert and Mark Sinclair, *Distributed Renewable Energy Finance and Policy Toolkit*, Clean Energy States Alliance, 2009, cesa.org/assets/Uploads/CESA-renewableenergy-FinancePolicy-toolkit2009.pdf.

[502] Furthermore, establishing additional steps or barriers to receiving the tax exemption can actively deter development. For example, Dorchester County Bill No. 2017-2 imposes a specific tax on the value of utility-scale energy equipment. Developers must approach the County to negotiate or obtain exemption from this tax.

[503] Maryland Tax Property Code, Title 9-203, Effective January 1, 2019, law.justia.com/codes/maryland/2005/gtp/9-203.html.

Table 6-5. Maryland Tax Credit/Tax Exemption Programs Focused on Renewable Energy

Program	Incentive Type	Applicable Sector	Incentive Amount	Maximum Incentives	Eligible Technologies
Anne Arundel County[1] ▪ Solar and Geothermal Equipment Property Tax Credits	Property tax credit – local option	Res.	50% of eligible costs minus any federal/state grants and tax credits, nonrefundable	$2,500	Solar water heat, solar space heat, solar PV, geothermal heat pumps
Baltimore County[2] ▪ Property Tax Credit for Solar and Geothermal Devices	Property tax credit – local option	Res.	50% of eligible costs,[3] nonrefundable	▪ Heating system: $5,000 ▪ Hot water supply system: $1,500 ▪ Electricity generation: $5,000	Solar PV, geothermal heat pumps, solar water heat
Harford County[4] ▪ Property Tax Credit for Solar and Geothermal Devices	Property tax credit – local option	C&I, Res.	100% of total real property taxes for one year,[5] nonrefundable	$2,500 per device; $5,000 per property, per fiscal year	Solar water heat, solar space heat, geothermal electric, solar PV, geothermal heat pumps, geothermal direct-use
Prince George's County[6] ▪ Solar and Geothermal Residential Property Tax Credit	Property tax credit – local option	Res.	50% of eligible costs,[7] nonrefundable	▪ Space heating: $5,000 ▪ Water heating: $1,500 ▪ Solar electric (PV): $5,000	Solar water heat, solar space heat, solar PV, geothermal heat pumps
Maryland ▪ Property Tax Exemption for Solar and Wind Energy Systems[8]	Property tax exemption	C&I, Res.	100% of total real property taxes	N/A	Solar water heat, solar thermal electric, solar PV, wind
▪ Sales and Use Tax Exemption for Residential Solar and Wind Electricity Sales[9]	Sales tax exemption	Res.	100% exemption	N/A	Solar PV, small wind
▪ Sales and Use Tax Exemption for Renewable Energy Equipment[10]	Sales tax exemption	C&I, Res., Agr.	100% exemption	N/A	Solar water heat, solar space heat, solar thermal electric, solar PV, geothermal heat pumps, small wind

[1] programs.dsireusa.org/system/program/detail/2908.

[2] programs.dsireusa.org/system/program/detail/5042.

[3] The Baltimore County property tax credit has reached its allocated budget. There is a waitlist for new applicants that extends to at least July 2024.

[4] programs.dsireusa.org/system/program/detail/2832.

[5] The total volume of tax credits allowed for any one year is $250,000, effective July 2010.

[6] programs.dsireusa.org/system/program/detail/3106.

[7] The total property tax credit granted by a county is capped at $250,000 per fiscal year. As of 2015, the Prince George's County property tax credit has been fully subscribed until 2020.

[8] programs.dsireusa.org/system/program/detail/2542.

[9] programs.dsireusa.org/system/program/detail/4853.

[10] programs.dsireusa.org/system/program/detail/2928.

6.8. Investment Tax Credits

ITCs allow individuals or businesses to deduct from their income taxes a portion of the cost of developing and installing a new renewable energy project. The size of an ITC, therefore, depends on the amount of capital invested in renewable energy projects.[504] An ITC will generally only apply to new equipment. Businesses and individuals can claim the one-time ITC in the year it is placed into service. This section discusses ITC programs that have been implemented at both the federal and state levels as well as the general advantages and disadvantages of ITC programs. Thirteen states and the District of Columbia provide ITCs for renewable energy projects, as shown in Figure 6-13.

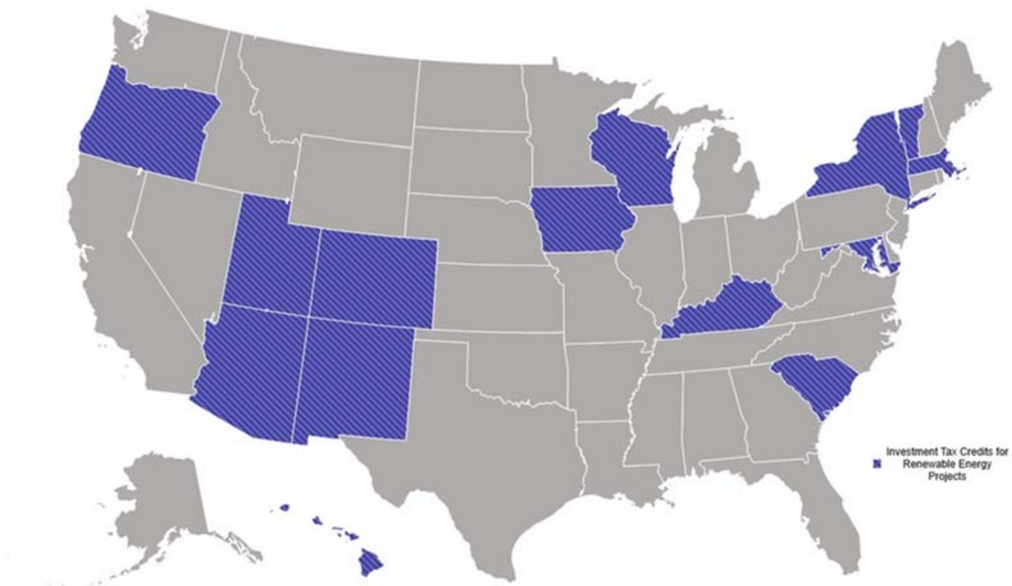

Figure 6-13. States with Investment Tax Credits for Renewable Energy Projects

Source: NCCETC DSIRE.

6.8.1. Experience with Investment Tax Credits at the Federal Level and in Other States

Federal

ITCs are well-established at the federal level. The federal Business Energy Investment Tax Credit is a corporate tax credit that allows project owners to receive tax credits for installing eligible renewable energy generation equipment placed in service through 2024. Table 6-6 shows the federal Business Energy ITCs available by year and technology. Rather than taking the ITC to offset the year's tax bill, businesses can elect to receive a cash grant from the U.S. Treasury equal to the tax credit they otherwise could claim.[505]

[504] These credits are in addition to normal allowances for depreciation. ITCs differ from accelerated depreciation in that they offer a percentage deduction at the time an asset is purchased.

[505] Energy.gov, Business Energy Investment Tax Credit, energy.gov/savings/business-energy-investment-tax-credit-itc.

Table 6-6. Federal Business Energy Investment Tax Credit Levels, by Technology and Year

Year	Solar, Fiber Optic Solar, Fuel Cells, Small Wind	Microturbines, CHP, Geothermal Heat Pump
2019	30%	10%
2020	26%	10%
2021	22%	10%
2022-24	10% (solar and geothermal only)	

There also is a tax credit for residential taxpayers making investments in eligible renewable energy technologies. Specifically, residential taxpayers can claim a credit to their personal income tax for investments in solar electric, solar water heating, fuel cells using renewable fuels, small wind, and geothermal heat pumps located on the property of the taxpayer. The value of the credit for systems placed into service prior to December 31, 2019, is 30% of total project costs and is subject to a stepdown. The credit will be equal to 26% for systems placed into service before January 1, 2021, and 22% for systems placed into service before January 1, 2022. The residential ITC programs offered by the federal government allows the taxpayer to carry over to a subsequent tax year the amount of the tax credit that exceeds tax liability.[506]

Other States

In addition to the federal ITC, some states have also implemented these ITC programs. Currently, there are 14 states, including Maryland, that offer both personal and corporate state income tax credits on renewable energy system investments and installation costs.[507] Credits on residential systems are frequently capped at low amounts (e.g., $2,000 for Utah's Renewable Energy Systems Tax Credit),[508] while commercial and industrial systems have caps that may range upward up $750,000 (e.g., Colorado's EZ Investment Tax Credit Refund for Renewable Energy Projects)[509] or have no credit limit at all (e.g., Montana's Alternative Energy Investment Tax Credit).[510]

Receipt of the federal ITC does not preclude eligibility for a state ITC. In fact, many state ITCs act as complements to the federal ITC. One example of this is the Vermont Investment Tax Credit, which requires receipt of the federal ITC and sets its personal income tax credit

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[506] Energy.gov, Residential Renewable Energy Tax Credit, energy.gov/savings/business-energy-investment-tax-credit-itc.

[507] North Carolina Clean Energy Technology Center, DSIRE, "Programs," programs.dsireusa.org/system/program.

[508] Utah State Legislature, Section 59-7-614 "Renewable Energy Systems Tax Credits," le.utah.gov/xcode/Title59/Chapter7/59-7-S614.html?v=C59-7-S614_2016071320160717.

[509] Colorado Legal Resources, Section 39-30-104, "Credit against tax – investment in certain property," advance.lexis.com/documentpage/?pdmfid=1000516&crid=3f4b19c5-8721-4d1c-a225-12a44daa5fb9&config=014FJAAyNGJkY2Y4Zi1mNjgyLTRkN2YtYmE4OS03NTYzNzYzOTg0OGEKAFBvZENhdGFsb2d592qv2Kywlf8caKqYROP5&pddocfullpath=%2Fshared%2Fdocument%2Fstatutes-legislation%2Furn%3AcontentItem%3A5TYF-BRF0-004D-10W5-00008-00&pddocid=urn%3AcontentItem%3A5TYF-BRF0-004D-10W5-00008-00&pdcontentcomponentid=234176&pdteaserkey=sr2&pditab=allpods&ecomp=-Jx7kkk&earg=sr2&prid=b2a35ad5-a3c5-4774-8b95-394018de7eaf.

[510] Montana Code Annotated 2017, Title 15: Taxation, Chapter 32, "Energy-Related and Ecological Tax Incentives, Part 2. Tax Credit for Installing Alternative Energy System," leg.mt.gov/bills/mca/title_0150/chapter_0320/part_0020/sections_index.html.

limit based upon the amount received under the federal ITC. The Vermont ITC is equal to 24% of the "Vermont-property portion" of the federal ITC,[511] which constitutes a 7.2% state-level credit for solar, small wind, and fuel cell systems and a 2.4% credit for geothermal devices placed in service on or before December 31, 2019.[512,513]

6.8.2. Advantages and Disadvantages of Investment Tax Credits

Advantages

- *Easy to administer* – ITCs require little to no administrative oversight, nor do they require annual appropriations or direct funding.
- *Flexible to market changes* – ITC levels can be adjusted quickly to account for the availability of other federal, state, and local policy support or incentives, as well as changes in market conditions.
- *Promotes investment* – Tax credits result in a direct reduction in the tax liability of an individual or business, thereby enhancing after-tax cash flows.

Disadvantages

- *Insufficient tax liability* – An individual or business may not have sufficient tax liability in order to take advantage of the ITC and therefore would not be incentivized to develop renewable energy projects, unless they can find individuals or businesses with sufficient tax liability that can enter into a leasing/financing arrangement with them (see next bullet).
- *Financing complexity* – Individuals or businesses with insufficient tax liability will enter into complex transactions with entities that do. For example, under a "flip" transaction, a project is sold to another entity (that has tax liability) for 10 years before reverting back to the original owner. The complexity of these transactions limits the pool of available financiers and increases the cost of financing.
- *Setting the incentive level* – Determining the proper incentive level to encourage eligible energy technologies may be challenging—too high can lead to a "gold rush," while too low could lead to little or no project development.
- *Impact on state revenue* – State ITCs can have a greater-than-anticipated impact on state tax revenues unless they are structured with limits on the amount that individual projects can claim annually, or what can be claimed in aggregate annually.

6.8.3. The Maryland Energy Storage Income Tax Credit

In January 2018, MEA announced the launch of the Maryland Energy Storage Income Tax Credit (ESITC). The ESITC offers a tax credit to residential and commercial taxpayers who have installed an energy storage system on their Maryland residential or commercial property during the corresponding tax year. The ESITC is expected to run through 2022 and is granted on a first-come, first-served basis. For each tax year that the tax credit is

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[511] Vermont General Assembly, The Vermont Statutes Online, Title 32: Taxation and Finance, Chapter 151: Income Taxes, Subchapter 002: "Taxation of Individuals," legislature.vermont.gov/statutes/section/32/151/05822.

[512] This ITC program is subject to the assigned stepdowns from 2020 onward.

[513] Energy.gov, Business Energy Investment Tax Credit, energy.gov/savings/business-energy-investment-tax-credit-itc.

offered, the ESITC budget is set at $750,000, split between $300,000 for residential taxpayers and $450,000 for commercial taxpayers. The incentive amount for each storage project is the lesser amount of: (a) $5,000 for a residential property; (b) $75,000 for a commercial property; or (c) 30% of the total costs for installing the storage system. The tax credits received under the ESITC are nonrefundable and cannot be carried over to any other tax year.[514]

6.9. Production Tax Credits

A PTC is a tax credit for eligible energy technologies based on measured system output.[515] Specifically, the PTC reduces a business' or individual's income tax liability based upon the amount, in kWh, of energy generated by an eligible energy project over a period of time, such as five or 10 years, that is sold to a third party. The actual PTC rate can vary by eligible energy technology. Only one state, Arizona, offers a PTC for renewable energy projects.

6.9.1. Experience with Production Tax Credits at the Federal Level and in Other States

Federal

At the federal level, Congress enacted the PTC as part of the Energy Policy Act of 1992, and it has been periodically renewed and expanded since then, although usually for short periods of time and sometimes not until after the PTC actually expired. The tax credit amount is inflation-adjusted to $0.015/kWh (1993$) for solar, geothermal, closed-loop biomass, and wind, and half that amount for hydro, ocean energy, MSW, and LFG, equaling $0.024/kWh and $0.012/kWh for 2018, respectively.[516,517] The PTC for all technologies but wind expired at the end of 2017.

In December 2015, Congress enacted a five-year extension of the PTC for wind projects that begin construction before January 1, 2020. In 2016, the IRS published rules allowing four years for project completion after the start of construction to receive the PTC. The federal PTC is also reduced by 20% per year for wind projects beginning construction after 2016. Wind projects that begin construction in 2020 and thereafter will not be eligible for the federal PTC.[518]

Other States

In addition to the federal PTC, there is currently only one state, Arizona, that utilizes a PTC. Arizona's Renewable Energy Production Tax Credit began in 2010 and expires on December 31, 2020. It is available as both a personal and a corporate tax credit. Wind, solar, and biomass technologies of at least 5 MW are eligible for $0.01/kWh for the first 200,000 MWh produced by a wind and biomass facility in the calendar year, and an initial credit of $0.04/kWh for solar that steps down to $0.01/kWh over 10 years. Like the federal PTC, the credit is paid out over 10 years. The amount of the credit for individual facilities is capped at

[514] Maryland Energy Administration, "Maryland Energy Storage Income Tax Credit (ITC) (Tax Year 2019)," energy.maryland.gov/business/Documents/TY%202019%20Energy%20Storage%20FOA.pdf.

[515] Section 6.7, "Tax Incentives for Renewable Energy" provides an overarching review of tax incentives, including tax credits.

[516] The IRS publishes the inflation adjustment factor in the Federal Register in April each year.

[517] Federal Register, 83(76), April 2018, govinfo.gov/content/pkg/FR-2018-04-19/pdf/2018-08201.pdf.

[518] Ryan Wiser and Mark Bolinger, *2017 Wind Technologies Market Report*, U.S. Department of Energy, August 2018, emp.lbl.gov/sites/default/files/2017_wind_technologies_market_report.pdf.

$2 million annually, and the cumulative credit is limited to $20 million annually. Any unused credit can be carried forward for five years.[519]

6.9.2. Advantages and Disadvantages of Production Tax Credits

Advantages

- *Easy to administer* – State or local PTCs do not require an agency to provide oversight duties, a direct source of funding, or annual appropriations.
- *Flexible to market changes* – PTC levels can be adjusted quickly to account for the availability of other federal, state, and local policy support or incentives, as well as changes in market conditions.

Disadvantages

- *Insufficient tax liability* – An individual or business may not have sufficient tax liability in order to take advantage of the PTC and therefore would not be incentivized to develop renewable energy projects, unless they can find individuals or businesses with sufficient tax liability that can enter into a leasing/financing arrangement with them (see next bullet).
- *Financing complexity* – Individuals or businesses with insufficient tax liability will enter into complex transactions with entities that do. For example, under a "flip" transaction, a project is sold to another entity (that has tax liability) for 10 years before reverting back to the original owner. The complexity of these transactions limits the pool of available financiers and increases the cost of financing.
- *Impact on state revenue* – State PTCs can have a greater-than-anticipated impact on state tax revenues unless they are structured with an overall financial limit, either by project or cumulatively.[520]

6.9.3. Maryland's Use of Production Tax Credits

Maryland had a state PTC from 2006-2018. The Maryland Clean Energy Incentive Tax Credit offered Maryland businesses and individuals a state income tax credit for electricity generated by qualified resources (wind, biomass, landfill methane, methane from wastewater treatment plants, geothermal, MSW, and qualified hydro) of 0.85 cents/kWh, and 0.5 cents/kWh for electricity generated from co-firing a qualified resource with coal.[521] Eligible applicants had to apply for and receive an initial credit certificate from MEA that estimated the amount of electricity that was expected to be produced by a qualified facility over a five-year period. The total amount of the credit specified in the initial credit certificate could not exceed $2.5 million and had to be a minimum of $1,000. Although the credit was available to eligible clean energy technologies that became operational between

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[519] Arizona State Legislature, Section 43-1083.02, Renewable energy production tax credit, azleg.gov/FormatDocument.asp?inDoc=/ars/43/01083-02.htm&Title=43&DocType=ARS.

[520] Charles Kubert and Mark Sinclair, *Distributed Renewable Energy Finance and Policy Toolkit*, Clean Energy States Alliance, 2009, cesa.org/assets/Uploads/CESA-renewableenergy-FinancePolicy-toolkit2009.pdf.

[521] Maryland Energy Administration, "Clean Energy Production Tax Credit," energy.maryland.gov/business/pages/incentives/cleanenergytaxcredit.aspx.

January 1, 2006 and December 31, 2018, MEA was not permitted to issue any initial credit certificates after December 31, 2015.[522]

6.10. System Benefits Charges

System benefits charges (SBCs), also known as public benefit funds, are special-purpose funds intended to support technologies or initiatives such as renewable energy, energy efficiency, research and development, and low-income energy assistance. Many states created SBCs in conjunction with enacting retail electric competition to ensure that technologies or initiatives that are perceived to have non-monetized public benefits would continue to exist as states transition to competitive power markets. SBCs are primarily funded through a non-bypassable, per-kWh surcharge on customer electric bills, although some state SBCs have received funding allocations from utility settlements or merger agreements. SBCs can be established by legislation or regulation, and when established, the legislation or regulation will specify the broad parameters such as the maximum level of funding (either annually or over a period of time, or both), set a sunset date for the collection of funds, and outline guidelines on how the funds may be utilized. The funds can be administered by a third-party administrator on behalf of a state office or agency, an existing state office or agency such as a utility commission or energy office, or an electric utility.[523] Seventeen states and the District of Columbia have an SBC in place that funds renewable energy, as shown in Figure 6-14.

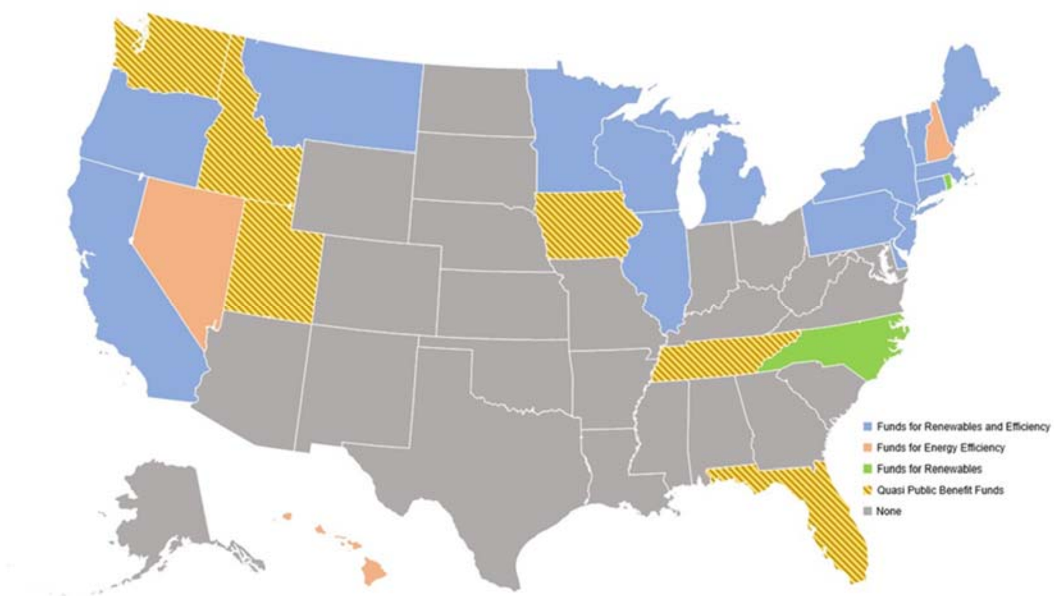

Figure 6-14. States with System Benefits Charges to Fund Renewable Energy Projects

Source: Center for Climate and Energy Solutions, "Public Benefits Funds," c2es.org/document/public-benefit-funds/.

[522] Comptroller of Maryland, "Spotlight on Maryland Taxes: Clean Energy Incentive Tax Credit," 2019, taxes.marylandtaxes.gov/Resource_Library/Tax_Publications/Business_Tax_Credits/Clean_Energy_Incentive_Tax_Credit.shtml.

[523] Charles Kubert and Mark Sinclair, *Distributed Renewable Energy Finance and Policy Toolkit*, Clean Energy States Alliance, 2009, cesa.org/assets/Uploads/CESA-renewableenergy-FinancePolicy-toolkit2009.pdf Public Benefits Funds," Center for Climate and Energy Solutions, c2es.org/document/public-benefit-funds/.

6.10.1. Experience with System Benefits Charges in Other States

North Carolina and Rhode Island are the only states with SBCs established strictly to fund renewable energy programs. In addition, 15 states and the District of Columbia have SBCs designed to collectively fund renewable energy and energy efficiency programs. Below are a few examples of SBCs that have been implemented to promote renewable energy initiatives.

Rhode Island implemented an SBC, the Renewable Energy Fund, in 2007 that collects $0.03/kWh of electricity sales to provide grants for renewable energy projects. The SBC will sunset in at the end of 2022. The SBC is administered by the Rhode Island Commerce Corporation, a quasi-public economic development organization, and funds are collected by the EDC. In 2017, the SBC funded 204 small-scale renewable energy projects by issuing approximately $1.4 million in grants, and funded 40 commercial-scale renewable energy projects that were collectively granted $3 million.[524]

Massachusetts established the Massachusetts Renewable Energy Trust Fund in 1998, with funding from a $0.0005/kWh assessment on customers served by IOUs and municipal utilities that participate in retail electric competition.[525] The fund is administered by the MassCEC, a state economic development agency, along with oversight from the Massachusetts DOER and an advisory board. The SBC provides grants, contracts, loans, RECs, bill credits, and customer rebates for various renewable energy technologies, such as solar, wind, fuel cells, LFG, hydro facilities, CHP systems, etc.

NYSERDA was created in 1975 to decrease energy consumption; increase energy efficiency and renewable energy; and help implement the New York State RPS, energy efficiency initiatives, reformation of the state's energy markets, and climate change mitigation goals.[526] NYSERDA receives its funding through the Clean Energy Fund (CEF), an SBC imposed on investor-owned distributed electric utilities and gas companies, and from proceeds raised by auctions for the RGGI.[527] For the CEF, NYSERDA oversees four program areas: market development for energy efficiency and clean energy; NY-SUN, NYSERDA's solar program, for growing the state's solar market; the New York Green Bank for increasing capital availability for clean energy projects; and innovation and research for facilitating growth in cleantech businesses specializing in smart grid technologies, renewable energy and DER technologies, high-performance buildings, transportation, and cleantech startup and innovation development.[528]

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[524] Rhode Island Commerce Corporation, *RI Renewable Energy Development Fund: Annual Financial and Performance Report for the Calendar Year Ending 12/31/2017*, March 2018, commerceri.com/wp-content/uploads/2018/04/REF_Financial-and-Performance-Report-CY17.pdf, Attachments 1 and 2.

[525] Energy.gov, "Renewable Energy Trust Fund," energy.gov/savings/dsire-page.

[526] New York State Energy Research Development Authority, "History of NYSERDA," nyserda.ny.gov/About/History-of-NYSERDA.

[527] New York State Energy Research Development Authority, "Funding," nyserda.ny.gov/About/Funding. The RGGI is further discussed in Section 3.3, "Impact of the Maryland RPS on Air Emissions." As referenced more in that section, Maryland also receives funding from RGGI.

[528] New York State Energy Research Development Authority, *Reforming the Energy Vision: Clean Energy Fund*, 2016, fact sheet available at nyserda.ny.gov/About/Clean-Energy-Fund.

6.10.2. Advantages and Disadvantages of System Benefits Charges

Advantages

- *Non-bypassable* – Since charges are assessed to distribution utilities, which are monopolies, all customers are assessed the charge, including self-generating customers and electric choice customers.
- *Competitively neutral* – Customers all receive the same charge, regardless of their distribution utility.
- *Flexibility* – SBCs can be designed to support a variety of mechanisms to support renewable energy, such as research and development, loans, rebates, performance- and production-based incentives, and can be changed in response to market conditions.
- *Independent funding mechanism* – Because SBCs are funded separately, they are not dependent on annual state budget appropriations.
- *Independent of industry structure* – SBCs can function successfully in restructured electric markets or whether electric utilities are still vertically integrated and regulated by state utility commissions.

Disadvantages

- *Disproportionate return* – A disproportionate amount of the SBC may be used in various portions of the state. For example, one populated county could pay a significant portion of the SBC, but another county may receive the majority of the benefits.
- *Redirection of funds* – Monies raised through an SBC have been re-allocated to the state's general revenue fund, or "raided" by state legislatures, as opponents term it.
- *Durability* – Long-term funding assurance is needed, as it can take time to design and launch new programs or initiatives.

6.10.3. Maryland's Use of System Benefits Charges

Maryland does not have an established SBC for energy efficiency or renewable energy; however, it does have a Universal Service Charge (USC), which is assessed to all distribution customers. The USC, created by the Maryland General Assembly, is used to fund programs for low-income weatherization, bill assistance, and the retirement of arrearages. The implementation of these programs by the Office of Home Energy Programs (OHEP), an agency of the Maryland Department of Human Services, is overseen by the Maryland PSC.

Maryland also has an Environmental Trust Fund that is financed exclusively through an Environmental Surcharge assessed on all electricity consumption in Maryland other than self-supplied electricity. Funding raised through this surcharge supports PPRP, and it also provides added funding to MEA and the Chesapeake Bay Trust. The charge is set annually by the PSC to meet PPRP's budget requirements with recognition of the MEA and Chesapeake Bay Trust contributions. The Environmental Surcharge has a maximum level of $0.00015/kWh (0.15 mills) and is limited to $1,000/month for any individual customer. For a typical residential customer consuming 1,000 kWh/month, the Environmental Surcharge equates to 15 cents/month.[529]

6.11. Integrated Resource Plans/Distribution System Plans

6.11.1. Integrated Resource Plans

Integrated resource plans (IRPs) present a utility's long-term plan for meeting projected electricity demand through a mix of supply-side resources (e.g., generation), demand-side resources (e.g., demand response, energy efficiency), and transmission for the next 10, 15, or 20 years. Important aspects of an IRP include any identification of resources needed to meet future electricity demand; a preferred portfolio of supply- and demand-side resources to satisfy this demand; a rigorous evaluation of alternative portfolios, scenarios, and risk and uncertainty; a public participation process for stakeholders to review and comment; and a near-term action plan covering the next two to five years. State utility regulatory commissions review IRPs on a regular basis, usually every two to five years, for compliance with various economic and environmental policy objectives. Thirty-three states require utilities to file IRPs with their utility regulatory commission, as shown in Figure 6-15.[530]

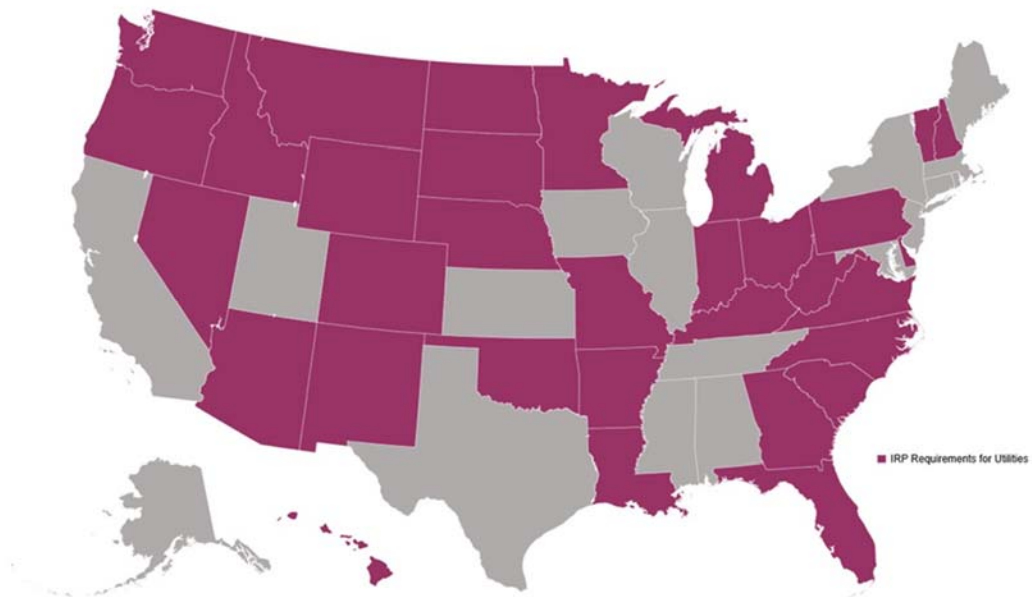

Figure 6-15. States with Integrated Resource Planning Requirements for Utilities

Source: Advanced Energy Economy, "Advanced Energy Perspectives," blog.aee.net/understanding-irps-how-utilities-plan-for-the-future.

In regulated states, utilities are permitted to own generation resources, and are often required by law to consider scenarios with high levels of renewable energy in their IRPs. In deregulated states, including Maryland, EDCs are typically barred from owning their own generation assets. Their IRPs may include plans to manage a portfolio of contracts for SOS

[529] 2013 Annotated Code of Maryland, PUA § 7-203 – Electric companies – Environmental surcharge, law.justia.com/codes/maryland/2013/article-gpu/section-7-203/.

[530] Coley Girouard, "Understanding IRPs: How Utilities Plan for the Future," Advanced Energy Economy, 2015, blog.aee.net/understanding-irps-how-utilities-plan-for-the-future.

customers, including for RECs in order to comply with state RPS requirements, and long-term procurement plans to ensure projected electricity demand is satisfied.

IRP requirements emerged in the 1980s as a means of ensuring demand-side resources are considered as well as supply-side resources, and in response to unexpectedly large investments in central station power plants that far exceeded original cost projections. States moved away from IRPs in the 1990s when implementing utility restructuring and competitive retail power markets, but the electricity power crisis in California in 2000 caused several states to reassess utility restructuring and, in some cases, to turn back to IRPs.

6.11.2. Distribution System Plans

In recent years, regulators have grown increasingly interested in distribution system plans (DSPs) as a corollary to IRPs. Utilities' actions at the distribution level can impact how much distributed renewable energy generation can be added to the grid and whether these resources are tapped to provide grid services. For these reasons, numerous states are considering or adopting measures to require annual long-term DSPs. Like IRPs, these reports are scenario-based studies of distribution grid impacts to identify any necessary grid updates and/or alternative solutions such as potential operational changes or non-wires alternatives.[531] Ten states and the District of Columbia require utilities to file DSPs with their utility regulatory commission, as shown in Figure 6-16.

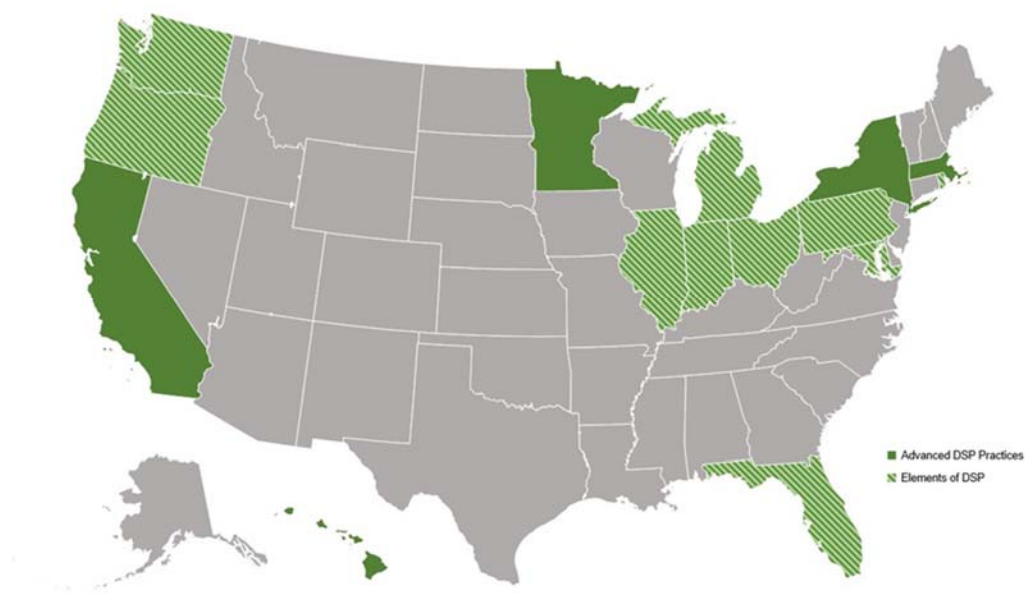

Figure 6-16. States with Distribution System Planning Requirements

Source: DOE Grid Modernization Laboratory Consortium, *State Engagement in Electric Distribution System Planning*, December 2017, emp.lbl.gov/sites/default/files/state_engagement_in_dsp_final_rev2.pdf.

Perhaps because DSPs are a newer form of oversight than IRPs, there is no industry standard for communication between utilities and commissions. Instead, a wide variety of

[531] Julie Homer, Alan Cooke and Lisa Schwartz, *et al.*, *State Engagement in Electric Distribution System Planning*, U.S. Department of Energy's Grid Modernization Laboratory Consortium, 2017, emp.lbl.gov/sites/default/files/state_engagement_in_dsp_final_rev2.pdf.

planning tools are considered elements of “Integrated Distribution System Planning.” They are illustrated below in Figure 6-17 and then described in the following bullet points.[532]

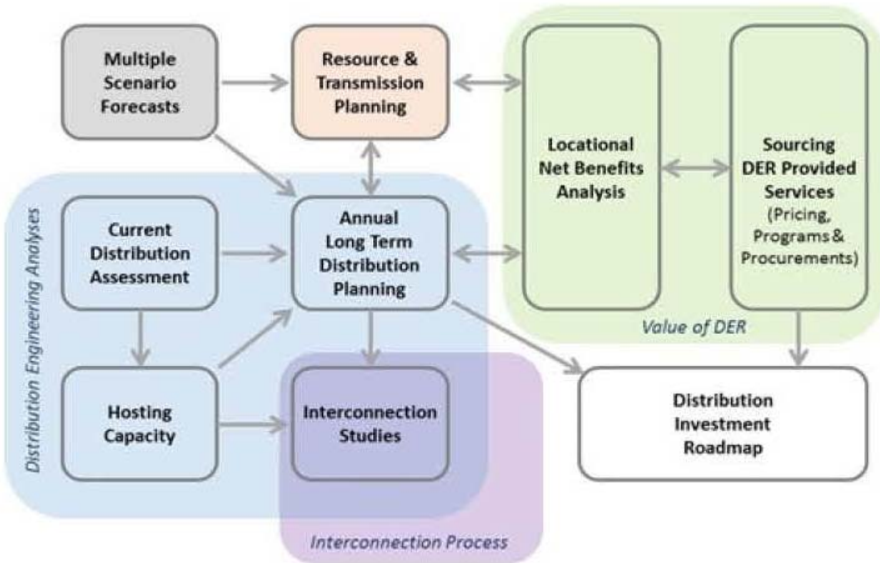

Figure 6-17. Elements of Integrated Distribution System Planning

Source: DOE Grid Modernization Laboratory Consortium, *State Engagement in Electric Distribution System Planning*, December 2017, emp.lbl.gov/sites/default/files/state_engagement_in_dsp_final_rev2.pdf.

Integrated Distribution System Planning Tools

- *Multiple Scenario Forecasts*, where multiple growth projections of DG are used to assess current system capabilities, identify incremental infrastructure requirements, and enable analysis of the locational value of DG.
- *Current Distribution Assessment*, consisting of an evaluation of current feeder and substation reliability, asset loading, and operations.
- *Hosting Capacity*, which is an analysis to define a baseline of the maximum amount of DG the existing distribution grid (feeder through substation) can absorb without requiring infrastructure upgrades.
- *Annual Long-term Distribution Planning*, consisting of multiple scenario-based studies of distribution grid impacts to identify any necessary grid updates, and the identification of solutions such as potential operational changes, infrastructure replacement, and non-wires alternatives.
- *Interconnection Studies*, defined as engineering studies to determine whether individual or multiple DG facilities can be safely connected to the distribution grid.
- *Resource and Transmission Planning*, where distribution planning is conducted in conjunction with transmission and integrated resource planning to realize a collective view of system needs.

[532] This overview was also included in PPRP’s *Energy Storage Report*.

- *Locational Net Benefits Analysis*, where the ability and value of DG to provide grid services is assessed by locality, net of infrastructure or operational costs that may be incurred.
- *Sourcing DER-provided Services*, where some states are currently establishing distribution markets to allow DERs to provide services in lieu of certain utility distribution capital investments and operational expenses, such as distribution capacity deferral, steady-state voltage management, transient power quality, reliability and resiliency, and distribution line loss reduction.
- *Distribution Investment Roadmap*, which is the creation of a plan to guide the pace and implementation of DG over time.[533]

6.11.3. Experience with IRPs/DSPs in Other States

IRPs are most common in regulated states, where utilities remain vertically integrated. Three of Maryland's neighbors (Delaware, Pennsylvania, and Virginia) require IRPs. (New Jersey does not.)

Every two years, DPL is required to submit an IRP to the Delaware PSC. The report tracks DPL's performance on several measures associated with RPS compliance: maintaining a diverse portfolio of contracts with REC providers, minimizing ACP payments, and providing information on the cost of RPS compliance.[534]

According to a 2018 DOE report, five states have engaged in advanced elements of integrated distribution system planning. Another 11 states, including Maryland and the District of Columbia, have taken smaller steps to oversee some elements of distribution system planning.

In 2015, the Minnesota PUC began a multi-year grid modernization initiative with a focus on distribution system planning. In 2018, the PUC issued Integrated Distribution System Planning requirements for Xcel Energy, the state's largest utility. The plan requires Xcel to model base-case, medium, and high scenarios of DER adoption and discuss the system impacts and benefits associated with these scenarios. This modeling must be used to inform a 5-Year Action Plan for distribution system investments.[535]

6.11.4. Advantages and Disadvantages of IRPs/DSPs

Advantage

- *Public insight and feedback* – Making a utility's long-term plans public gives a wide range of stakeholders the chance to review and provide feedback on the assumptions being used to plan investments. For example, renewable energy developers may have state-of-the-art information on the costs and capabilities of renewable energy systems that can be used to refine utility plans.

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[533] Julie Homer, Alan Cooke and Lisa Schwartz, *et al.*, *State Engagement in Electric Distribution System Planning*, U.S. Department of Energy's Grid Modernization Laboratory Consortium, 2017, emp.lbl.gov/sites/default/files/state_engagement_in_dsp_final_rev2.pdf.

[534] Delmarva Power and Light, Integrated Resource Plan, 2016, depsc.delaware.gov/wp-content/uploads/sites/54/2017/03/DPL-Public-IRP-113016.pdf.

[535] Minnesota PUC, Docket No. E-002/CI-18-251, "Order Approving Integrated Distribution System Planning Filing Requirements for Xcel Energy," August 2018, edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BF05A8C65-0000-CA19-880C-C130791904B2%7D&documentTitle=20188-146119-01.

Disadvantage

- *Administrative burden and complexity* – The creation and vetting of long-term plans requires substantial time and effort on the part of utilities, stakeholders, and regulators.

6.11.5. Maryland's Use of IRPs/DSPs

The IRP process in Maryland mostly lapsed when the state deregulated its electricity market in 1999.[536] Since then, Maryland has implemented other laws and initiatives concerning resource planning and acquisition. The EmPOWER Maryland program requires the state's EDCs to utilize two demand-side resources, demand response and energy efficiency, to meet state objectives for lowering per-capita peak demand and energy usage. EDCs are also required to submit energy sales and peak load forecasts for the annual *Ten-Year Plan*, prepared by Maryland PSC Staff. Additionally, as a stipulation of the Constellation/Exelon merger settlement, each of the Exelon utilities submitted one-time Distribution Investment Plans to the PSC. The plans include a section with high-level commentary on the use of advanced metering infrastructure (AMI) to improve the efficiency of DERs.

6.12. Performance-Based Regulation

Under traditional cost-of-service regulation, utilities fare best financially when they can make new investments in transmission or distribution assets, thus increasing the asset base upon which utilities earn a return. Having a perennial incentive to expand the grid puts the financial interests of utilities at odds with states aiming to expand the role of DERs such as energy efficiency, demand response, storage, and distributed PV. Performance-based regulation (PBR) is emerging as a popular way to align utility incentives with public policy goals. Under PBR, some or all of a utility's earnings are tied to achieving measurable objectives selected by state regulators. Meanwhile, some industry experts believe that the best way to align utility incentives with policy goals is to fundamentally change the role of the distribution utility. New York's efforts to do so are discussed briefly at the end of this primer. Fourteen states have proceedings to consider or implement PBR, as shown in Figure 6-18.

[536] Kaye Scholer LLP, Levitan Associates, Inc. and Semcas Consulting Associates, *State Analysis and Survey on Restructuring and Reregulation*, Maryland Public Service Commission, 2008, energymarketers.com/documents/kayescholerreport.pdf.

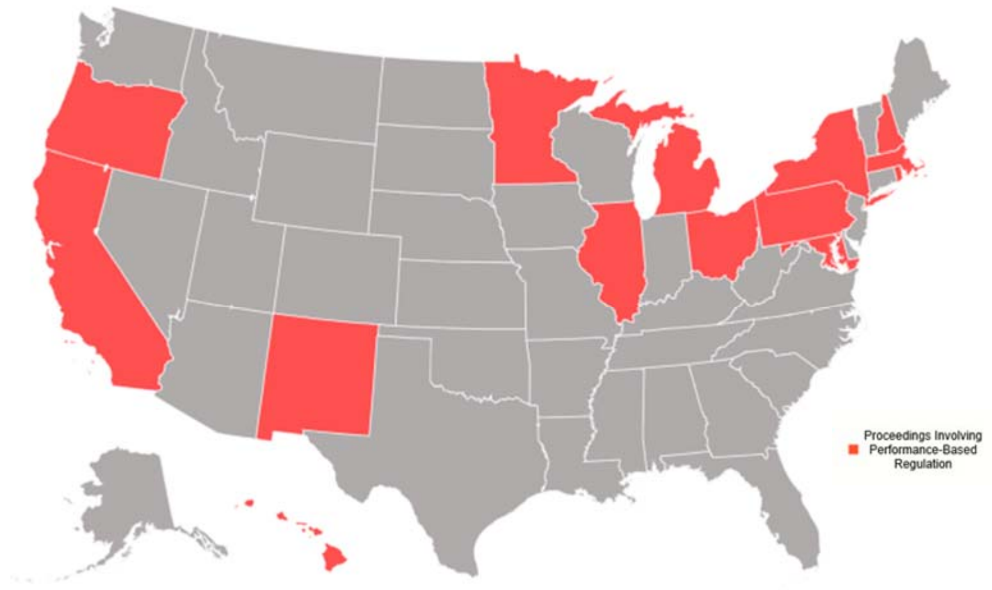

Figure 6-18. States with Proceedings Involving Performance-Based Regulation

Source: Advanced Energy Economy Powersuite via Sonia Aggarwal, "America's Utility of the Future Forms Around Performance-Based Regulation," Forbes, May 2018, forbes.com/sites/energyinnovation/2018/05/07/americas-utility-of-the-future-forms-around-performance-based-regulation/#cf0a7e62bb24.

Note: Maryland has been added based on an order issued by the PSC in August 2019.

Utilities, it should be noted, may be willing participants in these proceedings. In a recent survey of over 500 utility executives and professionals, 37% said that a mix of cost-of-service regulation and PBR is the most appropriate regulatory model for the 21st century and 31% of respondents favored predominantly PBR.[537]

6.12.1. Experience with Performance-Based Regulation in Other States

There are two ways that utility incentives can be designed. Either a utility's rate of return is adjusted (up or down) to reflect its performance across various areas of interest to regulators, or a utility benefits directly from a desired outcome through shared savings or profits.[538] With respect to renewable energy, commissions can use PBR to reward increased reliance on renewable energy resources, increased DER deployment, improved response times for interconnection requests, or greater access to information about locations where DERs will be most beneficial to the grid.[539] A few examples of state actions to adopt PBR are provided below.

[537] Utility Dive, *State of the Electric Utility Survey 2019*, d12v9rtnomnebu.cloudfront.net/paychek/SEU_2019_Survey_Report.pdf?mxcpi=04911a0c-35bf-4a56-a859-136dd1d47ef7.

[538] Sonia Aggarwal, "Performance Based Regulation: Presentation to the National Governor's Association," 2015, energyinnovation.org/resources/project-series/going-deep-performance-based-regulation/.

[539] David Littell and Jessica Shipley, *Performance-Based Regulation Options: White Paper for the Michigan Public Service Commission*, 2017, ourenergypolicy.org/wp-content/uploads/2017/08/rap-littell-shipley-performance-based-regulation-options-august2017.pdf.

Hawaii's Legislature passed a bill in 2018 to end cost-of-service regulation, replacing it with PBR incentives by 2020. Hawaii intends to use incentives and penalties to increase electricity affordability, service reliability, customer engagement, system information access, and renewable energy resource integration, including integration of DERs. The push for PBR in Hawaii is considered key to achieving its goal of 100% renewable energy by 2045.[540]

Minnesota is using a three-phase stakeholder process, known as the e21 initiative, to explore PBR, among other regulatory concepts. At the end of Phase I of e21, participants called for utilities to be able to submit performance-based business plans, covering up to five years, in lieu of filing a traditional rate case.[541] During Phase II, stakeholders fleshed out PBR for nine potential outcomes, including the fair valuation and integration of DERs.[542] The third and final phase, which began in 2017, involves turning the ideas developed thus far into pilot projects and regulatory filings.

In Illinois, utilities can participate in a PBR process rather than periodic rate cases. However, this permission is contingent upon meeting certain smart-grid investment milestones. For instance, utilities must develop a 10-year investment plan and a 10-year performance plan, to which they are held accountable. Commonwealth Edison's (ComEd's) performance plan includes goals related to decreasing the frequency and duration of customer interruptions, reducing the number of estimated utility bills, and increasing capital expenditures paid to minority- and women-owned businesses.[543]

6.12.2. Advantages and Disadvantages of Performance-Based Regulation

Advantages

- *Versatile* – Not only can PBR can be used to promote a wide range of policy objectives, it can be implemented with all utility types (IOUs, munis, and rural co-ops).
- *Complementary with traditional regulation* – Earnings adjustment mechanisms can be used with traditional cost-of-service regulation.
- *Flexibility* – By focusing on outcomes, PBR provides utilities with the flexibility to select the best strategies for their service territory.
- *Cost savings* – With the right combination of metrics and incentives, PBR may result in cost savings for ratepayers.
- *Innovation* – With the increased flexibility, utilities may seek alternative solutions or pilot various efforts to achieve desired outcomes.

[540] Hawaii State Legislature, SB 2939 S.D. 2, 2018, capitol.hawaii.gov/session2018/bills/SB2939_SD2_.HTM.

[541] e21 Initiative, *Phase I Report: Charting a Path to a 21st Century Energy System in Minnesota*, 2014, e21initiative.org/wp-content/uploads/2018/01/e21_Initiative_PhaseI_Report_2014.pdf.

[542] e21 Initiative, *Phase II Report: On implementing a Framework for a 21st Century Electric System in Minnesota*, 2016, e21initiative.org/wp-content/uploads/2018/01/e21_Initiative_PhaseII_Report_2016.pdf.

[543] Sonia Aggarwal and Eddie Burgess, *New Regulatory Models*, Utility of the Future Center, 2014, westernenergyboard.org/wp-content/uploads/2014/03/SPSC-CREPC_NewRegulatoryModels.pdf.

Disadvantages

- *Experimentation required* – There is no "one-size-fits-all" solution with PBR; it takes time and experimentation to determine the most effective metrics and incentives.
- *Unintended consequences* – Implementing poorly designed metrics can create perverse incentives; for example, cost control metrics can lead to poor customer performance.
- *Short cycles* – It is recommended that incentives periods only last three to five years to allow for correction of incentives and metrics, which can increase regulatory costs and require additional regulatory proceedings.

6.12.3. Distribution System Platforms

As noted earlier, some industry experts believe that distribution utilities must fundamentally change their role and, with it, their revenue model. For example, in 2015, NREL published *Power Systems of the Future.* The report envisions traditional distribution system operators being "transformed into distribution-level retail market operators who use dynamic price signals to invite consumers, marketers, and other service providers to participate."[544] Put another way, utilities (or other entities, such as nonprofits) would administer markets for distribution-level grid services, similar to (and integrated with) the markets that PJM administers for transmission-level grid services.

Perhaps the best-known effort to enact such a transformation is New York's Reforming the Energy Vision (REV) proceeding. NY REV encompasses over 40 initiatives spanning renewable energy, energy efficiency, resiliency, grid modernization, and more.[545] Utility-administered markets, called distributed system platforms, lie at the heart of REV.

Distributed system platforms are the foundational network platforms of the electric grid envisioned under REV, enabling market-friendly connections between DERs, large-scale power generators, customers, and other parts of the energy system. As utilities mature as a DSP, energy and data will flow across the grid in multiple directions to allow storage, microgrids, demand-response technology, and other innovative services to increase efficiency while lowering costs and harmful emissions.[546]

NY REV is a complex, multi-year undertaking, and DSPs are not yet up and running. At least one utility, National Grid, is conducting a DSP pilot.[547] Meanwhile, New York is using other PBR strategies, such as shared savings from non-wires alternatives projects and earnings adjustment mechanisms to support its policy goals.[548]

Outside of the REV proceeding, four utilities (Avista, Duke Energy, APS, and Entergy) have launched a utility-led effort to build an open-source operating system for DSPs called

[544] Owen Zinaman, Mackay Miller and Ali Adil, *et al.*, *Power Systems of the Future: A 21st Century Power Partnership Thought Leadership Report* 21st Century Power Partnership and Clean Energy Ministerial, 2015, nrel.gov/docs/fy15osti/62611.pdf, 27.

[545] New York State, "REV Initiatives," rev.ny.gov/rev-initiatives.

[546] New York REV Connect, *Order Adopting Regulatory Policy Framework and Implementation Plan*, "Track One: Defining the REV Ecosystem," 2015, nyrevconnect.com/rev-briefings/track-one-defining-rev-ecosystem/.

[547] National Grid, "National Grid Launches Distributed System Platform With Buffalo Niagara Medical Campus Members," June 2018, news.nationalgridus.com/2018/06/national-grid-launches-distributed-system-platform-with-buffalo-niagara-medical-campus-members/.

[548] Elizabeth Stein and Ferit Ucar, *Driving Environmental Outcomes Through Utility Reform: Lessons from New York REV*, January 2018, edf.org/sites/default/files/documents/driving-environmental-outcomes.pdf.

OpenDPS. DOE is providing research support for the effort, with the first beta version anticipated in late 2019.[549]

6.12.4. Maryland's Use of Performance-Based Regulation

Maryland has not implemented PBR. However, in February 2019, the Maryland PSC initiated Public Conference 51 (PC 51) to evaluate implementation of alternative ratemaking concepts. Two days of public hearings were held in April, and a Public Comment period concluded in May.[550] During the 2019 legislative season, five delegates sponsored HB 653, which would have allowed electric and gas utilities to submit alternative rate plans that provide for performance standards, subject to the approval of the PSC, that are designed to achieve improvements in reliability and customer satisfaction.[551] The bill passed in the House, but it failed the Senate. In August 2019, the Maryland PSC issued an order requiring that a working group of stakeholders be convened to determine how best to implement multi-year rate plans. The working group is tasked to explore ways to incorporate PBR measures into these plans.[552]

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[549] "Open Distributed System Platform: A Utility Collaborative," *T&D World*, December 2018, tdworld.com/webinars/open-distributed-system-platform-utility-collaborative.

[550] Public Service Commission of Maryland, Docket No. PC51, *Exploring the Use of Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric Company or Gas Company*, February 2019, Webapp.Psc.State.Md.Us/Newintranet/Admindocket/Caseaction_New.Cfm?Casenumber=Pc51.

[551] State of Maryland, HB 543, *AN ACT Concerning 2 Electric Companies and Gas Companies – Rate Regulation – Alternative Rate 3 Plans*, February 2019, mgaleg.maryland.gov/2019RS/bills/hb/hb0653T.pdf.

[552] Maryland PSC, "Maryland PSC Advances Alternative Ratemaking Policy PSC Opens Path for Multi-Year Rate Plans," August 2019, psc.state.md.us/wp-content/uploads/MD-PSC-Advances-Alternative-Forms-of-Ratemaking__080919.pdf.

7. EMERGING ISSUES

This chapter of the final report addresses several residual topics identified in Ch. 393, as well as other topics identified by PPRP as "relevant to the analysis of the issues outlined" in Ch. 393. Each of these topics represents an evolving issue relevant to the present and future design of the Maryland RPS.

The first section, "System Flexibility and Energy Storage" covers two specific requirements in Ch. 393 related to system flexibility, meaning the grid's ability to manage supply and demand imbalances. This overview discusses both transmission- and distribution-level flexibility requirements, as well as identifies policy options to support the integration of flexibility resources, such as energy storage. The next section, "Land Use" briefly summarizes two studies concerning the potential land use impacts of additional solar development as a result of the solar carve-out of the Maryland RPS. This section also describes recent developments in county zoning that will influence solar project siting. The final section, "State-Level Subsidies for Nuclear Energy" reviews recent challenges facing the nuclear sector and the policy initiatives undertaken in other states to support economically imperiled nuclear power plants. These initiatives include the creation of ZECs, the implementation of monthly customer surcharges, state-required solicitations of power from resources including nuclear power, and the inclusion of nuclear power in state energy portfolio standards. For each example in this section, an abbreviated case history is provided as context. Additionally, this section also summarizes recent legal and regulatory challenges specific to these nuclear policy initiatives.

The subsequent discussion for each section topic is not intended to be exhaustive. Rather, it is meant to summarize the state of current research, review existing case studies or examples, and/or identify additional policy considerations.

7.1. System Flexibility and Energy Storage

System flexibility has been defined as the grid's ability to accommodate both predictable and unpredictable imbalances between supply and demand.[553] All power grids are designed to have some degree of flexibility in order to balance supply and demand. Additionally, variability and uncertainty have always been present for grid system operators as electricity demand changes over time, sometimes unpredictably, while conventional generation resources can go offline unexpectedly. Variable generation such as wind and solar can increase grid system supply uncertainty. Both wind and solar generation production can vary on a sub-hourly, hourly, daily, and seasonal basis.[554]

Higher amounts of wind and solar drive a need for additional system flexibility. As the penetration of these variable resources grows in a region, their impact on the grid becomes more noticeable, sometimes causing overall generation to ramp up and down more steeply on sub-hourly, hourly, daily, and seasonal time scales.

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553 Robbie Orvis and Sonia Aggarwal, *A Roadmap for Finding Flexibility in Wholesale Markets: Best Practices for Market Design and Operations in a High Renewables Future*, America's Power Plan and Energy Innovation: Policy and Technology, LLC, October 2017, energyinnovation.org/wp-content/uploads/2017/10/A-Roadmap-For-Finding-Flexibility-In-Wholesale-Power-Markets.pdf.

554 Jaquelin Cochran, Mackay Miller and Owen Zinaman, *et al.*, *Flexibility in 21st Century Power Systems*, 21st Century Power Partnership, National Renewable Energy Laboratory, 2014, nrel.gov/docs/fy14osti/61721.pdf.

In 2018, wind and solar jointly represented just 2.9% of generation in PJM and slightly more, 4.1%, in Maryland.[555,556] Due to this low level of penetration, combined with PJM's large footprint, wind and solar do not pose a major challenge to system operations in PJM today. However, continuing growth in variable generation, driven partly by substantial increases in state RPS requirements in Maryland and New Jersey, could increase the amount of renewable energy meeting demand in PJM. As variable generation grows, system flexibility is an important consideration, especially since maintaining or increasing system flexibility may require advance planning, regulatory reforms, new market services, or changes in PJM operating practices to garner more flexible resources.

In recognition of these considerations, Ch. 393 calls for a discussion of "how energy storage and other flexibility resources should continue to be addressed in support of renewable energy and state energy policy." Specifically, Ch. 393 asks whether flexibility resources should be encouraged through procurement, production, or installation incentives; whether it would be advisable to provide energy storage devices to increase the distribution system's ability to host on-site renewable energy generation; and what the costs and benefits of energy storage deployment in the state would be under future goal scenarios.[557] To provide context for these policy questions, this section first reviews the forms of flexibility needed on any electrical grid and the many resources that can help to provide this flexibility. It then briefly summarizes a study that PJM conducted to better understand the likely impact of higher levels of renewable energy at the transmission level. Finally, it returns to the question of Maryland's role in promoting system flexibility at the distribution level, in conjunction with renewable energy generation. Key findings from this section are:

Transmission-Level Flexibility

- A 2014 study determined that PJM could absorb up to 30% wind and solar generation by increasing regulation reserves and investing in new transmission to limit congestion.
- The same study found that PJM already employs many best practices in integrating wind and solar generation, such as sub-hourly scheduling and dispatch and wind and solar forecasting. The study also determined that there were relatively few hours where the projected ramping needs caused by renewable energy resources would be greater than the ramping capability of generation in PJM, and those few events should not affect PJM's operating performance or reliability.

Distribution-Level Flexibility

- If supply or demand is concentrated in a given area, distribution system capacity can become a limiting factor, creating localized imbalances.
- The need for flexibility resources at the distribution level depends, in large part, on the amount of renewable energy that is generated by in-state distributed resources. In practical terms, this tends to mean the amount of distributed PV spurred by the state's solar carve-out; and the degree to which this PV generation is concentrated on specific distribution lines that are or will be constrained.

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555 Monitoring Analytics, LLC, *2018 State of the Market Report for PJM*, March 2019, monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-sec3.pdf.

556 U.S. Energy Information Administration, "Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923), eia.gov/electricity/data/state/; EIA, "Form EIA-861M (formerly EIA-826) detailed data," eia.gov/electricity/data/eia861m/.

557 Maryland General Assembly, HB 1414, 2011, mgaleg.maryland.gov/2017rs/bills_noln/hb/ehb1414.pdf.

- A proposed regulation in Maryland would require utilities to reserve hosting capacity on distribution circuits for smaller generators.

Policy Options

- Maryland could use direct incentives to promote the adoption of flexibility resources on the distribution system. Naturally, this is most helpful on circuits where there is little to no available hosting capacity.
- While installation incentives are simple to administer and address upfront capital costs, they do not reward real-world results. One way to address this disadvantage is to pair installation incentives with rate designs that reward grid-friendly electricity usage patterns. The Maryland PSC has a time-of-use (TOU) rate design pilot project for residential customers underway.
- Production incentives are a difficult "fit" for flexibility resources because their value lies not in electricity production per se, but in strategically meeting grid needs at certain times and locations.
- Procurement targets or technology-specific RFPs can help to guarantee specific levels of resource deployment. For example, six states (Arizona, California, Massachusetts, New Jersey, New York, and Oregon) have set procurement targets for energy storage. These targets are intended to foster the use of storage for a wide variety of purposes, not simply the integration of wind and solar generation. On the bulk power grid, the California ISO (CAISO) has incorporated flexibility into its resource adequacy requirements.
- It may be possible to identify and support multi-use storage projects—that is, projects that serve additional purposes such as customer bill reduction—whose cost is less than the system-wide cost savings they would realize. However, given the low penetration of wind and solar in Maryland, it is unclear whether storage benefits to the grid would outweigh their costs in the near term. In 2019, the Maryland General Assembly enacted SB 573 (Chapter 427), requiring that the PSC establish an energy storage pilot project exploring multi-use storage applications.
- Maryland's goal is to deploy 300,000 EVs by 2025. Enhancing investment in EVs may be more economical than simultaneously investing in direct energy storage devices. MEA offers incentives for EVs and EV charging stations. The Maryland PSC also has approved an EV charging infrastructure pilot program that is expected to support the deployment of over 5,000 charging stations.

7.1.1. Basic Power System Flexibility Needs

Power system operators must keep electricity supply and demand in balance at all times. Mismatches between supply and demand can reduce power quality, disrupt voltage or frequency levels, trip generation power plants offline, or overload transmission and distribution networks, possibly leading to power outages. The task of keeping supply and demand in balance is divided up into different time frames, as described below. Unless otherwise noted, PJM takes the lead in balancing supply and demand throughout its entire footprint.

- *Regulation.* Small mismatches between supply and demand constantly occur, due to moment-to-moment changes in customer electricity demand or changes in generation. To address these mismatches, PJM calls on resources that can respond to automatic signals sent by PJM. PJM has two types of regulation: Regulation D is intended for regulations that can respond almost instantaneously, while Regulation A is for addressing longer and larger variations in system conditions.

- *Primary and supplemental reserves.* Larger imbalances between supply and demand also frequently arise; for instance, when a large generator goes offline unexpectedly. PJM compensates certain generators (and demand response resources) to be "at the ready" to restore balance within 10 to 30 minutes. Primary reserves are synchronized to the grid and can respond within 10 minutes. Supplemental reserves, in contrast, may or may not be synchronized to the grid but can respond within 10 to 30 minutes.
- *Ramping*. Sometimes power needs shift rapidly. For instance, in PV-heavy regions, solar generation drops at sunset, just as customers begin to require more lighting. Ramping resources are typically called upon for one to three hours, in a predictable pattern, to scale production up or down. Note that PV-related ramping is not an issue for PJM.
- *Seasonal balancing*. Wind, solar, and hydro generation follow separate seasonal patterns, due to annual cycles of rainfall and wind speed. Likewise, consumer demand has seasonal peaks driven by cold and hot weather. Hydro dams provide a form of seasonal balancing.
- *Locational balancing*. If supply or demand is concentrated in a given area, transmission or distribution system capacity can become a limiting factor, causing localized imbalances. These "bottlenecks" can be prevented either by expanding transmission and distribution system capacity or by strategically locating flexibility resources in areas that would otherwise be stressed. At the distribution level, this is the realm where work at the state level is most pertinent, since it deals with challenges and opportunities that are specific to Maryland.

7.1.2. Flexibility Resources

Numerous sources can enhance system flexibility, including traditional generators, traditional loads, and enhancements to the grid. In addition, electricity can either be stored directly for later use or converted into another form of energy, such as heat, for later use. Institutional reforms such as sub-hourly scheduling of resources and load, or larger balancing areas, are also sources of flexibility. Finally, variable generation itself can provide flexibility. Figure 7-1 provides an overview of several flexibility resources and their technical suitability for providing specific forms of flexibility to the grid.

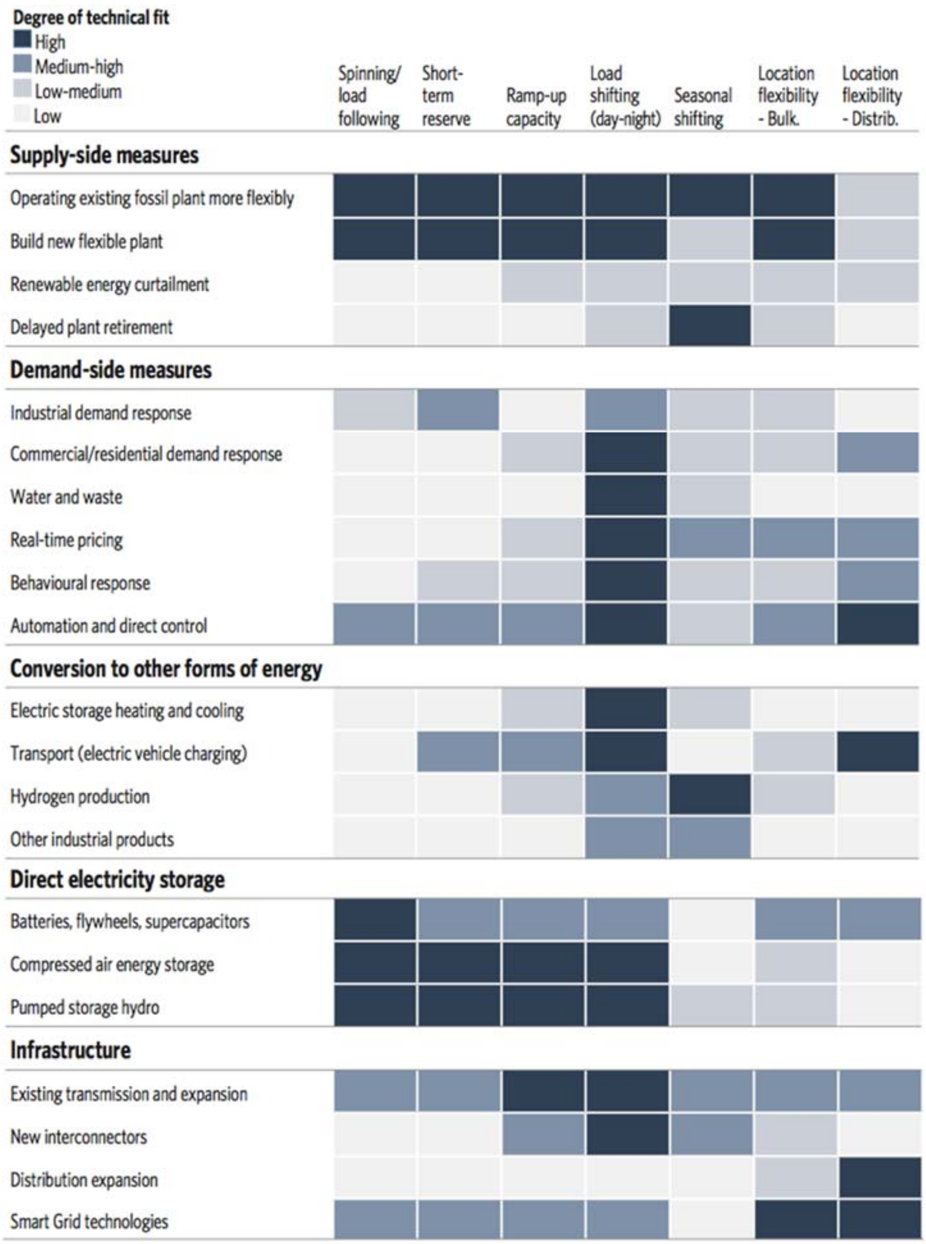

Figure 7-1. Resources That Can Provide Flexibility, Ranked by Technical Suitability for Specific Applications

Source: CPI.

In Figure 7-1, four types of resources are highlighted as especially suitable for providing location flexibility at the distribution level: automation and direct control, EV charging, distribution expansion, and Smart Grid infrastructure. These resources are discussed below, along with battery storage, which is expected by many industry experts to become increasingly cost-competitive.

- Automated and direct control, EVs, and batteries. At high levels of penetration, distributed generation can create power quality issues at the distribution level. In such cases, reverse power flows from PV systems can stress distribution system equipment designed for a one-way flow of electricity. One way to avoid such issues is to co-locate distributed generation with resources that absorb excess PV generation immediately, rather than having it flow back to the grid. Figure 7-2 shows current and 2030 cost estimates for the full suite of daily load-shifting technologies (i.e., small-scale through utility-scale). Of the technologies that can be used at the distribution level, automated load shifting and EV charging are among the most cost-effective. Lithium-ion batteries are expected to become so by 2030. Figure 7-3 is focused on energy usage patterns in California, but it provides a general sense of the types of loads that can be shifted to align with PV generation and their relative magnitudes. At least one quarter of all load associated with appliance usage, space cooling and ventilation, and space and water heating is considered "shiftable." Automation and direct load-control technologies facilitate such load shifting by enabling it to occur without customer intervention.

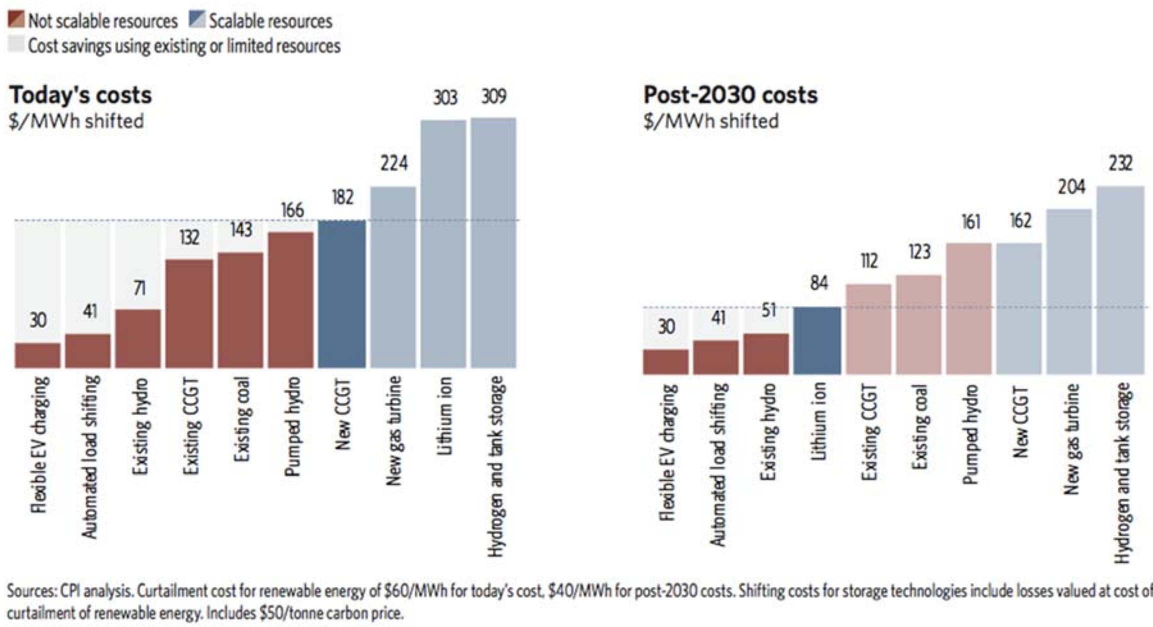

Figure 7-2. Estimated Cost of Daily Load Shifting in 2017 and Post-2030

Source: Brendan Pierpont, *et al.*, *Flexibility: The path to low-carbon, low-cost electricity grids*, Climate Policy Initiative, April 2017.

Note: Costs shown are specific to California, but indicative of overall differentials in technology costs.

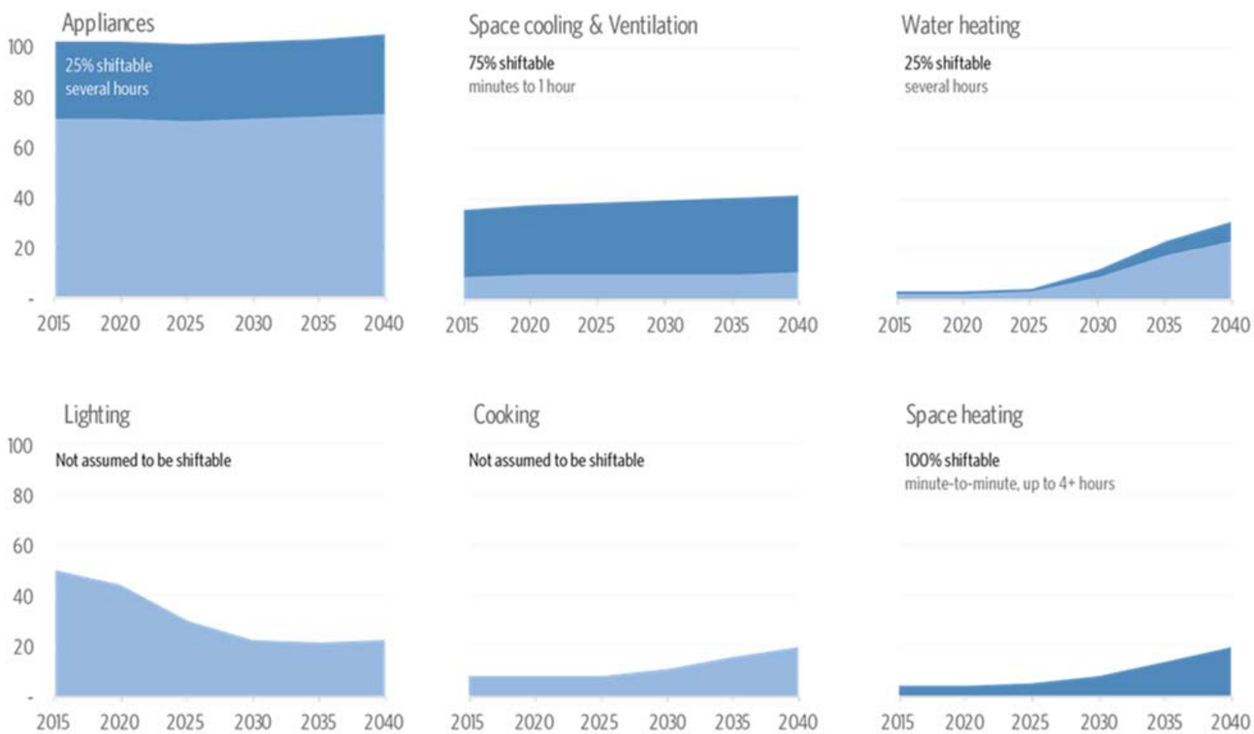

Figure 7-3. Opportunities for Demand-Side Flexibility in California (thousand GWh)

Source: CPI.

- Smart Grid Technologies. Smart Grids use a variety of advanced communication and energy technologies to enable two-way flows of electricity and communication throughout a distribution system. Advanced inverters, or smart inverters, are among the most important technologies for integrating distributed PV. Traditional inverters convert PV output from direct current to alternating current that can be fed into the grid. In addition to performing this basic function, advanced inverters can monitor the status of the grid, receive remote operation instructions, or make autonomous decisions to maintain grid stability. These capabilities can be used to facilitate high levels of distributed PV by (1) directing PV systems to stay online during short, small disturbances in frequency or voltage; (2) injecting or absorbing electricity to help maintain voltage and frequency within specified limits; or (3) staggering reconnection to the grid after a power outage in order to avoid power spikes that could trigger another disturbance.[558]

Variable generation resources can also be a source of flexibility. Generally, variable generation resources can provide "down" regulation by having their output curtailed, or they can run at a lower production level and then be dispatched upward or downward as needed. This has been tested and evaluated in California and Florida. Indeed, in Florida, it was found that operating solar PV at a lower level allows more solar to be added to the grid, as

[558] Benjamin Mow, "Smart Grid, Smart Inverters for a Smart Energy Future," National Renewable Energy Laboratory, 2017, nrel.gov/state-local-tribal/blog/posts/smart-grid-smart-inverters-for-a-smart-energy-future.html.

curtailment is reduced.[559] It is important to note that having variable generation resources provide this flexibility comes at the cost of decreased energy production. Therefore, variable generators may need to be compensated for providing flexibility services. In addition, NREL, CAISO, and First Solar found that solar PV has the technical capabilities to provide spinning reserves, load following, voltage support, ramping, frequency response, variability smoothing, frequency regulation, and power quality improvement.[560]

7.1.3. Assessing and Addressing Flexibility Needs That Fall Under PJM's Purview

The majority of Maryland's flexibility needs fall under PJM's purview. PJM is responsible for managing two key forms of system flexibility: regulation and operating reserves.[561] These needs are met through wholesale markets run by PJM. PJM also manages locational flexibility at the bulk transmission level, including determining when and where to build additional transmission lines.

In 2014, PJM and a team of consultants led by General Electric's Energy Consulting Group completed a multi-year study, the *PJM Renewable Integration Study* (PRIS), to investigate the market, operational, and planning impacts of large-scale wind and solar representing up to 30% of PJM's generation mix in 2026. (In 2017, all forms of renewable energy generation represented 5% of PJM's generation mix.) The study team modeled a reference case and nine alternative scenarios, each of which incorporated generation from existing renewable energy resources, then with generation in the PJM Queue, and next with hypothetical generation by various combinations of new solar facilities, new onshore wind facilities, and/or new offshore wind facilities. Even with two "high solar" scenarios, wind generation represented roughly twice the generation of solar. In other scenarios, wind represented as much as five times the solar generation. The study's methodology and results are summarized in detail in Appendix J. Study highlights are provided here as a basis for discussion of Maryland's role in promoting system flexibility.

The overarching conclusion of the PRIS was that PJM could absorb up to 30% renewable energy generation. To do so, the study team determined that PJM would need to increase regulation reserves and invest in new transmission to keep congestion down to a target level. However, the study team concluded that no additional primary or supplemental reserves would be needed, due to PJM's size and geographic spread. Likewise, no incremental improvements would be needed in PJM's energy scheduling practices, which rely on sub-hourly scheduling that facilitates renewable energy integration. The study team also determined that there were relatively few time periods in a year when projected ramping needs caused by renewable energy resources would be greater than the ramping capability of generation in PJM, and those few events should not affect PJM's operating performance or reliability. In addition, PJM relies on wind and solar forecasting to help predict wind and solar output in advance, which aids in integrating renewable energy generation.

From the viewpoint of Maryland and other PJM states, the PRIS provides an important confirmation that with continuing grid monitoring, management, and planning, policies to

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[559] Energy and Environmental Economics, *Investigating the Economic Value of Flexible Solar Power Plant Operation*, October 2018, ethree.com/wp-content/uploads/2018/10/Investigating-the-Economic-Value-of-Flexible-Solar-Power-Plant-Operation.pdf.

[560] California ISO, National Renewable Energy Laboratory and First Solar, *Using Renewables to Operate a Low-Carbon Grid: Demonstration of Advanced Reliability Services from a Utility-Scale Solar PV Plant*, 2017, caiso.com/documents/usingrenewablestooperatelow-carbongrid.pdf.

[561] Ramping is addressed through normal scheduling via day-ahead markets.

significantly increase renewable energy generation in the near term could be pursued without fear of jeopardizing bulk electricity system reliability. A fuller description of the PRIS is available in Appendix J.

7.1.4. Assessing and Addressing Flexibility Needs at the Distribution Level

When contemplating the need for distribution-level system flexibility to support renewable energy, it is important to keep in mind that a small fraction of the renewable energy that Maryland relies upon to fulfill its current RPS comes from distributed resources (see Section 2.1, "Deployment of Renewable Energy"). DG in Maryland does not appear to be taxing the state's distribution system greatly at this time. However, Pepco and DPL currently have several circuits in Maryland that are unable to absorb additional DG or must restrict the size of new projects.[562] The Joint Utilities, and their co-op and municipal counterparts, will be important resources for understanding how much more DG can be absorbed without triggering the need for new flexibility resources, and, at higher levels of PV penetration, what resources would be needed.

To the extent that Maryland is interested in laying the groundwork for large-scale deployment of distributed solar (and other DERS), there are several regulatory actions that could be pursued or, in some cases, are already underway. These actions include updating standards for customer systems and long-term changes to the way that utilities consider, facilitate, utilize, and compensate (or otherwise provide a financial benefit to) flexibility resources.

- Updating interconnection standards in Maryland for DG. Smart inverters can only be used in Maryland to the extent that they are permitted by the regulations that govern DG. As part of the Maryland PSC's Grid Modernization Public Conference (PC 44), an Interconnection Work Group (WG) is providing recommendations for updating COMAR 20.50.09, which addresses the interconnection of small generators. The Interconnection WG created a team to determine what types of smart inverters should be permitted, or perhaps required, when PV owners seek to interconnect to the grid. The group's final report was submitted to the PSC in July 2019. The report's recommendations that the PSC enact a Smart Inverter Requirement and companion regulations were approved for publication in the Maryland Register on September 18, 2019, and that should take effect on January 1, 2022.[563] Meanwhile, the PSC has already approved an update that allows utilities to submit plans for using customers' smart inverters to monitor and control facilities under 2 MW, in aggregate. Previously, utilities were only permitted to monitor and control individual facilities >2 MW.[564] (See also the discussion of installation incentives in Chapter 6, "Non-RPS Policies to Promote Renewable Energy".)
- Providing hosting capacity analysis information and forecasting DG deployments. An entire section of the PC 44 Interconnection WG's final report is devoted to hosting capacity (i.e., the ability of a given distribution line to accommodate DERs). Hosting capacity analysis (HCA) facilitates cost-effective, efficient decisions about when and where to deploy DERs. Pepco and DPL (collectively, PHI) already provide HCA maps, and BGE is working on doing so. When a distribution line is nearing full capacity, PHI's protocol is to reserve a portion of the remaining capacity for small projects, such as distributed solar. (Otherwise, a single, larger project could "use up" all of the

[562] PC 44 Interconnection Work Group, *PC 44 Interconnection Work Group Final Report*, March 2019.

[563] Ibid.

[564] Ibid.

remaining capacity on a line.) The Interconnection WG is also proposing that utilities use DER forecasting to determine how much hosting capacity should be reserved for smaller generators, instead of a limit set by company policy.[565]

- Leveling the playing field between traditional grid upgrades and DERs. Currently, the standard fix for any portion of the distribution grid that is under stress (whether due to renewables growth or load growth) is to upgrade the grid. This investment, if deemed prudent by the Maryland PSC, becomes part of a distribution utility's rate base, upon which the utility earns a return. Regulations that require or reward the use of customer-based resources could help to ensure these resources receive due consideration. Several other states, including California, Maine, New Hampshire, New York, and Vermont, now require utilities to evaluate so-called non-wires alternatives (NWAs) instead of traditional grid upgrades.[566] Alternatively or additionally, Performance Based Regulation (PBR) can be used to reward utilities for facilitating the deployment of customer-based energy/flexibility resources. (See also the discussions of Distribution System Planning and PBR, respectively, in Subsections 6.11 and 6.12.)
- Compensating DERs for distribution-level grid stability services. PV owners could be financially rewarded for providing grid-stability services using smart inverters. Likewise, utilities could provide a financial incentive for consumers to increase self-consumption of PV generation, to avoid or diminish reverse power flows. These incentives could involve time- and/or location-based power pricing or programs (similar to EmPOWER Maryland's peak-shaving programs) that allow utilities to direct the use of appliances in homes and businesses.

In addition to these systemic changes, the state could use direct incentives to promote the adoption of resources that are well-suited to increasing distribution-level system flexibility. The applicability of installation and production incentives is discussed below. Naturally, the use of these incentives and procurement mechanisms is likeliest to be worthwhile in instances where the need for greater distribution-level flexibility is imminent or anticipated within a reasonable time frame.

- Installation Incentives – A core advantage of installation incentives is their administrative simplicity and their ability to address upfront capital costs. Conversely, a core disadvantage of such incentives is that they are not based on the real-world performance of a device. One way to address this disadvantage is to pair installation incentives with rate designs that reward grid-friendly electricity usage patterns. In January 2019, the Maryland PSC adopted this approach for residential EVs. Specifically, the PSC approved plans by the state's four major utilities (BGE, DPL, Pepco, and Potomac Edison) to provide rebates to customers for purchasing EV chargers with "smart" functionality. As a condition of this approval, the PSC is requiring that the utilities pair the residential rebates with TOU rates that will encourage EV owners to charge their vehicles during off-peak times.[567]
- Production Incentives – A core advantage of production incentives is their ability to reward the active use of a desirable resource, not simply its purchase or installation.

[565] Ibid., *Draft Rev 0*, February 2019.

[566] Maryland Department of Natural Resources, Power Plant Research Program, *Energy Storage in Maryland: Policy and regulatory options for promoting energy storage and its benefits*, 2018, dnr.maryland.gov/pprp/Documents/Energy-Storage-In-Maryland.pdf.

[567] Public Service Commission of Maryland, "Maryland PSC Approves Modified Utility Electric Vehicle Portfolio," January 2019, psc.state.md.us/wp-content/uploads/MD-PSC-Approves-Modified-Utility-EV-Charging-Portfolio_01142019-1.pdf.

However, the value of flexibility resources lies not in electricity production per se, but in strategically meeting grid needs at certain times and locations. Additionally, because energy storage devices charge and discharge, a production-based incentive may provide little benefit for energy storage, as the net production may be very low, zero, or even negative.

- A new type of production incentive, the clean peak standard, is intended to address the time-based value of generation. Specifically, clean peak standards incentivize the production (or discharge) or electricity at times of peak demand, thus limiting the need for power from traditional peaking plants. In late 2018, Massachusetts became the first state to adopt a clean peak standard. California and Arizona have also contemplated clean peak standards in prior legislative seasons. See Section 4.9, "Creating a Clean Peak Standard" for a discussion of the pros and cons of a clean peak standard.
- Procurement Mechanisms – Technology-specific RFPs or procurement targets can help to guarantee specific levels of resource deployment, and thus are often used to "jump-start" reliance on a new technology or a suite of technologies. For example, six states (Arizona, California, Massachusetts, New Jersey, New York, and Oregon) have set procurement targets for energy storage. However, these targets are intended to foster the use of storage for a wide variety of purposes, which are discussed in the following subsection. For bulk power, CAISO added a flexible resource requirement, requiring LSEs to procure sufficient flexible resources based on each month's maximum three-hour ramp and peak demand.

7.1.5. Additional Considerations Related to Energy Storage

In addition to helping to integrate renewable energy resources at the distribution level (i.e., to increase hosting capacity), energy storage devices have the potential to provide a range of services for consumers, generators, grid operators, distribution utilities, and other LSEs in Maryland. The list below summarizes several important applications for energy storage. Note that aggregation software can be used to coordinate BTM storage resources, so that they can provide bulk energy and/or distribution system services. Also note that energy storage devices must often provide multiple services, staggered over time, to be cost-effective.

Bulk Energy Services

- Regulation Services – Fast-responding resources can offset short-duration (i.e., a few seconds to a few minutes) fluctuations in net load (i.e., electricity demand after subtracting wind and solar production). PJM solicits these services through its regulation market.
- Renewables Firming – Alternatively, a merchant developer can use storage to make wind/solar generation more predictable or to extend times of production, such as when solar ramps down during the afternoon.
- Peak Shaving – Energy storage can help to "flatten" a region's peak demand, which lowers the average cost of electricity.
- Peaker Replacement / Time Shift – In theory, storage could be charged by a renewable energy resource during off-peak hours, and dispatched during on-peak hours, thus supplanting "peaker" power plants often fueled by natural gas.

- Black Start – Like a traditional generator, utility-scale storage can serve as a "kick-start" resource to restore the grid following power outages.

Distribution System Services

- Infrastructure Deferral – Strategically placed storage can decrease or defer the need to invest in traditional distribution system upgrades caused by load growth (as opposed to DG). Often, storage investments can be closely scaled to a current need, whereas traditional upgrades must be larger.

Customer Services

- Bill Management and Backup Power – Customers can use demand management strategies, including storage, to shave their individual peak demand and any associated bill charges. Storage can also provide backup power for individual customers or communities when grid power is unavailable. When paired with renewable energy resources, storage may be able to keep critical circuits (typically 10-20% of total building load) running indefinitely.[568]

In recent years, reductions in the cost of batteries and improvements in aggregation software have begun to open new applications for energy storage. Yet, in a PPRP report on energy storage, 12 key obstacles to storage are identified. Some obstacles are at the PJM level,[569] some are at the state level. The latter barriers include rate designs that mask the real-time cost of energy; questions about the level of utility review needed for BTM storage; the lack of mechanisms for paying storage owners to help *avoid* distribution system costs; the lack of protocols for dispatching BTM storage to provide services to the grid; and opaque distribution system planning processes.[570]

These obstacles have led some stakeholders to call for policies targeted specifically at promoting energy storage. Proponents of state-level subsidies and related supports for energy storage cite the long-term environmental and economic benefits of helping to expand the market for storage and increase in-state understanding of how to best utilize it. Opponents cite the costs imposed by subsidies, which they consider unwarranted, and the possibility of increasing CO_2 emissions, since some energy is always lost during the charging and discharging of storage devices.[571]

When deliberating storage-specific policies, it is important to evaluate the range of services that energy storage can provide to the grid, rather than view storage as a resource solely to accommodate wind and solar energy generation. As with EmPOWER Maryland projects, it may be possible to identify and support multi-use storage projects whose cost is less than the system-wide cost savings they would realize. However, given the low penetration of wind and solar in Maryland/PJM (among other factors), it is unclear whether storage benefits

[568] New York Battery and Energy Storage Technology Consortium, *Energy Storage Road Map for New York's Electric Grid*, 2016.

[569] In February 2018, the FERC took steps to give storage greater access to wholesale markets. FERC Order No. 841 compels PJM and other RTOs/ISOs to revise their market rules to facilitate the participation of energy storage resources in their energy, ancillary service, and capacity markets.

[570] Maryland Department of Natural Resources, Power Plant Research Program, *Energy Storage in Maryland: Policy and regulatory options for promoting energy storage and its benefits*, 2018, dnr.maryland.gov/pprp/Documents/Energy-Storage-In-Maryland.pdf.

[571] Round trip efficiency (RTE) is a measure of the energy preserved by a storage device for reuse, rather than lost in the process of charging/discharging. For example, lithium-ion batteries have 85-98% RTE. For RTE statistics on other storage technologies, *see:* Maryland Department of Natural Resources, Power Plant Research Program, *Energy Storage in Maryland: Policy and regulatory options for promoting energy storage and its benefits*, 2018, dnr.maryland.gov/pprp/Documents/Energy-Storage-In-Maryland.pdf.

to the grid would outweigh their costs in the near term.[572] Statewide or project-specific cost-benefit modeling would be necessary to provide insight into these questions.

Under future RPS scenarios, the value that energy storage (and other flexibility resources) could provide to the state depends, in large part, on the amount of renewable energy that is generated by in-state distributed resources. In practical terms, this tends to mean: the amount of distributed PV spurred by the state's solar carve-out, whether this PV generation is concentrated on specific distribution lines that are or will be constrained, and whether energy storage is the most economical solution. As discussed earlier, a range of resources and strategies can be used to increase the distribution system's hosting capacity for renewable energy resources, including TOU rate designs, EVs, batteries, automated and direct appliance controls, Smart Grid technologies, and traditional distribution system upgrades.[573] Solar+storage systems have the added benefit of contributing to the resiliency of customers.

The value of energy storage in Maryland will also be impacted by the level of EV deployment in the state. Maryland's goal is to deploy 300,000 EVs by 2025. In January 2019, the Maryland PSC approved a five-year pilot project involving the deployment of 5,000 EV charging stations to support this goal.[574] EVs can provide many of the same services that energy storage devices can provide, especially if EVs are equipped not only to charge from the grid but discharge back to it. Enhancing the state's investment in EVs may be more economical than simultaneously investing in direct energy storage devices. For example, a recent study focused on California (which has a goal of deploying 1.5 million ZEVs by 2025) concluded that EVs could achieve many of the same benefits as the state's 1.3-GW storage target at a fraction of the cost.[575]

7.2. Land Use

Land use concerns have become more prominent as the number of large-scale solar projects deployed or proposed across Maryland has increased in recent years. Some stakeholders have expressed concern that siting solar projects on agricultural land will have adverse impacts on local industry and culture. Converting agricultural land into PV systems, it has been argued, makes it harder for businesses that support agricultural activities to stay in business. Conversely, concerns have also been raised about the state's ability to meet higher solar carve-outs if county regulations restrict or cap solar development. This section estimates the potential land use impacts of solar PV in Maryland and summarizes recent developments in county zoning that will influence the siting of PV projects in the state. Key findings from this discussion include:

- Fulfilling the 14.5% solar carve-out using solely new PV systems sited on farmland would require about 1.3% of Maryland's agricultural land. Because this estimate assumes the entire 14.5% solar carve-out would be met by utility-scale solar plants

[572] As noted in PPRP's *Energy Storage Report*, "Maryland has the advantage of not being under pressure to address certain problems that storage can help to mitigate, such as constraints on fossil fuel supplies, widespread curtailment of utility-scale wind and solar plants, or significant upward pressure on transmission and distribution costs due to load growth."

[573] An entire section of the PC 44 Interconnection WG's final report is devoted to hosting capacity. It includes numerous recommendations for near- and long-term actions that should help the state, in conjunction with its distribution utilities, anticipate and address future hosting capacity challenges.

[574] Maryland PSC, "Maryland PSC Approves Modified Utility Electric Vehicle Portfolio," January 14, 2019, https://www.psc.state.md.us/wp-content/uploads/MD-PSC-Approves-Modified-Utility-EV-Charging-Portfolio_01142019-1.pdf.

[575] Jonathan Coignard *et al.*, "Clean vehicles as an enabler for a clean electricity grid," 2018 *Environmental Research Letters*, 13 (2018) 054031, iopscience.iop.org/article/10.1088/1748-9326/aabe97/pdf.

and does not account for existing utility-scale and distributed solar capacity, this represents an absolute maximum amount of farmland that could be impacted by the solar carve-out.

- If it is instead assumed that all existing solar PV systems in Maryland greater than or equal to 1 MW are sited on farmland, and 50% of new solar capacity will be sited on farmland, fulfilling the 14.5% carve-out would require about 0.6% of Maryland's farmland.
- Similarly, if it is assumed that all existing solar PV systems in Maryland greater than or equal to 1 MW are sited on farmland, and 100% of new solar capacity will be sited on farmland, fulfilling the 14.5% carve-out would require about 1.0% of Maryland's farmland.
- With the exception of Charles County, every Maryland county has enacted zoning regulations that limit or prohibit the development of utility-scale solar projects. For projects greater than 2 MW, the Maryland PSC has the statutory authority to preempt county zoning decisions. The PSC is required, though, to give due consideration to several factors, including the recommendations of local and county governments.

7.2.1. Estimated Land Use Impacts of Solar PV

The amount of solar PV capacity that will be needed in Maryland is a function of SREC obligations, which are themselves a function of retail electricity sales. To estimate future SREC obligations by year, through 2030, the following formula is used:

$$Projected\ Energy\ Sales\ (MWh) * Solar\ Carveout\ Requirement\ (\%) = SREC\ Obligation\ (MWh)$$

Retail electricity sales projections, net of DSM programs, were drawn from the Maryland PSC's 2018-2027 *Ten-Year Plan*. Since Maryland's two cooperatives, SMECO and Choptank, are excluded from the increased solar carve-out requirements in Ch. 757, their load projections are addressed separately. The progression from projected energy sales to annual SREC obligation is shown below in Table 7-1. Note that total energy sales are projected to fall annually, while the SREC obligation increases. As a result, the projected SREC obligation peaks in 2028, when the solar carve-out reaches its maximum percentage requirement (14.5%), rather than in 2030.

Table 7-1. Projected Energy Sales, SREC Obligations, and Solar PV Capacity Needs in Maryland

Year	Energy Sales, Net of DSM (MWh)			SREC Requirement (% of Retail Sales)		SREC Obligation (MWh)		Total Solar PV Capacity Needed (MW)[4]
	Total[1],[2]	Coop[1],[2]	All Other Utilities	Coop[3]	All Other Utilities	Coop	All Other Utilities	
2019	59,432,000	4,555,000	54,877,000	5.5%	5.5%	88,820	3,018,200	**1,493**
2020	58,967,000	4,572,000	54,395,000	2.5	6.0	114,300	3,263,700	**1,542**
2021	58,282,000	4,575,000	53,707,000	2.5	7.5	114,380	4,028,000	**1,892**
2022	57,618,000	4,589,000	53,029,000	2.5	8.5	114,730	4,507,500	**2,111**
2023	57,092,000	4,607,000	52,485,000	2.5	9.5	115,180	4,986,100	**2,329**
2024	56,649,000	4,624,000	52,025,000	2.5	10.5	115,600	5,462,600	**2,547**
2025	56,017,000	4,642,000	51,375,000	2.5	11.5	116,050	5,908,100	**2,751**
2026	55,496,000	4,671,000	50,825,000	2.5	12.5	116,780	6,353,100	**2,954**
2027	54,994,000	4,705,000	50,289,000	2.5	13.5	117,630	6,789,000	**3,154**
2028	54,466,000	4,724,000	49,742,000	2.5	14.5	118,100	7,212,600	**3,347**
2029	53,943,000	4,743,000	49,200,000	2.5	14.5	118,590	7,134,000	**3,312**
2030	53,425,000	4,763,000	48,663,000	2.5	14.5	119,070	7,056,100	**3,276**

[1] *Source:* Maryland PSC 2018-2027 *Ten-Year Plan*, Appendix Table 2(a)(ii).
[2] 2028-2030 values are extrapolated using the CAGR from the preceding period.
[3] In Ch. 757, the state's electric cooperatives, SMECO and Choptank, are held to a 2.5% solar carve-out from 2020 onwards.
[4] Assuming a 25% capacity factor.

In the final column of Table 7-1, each year's SREC obligation is converted into a PV capacity requirement using the following formula:

$$\frac{SREC\ Obligation\ (MWh)}{(PV\ Capacity\ Factor) * 8760\ hours/year} = Solar\ PV\ Capacity\ Needed\ (MW)$$

A 25% capacity factor is assumed for this calculation. As a point of reference, NREL's most recent ATB (2019) provides capacity factors for utility-scale solar in five U.S. cities. Chicago is the city with the most similar solar resource to Maryland. For utility-scale PV in Chicago, the direct current-based capacity factor is 17.7% and the alternating current-based capacity factor is 23%.[576,577] A slightly higher capacity factor was selected, based on the expectation that PV technology will continue to improve over the review period.

The maximum projected PV capacity requirement, 3,347 MW in 2028, is translated into land use estimates using the following formula:

$$Total\ PV\ Capacity\ Needed\ (MW) * \frac{Acres}{MW} * \ Percent\ of\ PV\ on\ Farmland = Total\ Farmland\ Used\ (acres)$$

[576] Capacity factor (CF) is the ratio of actual energy produced by a generation system to the hypothetical maximum possible (i.e., energy produced from continuous operation at full-rated capacity) during a given period (see formula below). For a solar PV system, CF can be expressed in terms of the aggregate system-rated capacity of (1) all its modules (kW_{DC}); or (2) all its inverters (kW_{AC}). A PV system's DC-rated capacity is typically higher than its AC-rated capacity, so the value of using approach (1) is lower than approach (2).

$$Capacity\ Factor = \frac{Annual\ Energy\ Production\ (kWh)}{System\ Rated\ Capacity\ * 24\frac{hours}{day} * 365\frac{days}{year}}$$

[577] NREL, "Utility Scale PV," Annual Technology Baseline: Electricity, atb.nrel.gov/electricity/2019/index.html?t=su.

For this step, it is assumed that utility-scale solar requires eight acres/MW. This estimate draws on NREL's 2013 report, *Land-Use Requirements for Solar Power Plants in the United States*, which states that 8.7 acres of total land use (6.3 acres of direct land use) are required per MW for single-axis, utility-scale solar PV.[578] Similarly, a 2018 presentation published by NREL states that "more than 5-7 acres/MW" are needed for utility-scale solar.[579]

In addition, it is assumed that 50% of the new PV capacity needed to fulfill the solar carve-out will be sited on farmland. This assumption relies on nationwide PV installation forecasts, such as the one shown in Figure 7-4, which project that well over 50% of solar capacity installations in the United States in future years will be utility-scale. Given that at least a portion of utility-scale solar PV will be sited on brownfields or industrial rooftops, the slightly lower attribution to farmland of 50% was deemed reasonable. In order to gauge the upper bound of potential impacts to farmland, the land use impact of siting all PV capacity needed to fulfill the solar carve-out on farmland was also calculated. Additional calculations are used to account for existing utility-scale and distributed solar PV systems in the state.

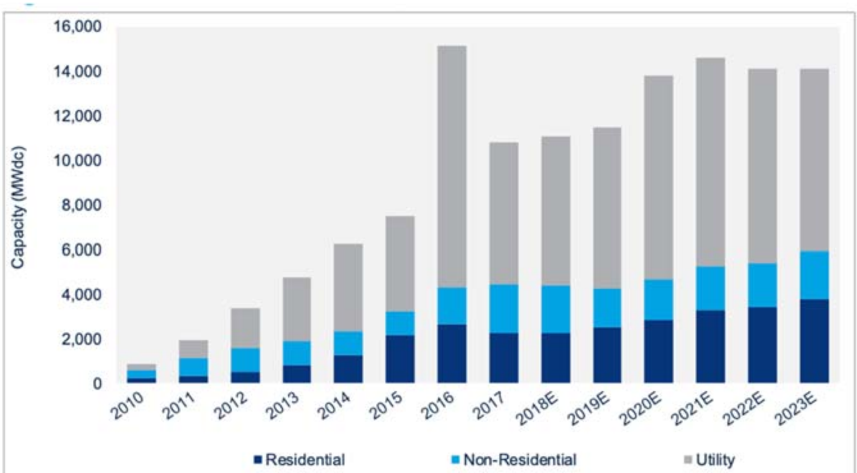

Figure 7-4. U.S. PV Installation Forecast, 2010-2023

Source: SEIA and Wood Mackenzie Power and Renewables, *U.S. Solar Market Insight*™, Q4 2018, Executive Summary.

Finally, to gauge the percentage of farmland that may be impacted by the solar carve-out, the 2012 USDA census value for all farmland in the state, 2,030,745 acres, is used in the following formula:[580]

$$\frac{Total\ Farmland\ Used\ (acres)}{Total\ Farmland\ in\ Maryland\ (acres)} = Percent\ of\ Farmland\ Impacted$$

Ultimately, all the steps and assumptions discussed above result in the following land use estimates presented in Table 7-2.

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[578] Sean Ong, Clinton Campbell and Paul Denholm, *et al.*, *Land-Use Requirements for Solar Power Plants in the United States*, NREL, 2013, nrel.gov/docs/fy13osti/56290.pdf.

[579] Megan Day, Land Use Planning for Large-Scale Solar, NREL, September 2018, nrel.gov/docs/fy19osti/72470.pdf

[580] UDSA, Farmland Information Center, farmlandinfo.org/statistics/maryland. There is a 2017 census available from the USDA; however, it has yet to be summarized by the Maryland Department of Agriculture (MDA) or the Farmland Information Center. The USDA's Quick Stats Tool provides a wide variety of statistics related to agricultural acreage in Maryland, and it is not clear which statistic is most relevant.

Table 7-2. Farmland in Maryland Required to Fulfill the 14.5% Solar Carve-out Requirement by 2035

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

[1] According to PJM-GATS, there are currently 1,159 MW of solar capacity in Maryland, of which 450 MW are due to facilities ≥1 MW.

These estimates differ from those in PPRP's 2016 LTER in that they use an updated (and lower) load forecast, assume more land per MW, assume a higher capacity factor for solar PV, and look at all farmland in Maryland, rather than excluding farmland in Western Maryland.

Another point of reference is the 2018 *Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland* (Value of Solar Study), which was published by Daymark Energy Advisors before the passage of SB 516 raised the solar carve-out to 14.5%. The Value of Solar Study looked at three land types that could be suitable for utility-scale projects: agricultural, forested, and vegetated lands. The study then excluded areas that would not be suitable for PV, such as: open water, developed areas, wetlands, parks, federal lands, airport buffers, and slopes greater than 10%.[581] The Value of Solar Study's central assumptions are summarized as follows:

- 2.4 GW of utility-scale solar will be installed in Maryland from 2018-2028;
- Average land impact is 7.25 acres per MW, equating to 17,400 acres of land needed to site the utility-scale solar;
- Suitable land for siting solar included 1,970,235 acres of agricultural land, 2,068,306 acres of forested land, and 138,330 acres of vegetated land; and
- Land acreage from Carroll, Frederick, Harford, Kent, and Montgomery counties is excluded based upon zoning regulations for solar installations.[582]

The Value of Solar Study concluded that there are a total of 1.3 million acres of Maryland land suitable for utility-scale solar projects, of which approximately 757,000 acres are agricultural land, 518,500 acres are forested, and 53,200 acres are vegetated. Of the estimated acres, approximately 15%, or 194,000 acres, is expected to contain sensitive

[581] All excluded land types are summarized in the Value of Solar Study.

[582] Daymark Energy Advisors, RLC Engineering and ESS Group, *Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland*, November 2018.

species that would require a project review and add complexity to project siting.[583] Table 7-3 illustrates these estimates.

Table 7-3. Land Required for Anticipated Utility-Scale Solar Deployments in Maryland

Anticipated utility-scale solar deployments (2018-2028)	2,400 MW
Land required for anticipated deployments at 7.25 acres per MW	17,400 acres
Land suitable for utility-scale solar	1,300,000 acres
Percentage of land suitable for utility-scale solar needed to meet anticipated deployments	1.3%
Percentage of land suitable for utility-scale development that contains sensitive species	15%

Source: Daymark Energy Advisors, RLC Engineering, and ESS Group, *Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland*, November 2018.

7.2.2. County Zoning Related to Utility-Scale Solar

In recent years, Maryland counties have updated their comprehensive plans and zoning laws to address the siting of renewable energy facilities. Several counties enacted temporary moratoriums on the deployment of utility-scale solar projects; however, by the end of 2018, all of these moratoriums had ended. With the exception of Charles County, every Maryland county has enacted permanent regulations that limit or prohibit the development of utility-scale solar projects. The zoning regulations for Garrett and Prince George's counties ban utility-scale PV projects anywhere in the county. In the other counties, zoning regulations typically restrict utility-scale projects to areas such as industrial, commercial, and/or

[583] Ibid.

agricultural zones. Figure 7-5 identifies (in orange) areas where solar generation projects of 1-10 MW are prohibited by county zoning.

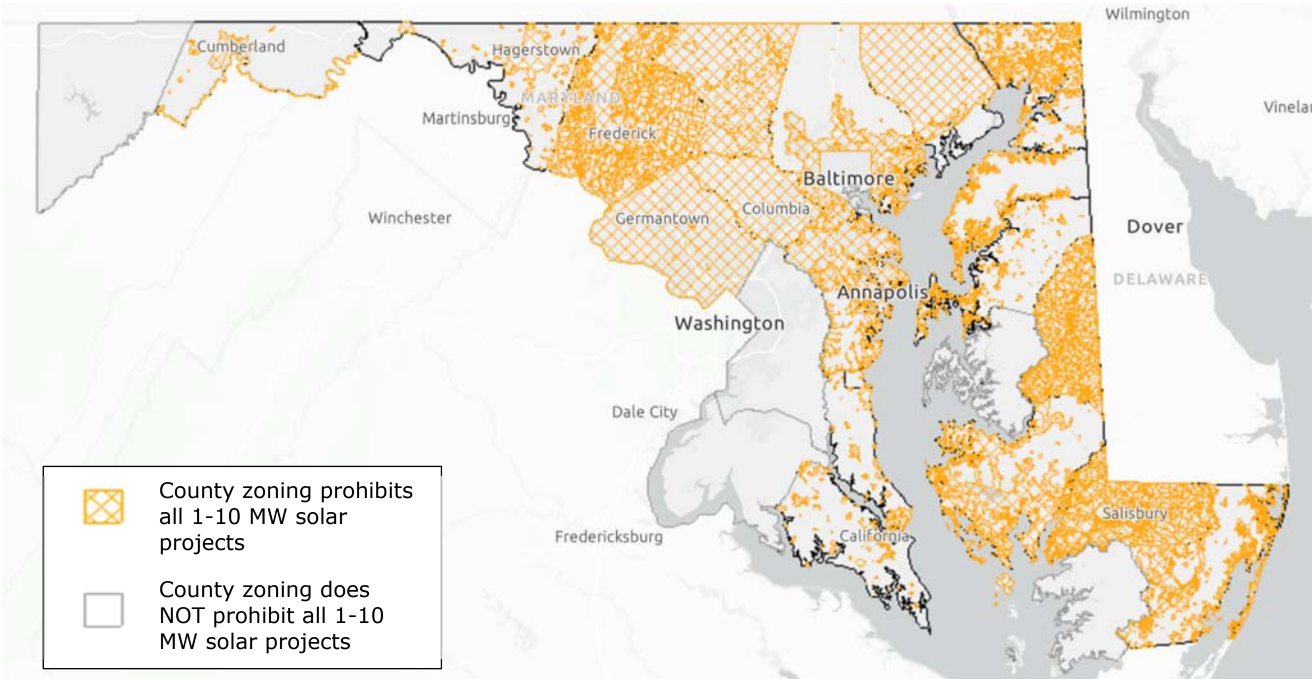

Figure 7-5. Utility-Scale Solar Zoning in Maryland Counties

Source: PPRP, SmartDG+: A Screening Tool for 2+ MW Distributed Generation and Renewable Energy Projects, erm.maps.arcgis.com/apps/webappviewer/index.html?id=3c97ba78d94f4ccead1cae201fae540b&level=8.

Note: Viewing this map at the statewide level can obscure areas that are not shaded orange and vice versa.

The Maryland PSC has final authority over the siting of >2-MW PV projects in the state. This means that the PSC can preempt county zoning. However, during the PSC's review process, a county (or municipality) can file comments and recommendations regarding any proposed solar project within its jurisdiction. Per Maryland Public Utility Articles § 7-207 (e)(1), the Maryland PSC must take these recommendations into consideration.

7.3. State-Level Subsidies for Nuclear Energy

Recently, policymakers in a number of states have considered using state energy portfolio policies, customer surcharges, and state-required power solicitations to support nuclear energy in response to a combination of factors that have imperiled the economic viability of many nuclear power generators in wholesale power markets.

The current state of the nuclear power industry and economic viability of nuclear power plants is of importance to Maryland because the state hosts a nuclear power plant, Calvert Cliffs, which is jointly owned by Exelon and Électricité de France, and it is operated by Exelon. Calvert Cliffs accounted for 33.1% of Maryland's net electricity generation and 72.3% of its emission-free electricity in 2018.[584] The plant, which consists of two reactors with a combined capacity of 1,756 MW, employs 900 workers and pays $22 million annually

[584] "U.S. Energy Information Administration, Electricity Data Brower, "Net Generation for All Sectors, annual," eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=vtvv&geo=00000008&sec=g&linechart=ELEC.GEN.ALL-MD-99.A&columnchart=ELEC.GEN.ALL-MD-99.A&map=ELEC.GEN.ALL-MD-99.A&freq=A&ctype=linechart&ltype=pin&rtype=s&pin=&rse=0&maptype=0.

in state and local taxes.[585] The Calvert Cliffs plant operated at an average capacity factor of over 97% from 2016-2018.

This section summarizes the current state-level policies that are available to support nuclear power, previous attempts at integrating nuclear power into state RPS policies, anticipated developments, and the regulatory and legal challenges that face these efforts. Note that the provided information is up to date as of June 2019, and may not reflect subsequent decisions, updates, or the status of ongoing legal challenges. Key findings from this overview of state subsidies for nuclear energy include:

- Existing nuclear power plants face a variety of economic challenges as a result of low energy market and capacity market prices, stemming from flat demand and competition from natural gas and, to a lesser extent, renewable energy generation.
- Several states have recently taken action to support existing nuclear power plants, including the implementation of: ZECs (New York, Illinois, and New Jersey), monthly customer surcharges (Ohio), and state-required solicitations of power (Connecticut).
- Existing nuclear power plants have historically been excluded from state RPS policies. Several states have considered supporting new or existing nuclear through their RPS, including the creation of new resource tiers (e.g., Tier 3 requirements), the addition of nuclear to existing resource tiers, and converting the RPS into a CES. A multi-tiered RPS policy is currently under consideration in Pennsylvania.
- Efforts to support existing nuclear power, either through an RPS or through initiatives that borrow elements of the RPS, face legal and regulatory challenges. The lawsuits against the Illinois and New York ZEC initiatives were recently resolved with decisions that are favorable to the continuation of the initiatives. Proposed changes to PJM's RPM that could counteract the actions of states to subsidize generation, whether it be nuclear power or renewable energy generation, are pending FERC action, creating uncertainty for market participants and state policymakers.

A separate report on nuclear power, as required by Ch. 757, provides additional assessment of policy initiatives and issues related to existing and proposed nuclear generation in Maryland.

7.3.1. Introduction

The United States has 60 nuclear power plants, consisting of 98 separate reactors, in operation as of August 2018.[586] These plants provide 19.3% of the electricity generation and 53.1% of the zero-carbon generation in the U.S.[587,588] Nuclear power plants have increasingly faced financial challenges in recent years due to reduced wholesale electricity prices, low growth in electricity demand, and competition from other, lower-cost

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585 Nuclear Energy Institute, "Fact sheet – Maryland and Nuclear Energy," nei.org/CorporateSite/media/filefolder/resources/fact-sheets/state-fact-sheets/Maryland-State-Fact-Sheet.pdf.

586 U.S. Energy Information Administration, "How many nuclear power plants are in the United States, and where are they located?," eia.gov/tools/faqs/faq.php?id=207&t=3; Nuclear Energy Institute, "Nuclear Plants in Regulated and Deregulated States," nei.org/resources/statistics/nuclear-plants-in-regulated-and-deregulated-states.

587 Based upon U.S. electricity generation data from EIA for 2018, nuclear generation provides 19.3% of electricity generation and 53.1% of zero-carbon generation when including solar, wind, hydropower, biomass and geothermal as zero-carbon generation resources. *Source:* U.S. Energy Information Administration, "What is U.S. electricity generation by energy source?," eia.gov/tools/faqs/faq.php?id=427&t=3.

588 *Source:* Ibid.

generators.[589] A *Bloomberg New Energy Finance* analysis determined that more than half of America's nuclear reactors are no longer profitable, incurring losses totaling approximately $2.9 billion annually.[590] As a result, the number of plants in the U.S. is declining, with six nuclear reactors closing since 2013 and another 12 reactors scheduled to shut down through 2025.[591]

Within PJM, two nuclear plants with a combined capacity of approximately 4,700 MW are slated to close by 2021.[592,593] These pending retirements correspond with financial challenges for the region. Energy prices have dropped by more than 40% since 2014, falling from $53.14/MWh to $30.99/MWh in 2017 before bouncing back in 2018 but still remaining below $40/MWh.[594] Additionally, in May 2018, approximately one-third of the nuclear capacity in PJM, representing 10,643 MW, failed to clear the PJM BRA for DY 2021/2022.[595]

The current state of the nuclear industry is of great importance to Maryland, as the state hosts a major nuclear power plant, Calvert Cliffs, which is jointly owned by Exelon and Électricité de France, and it is operated by Exelon. Calvert Cliffs accounted for 33.1% of Maryland's net electricity generation and 72.3% of its emission-free electricity in 2018.[596] The plant, which consists of two reactors with a combined capacity of 1,756 MW, employs 900 workers and pays $22 million annually in state and local taxes.[597,598] The Calvert Cliffs plant operated at an average capacity factor of over 97% from 2016-2018.

To date, Exelon has not publicly indicated that Calvert Cliffs faces an imminent threat of closure. Outside of Maryland, however, unfavorable market conditions have drawn the attention of policymakers in other states, with some enacting legislation or regulations with financial mechanisms intended to preserve nuclear plants that are otherwise not economically viable. Recently, New York, Illinois, and New Jersey have all implemented ZEC initiatives that require utilities or LSEs to maintain or procure ZECs. Each ZEC represents 1 MWh of generation from a nuclear power plant. ZEC requirements are set either at a specified level or based on a percentage of retail sales. These programs are designed to

[589] Though new nuclear reactors are not the focus of this discussion, Georgia Power anticipates bringing two new reactors online by the end of 2022. Small modular reactors may also be developed in the future. A forthcoming report on nuclear power in Maryland, which was included in the requirements of Ch. 757, will address prospects for existing and new nuclear power plants in more detail.

[590] Jim Polson, "More Than Half of America's Nuclear Reactors Are Losing Money," *Bloomberg New Energy Finance*, bloomberg.com/news/articles/2017-06-14/half-of-america-s-nuclear-power-plants-seen-as-money-losers.

[591] U.S. Energy Information Administration, "America's oldest operating nuclear power plant to retire on Monday," September 2018, eia.gov/todayinenergy/detail.php?id=37055.

[592] Planned closures include: Exelon's 805-MW Three Mile Island plant, located in Pennsylvania, by September 2019; and FirstEnergy Solutions Corp.'s (FES's) 1,777-MW Beaver Valley plant, located in Pennsylvania and consisting of two reactors, by October 2021.

[593] Michael Scott, "Nuclear Power Outlook," *Annual Energy Outlook 2018*, U.S. Energy Information Administration, eia.gov/outlooks/aeo/npo.php; Rod Walton, "FirstEnergy Solutions Reluctantly files First Steps to Shutting down Nuclear Plants," *Power Engineering*, August 2018, power-eng.com/articles/2018/08/firstenergy-solutions-reluctantly-files-first-steps-to-shutting-down-nuclear-plants.html.

[594] Monitoring Analytics, LLC, 2018 *State of the Market Report for PJM*, March 2019, monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-volume1.pdf.

[595] Exelon Corp., "Exelon Announces Outcome of 2021-2022 PJM Capacity Auction," May 2018, exeloncorp.com/newsroom/exelon-announces-outcome-of-2021-2022-pjm-capacity-auction.

[596] U.S. Energy Information Administration, Electricity Data Brower, "Net Generation for All Sectors, annual," eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=vtvv&geo=00000008&sec=g&linechart=ELEC.GEN.ALL-MD-99.A&columnchart=ELEC.GEN.ALL-MD-99.A&map=ELEC.GEN.ALL-MD-99.A&freq=A&ctype=linechart&ltype=pin&rtype=s&pin=&rse=0&maptype=0.

[597] Nuclear Energy Institute, "Fact sheet – Maryland and Nuclear Energy," nei.org/CorporateSite/media/filefolder/resources/fact-sheets/state-fact-sheets/Maryland-State-Fact-Sheet.pdf.

[598] Ibid.

function separately from the RPS/CES.[599] They can, however, be considered part of a suite of policy tools aimed at encouraging clean energy.

Ohio recently enacted legislation that imposes a customer surcharge mostly dedicated to support two nuclear plants in Ohio and two coal plants, one in Ohio and the other in Indiana.[600] The Ohio legislation also reduces the Ohio RPS from 12.5% by 2027 to 8.5% by 2026, and terminates it altogether at that time. Furthermore, Ohio utilities no longer have to comply with Ohio's energy efficiency standard once they reduce customer energy use by 17.5% from 2008 levels.[601]

This section summarizes the current policies that are available, previous attempts at integrating nuclear energy into state RPS policies, anticipated developments, and the regulatory and legal challenges that face these efforts. Note that the provided information is up to date as of June 2019, and may not reflect subsequent decisions, updates, or the status of ongoing legal challenges. (A companion discussion, in Section 4.12, examines the strengths and weaknesses of Maryland adopting the use of ZECs.)

7.3.2. Zero-Emission Credits

ZECs are similar to RECs insofar as they compensate generating facilities based on specified attributes. ZECs, however, are intended to provide a stable source of income for existing, at-risk nuclear plants. ZECs are also generally allocated in advance (i.e., prior to generation), are not eligible for trading, and serve a closed market. To date, Illinois, New York, and New Jersey have adopted ZEC programs, each with their own pricing mechanisms and distribution conditions.

New York

In 2016, the New York State Department of Public Service filed a "Staff White Paper on Clean Energy Standard" in an ongoing New York PSC case on the topic.[602] The white paper proposed the creation of a ZEC requirement as part of the state's CES, citing concerns about the economic pressures facing New York's nuclear fleet. Specifically, the paper mentioned Exelon's claims that its Robert Emmett Ginna Nuclear Power Plant (Ginna) and Nine Mile Point Nuclear Station (Nine Mile) were no longer financially viable and would close in the absence of a state nuclear subsidy program. The white paper also noted Entergy Corporation's (Entergy's) plans to close its James A. FitzPatrick Nuclear Power Plant (FitzPatrick). In March 2017, Exelon purchased FitzPatrick from Entergy and assumed both ownership and management of operations.[603]

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[599] California became the first state to formally integrate large-scale nuclear generation (i.e., credit nuclear generation toward generation requirements) into a CES. California's CES, however, operates in parallel but separately from the state's RPS.

[600] Of the $170 million expected to be raised annually by the surcharge, $20 million will be allocated among six existing solar projects located in rural areas in Ohio.

[601] The Ohio Legislature, HB 6, *Creates Ohio Clean Air Program*, legislature.ohio.gov/legislation/legislation-summary?id=GA133-HB-6.

[602] New York State Department of Public Service, Case No. 15-E-0302, "Staff White Paper on Clean Energy Standard," 2016.

[603] Exelon Corp., "James A. FitzPatrick Nuclear Power Plant Joins Exelon Generation Nuclear Fleet," March 2017. exeloncorp.com/newsroom/fitzpatrick-joins-exelon-generation-nuclear-fleet.

In 2016, New York became the first state to adopt a ZEC requirement when the NY PSC ordered its establishment as part of the state's CES.[604,605] Under the NY PSC order, all six of New York's IOUs and other LSEs in the state are required to purchase ZECs from qualifying at-risk nuclear plants. The NY PSC ultimately agreed that failure to implement a state policy that values the emission-free attributes of nuclear energy would result in significant backsliding in the state's efforts to limit GHG emissions. This finding was consistent with an NY PSC order in another, related case established to consider the cost of maintaining and operating the Ginna and Nine Mile plants.[606] This examination revealed that the zero-emission benefits of the two plants were at serious risk absent efforts to value and pay for these attributes.

As part of the ZEC requirement, NYSERDA facilitates LSE purchases of ZECs and determines the number of ZECs required. ZEC payments are provided to facilities that meet public necessity criteria, which are determined on a plant-by-plant basis by the NY PSC upon consideration of:

1. The historical contribution of the plant to the clean energy resource mix consumed by retail consumers in New York;
2. The degree to which revenues received by the plant from energy, capacity, and ancillary services have been inadequate compensation to maintain operations;
3. The cost of adequate compensation in relation to other clean energy alternatives;
4. The impacts of such costs on ratepayers; and
5. The public interest.

The ZEC contracts for selected nuclear facilities are administered in six (6) two-year tranches. The total number of ZECs a selected nuclear facility can sell is capped at the total generation output of the facility from July 2015 – June 2016. The price paid for the ZECs, as calculated by the NY PSC, is based on the projected SCC average for each tranche (April through March),[607] minus the fixed baseline portion of the cost that is already captured through the RGGI over the same period.[608] The NY PSC uses SCC projections from the U.S. Interagency Working Group July 2015 Technical Update.[609] For the first tranche (April 2017 – March 2019), the NY PSC set a ZEC price of $17.48/MWh.[610] The value of ZECs is reduced if wholesale electricity prices rise to more than $39/MWh, because the ZEC price would drop

[604] State of New York Public Service Commission, Case Nos. 15-E-0302 and 16-E-0270, "Order Adopting A Clean Energy Standard," 2016.

[605] The carbon benefits of preserving the nuclear zero-emission attributes through the ZEC requirement do not count toward New York's 50% renewable energy by 2030 CES goal. The RES and ZEC programs, however, both contribute to the state's comprehensive GHG reduction goals.

[606] New York State Department of Public Service, Case No. 16-E-0270, "Petition of Constellation Energy Nuclear Group LLC; R.E. Ginna Nuclear Power Plant, LLC; and Nine Mile Point Nuclear Station, LLC to Initiate a Proceeding to Establish the Facility Costs for the R.E. Ginna and Nine Mile Point Nuclear Power Plants," 2016.

[607] The New York CES defines the SCC as the nominal price, per short ton, of CO_2.

[608] The New York CES estimates RGGI values for each tranche using RGGI prices forecasted by NYISO's Congestion Assessment and Resource Integration Study (CARIS) model.

[609] Interagency Working Group on Social Cost of Carbon, *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866*, United States Government, 2013 (revised 2015), obamawhitehouse.archives.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf.

[610] The projected SCC for the first tranche is equal to nominal $42.87/short ton. The nominal RGGI fixed baseline portion for Tranche 1 is $10.41/short ton. This yields a net cost of carbon of nominal $32.47/short ton. Using a fixed conversion factor of 0.53846 to convert cost per short ton to cost per MWh yields a ZEC price of $17.48/MWh.

correspondingly.[611] However, if electricity prices fall, the ZEC price would likely rise to compensate for the lost revenue.

In December 2016, based upon the public necessity criteria described above, as well as the findings of several NY PSC cases, the NY PSC directed NYSERDA to offer long-term contracts for the purchase of ZECs from FitzPatrick, Ginna, and the two units at Nine Mile.[612] NYSERDA will purchase up to a combined 27,618,000 ZECs from the three plants annually. The costs associated with an LSE procuring ZECs from qualifying nuclear facilities will be recovered entirely through a commodity charge on customer bills. LSEs will collect this fee and use it to pay NYSERDA, which in turn will pay the nuclear plants for the ZECs. According to the NY PSC final order, the total cost to ratepayers from the six tranches is estimated at $7.6 billion, with the first two years of expected to cost $965 million. On average, the NY PSC predicts that the typical customer in the state will pay an additional $2/month on their electricity bill as a result of ZECs.

Illinois

In early 2014, Exelon stated it would shut down two of its Illinois nuclear plants that were no longer earning a profit, Clinton Power Station (Clinton) and Quad Cities Generation Station (Quad Cities), unless legislation was passed that recognized nuclear's emission-free attributes. In May 2014, the Illinois General Assembly enacted House Resolution (HR) 1146, which urged the Illinois Commerce Commission (ICC), IPA, and the Department of Commerce and Economic Opportunity (DCEO) to prepare a report concerning the potential economic, societal, and grid reliability impacts from the closure of nuclear power plants.[613] The resolution also requested that these entities propose market-based solutions to support nuclear power. In January 2015, the ICC, IPA, and DCEO, as well as the Illinois Environmental Protection Agency (IEPA), published the *Potential Nuclear Power Plant Closings in Illinois* report (2015 Report), which proposed a Low Carbon Portfolio Standard (LCPS) that would require wholesale purchasers of electricity to obtain a specific portion of their supply from zero- or low-carbon sources, such as nuclear energy.[614]

In February 2016, SB 1585 was introduced. The bill called for a new procurement process that would include low-carbon energy credits, similar to ZECs, from low-carbon energy sources. The legislative findings highlighted that, under current Illinois law, nuclear power is not considered a renewable energy resource and therefore lacks a mechanism, like a REC, to value its zero-emission attributes. The Illinois General Assembly therefore determined that the state needed a Zero Emission Standard (ZES), separate from the RPS, that would support state efforts to reduce CO_2 and other air pollutants, as well as efforts to expand the state's commitment to zero-emission energy generation.

[611] The wholesale electricity price of $39/MWh is equal to the NY PSC's forecast for long-term avoided power costs.

[612] New York Public Service Commission, "Agreement for the Sale of Zero-Emissions Energy Certificates," December 2016.

[613] Illinois General Assembly, HR 1146, Nuclear Power Plant Closures, ilga.gov/legislation/BillStatus.asp?DocNum=1146&GAID=12&DocTypeID=HR&LegId=82396&SessionID=85&GA=98.

[614] Illinois Commerce Commission, Illinois Power Agency, Illinois Environmental Protection Agency and Illinois Department of Commerce and Economic Opportunity, *Potential Nuclear Power Plant Closings in Illinois: Impacts and Market-based Solutions*, 2015, ilga.gov/reports/special/Report_Potential%20Nuclear%20Power%20Plant%20Closings%20in%20IL.pdf

In December 2016, the State of Illinois enacted SB 2814, or the Future Energy Jobs Act (FEJA). The FEJA is an all-encompassing energy reform bill that both amends the state's existing energy efficiency and RPS policies as well as establishes a ZES.[615] The ZES requires that three of Illinois' LSEs—ComEd, Ameren Illinois (Ameren), and MidAmerican Energy Company (MidAmerican)—purchase ZECs from the state's qualifying nuclear facilities.

The FEJA, which amended the 2007 Illinois Power Agency Act, established a ZES Procurement Plan, which outlines the process by which the IPA will annually purchase ZECs from capable zero-emission facilities. The procurement plan specifies that winning zero-emission facilities should be selected based on public interest criteria that focus on minimizing GHG emissions resulting from electricity consumed in Illinois, including:[616]

1. The avoided GHG emissions of continued operation of the zero-emission facility; and
2. The cost of replacing nuclear generation with other zero-emission resources such as wind and solar PV.

Under the ZES, beginning in DY 2017/2018,[617] the IPA is required to procure ZECs for electric utilities that serve at least 100,000 retail customers in Illinois (i.e., ComEd and Ameren) or that serve less than 100,000 Illinois retail customers but have requested that IPA procure ZECs for the portion of the utility's load that serves Illinois (i.e., MidAmerican). The procured ZECs will be equal to 16% of the total amount of electric load procured by IPA and delivered to Illinois retail customers during 2014 for each electric utility. The ZECs are delivered to the suppliers selected during the ZES procurement through a 10-year contract period of June 1, 2017 – May 31, 2027. The procurement process selects suppliers up until the 16% requirement is reached.

The price of each ZEC for each DY is set based on the SCC.[618] The SCC will be $16.50/MWh in the initial DY and will increase by $1/MWh beginning with DY 2023/2024 and each DY thereafter. A Price Adjustment is included to ensure that the ZEC procurement remains affordable for retail customers. The ZEC price will be reduced to below the SCC by the amount that the market price index exceeds the baseline market price index (which is equal to $31.40/MWh for the year ended May 31, 2016).[619] If electricity prices increase to the point that the adjustment is greater than the SCC price, the ZEC price would be zero.

The ZES allows electric utilities to recover all costs associated with the purchase of ZECs from retail customers through a single, uniform $/kWh charge. The ZES also sets a 1.65% annual cost cap on the amount of total customer costs that can be paid through customer surcharges for the purchase of ZECs. This cap is calculated based on retail customer costs during the year ended May 31, 2009, thereby setting a budget of approximately

[615] Illinois General Assembly, SB 2814, Public Act 099-0906 ("Future Energy Jobs Act"), ilga.gov/legislation/publicacts/fulltext.asp?Name=099-0906.

[616] Zero-emissions facilities must also provide the IPA with the following to be considered for procurement: (1) the useful lifespan of the facility; (2) annual power generation from 2005-2015 and projected ZEC generation over the remaining useful life of the facility; (3) annual zero-emission facility cost projections ($/MWh) over the next six DYs; and (4) a commitment to continue operation through the contract executed under the ZES Standard Procurement Plan.

[617] The Illinois DY commences on June 1 (e.g., DY 2017/2018 was June 1, 2017 – May 31, 2018).

[618] Based upon the U.S. Interagency Working Group on Social Cost of Carbon's price in the August 2016 Technical Update.

[619] The market price index for a DY shall be the sum of projected energy prices and projected capacity prices. The baseline market price index for the year ended May 31, 2016 is the sum of: (1) the average day-ahead energy price across all hours at the PJM Northern Illinois Hub; (2) 50% multiplied by the BRA capacity price for the rest of the PJM zone group, divided by 24 hours per day; and (3) 50% multiplied by the Planning Resource Auction (PRA) capacity price for Zone 4 determined by MISO, divided by 24 hours per day.

$235 million per DY.[620] If the amount of ZECs procured results in a cost to the IPA that exceeds the cost cap to customers, the resulting ZECS will be delivered but will constitute unpaid contractual volume. This volume will be eligible for payment in a future DY that is not limited by the cost cap but is second in priority to the payments for the ZECs delivered in that year.

As directed by FEJA, the IPA published the final version of its 2017 ZES Procurement Plan in October 2017. The plan determined the overall annual target quantity of ZECs to be 20,118,672, or 16% of the electricity delivered by Ameren and ComEd during 2014 and 16% of the portion of electricity procured by the IPA for MidAmerican. The procurement plan was approved by the ICC who had determined that the procurement of ZECs would be cost effective (i.e., the resulting retail customer rates from the projected costs would not exceed the 1.65% cost cap to customers, and that the proposed procurement satisfied the public interest criteria).[621]

In January 2018, the ICC voted to approve the winning zero-emission facilities from a ZECs procurement held the week earlier. The successful suppliers were those that received the highest scores from the public interest criteria analysis. The three winning suppliers were Units 1 and 2 of Quad Cities and the first unit of Clinton. For each DY, the Illinois ZEC initiative will provide 20,118,672 ZECs to utilities, which results in a total ZEC cost of $332 million annually. Ratepayers will pay only the cost cap of $235 million, which results in 5,886,683 ZECs of unpaid contractual volume.[622]

New Jersey

In May 2018, the New Jersey governor signed into law SB 2313, making New Jersey the third state to enact ZEC legislation. The bill authorized the creation of ZECs and gave the New Jersey Board of Public Utilities (NJPBU, or Board) authority to develop the method for selecting recipient nuclear power plants and the mechanism to purchase ZECs. The bill was created after Public Service Enterprise Group (PSEG) lobbied for legislators to create a program that could subsidize two nuclear power plants in New Jersey—Hope Creek Nuclear Generating Station (Hope Creek) and Salem Nuclear Power Plant (Salem)—both of which had experienced financial challenges.[623]

Under SB 2313, the NJPBU was required to complete a proceeding no later than 180 days after the enactment of the bill to allow for the commencement of a ZEC program (i.e., by November 19, 2018). The proceeding was to include: (1) a method for selecting eligible plants based on a ranking system; and (2) a mechanism for each EDC to purchase ZECs from selected nuclear power plants. Under SB 2313, the ranking system must measure the contribution each plant makes to minimizing air pollution emissions and the degree to which the plant is unable to cover its costs. Nuclear power plants must submit an application to NJPBU to be considered for the ZEC program along with certain financial documentation. SB 2313 also required NJBPU to file a subsequent proceeding 330 days (i.e., April 18, 2019) after the bill enactment date that will certify applicant nuclear plants as eligible and establish a rank-ordered list of nuclear power plants to receive ZECs. In order to be

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[620] Illinois Power Agency, *Zero Emission Standard Procurement Plan*, 2017, illinois.gov/sites/ipa/Documents/2018ProcurementPlan/Zero-Emission-Standard-Procurement-Plan-Approved.PDF.

[621] Illinois Commerce Commission, Docket No. 17-0333, icc.illinois.gov/docket/Documents.aspx?no=17-0333.

[622] Illinois Power Agency, *Zero Emission Standard Procurement Plan*, 2017, illinois.gov/sites/ipa/Documents/2018ProcurementPlan/Zero-Emission-Standard-Procurement-Plan-Approved.PDF.

[623] PSEG is the sole owner and operator of Hope Creek. The co-owners of Salem are PSEG (57%) and Exelon (43%), but PSEG is the sole operator.

considered eligible to participate in the ZEC program, SB 2313 requires a nuclear power plant to:

1. Be licensed to operate by the Nuclear Regulatory Commission (NRC) by the bill enactment date and through 2030 or later;
2. Demonstrate that it makes a significant and material contribution to the air quality in New Jersey by minimizing emissions that result from electricity consumption in the state;
3. Demonstrate that the plant will cease operations unless it experiences a material financial change;
4. Demonstrate that the plant does not receive any direct or indirect payment or credit that would eliminate the need for the plant to retire prematurely, despite its reasonable and best efforts to obtain any such payment or credit; and
5. Submit an application fee to NJBPU for an amount to be determined by the Board, which is not to exceed $250,000, to be used to defray the costs incurred by the Board to administer the ZEC program.

Immediately following the selection proceeding, selected plants will receive ZECs according to their ranking up to the cap of 40% of the electricity (MWh) distributed in the state in energy year (EY) 2017.[624] The two eligible nuclear power plants, Salem and Hope Creek, are expected to produce combined generation of 25,300,096 MWh, and therefore would receive 25,300,096 ZECs if selected by the Board.[625,626] Selected nuclear power plants will initially receive ZECs for an eligibility period that will run through the end of the first EY in which the nuclear power plant is selected, plus an additional three EYs thereafter. After this initial period, the plants will be subject to Board review for renewed eligibility for an additional three EYs. There is no sunset date specified in the legislation.

SB 2313 specifies that the pricing mechanism for the ZEC program is structured so that the costs are guaranteed to be significantly less than the SCC, in order to ensure that the program does not place an undue financial burden on retail distribution customers.[627] To determine the price, the NJBPU must divide the projected annual revenue from the ZEC program at the end of the EY (estimated at $301.4 million) by the greater of: (1) 40% of the total number of MWh of electricity distributed by public electric utilities in the prior EY; or (2) the amount of MWh of electricity generated in a prior EY selected by the nuclear plant.[628] For the Salem and Hope Creek units, the former is estimated to be the greater of the two and approximately equal to 30,143,748 MWh, resulting in an estimated per-ZEC cost of about $10.00.

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[624] The New Jersey EY commences on June 1 and ends on May 31 (e.g., EY 2017 was June 1, 2017 – May 31, 2018).

[625] Oyster Creek Nuclear Generating Station closed in October 2018 and therefore was not eligible for the ZEC program.

[626] Based upon calculations made by the New Jersey Office of Legislative Services (OLS) in the April 2018 Legislative Fiscal Estimate using 2016 EIA data.

[627] Senate and General Assembly of the State of New Jersey, SB 2313, "An Act concerning nuclear energy, and supplementing Title 48 of the Revised Statutes," May 2018, njleg.state.nj.us/2018/Bills/AL18/16_.HTM.

[628] Ibid.

All New Jersey public electric utilities, including the state's four investor-owned EDCs and a municipal EDC,[629] will be required to pay qualifying nuclear plants for the ZECs received during each EY in the same proportion that they supply electricity to the state. Electric utilities will be allowed to recover the full cost associated with procurement of ZECs through a non-bypassable $0.004/kWh charge imposed on all retail distribution customers of the utility. This rate reflects the emissions avoidance benefits associated with the continued operation of the selected nuclear power plants.

In August 2018, NJBPU filed an order commencing the ZEC program and initiating a public hearing process as well as a stakeholders comment solicitation.[630] In November 2018, the Board filed the required order establishing recipient selection parameters and setting a deadline for comments on recipient applications of January 31, 2019.[631] The order established two teams to evaluate nuclear power plant applications: an Eligibility Team and a Ranking Team. The Eligibility Team, which included a consulting group (Levitan & Associates), NJBPU Staff, and New Jersey Department of Environmental Protection (NJDEP) Staff,[632] was responsible for reviewing the applications according to the five eligibility criteria listed above as well as 20 additional criteria aimed at determining the economic, GHG, fuel security, and operations impacts of the premature retirement of an applicant.[633] The Ranking Team was then responsible for creating a methodology and criteria to score the eligible applicants and then provide the NJBPU with a rank-ordered list of qualified units. The order set a deadline of April 19, 2019 for both teams to complete their tasks.

The NJBPU received applications for ZEC eligibility from Units 1 and 2 of Salem as well as from Hope Creek in December 2018.[634,635,636] The Eligibility Team then reviewed the three applications, as well as comments submitted. During the review period, the Eligibility Team determined that all three applicants failed to meet the full eligibility requirements under the five main ZEC eligibility criteria. Specifically, the Eligibility Team determined that the Hope Creek, Salem 1, and Salem 2 nuclear units were not in financial distress and remained viable under current market conditions.

On April 18, 2019, the NJBPU went against the Eligibility Team recommendations and voted to approve the ZEC eligibility of the Hope Creek unit and the two Salem units. The order sited other factors, beyond the five main criteria, as the reasoning behind the approval,

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[629] These include PSEG; Exelon's Atlantic City Electric Co.; FirstEnergy Solutions Corp.'s Jersey Central Power & Light Co.; Consolidated Edison, Inc.'s (Con Ed's) Rockland Electric Co.; and Butler Municipal Electric Power and Light, owned by the borough of Butler, New Jersey.

[630] The full list of questions asked by the Board to stakeholders can be found at: State of New Jersey Board of Public Utilities, Docket No. EO18080899, "Notice of Public Hearing," September 2018, state.nj.us/bpu/pdf/publicnotice/ZEC-Program-Public-Hearing-Notice.pdf.

[631] Ibid., "Order Establishing the Program, Application, and Procedural Process," November 2018, state.nj.us/bpu/pdf/boardorders/2018/20181120/11-19-18-9A.pdf.

[632] Ibid., "Order Approving Consultant and Setting Application Fee," December 2018, bpu.state.nj.us/bpu/pdf/boardorders/2018/20181218/12-18-18-9A.pdf.

[633] The full list of criteria considered by the Eligibility Team can be found at: State of New Jersey Board of Public Utilities, No. EO18080899, "Order Establishing the Program, Application, and Procedural Process," November 2018, state.nj.us/bpu/pdf/boardorders/2018/20181120/11-19-18-9A.pdf.

[634] PSEG Services Corporation, "Application for the Receipt of Zero Emissions Credits of Salem 1 Generating Station Submitted in the Matter of the Implementation of L. 2018, c.16 Regarding the Establishment of Zero Emissions Certificate Program for Eligible Nuclear Power Plants," State of New Jersey Board of Public Utilities Docket No. EO18080899," December 2018, corporate.pseg.com/aboutpseg/companyinformation/thepsegfamilyofcompanies/-/media/1D845258223545D69B3CF19092C25EA1.ashx.

[635] Ibid. (Salem 2): corporate.pseg.com/aboutpseg/companyinformation/thepsegfamilyofcompanies/-/media/10D2AE337C024A4DA8353C8BF17A0F5D.ashx.

[636] Ibid. (Hope Creek): corporate.pseg.com/aboutpseg/companyinformation/thepsegfamilyofcompanies/-/media/E26DB24D6B074FEB8CD0895A1ED1D45C.ashx.

namely: fuel diversity, resiliency, and the economic and environmental impact if the units were to shut down. Based on this decision, all three nuclear units will receive ZECs in accordance with SB 2313 for the initial eligibility period of April 18, 2019 through May 31, 2022. The ZEC program is expected to cost New Jersey electric customers approximately $301.4 million a year, adding an extra $40 per year to customer electric bills on average.[637] Based on an estimated price of $10 per ZEC, Hope Creek and Salem are expected to receive approximately $253 million in revenue from ZEC sales annually.[638]

In May 2019, the New Jersey Division of Rate Counsel (NJDRC) filed a notice of appeal with the New Jersey Superior Court Appellate Division on the grounds that the NJBPU decision was not supported by the findings of the Eligibility Team, which determined that none of the three nuclear units that applied for ZECs were "at risk" of early retirement.[639] Additionally, the appeal maintained that there was no evidence to support the $0.004/kWh rate, used to recover the costs of the ZEC program, as representing the emissions avoidance benefits of the output of the nuclear plants.[640]

7.3.3. Monthly Customer Surcharges

Monthly customer surcharges are used to support a wide variety of measures, such as public benefit funds for specified technologies such as renewable energy, distributed generation, and energy efficiency technologies; to recover costs utilities incur for fuel and power purchases; or to recover costs utilities incur as a result of a catastrophic storm, among other things. Monthly customer charges are established through either legislation or regulation and are primarily funded through a non-bypassable, per-kWh surcharge on customer electric bills. When established, the legislation or regulation will specify broad parameters such as the maximum level of funding (either annually or over a period of time, or both), set a sunset date for the collection of funds, and outline guidelines on how the funds may be utilized.

Ohio

In July 2019, the Ohio governor signed HB 6 (Clean Air Program) into law, which will create a public benefit fund for Ohio's nuclear generation facilities at risk of early retirement.[641] The bill authorizes the Ohio Air Quality Development Authority (OAQDA) to provide credits per MWh of electricity produced to qualifying nuclear generating facilities from a Nuclear Generation Fund. HB 6 was borne out of FirstEnergy Solutions Corp.'s (FES's) plans to retire its Ohio plants—the 907-MW Davis-Besse Nuclear Power Station (Davis-Besse) and the 1,268-MW Perry Nuclear Generating Station (Perry)—unless some support of financial support mechanism was enacted.[642]

[637] State of New Jersey Board of Public Utilities, Docket No. EO18080899, "Order Establishing the Program, Application, and Procedural Process," November 2018, state.nj.us/bpu/pdf/boardorders/2018/20181120/11-19-18-9A.pdf.

[638] This number could range between $253 million and the total revenue from the project (i.e., $301.4 million) depending on total electricity distribution. Any excess revenue produced by the tariff and held by the electric utility that is not used to pay the nuclear power plants will be returned to customers at the end of each EY.

[639] State of New Jersey Division of the Rate Counsel, "Notice of Appeal and Civil Case Information Statement," May 2019, nj.gov/rpa/docs/ZEC_Rate_Counsel_Notice_of_Appeal_and_CIS_hardcopies_5-15-19.pdf.

[640] Ibid.

[641] The Ohio Legislature, HB 6, *Creates Ohio Clean Air Program*, legislature.ohio.gov/legislation/legislation-summary?id=GA133-HB-6.

[642] FES reported that the 1,872 MW Beaver Valley plan in Pennsylvania would also be shut down early.

HB 6 is not Ohio's first attempt to implement nuclear subsidy legislation. In 2017, the state introduced ZEC legislation in both the House (HB 178 and HB 381)[643,644] and Senate (SB 128),[645] but all three ultimately did not pass Committee review. Legislative activity then stalled, but resumed following a report on March 28, 2018 that FES, a subsidiary of FirstEnergy Corporation, would be shutting down Davis-Besse and Perry by May 2020 and May 2021, respectively.[646] The next day, FES requested an emergency order from DOE to provide cost recovery to coal and nuclear plants within PJM,[647] and one day later, FES filed for Chapter 11 bankruptcy and maintained that the Davis-Besse and Perry units in Ohio, along with its other nuclear and coal units in both Ohio and Pennsylvania,[648] had been unable to compete against low-cost, natural-gas-fired power and renewable energy, and had contributed significantly to the debt incurred by FES.[649] In April 2019, HB 6 was introduced.

HB 6 creates an annual Nuclear Generation Fund, equal to $150 million, to be disbursed among eligible nuclear generating facilities. Beginning on January 1, 2021, Ohio's EDCs are required to collect from their state retail customers charges that, when aggregated, will total $170 million annually—equal to a $150 million revenue requirement for disbursements from the Nuclear Generation Fund and a $20 million revenue requirement for disbursements from a separate Renewable Generation Fund, also created by HB 6.

The monthly charge to retail customers to recover the $170 million for both funds will not exceed $0.85 for residential customers and $2,400 for industrial customers. The Public Utilities Commission of Ohio (PUCO) is responsible for determining how the revenue requirement will be allocated to each EDC and will base the method on some combination of number of customers and relative quantity of kWh sales. The PUCO will also determine how the monthly charge will appear on each customer's bill, be it an increase in base rates or a separate rider. The funds are administered and distributed by the State Treasurer.

Using the Nuclear Generation Fund, OAQDA will issue credits to qualifying nuclear generating units.[650] OAQDA will approve credits for nuclear generating units based upon the provision of:

1. Financial information;
2. Certified cost and revenue projections through December 31, 2026;
3. Operations and maintenance expenses;
4. Fuel expenses, including spent-fuel expenses;

643 The Ohio Legislature, HB 178, legislature.ohio.gov/legislation/legislation-summary?id=GA132-HB-178.

644 The Ohio Legislature, HB 381, legislature.ohio.gov/legislation/legislation-summary?id=GA132-HB-381.

645 The Ohio Legislature, SB 128, legislature.ohio.gov/legislation/legislation-status?id=GA132-SB-128.

646 FirstEnergy Solutions Corp., "FirstEnergy Solutions Files Deactivation Notice for Three Competitive Nuclear Generating Plants in Ohio and Pennsylvania," March 2018, fes.com/content/dam/fes/about/files/newsreleases/deactivation-release-final-letterhead.pdf.

647 FirstEnergy Solutions Corp., "Request for Emergency Order Pursuant to Federal Power Act Section 202(c)," March 2018, statepowerproject.files.wordpress.com/2018/03/fes-202c-application.pdf.

648 Bruce Mansfield Coal plant in Pennsylvania; W.H. Sammis Plant in Ohio; Beaver Valley Power Station in Pennsylvania.

649 United States Bankruptcy Court for the Northern District of Ohio, Official Form 201, "Voluntary Petition for Non-Individuals Filing for Bankruptcy," (FirstEnergy Solutions Corp., March 2018), online.wsj.com/public/resources/documents/FESpetition.pdf?mod=article_inline.

650 The Clean Air Program defines a qualifying nuclear generating unit as an electric generating facility in Ohio fueled by nuclear power, with its operator maintaining both a principal and substantial place of business in Ohio.

5. Non-fuel capital expenses;
6. Fully allocated overhead costs;
7. The cost of operational risks and market risks that would be avoided by ceasing operation of the resource;[651] and
8. Any other information, financial or otherwise, that demonstrates that the resource is projected to not continue being operational.

Upon approval of the application, qualifying nuclear generating units must provide OAQDA with the number of MWh that the resource produced, if any, in the quarter immediately preceding the approval. For each MWh reported, OAQDA will provide one nuclear credit worth $9.00.

The OAQDA and PUCO are required to submit a joint report for each year of the Clean Air Program. This report will conduct a retrospective management and financial review of the owner or operator of a qualifying nuclear resource and any such resource that receives payments for nuclear resource credits, and determine whether any reductions to the annual $150 million revenue requirement need to be made. A reduction will only take place if:

1. The FERC or NRC have established a subsidy payment to continue the nuclear generating unit's commercial operation;
2. The nuclear generating unit is no longer considered a qualifying unit;
3. The unit's owner or operator applies for the decommissioning of the resource before May 1, 2027; or
4. The funding for nuclear resource credits remains reasonable (i.e., the market price index exceeds the strike price on June 1 of the report year).[652]

In the case of the item (4) above, OAQDA will adjust the credit price for the 12-month period ended May 31 that immediately succeeds the report year. Each quarter, qualifying units must report on their previous quarter's production, which will be subject to approval by OAQDA. The units will then receive credit payments based upon the reported production from April 1, 2021 to January 21, 2028. Any amount remaining in the Nuclear Generation Fund as of December 31, 2018, minus the remittance due to resources through January 21, 2019, shall be refunded to the customers in a manner determined by the PUCO.

7.3.4. State-Required Solicitations of Power from Clean Energy Resources

Some states have directed utilities to issue power solicitations intended for certain resources such as renewable energy technologies. The winning bidder(s) receives a long-term PPA.[653] Connecticut recently became the first state to implement a solicitation mechanism that

[651] An operational risk is defined as the risk that operating costs will be higher than anticipated because of a lower-than-expected capacity factor. A market risk is defined as the risk of a forced outage and the associated costs arising from contractual obligations, and the risk that output from the resource may not be able to be sold at projected levels.

[652] The strike price is $46/MWh. The market price index is the sum of: (1) the projected energy prices, using the PJM AEP-Dayton Hub futures contract; and (2) the projected capacity prices, using the PJM market clearing price for the "rest-of-RTO"; for the 12-month period ended May 31 of the report year.

[653] Jesse Heibel and Jocelyn Durkay, "State Policies for Power Purchase Agreements," National Conference of State Legislatures, 2015, ncsl.org/research/energy/state-policies-for-purchase-agreements.aspx.

allows for existing nuclear energy to bid for state contracts alongside other clean energy resources.

Connecticut

In October 2017, Connecticut enacted SB 1505, "An Act Concerning Zero Carbon Solicitation and Procurement" (Act).[654] The Act allows Connecticut's Public Utilities Regulatory Authority (PURA) and Department of Energy & Environmental Protection (DEEP) to establish a competitive solicitation process for zero-emission resources, including nuclear power plants, that are found to be in the best interest of ratepayers. In effect, the Act allowed for Connecticut's lone nuclear generating station, Dominion's 2,088-MW Millstone Power Station (Millstone), to bid against other zero-emission resources for PPAs as well as sell a portion of its capacity to EDCs at a contracted price.[655]

As with the ZEC legislation in New York, Illinois, and New Jersey, SB 1501 was initiated by the owner of a financially challenged nuclear power plant. Dominion asserted that the two units of Millstone could not be financially maintained and operated in the face of low energy prices on the wholesale market. In response, the Connecticut General Assembly's Energy and Technology Committee held an informational forum in March 2017 regarding the economic viability of the Millstone plant.[656] The forum explored possible changes to Connecticut law and actions the ISO-NE could take to facilitate the continued operation of Millstone. Dominion argued that if Millstone were to continue operations, the existing renewable energy solicitation process would need to be expanded to include nuclear power. Through an "Act Concerning Connecticut's Clean Energy Goals" created in 2013, the Connecticut General Assembly empowered DEEP to solicit proposals for renewable energy sources, select winners of the solicitation, and direct Connecticut's EDCs to enter into PPAs with the chosen winners.[657]

The forum inspired SB 344, the first piece of legislation in Connecticut aimed at including nuclear in long-term PPAs held by the state's two EDCs—Eversource Energy (Eversource) and United Illuminating Co. (United). It also inspired SB 106 and SB 778.[658,659,660] These bills proposed several long-term contract solicitation process variants that included nuclear among other zero-carbon resources. Ultimately, however, none passed.[661] SB 1501 was introduced in the June 2017 Connecticut General Assembly Special Session, but was passed by the Senate and transmitted to the House only after the Connecticut governor signed EO

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[654] Connecticut General Assembly, SB 1505, "An Act Concerning Zero Carbon Solicitation and Procurement," cga.ct.gov/2017/act/pa/pdf/2017PA-00003-R00SB-01501SS1-PA.pdf.

[655] The Act includes also includes hydro, Class I renewable energy sources, and energy storage systems in the solicitation process.

[656] Katie Dykes, "Informational Forum on the Adequacy of Energy Supplies Including Nuclear Power in the State," Connecticut Department of Energy and Environmental Protection, 2016, mediad.publicbroadcasting.net/p/wnpr/files/201603/katie_dykes_presentation.pdf.

[657] Connecticut General Assembly, SB 1138, "An Act Concerning Connecticut's Clean Energy Goals," 2013, cga.ct.gov/2013/FC/pdf/2013SB-01138-R000879-FC.pdf.

[658] Connecticut General Assembly, SB 344, "An Act Requiring A Study of the Adequacy of Energy Supplies in the State," 2016, cga.ct.gov/2016/amd/S/2016SB-00344-R00SA-AMD.htm.

[659] Connecticut General Assembly, SB 106, "An Act Concerning the Diversity of Baseload Energy Supplies in the State and Achieving Connecticut's Greenhouse Gas Emissions Mandated Levels," 2017, cga.ct.gov/2017/TOB/s/2017SB-00106-R01-SB.htm.

[660] Connecticut General Assembly, SB 778, "An Act Concerning Expenses for Consultants Borne by Telecommunications Providers," cga.ct.gov/2017/amd/S/2017SB-00778-R00SA-AMD.htm.

[661] SB 106 included a provision that expanded the RPS, and SB 778 had a duel-option approach where nuclear facilities would either enter into a competitive solicitation or sell energy directly to EDCs.

59 in July 2017.[662] The EO directed PURA and DEEP to conduct a resource assessment to evaluate the current and projected economic viability for the continued operation of Millstone. At the end of July 2017, DEEP and PURA filed a joint proceeding.[663]

SB 1501 required DEEP and PURA to conduct an appraisal of nuclear power generating facilities within the control area of ISO-NE that are licensed to operate through January 1, 2030 or later.[664] The appraisal is intended to determine the current and projected economic conditions of nuclear facilities as well as the impact of their retirement on the electric grid, GHG emissions, and the state, regional, and local economy. In February 2018, DEEP and PURA released the *Final Resource Assessment, Appraisal, and Determination of Millstone* report.[665,666] Dominion failed to provide documentation necessary for DEEP and PURA to complete the analysis. Nevertheless, the assessment still found that the zero-emission solicitation under SB 1501 would be necessary.

While the report concluded that the Millstone units would be profitable through 2035, it found that Connecticut and ISO-NE would continue to need Millstone for its critical contributions to fuel security and GHG reduction goals.[667] The report also recommended an additional step in the power procurement process that would allow eligible, existing zero-carbon resources to demonstrate that they are at risk of retirement if they wish to be evaluated on attributes other than price. At-risk resources are eligible for above-market rates (as determined by PURA) just like new resources, whereas existing resources are only able to bid into the solicitation at PURA's projected wholesale power prices. This recommended step would ensure that the state's ratepayers would be protected from paying above-market costs for resources that are not verified to be at risk of retirement. In May 2018, Dominion filed a petition seeking a determination that the Millstone plant is a confirmed at-risk existing resource. Dominion was the only generator to request at-risk status. In July 2018, DEEP issued an RFP to secure zero-carbon resources. DEEP was required to evaluate each proposal to determine whether the resulting contract would be in the best interest of the ratepayer (i.e., the benefit of the contract outweighs the cost to electric ratepayers).[668] The RFP solicited 105 bids from zero-emission resources, including 24 bids from Millstone.

In November 2018, PURA released an interim decision regarding Dominion's at-risk petition, and determined that Millstone was in fact an existing resource at risk of retirement. DEEP

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[662] State of Connecticut Governor Dannel P. Malloy, Executive Order No. 59, 2017, portal.ct.gov/-/media/32CB330A0E0B415284EB60E71C54C1A6.pdf.

[663] Connecticut Department of Energy and Environmental Protection and Connecticut Public Utilities Regulatory Authority, Docket No. 17-07-32, "DEEP and PURA Joint Proceeding to Implement the Governor's Executive Order Number 59," 2017, ct.gov/deep/lib/deep/energy/eo59/2017Aug02__Notice_of_Joint_Proceeding_EO59.pdf.

[664] Millstone was the only nuclear generating plant considered in the appraisal, as Entergy's Pilgrim Nuclear Power Station in Massachusetts closed in May 2019 and NextEra Energy's Seabrook Station in New Hampshire is awaiting relicensing.

[665] Connecticut Department of Energy and Environmental Protection and Connecticut Public Utilities Regulatory Authority, *Resource Assessment of Millstone Pursuant to Executive Order No. 59 and Public Act 17-3; Determination Pursuant to Public Act 17-3*, February 2018, dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/a2d566dfd5533fed8525822700725e33/$FILE/DEEP-PURA%20FINAL%20Report%20and%20Determination%202-1-18.pdf.

[666] This assessment effectively closed Docket No. 17-07-32.

[667] In 2017, 48% of Connecticut's net electricity generation came from Millstone plant.

[668] This cost-benefit analysis is based on whether the delivered prices of sources included in such contract or proposal are less than the forecasted price of energy and capacity. DEEP examines the potential benefits of the solicitation process to grid operations and reliability, GHG reductions and improved air quality, fuel diversity, and meeting the policy goals outlined in the Connecticut IRP.

announced the selection of winning bids in December 2018.[669] Among its selections was a 10-year bid for approximately 50% of Millstone's annual output, or approximately 9 million MWh. DEEP approved Millstone's at-risk status for the first three years of the PPA, during which time the selected price would reflect the energy-only bid price that Dominion submitted during the solicitation.[670] For the remaining years of the PPA, DEEP concluded that the bid price was not in the best interest of ratepayers and directed Eversource and United (the EDCs) to enter into contract negotiations with Dominion. Negotiations were concluded in March 2019.[671,672] The remaining output that is not sold through the solicitation process will be sold on the wholesale electricity market at market price, or through other bilateral contracts not facilitated by the state. Also in March 2019, the EDCs filed an application with PURA for the review and approval of the contracts with Dominion. PURA has not yet reached a decision on the contracts. SB 1501 allows the net cost of the PPA to be recovered entirely through a non-bypassable electric charge to all customers. Once the contract is approved by PURA, the customer charges will be set.

7.3.5. State Energy Portfolio Standards

As noted earlier, existing nuclear power plants have historically been excluded from state RPS policies out of concern that generation from nuclear power will swamp the RPS requirement, driving down REC prices and making it difficult, if not impossible, for new renewable energy capacity to be developed. As noted earlier in the final report, there are currently 29 states (and the District of Columbia) that have either an RPS or CES.[673] To date, three states have incorporated nuclear generation into their RPS/CES.[674]

In August 2017, Massachusetts created a CES that set a requirement for LSEs to procure a minimum percentage of electricity sales from clean energy sources, beginning with 16% in 2018 and increasing 2% annually until 80% in 2050.[675] The CES, which complements the state's existing RPS, allows nuclear generation to participate in supplying clean energy. However, Massachusetts' CES only allows nuclear generation from plants that commence commercial operations after December 31, 2020, effectively barring Massachusetts' only nuclear reactor, Pilgrim Nuclear Power Station (Pilgrim), from participating. The Pilgrim plant was retired in May 2019.[676]

[669] Connecticut Department of Energy and Environmental Protection, "Gov. Malloy Announces Zero-Carbon Resource Selections," December 2018, ct.gov/deep/cwp/view.asp?Q=607002&A=4965.

[670] This price was not disclosed.

[671] Ibid.

[672] Dominion Energy, "Signed Agreement Ensures Millstone Power Station will Continue to Provide More than 90% of Connecticut's Carbon-free Electricity for Next 10 Years," March 2019, news.dominionenergy.com/2019-03-15-Dominion-Energy-Millstone-Nuclear-Statement.

[673] Not included in this count are Virginia and Indiana, both of which qualify nuclear generation for their energy standards. The impact is negligible, though, because both states' RPS policies are voluntary and therefore provide minimal policy support.

[674] North Carolina Clean Energy Technology Center, DSIRE, "Programs," programs.dsireusa.org/system/program.

[675] Massachusetts Department of Environmental Protection and Massachusetts Executive Office of Energy & Environmental Affairs, "Fact Sheet: Electricity Sector Regulations," 2017, massdep.org/BAW/air/3dfs-electricity.pdf.

[676] Tomi Kilgore, "Entergy permanently shuts down Pilgrim nuclear plant as a result of a number of financial factors," *MarketWatch*, June 2019, marketwatch.com/story/entergy-permanently-shuts-down-pilgrim-nuclear-plant-as-a-result-of-a-number-of-financial-factors-2019-06-03.

Likewise, Ohio's AEPS only allows advanced nuclear energy reactors to participate, none of which are operational in Ohio.[677,678] In August 2016, New York established a CES, which replaced its previous RPS. The CES has a three-tier structure, with Tiers 1 and 2 constituting a renewable energy goal of 50% by 2030.[679] Tier 3, meanwhile, is dedicated entirely to nuclear generation.[680] New York's procurement of nuclear resources as part of the Tier 3 requirement is described further in the preceding subsection, "Zero-Emission Credits."

In other states, policymakers have unsuccessfully attempted to pass legislation that would integrate nuclear generation into their energy standards. In January 2018, the Arizona Corporation Commission (ACC) submitted a proposal to revise Arizona's Energy Standard by expanding the existing 15% by 2025 renewable energy requirement, which Arizona's IOUs had already met, to 80% by 2050, which could be met by a wider set of carbon-free resources, including nuclear generation.[681] The proposal was included on the Arizona ballot as a state constitutional amendment in the 2018 general election, but was defeated.[682] Similarly, in 2015, legislators in Illinois introduced a bill (HB 3293) to establish an LCPS that would include nuclear generation and replace the existing RPS. HB 3293 would have required utilities to purchase 70% of their power from low-carbon sources, including nuclear.[683] However, the bill did not pass, and Illinois ultimately turned to ZECs as its preferred method for subsidizing nuclear generation.

Another legislative approach to include nuclear in an RPS/CES is to change the definition of renewable energy.[684] In 2015, Arizona considered a bill (SB 1134) that would do just that; the bill proposed to change the definition of renewable energy to include "nuclear energy from sources that are fueled by uranium fuel rods that include 80% or more of recycled nuclear fuel and natural thorium reactor resources under development." The bill reached the Senate floor during the 2015 session, but ultimately died.[685]

An alternative legislative approach would be to create a multi-tiered CES/RPS that partially separates nuclear generation from some renewable generation resources. This approach would ensure that renewable energy resources continue to grow within a designated tier, but it would also provide some support to other resources such as nuclear power, and is equivalent to the multi-tiered RPS that Maryland has now. Sources in a lower tier, such as Tier 2, would receive support through a clean power requirement but be subject to competition from resources from other tiers. This approach is already favored by many

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[677] Ohio considers advanced nuclear energy technology to consist of Generation III technology, as defined by NRC, or other later technology.

[678] State of Ohio, Ohio Administrative Code, Ch. 4901:1-40 Alternative Energy Portfolio Standard, Definitions, codes.ohio.gov/oac/4901%3A1-40.

[679] The renewable energy component is comprised of: solar, wind, hydropower, biomass, fuel cells, biogas, and tidal energy.

[680] North Carolina Clean Energy Technology Center, DSIRE, "New York Clean Energy Standard," programs.dsireusa.org/system/program/detail/5883.

[681] Arizona Corporation Commission, *Arizona Energy Modernization Plan*, static.sustainability.asu.edu/giosMS-uploads/sites/22/2010/09/20122203/31518-Arizona-Energy-Modernization-by-Commissioner-Andy-Tobin.pdf.

[682] Arizona Secretary of State, Proposition 127, "Proposed Amendment to the Constitution by the Initiative Relating to Renewable Energy Production," azsos.gov/sites/default/files/Proposition_127_Final.pdf.

[683] Illinois General Assembly, HB 3293, Bill Status, ilga.gov/legislation/BillStatus.asp?DocNum=3293&GAID=13&DocTypeID=HB&SessionID=88&GA=99.

[684] Current RPS regulations in New Mexico and Missouri have explicitly named nuclear generation as a resource that cannot qualify as a renewable energy technology. Most other states, however, simply omit it from the list of eligible resources.

[685] LegiScan, Arizona SB 1134, 2015, legiscan.com/AZ/bill/SB1134/2015.

states to incorporate other existing resources, such as hydro. In its 2019 session, the Pennsylvania General Assembly considered two bills, HB 11 and SB 510, that would have added nuclear generation to the state's AEPS via a third tier. Both bills would have required that Pennsylvania's EDCs purchase 50% of the electricity they distribute from alternative energy sources included in Tier III. Tier III eligibility extends to other zero-emission alternative energy sources besides nuclear generation, such as solar, wind, hydro, and geothermal. However, nuclear generation is expected to dominate Tier III because it produces more energy per year, in-state, than any other eligible renewable energy source. Neither bill was enacted.

7.3.6. Challenges to State Nuclear Support Programs

The subject of state support for nuclear energy resources is controversial. Proponents believe that nuclear energy is crucial to maintaining progress in reducing carbon emissions and that subsidies would protect ratepayers from paying for new fossil plants such as natural gas to replace existing nuclear plants if they were to retire early. Opponents, on the other hand, have raised concerns about the negative impact on other resources, including renewables, and that the subsidies distort competitive power markets. Apart from the general disagreement surrounding state support for nuclear facilities, there are additional issues being raised in state circuit courts and regulatory proceedings. These are discussed below.

Circuit Court Lawsuits

Immediately following the adoption of the New York and Illinois ZEC initiatives, power producers and consumers filed several lawsuits challenging the legislation. Their concerns revolved around the impact of the subsidies on the wholesale market price of electricity, and were rooted in the U.S. Supreme Court 2016 ruling in the *Hughes v. Talen Energy Marketing* (*Hughes*) case. The *Hughes* case involved actions taken by the State of Maryland to contract for new generation capacity. The state was concerned about a possible shortfall in generating capacity and issued a solicitation for new generation capacity that resulted in a 20-year contract for CPV's 650-MW natural gas plant. Maryland directed CPV to bid into PJM's capacity auction at a price specified in a 20-year contract for differences. The plant would then sell its generation at the contract price rather than the clearing price for the PJM market. LSEs would then make up the difference if the contract price was greater than the clearing price in the PJM capacity auctions; hence, a "contract for differences." The Supreme Court determined that the Maryland contract for differences artificially suppressed electricity prices and infringed on FERC's exclusive authority to regulate interstate wholesale electricity rates.

The defining feature of the *Hughes* case was that Maryland's program was "tethered" to an interstate wholesale auction (i.e., receipt of subsidy was contingent on wholesale market participation). Plaintiffs in the ZEC lawsuits argued that this tether concept also applies to the ZEC programs. Additionally, the plaintiffs in each lawsuit also raised concerns that the programs violated the Dormant Commerce Clause by discriminating against out-of-state energy producers by allowing only New York and Illinois power plants to receive ZECs, and also by burdening interstate commerce through the distortion of market prices. The specifics of the Illinois and New York cases are further discussed below.

Illinois

In February 2017, a group of wholesale, non-nuclear generators and retail customers filed a lawsuit against the Illinois ZEC statute in the U.S. District Court for the Northern District of

Illinois, Eastern Division (Illinois District Court).[686] The plaintiffs argued that the Federal Power Act preempts the ZEC program and that it should be disallowed because it: (1) replaces wholesale prices and intrudes on FERC's exclusive jurisdiction over wholesale sales; and (2) conflicts with FERC's regulatory authority by distorting the outcomes in FERC-regulated markets. The plaintiffs also argued that Illinois violated the Dormant Commerce Clause and the equal protection clause by favoring in-state plants and imposing additional costs on Illinois consumers. In July 2017, the Illinois District Court rejected the plaintiff's argument and determined that ZECs were legally similar to other state incentives that support clean energy and have legal precedent. The Illinois District Court granted a motion by the defendants and Exelon to dismiss the case.[687] In August 2017, the case was appealed to the U.S. Court of Appeals for the Seventh Circuit (7th Cir.). In May 2018, the FERC and the U.S. Department of Justice (DOJ) filed a joint legal brief with the 7th Cir. in support of the Illinois ZEC program, which maintained that the Federal Power Act does not pre-empt the program to award ZECs because it does not require participation in FERC-jurisdictional markets and instead is focused on the ability of the plant to not emit CO_2, which does not interfere with FERC procedures.[688] In September 2018, the 7th Cir. concluded that the plaintiffs' claims were unfounded because they had failed to identify a "tether" under *Hughes* between the ZEC program and the wholesale market participation, and they could not identify any clear damage to FERC goals.[689]

New York

In October 2016, a coalition of non-nuclear generating companies filed a lawsuit in the U.S. District Court Southern District of New York (New York District Court) against New York's ZEC program with supporting briefs from anti-nuclear, environmental, and consumer advocate groups.[690] The plaintiffs complained that New York intruded on the exclusive authority of FERC over the sale of electric energy at wholesale in interstate commerce as defined in the Federal Power Act.[691] In July 2017, a New York District Court judge rejected the plaintiff's argument and determined that ZECs were legally similar to other state incentives that support clean energy and have legal precedent. The Court granted a motion filed by the defendants and Exelon to dismiss the case.[692] In August 2017, the case was appealed to the U.S. Court of Appeals for the Second Circuit (2d Cir.). In September 2018, the 2d Cir. affirmed the 7th Cir. decision in the Illinois case, as well as the FERC and DOJ

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686 The consolidated plaintiffs include: Multiple ComEd delivery service customers (Village of Old Mill Creek; Ferrite International Company; Got it Maid, Inc.; Nafisca Zotos; Robert Dillon; Richard Owens; and Robin Hawkins); Electric Power Supply Association; Calpine Corporation; Dynegy Inc.; Eastern Generation, LLC; and NRG Energy, Inc. The defendants were IPA and the ICC.

687 United States District Court for the Northern District of Illinois – Eastern Division, Case Nos. 17-CV-1163 and -1164, "Memorandum Opinion and Order," 2017, statepowerproject.files.wordpress.com/2017/02/il-zec-decision.pdf.

688 United States Court of Appeals for the Seventh Circuit, Case Nos. 17-2433 and -2445, "Brief for the United States and the Federal Energy Regulatory Commission as *Amici Curiae* in Support of Defendants – Respondents and Affirmance," May 2018, gallery.mailchimp.com/0554cc7ed0bda904329a48c93/files/de89e366-f825-4579-9cae-a04d764e58bb/2018_05_29_FERC_ZEC_Brief.pdf.

689 United States Court of Appeals for the Second Circuit, Case No. 17-CV-2654, 2017, blogs.edf.org/climate411/files/2018/09/NY-ZEC-2nd-Circuit-Opinion.pdf.

690 The plaintiffs included: Coalition for Competitive Electricity; Dynegy Inc.; Eastern Generation, LLC.; Electric Supply Associates; NRG Energy, Inc.; Roseton Generating LLC; and Selkirk Cogen Partners, L.P. The defendant was the New York PSC.

691 United States District Court for the Southern District of New York, Case No. 16-CV-8164, Document 1, Complaint, 2016.

692 United States District Court for the Southern District of New York, Case No. 16-CV-8164, "Memorandum Opinion & Order," Document 159, 2017, statepowerproject.files.wordpress.com/2014/03/ny-ces-opinion.pdf.

joint legal brief, and concluded that the plaintiffs' claims were unfounded for similar reasons as in the 7th Cir. decision.

Following the September 2018 decisions in the 2d Cir. and 7th Cir., plaintiffs for both cases filed a *certiorari* with the Supreme Court petitioning for the review of the appellate court rulings in New York and Illinois.[693,694] On April 15, 2019, the Supreme Court denied the *certiorari* for both states, effectively agreeing with the circuit court rulings and rejecting any future challenges to the ZEC programs in New York and Illinois.[695] This ruling will set a precedent for other states to implement similarly designed programs in the future.

FERC and Regional Markets

To address concerns about resources receiving subsidies from initiatives such as ZECs, both ISO-NE and PJM proposed making changes to their respective capacity auctions to essentially separate subsidized and unsubsidized resources. In March 2018, FERC approved ISO-NE's plan to split its capacity market auctions into two parts.[696] The proposal, Competitive Auctions with Sponsored Policy Resources (CASPR), suggested retaining a market for unsubsidized resources, then creating a substitution market for subsidized new capacity. ISO-NE would then hold substitution auctions, whereby subsidized resources can obtain capacity obligations from unsubsidized resources. This market structure would provide a payment to resources that voluntarily retire, while also preserving a competitive basis for capacity prices. For instance, the first capacity auction would operate as normal, but the second auction would transfer capacity obligations from resources that can no longer operate at the lower market price to the new, subsidized resources. Once the unsubsidized plant retires, it shifts its capacity obligation to the subsidized resource with no current obligation and pays the subsidized resource for meeting the obligation.

In April 2018, PJM also filed a request with FERC to make changes to the BRA, specifically citing the effects on capacity market prices from state ZEC and RPS policies. Specifically, PJM filed two proposals that would address state subsidies.[697,698] Its first proposal, the Capacity Repricing Proposal, proposed a two-stage capacity auction that would allow generators receiving subsidies to enter into a preliminary market where PJM would determine which resources would receive a capacity commitment based upon a clearing price.[699] The second stage would then reprice subsidized resources that had cleared the first stage to eliminate the effect of the subsidy before it could compete with unsubsidized resources.

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[693] Supreme Court of the United States, Docket No. 18-868, *Electric Power Supply Association, et al. v. Anthony M. Star, et al.*, January 2019, supremecourt.gov/docket/docketfiles/html/public/18-868.html.

[694] Ibid.

[695] Supreme Court of the United States, "Certiorari – Summary Dispositions," April 2019, supremecourt.gov/orders/courtorders/041519zor_h3dj.pdf.

[696] Federal Energy Regulatory Commission, Docket No. ER18-619-000, "Order on Tariff Filing," 162 FERC § 61,205, March 2018, iso-ne.com/static-assets/documents/2018/03/er18-619-000_3-9-18_order_accept_caspr.pdf.

[697] Federal Energy Regulatory Commission, Docket No. ER18-___-000, "Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market," April 2018, pjm.com/directory/etariff/FercDockets/3576/20180409-er18-1314-000.pdf.

[698] PJM's second proposal, the Minimum Offer Price Rule Ex (MOPR-Ex), aimed to mitigate offer prices for subsidized resources by screening subsidized resource offers and requiring these offers to adhere to a minimum price that reflects the cost of that resource without a subsidy.

[699] The PJM BRA construct is based on auctions for procurement of capacity three years in advance.

In June 2018, FERC rejected both of PJM's proposals.[700] In making its decision, FERC noted that the PJM proposals, unlike the ISO-NE capacity market reform which sought to compensate for market impacts of new subsidized resources (i.e., offshore wind and imported hydro), focused on existing resources, particularly the ZEC programs in Illinois and New Jersey and solar and wind projects backed by a state RPS. In addition, FERC found the current tariff that governs the PJM BRA to be "unjust and unreasonable" because it failed to mitigate the price-suppressive impacts of out-of-market payments to generators. FERC initiated a proceeding for PJM to design new rules and suggested an alternative to the rejected proposals in which changes are made to the FRR rule within the PJM tariff that allows utilities to opt out of the capacity market if they can serve demand with their own resources.

In October 2018, PJM filed another two market reform proposals that would remove subsidized resources from the capacity market and institute a strict price floor for unsubsidized resources.[701] The alternative proposals would increase capacity prices for unsubsidized resources in order to combat any price-suppressive effects resulting from the removal of subsidized resources. Both proposals garnered significant opposition that mirrored the same issues that many market participants identified with nuclear subsidies initially. Some generators believed that removing unsubsidized resources from the capacity market would endanger competitive pricing in the remaining market, while consumer advocates felt that boosting prices for unsubsidized resources would burden consumers with unnecessary costs. The proposals are still undergoing FERC and stakeholder review. In March 2019, PJM submitted an informational filing urging FERC to rule on the capacity market reforms PJM filed in October 2018 so that the rules could be in place before PJM's 2019 BRA.[702,703] To date, FERC has not taken action. PJM petitioned FERC to run a capacity market auction in 2019 under current rules, but FERC rejected PJM's request.[704]

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[700] Federal Energy Regulatory Commission, Docket No. EL16-49-000, *Order Rejecting Proposed Tariff Revisions, Granting in Part and Denying in Part Complaint, and Instituting Proceeding Under Section 206 of the Federal Power Act*, 162 FERC § 61,236, June 2018, ferc.gov/CalendarFiles/20180629212349-EL16-49-000.pdf.

[701] Federal Energy Regulatory Commission, Docket Nos. EL16-49-000, ER18-1314-000 and -001, and EL18-178-000, *Initial Submission of PJM Interconnection L.L.C.*, October 2018, pjm.com/-/media/documents/ferc/filings/2018/20181002-capacity-reform-filing-w0172181x8DF47.ashx.

[702] In August 2018, the PJM 2019 BRA was delayed from May to August 2019.

[703] PJM Interconnection, L.L.C., Letter to the Federal Energy Regulatory Commission, "Re: PJM Interconnection, L.L.C., Docket Nos. EL16-49-000, ER18-1314-001, EL18-178-000 Informational Filing on PJM's Plan in Preparation for the 2022/2023 Base Residual Auction," March 2019, pjm.com/-/media/documents/ferc/filings/2019/20190311-el16-49-000-et-al.ashx.

[704] Federal Energy Regulatory Commission, Docket Nos. EL16-49-000 and EL18-178-000, *Order on Motion for Supplemental Clarification*, 168 FERC § 61,051, July 2019, ferc.gov/CalendarFiles/20190725135527-EL16-49-000.pdf.

APPENDIX A. MARYLAND RPS ASSESSMENT – FINAL REPORT ANALYSIS TOPICS

The final report is statutorily required by the Maryland General Assembly's enactment of HB 1414 (Ch. 393) in 2017, as amended by SB 516 (Ch. 757) in 2019, that directs the DNR's PPRP to conduct a study of the Maryland RPS. Specifically, Ch. 393 and Ch. 757 call for the following:

(a) The Power Plant Research Program shall conduct a study of the renewable energy portfolio standard and related matters in accordance with this section.

(b) The study shall be a comprehensive review of the history, implementation, overall costs and benefits, and effectiveness of the renewable energy portfolio standard in relation to the energy policies of the State, including:

(1) the availability of all clean energy sources at reasonable and affordable rates, including in–State and out–of–state renewable energy options;

(2) the economic and environmental impacts of the deployment of renewable energy sources in the State and in surrounding areas of the PJM region;

(3) the effectiveness of the standard in encouraging development and deployment of renewable energy sources;

(4) the impact of alterations that have been made in the components of each tier of the standard, the implementation of different specific goals for particular sources, and the effect of different percentages and alternative compliance payment scales for energy in the tiers;

(5) an assessment of alternative models of regulation and market–based tools that may be available or advisable to promote the goals of the standard and the energy policies of the State; and

(6) the potential to alter or otherwise evolve the standard in order to increase and maintain its effectiveness in promoting the State's energy policies.

(c) Particular subjects to be addressed in the study include:

(1) the role and effectiveness that the standard may have in reducing the carbon content of imported electricity and whether existing or new additional complementary policies or programs could help address the carbon emissions associated with electricity imported into the State;

(2) the net environmental and fiscal impacts that may be associated with long–term contracts tied to clean energy projects, including:

(i) ratepayer impacts that resulted in other states from the use of long–term contracts for the procurement of renewable energy for the other states' standard offer service and whether the use of long–term contracts incentivized new renewable energy generation development; and

(ii) ratepayer impacts that may result in the State from the use of long–term contracts for each energy source in the State's Tier 1 and whether, for each of the sources, the use of long–term contracts would incentivize new renewable energy generation development in that source;

(3) whether the standard is able to meet current and potential future targets without the inclusion of certain technologies;

(4) what industries are projected to grow, and to what extent, as a result of incentives associated with the standard;

(5) whether the public health and environmental benefits of the growing clean energy industries supported by the standard are being equitably distributed across overburdened and underserved environmental justice communities;

(6) whether the State is likely to meet its existing goals under the standard and, if the State were to increase those goals, whether electricity suppliers should expect to find an adequate supply to meet the additional demand for credits;

(7) additional opportunities that may be available to promote local job creation within the industries that are projected to grow as a result of the standard;

(8) system flexibility that the State would need under future goals under the standard, including the quantities of system peaking and ramping that may be required;

(9) how energy storage technology and other flexibility resources should continue to be addressed in support of renewable energy and State energy policy, including:

(i) whether the resources should be encouraged through a procurement, a production, or an installation incentive;

(ii) the advisability of providing incentives for energy storage devices to increase hosting capacity of increased renewable on–site generation on the distribution system; and

(iii) discussion of the costs and benefits of energy storage deployment in the State under future goals scenarios for renewable generation;

(10) (i) the role of in–State clean energy in achieving greenhouse gas emission reductions and promoting local jobs and economic activity in the State;

(ii) the impact of item (i) of this item on ratepayers with respect to the requirement of in–state clean energy generation as an increasing percentage of the standard; and

(iii) the impact of all energy sources that qualify under the standard with respect to the requirement of in–state clean energy generation as an increasing percentage of the standard;

(11) an assessment of any change in solar renewable energy credit prices over the immediate 24 months preceding the submission of the interim report required under subsection (e) of this section;

(12) an assessment of the costs, benefits, and any legal or other implications of allowing the location anywhere in or off the coast of the contiguous united states of Tier 1 renewable sources that are currently required to be located in the PJM region or in a control area that is adjacent to the PJM region, if the electricity is delivered into the PJM region; and

(13) any other matters the Program considers relevant to the analysis of the issues outlined in this section.

Appendix B. Maryland RPS Work Group Members

Last updated: January 7, 2018

Name	**Organization**
Ken Capps – Work Group Chairman	Southern Maryland Electric Cooperative
Michael Aimone	The Roosevelt Group
Misty Allen	Baltimore Gas and Electric Company
Bruce Burcat	mid-Atlantic Wind Partnership
Janet Christensen-Lewis	Kent Conservation and Preservation Alliance
Gia Clark	OneEnergy Renewables
Stuart Clark	Town Creek Foundation
Josh Cohen	Business Network for Offshore Wind
Chris Ercoli	Brookfield Renewable Partners
Colby Ferguson	Maryland Farm Bureau
Bill Fields	Maryland Office of People's Counsel
John Finnerty	Standard Solar, LLC
Andrew Gohn	American Wind Energy Association
Susan Gray	Retired, Maryland Power Plant Research Program
Anne Grealy	FirstEnergy
Chris Hoagland	Maryland Department of the Environment
Brian Hug	Maryland Department of the Environment
Sally Jameson	Delegate, Retired, Maryland General Assembly
Andrew Johnston	Maryland Public Service Commission*
Andrew Kays	Northeast Maryland Waste Disposal Authority
Les Knapp	Maryland Association of Counties
Ivan Lanier	Potomac Electric Power Company
Matthew LaRocque	PJM Interconnection, LLC
Audrey Lyke	Exelon
Kathy Magruder	Maryland Clean Energy Center
David Murray	MDV-SEIA
Alex Pavlak	Future of Energy Initiative
John Quinn	Baltimore Gas and Electric Company
Lindsey Robinett Shaw	Montgomery County Dept. of Environmental Protection
John Sherwell	Retired, Maryland Power Plant Research Program
Cassie Shirk	Maryland Department of Agriculture
Julian Silk	Columbia University
Nicole Sitaraman	Sunrun, Inc.
Abigail Sztein	American Forest and Paper Association
Cyrus Tashakkori	Utility Scale Solar Energy Coalition of Maryland
Stephanie Tsao	S&P Global
Emily Trawick	Sage Energy, Inc.
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Maryland DNR PPRP Staff

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Appendix C. Academic Research on the Impacts of State RPS Policies on Economic Development

Employment and business impacts are among the most studied aspects of RPS policies. Much of the existing literature, however, is of limited relevance and use to formal evaluations of existing RPS policies. This is for a handful of reasons.[705] First, the predominant focus of the RPS literature to date has been on estimating job and business impacts prior to RPS implementation (i.e., *ex ante* evaluation); fewer sources assess the actual effect of an RPS (i.e., *ex post* evaluation).[706] Additionally, many green job estimates do not take the extra step to statistically assess the factors affecting green job growth, making it unclear what role, if any, the RPS played.

Second, comparing across studies is difficult due to variation in the technologies, regions, measurements, and employment effects utilized.[707] Among the considerations when evaluating employment impacts of an RPS are how to account for things like labor intensity, job losses, job quality, job skills, and cost increases as a result of added renewable energy sources.[708] Researchers can measure employment in several distinct ways, including snapshot totals of employment at one point in time, average employment over plant lifetime, and employment per unit of production, among other measures.[709] Since job gains as a result of an RPS are concentrated in construction, fabrication, and installation, estimates of the employment impacts of an RPS may vary a great deal depending on whether short-term jobs are adjusted to account for their duration.

Third, studies evaluating the job impact of an RPS are usually static and rarely account for time variation in market conditions. This results in a failure to account for factors such as efficiencies or input costs that can alter employment effects over time.[710] Fourth, very little literature examines the potential negative effects of green energy policies. Arguments made in the literature that do exist include:[711]

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[705] Note that the following challenges facing RPS studies also affect the literature looking at the regional economic impacts of renewable energy sources in general. A recent comprehensive literature review identifies almost all of the same concerns: Simon Jenniches, "Assessing the Regional Economic Impacts of Renewable Energy Sources—A Literature Review," *Renewable and Sustainable Energy Reviews*, 93C, 2018.

[706] Sanya Carley, Sara Lawrence and Adrienne Brown, *et al.*, "Energy-Based Economic Development," *Renewable and Sustainable Energy Reviews*, 15(1), 2011; Hongtao Yi, "Clean Energy Policies And Green Jobs: An Evaluation of Green Jobs in US Metropolitan Areas," *Energy Policy*, Vol. 56; Haitao Yin and Nicholas Powers, "Do State Renewable Portfolio Standards Promote In-State Renewable Generation?," *Energy Policy*, 38(2), 2010.

[707] Sanya Carley, Sara Lawrence and Adrienne Brown, *et al.*, "Energy-Based Economic Development," *Renewable and Sustainable Energy Reviews*, 15(1), 2011; Max Wei, Shana Patadia and Daniel Kammen, "Putting Renewables and Energy Efficiency to Work: How Many Jobs Can the Clean Energy Industry Generate in the US?," *Energy Policy*, 38(2), 2010; Rosebud Lambert and Patricia Silva, "The Challenges of Determining the Employment Effects of Renewable Energy," *Renewable and Sustainable Energy Reviews*, 16(7), 2012; William Bowen, Sunjoo Park and Joel Elvery, "Empirical Estimates of the Influence of Renewable Energy Portfolio Standards on the Green Economies of States," *Economic Development Quarterly*, 27(4), 2013.

[708] Rosebud Lambert and Patricia Silva, "The Challenges of Determining the Employment Effects of Renewable Energy," *Renewable and Sustainable Energy Reviews*, 16(7), 2012.

[709] Max Wei, Shana Patadia and Daniel Kammen, "Putting Renewables and Energy Efficiency to Work: How Many Jobs Can the Clean Energy Industry Generate in the US?," *Energy Policy*, 38(2), 2010, rael.berkeley.edu/old_drupal/sites/default/files/WeiPatadiaKammen_CleanEnergyJobs_EPolicy2010.pdf.

[710] Rosebud Lambert and Patricia Silva, "The Challenges of Determining the Employment Effects of Renewable Energy," *Renewable and Sustainable Energy Reviews*, 16(7), 2012.

[711] Andrew Morris, William Bogart, Andrew Dorchak and Roger Meiners, "Green Jobs Myths," *Missouri Environmental Law & Policy Review*, Vol. 16, 2009; Raquel Jara, Juan Ramon Julián and Jose Bielsa, "Study of the Effects on Employment of Public Aid to Renewable Energy Sources," 2009; Jonathan Lesser, "Renewable Energy

- Higher power prices that can result from an RPS can adversely affect consumers, even while also stimulating green employment;
- RPS policies can also cause job losses or job shifts (i.e., move jobs toward favored industries and away from disfavored industries) that are not captured when measuring gross job changes rather than net;
- Additional jobs are not necessarily a good thing if the new occupation is an inefficient use of labor, especially if low labor productivity precludes more productive uses of capital;
- Policies that promote more expensive renewable energy sources via set-asides or carve-outs neglect comparative advantage (i.e., the ability of a state to acquire renewable energy at lower costs from elsewhere, or to generate power in-state at less cost using alternative renewable energy resources) and, as a result, are inefficient; and
- Public sector investment can have a crowding-out effect that reduces private sector investment.

Despite the above challenges, the literature provides some insight into the nature and magnitude of economic benefits spurred by RPS policies. Among the first comprehensive evaluations of the impact of RPS policies on employment is a study by Wei, *et al.* that developed a job creation model for the power sector from 2009-2030.[712] As part of this effort, the authors used data from 15 earlier studies to estimate the job impacts of renewable energy generation added as a result of an RPS. The authors ultimately found that: (1) renewable energy creates more new jobs per MW than are lost from displaced fossil fuel alternatives (e.g., natural gas and coal generation); and (2) solar PV creates more jobs per unit of output than other renewable energy sources. The estimated impacts of renewable energy generation across multiple technologies are summarized in Table C-1.

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and the Fallacy of 'Green' Jobs," *The Electricity Journal*, 23(7), 2010; Rosebud Lambert and Patricia Silva, "The Challenges of Determining the Employment Effects of Renewable Energy," *Renewable and Sustainable Energy Reviews*, 16(7), 2012.

[712] Max Wei, Shana Patadia and Daniel Kammen, "Putting Renewables and Energy Efficiency to Work: How Many Jobs Can the Clean Energy Industry Generate in the US?," *Energy Policy*, 38(2), 2010, rael.berkeley.edu/old_drupal/sites/default/files/WeiPatadiaKammen_CleanEnergyJobs_EPolicy2010.pdf.

Table C-1. Impact in Total Job-Years of Renewable Energy Generation (Direct Employment Multipliers)

Technology	Number of Studies Assessed	AVERAGE EMPLOYMENT OVER LIFE OF FACILITY (total job-years/GWh) Construction Installation Manufacturing Low	Construction Installation Manufacturing High	O&M and Fuel Processing Low	O&M and Fuel Processing High	TOTAL (average)
Biomass	2	0.01	0.03	0.16	0.21	**0.21**
Geothermal	3	0.01	0.06	0.21	0.23	**0.25**
LFG	2	0.01	0.07	0.31	1.05	**0.72**
Small Hydro	1	0.03		0.24		**0.27**
Solar PV	3	0.16	0.84	0.07	0.57	**0.87**
Solar Thermal	3	0.05	0.12	0.06	0.29	**0.23**
Wind	5	0.03	0.14	0.05	0.13	**0.17**

Source: Max Wei, Shana Patadia and Daniel Kammen, "Putting Renewables and Energy Efficiency to Work: How Many Jobs Can the Clean Energy Industry Generate in the US?," *Energy Policy*, 38(2), 2010, rael.berkeley.edu/old_drupal/sites/default/files/WeiPatadiaKammen_CleanEnergyJobs_EPolicy2010.pdf, Table 2.

Note that Table C-1 uses average jobs over the lifetime of a facility as a measure of employment impacts. Wei, *et al.* argues that this approach can help account for differences in employment over time while also averaging across different types of employment, including construction, installation, and manufacturing jobs versus operations, maintenance, and processing jobs.[713] The numbers in Table C-1 can be multiplied by annual output to get an estimate for lifetime employment outcomes. For example, a 10-MW solar PV installation with a capacity factor of 20% would generate approximately 17,520 MWh per year and create 15.45 FTE jobs per year, on average, over the life of the project. Although these estimates are useful, they are likely to have changed in the decade since this study. The authors also acknowledge that the multipliers may over- or underestimate employment for a technology that is increasing or reducing market share rapidly, such as solar.

The small impacts identified by Wei, *et al.* for most technologies are consistent with other findings in recent literature. Yi (2013) found that each additional clean energy policy in a metropolitan area increases "green" jobs by as much as 1%.[714] The study, however, does not distinguish the duration and type of employment, and does not identify RPS policies as being a major driver. Bowen, Park, and Elvery estimated the marginal contribution of RPS policies to "green" businesses and jobs after controlling for economic development, public finance, knowledge stock (i.e., educational attainment), and other policies.[715] The authors, after accounting for RPS duration and stringency, did not find a discernible impact of the presence or absence of an RPS on green job growth. They did find, however, that the persistence of an RPS over time increases the number of green businesses. Bowen, Park, and Elvery estimate that, in a state with "…the average RPS percent and increment, each

[713] Ibid.

[714] Hongtao Yi, "Clean Energy Policies And Green Jobs: An Evaluation of Green Jobs in US Metropolitan Areas," *Energy Policy*, Vol. 56.

[715] William Bowen, Sunjoo Park and Joel Elvery, "Empirical Estimates of the Influence of Renewable Energy Portfolio Standards on the Green Economies of States," *Economic Development Quarterly*, 27(4), 2013.

additional year that an RPS policy has been in place is associated with a 0.2 increase in the number of green businesses per 1,000 businesses."[716] This finding suggests that, although the RPS does not cause green business growth, it may help sustain and grow the number of green businesses in a state.

Another study of the impact of RPS policies on green businesses found more favorable results. Yi (2014), using a longitudinal dataset, found that the "number of green businesses in a given state increased by 2% on average with the adoption of [an] RPS over time."[717] However, this finding decreased to 0.3% in states that allow RECs from other states, indicating spill-over effects of RPS policies. Like Bowen, Park, and Elvery, Yi (2014) also found that various labor market, economic, environmental, and political conditions were significant drivers of green business growth regardless of the presence of RPS policies.[718]

Besides direct estimates of the impact of RPS policies on employment or other economic outcomes, related literature has also emerged estimating the indirect impact of energy policies on employment as a result of increased electric rates. This impact is assessed through the estimated cross-price elasticity, meaning the measure of how the demand for one good (or service) changes in response to a change in the price of another good (or service), all else equal. Two studies offer Maryland-specific estimates.

Patrick, *et al.* used a Monte Carlo simulation approach to examine how a uniform increase in electricity prices would have a dissimilar impact on different industries across states, relative to existing electricity prices and accounting for allocation of the industries across states.[719] Their results indicated that policymakers should consider heterogeneous, state-level industry characteristics when calculating the potential cost of environmental regulations. Although not exclusively focused on Maryland, the study included state-specific results in its appendix. The study projected that, on average, a 10% increase in electricity prices in Maryland would result in a decrease of 18,277 FTE jobs in Maryland, other factors held constant. Given full-time employment in Maryland of approximately 2.65 million (in line with the Maryland Department of Labor, Licensing & Regulation's estimate), the cross-price elasticity estimated by Patrick, *et al.* is -0.067. That is, a 1% increase in electricity prices will result in a 0.067% decrease in Maryland employment, or approximately 1,760 jobs, relative to the baseline.

Beacon Hill Institute (BHI) similarly assessed the impact of increased electricity prices on employment, in this case looking at RPS-related price increases.[720] The cross-price elasticity estimated in the study is -0.022, which means that for a 1% increase in electricity prices, state employment would decrease by 0.022%, or about 580 less jobs, relative to the baseline. The composite, average result of the BHI and Patrick, *et al.* studies on electricity is an elasticity of -0.044, meaning that for a 1% increase in electricity prices, statewide employment would decrease by 0.044%, or approximately 1,170 jobs. Note that the direction of this impact is consistent with related studies. Recent academic research indicates a small complementarity (i.e., a negative elasticity) between electricity prices and employment, meaning an increase in the price of electricity leads to a decrease in the

[716] Ibid.

[717] Hongtao Yi, "Green Businesses in a Clean Energy Economy: Analyzing Drivers of Green Business Growth in U.S. States," *Energy*, Vol. 68, 2014.

[718] Ibid.

[719] Aron Patrick, Adam Blandford and Leonard Peters, "The Vulnerability of the United States Economy to Electricity Price Increases," 2015.

[720] The Beacon Hill Institute at Suffolk Hill University, *The Economic Impact of Maryland's Renewable Energy Standard*, 2014, beaconhill.org/BHIStudies/RPS/MD/MD-RPS-study-BHI-final.pdf.

demand for employment.[721] These studies also find, intuitively, that the negative relationship is greater (i.e., larger negative elasticity numbers) for energy-intense industries, such as material manufacturing, where electricity is a major component of production costs.

[721] For example, Henriksson, Soderholm, & Warell evaluated the impact of electricity costs on employment in the Swedish paper and pulp industry. Cox, Peichl, Pestel, & Siegloch did the same for German manufacturing. Using data from the United States, Deschenes evaluated cross-price elasticity in relation to U.S. climate policies, while Kahn & Mansur evaluated cross-price elasticities in the context of comparative advantage when siting manufacturing operations. *Sources:* Eva Henriksson, Patrik Soderholm and Linda Warell "Industrial Electricity Demand and Energy Efficiency Policy: The Role of Price Changes and Private R&D in the Swedish Pulp and Paper Industry," *Energy Policy*, Vol. 47, 2012; Michael Cox, Andreas Peichl, Nico Pestel and Sebastian Siegloch, "Labor Demand Effects of Rising Electricity Prices: Evidence for Germany, *Energy Policy*, 75(C), 2014; Oliver Deschenes "Climate Policy and Labor Markets," *The Design and Implementation of U.S. Climate Policy*, National Bureau of Economic Research, 2012; Matthew Kahn and Erin Mansur, "Do Local Energy Prices and Regulation Affect the Geographic Concentration of Employment? *Journal of Public Economics*, 101(C), 2013.

Appendix D. Recent History of REC and SREC Prices (Interim Report)

The subsequent information was compiled for the interim report in order to fulfill special requirement 11 of Ch. 393, which requested that Exeter present information about changes in SREC prices over the immediate 24 months preceding submission of the interim report (i.e., October 2016 – September 2018). In addition to SREC data, Exeter also collected recent Tier 1 non-carve-out and Tier 2 REC price data. The primary source of REC and SREC data was Marex Spectrometer, which summarizes spot market prices for REC and SREC trading, by state, on a monthly basis. Although spot market prices do not reflect all REC trades, many of which are long term or bundled into PPAs, the trends are generally indicative of changes in the market price for RECs and SRECs. The following text is an updated version of the original text from Exeter's interim report, as first submitted to PPRP in October 2018 and then submitted to the Maryland Legislature in February 2019.

Figure D-1 and Figure D-2 show changes in Tier 1 non-carve-out REC prices over the past three years for Maryland and select other states in PJM with an RPS.[722] Prices in Maryland, Pennsylvania, Delaware, and New Jersey have declined considerably over a two-year period beginning in late 2015. During this time, Tier 1 non-carve-out REC prices in Maryland fell from approximately $15.00/MWh to as low as $2.75/MWh. Prices have since increased, climbing to $7.75/MWh as recently as June 2018. Prices have remained flat from September 2018 – April 2019, ranging from $5.00-$6.13/MWh. The price trends in Maryland are consistent with other states in PJM that have similar resource eligibility requirements for their respective RPS policies.

Figure D-1. Tier 1 Non-Carve-out REC Prices in Maryland, Sep. 1, 2015 – Apr. 12, 2019

Source: Marex Spectrometer, Spectrometer U.S. Environmental.

[722] Note that Figure D-2 and subsequent graphs that include REC prices for other states in PJM make the following classifications: Tier 1 non-carve-out REC prices for Delaware only reflect RECs labeled as "New" in the Marex Spectrometer reporting, and Illinois REC prices are sourced from the Midwest Renewable Energy Tracking System (M-RETS), while all other reported state REC prices are sourced from PJM-GATS.

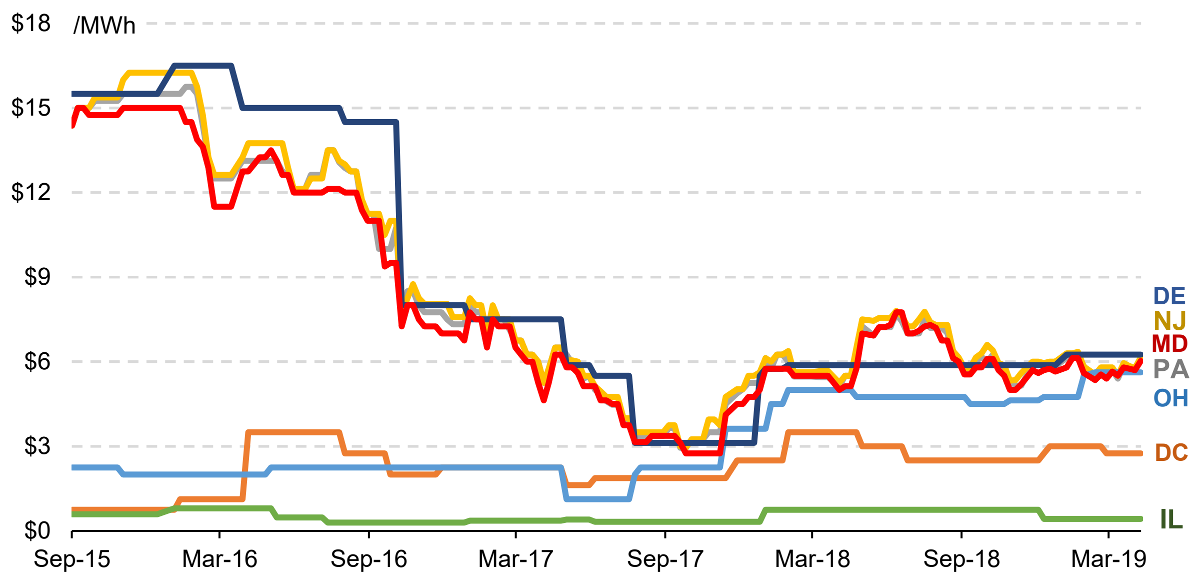

Figure D-2. Tier 1 Non-Carve-out REC Prices in Select States in PJM, Sep. 1, 2015 – Apr. 12, 2019

Source: Marex Spectrometer, Spectrometer U.S. Environmental.

The decline in Tier 1 non-carve-out REC prices in many states between September 2015 – September 2017 primarily reflects an increase in the number of renewable energy facilities capable of providing Tier 1 non-carve-out RECs throughout PJM.[723] Although RPS requirements during this period increased as a percentage of total consumption, the impact of this change was blunted by flat or declining electric consumption in states that participate in PJM. Many of the policy factors that influence REC supply and demand, such as adjustments to eligible technologies or geographic eligibility, went into effect before this period and are therefore already reflected in prices at the start of the time series. Federal tax incentives, including the PTC and the ITC, coupled with declining technology costs, are also partly responsible for the rapid expansion of renewable energy generation capacity.

Increases in REC prices from September 2017 – June 2018 are partially in response to preceding low prices, which induce developers to put certain renewable energy projects on hold or, in some cases, cancel projects that would have proceeded under more favorable economic conditions. This constriction of supply, coupled with growth in demand for renewable energy as states like Maryland and New Jersey increased their RPS requirements, has led to a modest rebound.

Figure D-3 and Figure D-4 show changes in SREC prices over the past three and a half years for Maryland and select other states in PJM with an RPS and solar carve-out. Unlike Tier 1 non-carve-out REC prices, SREC price levels vary between states in PJM. This is because solar carve-outs must be met by in-state solar generation. Maryland SREC prices in late 2015 were among the highest of states in PJM because, at the time, demand for SRECs from the solar carve-out was higher than the supply of SRECs.[724] In the subsequent two years, Maryland SREC prices fell from approximately $187.50/MWh in September 2015 to as low as approximately $5.00/MWh in September 2017, putting Maryland SREC prices on par

[723] U.S. Energy Information Administration, "Net generation, United States, all sectors, monthly," October 2018, eia.gov/electricity/data/browser/.

[724] Maryland's solar carve-out requirement was 0.5% in 2015. The only PJM participants with a higher carve-out requirement were: New Jersey, at 2.45%; Delaware, at 0.8%; and the District of Columbia, at 0.7%.

with all states in PJM except New Jersey and the District of Columbia. SREC prices briefly rebounded in early 2018, increasing to as high as $14.00/MWh in May 2018 before again trending downward and remaining low into December 2018. Since then, SREC prices have again trended upward, including a large price spike in early April 2019. From late March to early April 2019, SREC prices increased from $17.50/MWh to $48.75/MWh.

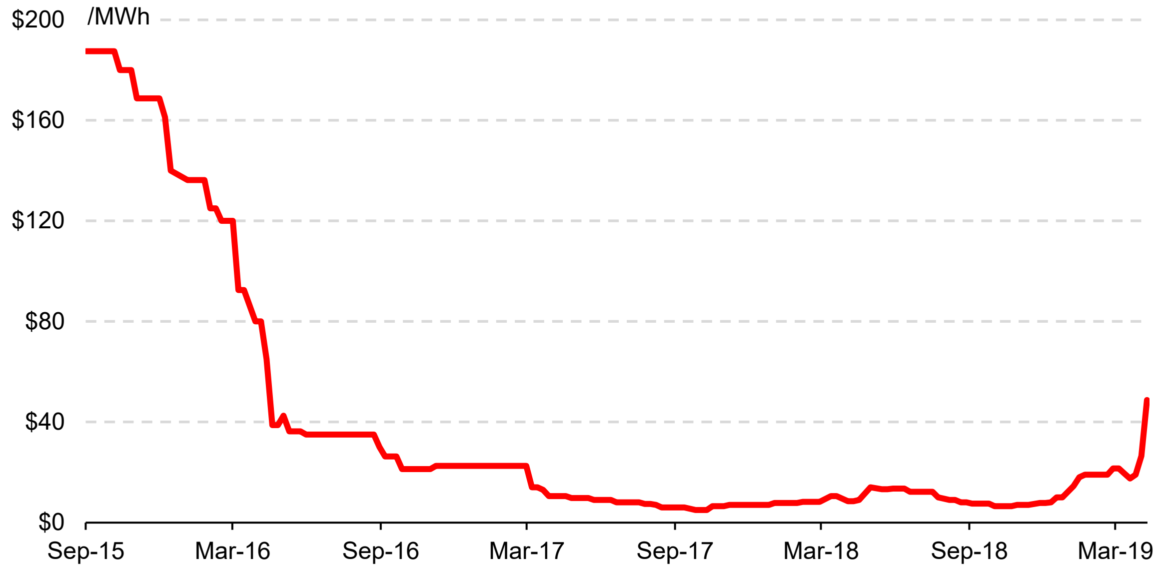

Figure D-3. SREC Prices in Maryland, Sep. 1, 2015 – Apr. 12, 2019

Source: Marex Spectrometer, Spectrometer U.S. Environmental.

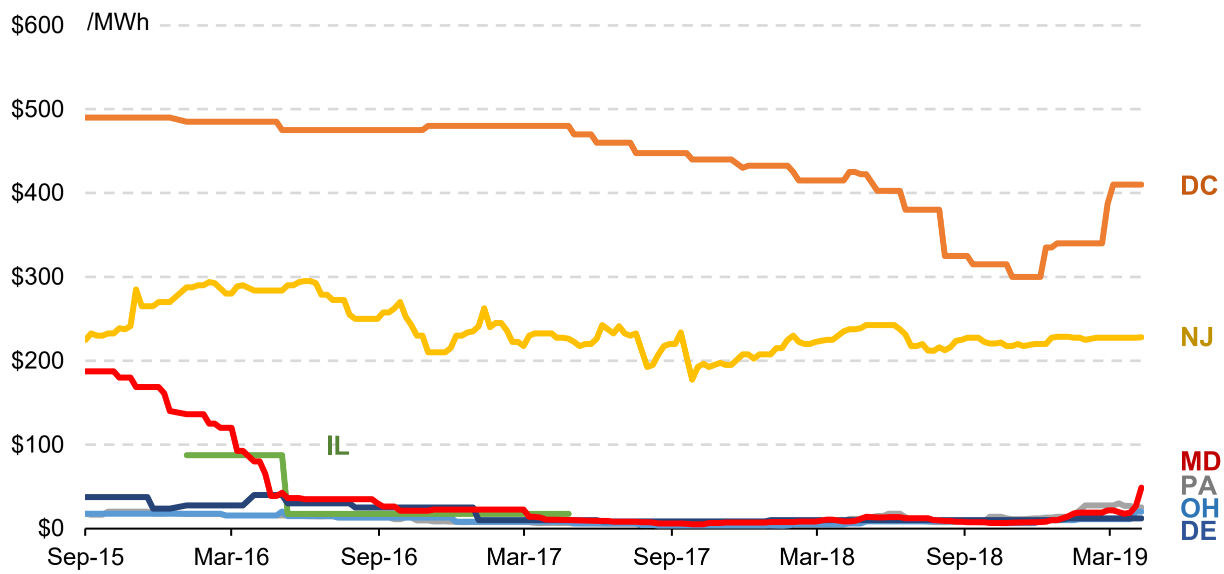

Figure D-4. SREC Prices in Select States in PJM, Sep. 1, 2015 – Apr. 12, 2019

Source: Marex Spectrometer, Spectrometer U.S. Environmental.

The very steep decline in Maryland SREC prices between September 2015 – May 2016 reflects both an increase in the amount of solar capacity in Maryland and significant reductions in solar technology costs. Both distributed and utility-scale solar costs have declined as installers, developers, and manufacturers have achieved economies of scale, realized new process efficiencies, and moved down the technology cost-curve. An NREL study evaluating solar during the Q1 2017 identified year-over-year cost declines of nearly 30% due to declining module and inverter prices, among other cost reductions.[725]

The recent increases in costs beginning in January 2019 correspond with the Maryland General Assembly convening for the 2019 legislative session. During the session, several committees contemplated legislation that has the potential to significantly increase the solar carve-out in Maryland. The largest SREC price increase occurred after the Legislature passed SB 516—an RPS bill with a 14.5% carve-out—in April 2019. Although the bill did not formally enter law until the end of May 2019, the preemptive acquisition of SRECs pushed SREC prices up by nearly an order of magnitude, from as low as $5/MWh to almost $50/MWh. SREC spot market trading reflects increased demand for SRECs; SB 516 changed the 2019 solar carve-out from 1.95% to 5.5%, with additional increases thereafter. SRECs acquired now can be used to meet both immediate-term and future RPS requirements, the latter of which is possible through banking.

Figure D-5 and Figure D-6 show changes in Tier 2 REC prices for Maryland and select other states in PJM with Tier 2 resource requirements. The time frame represented in these figures is the period from September 2015 through early April 2019. Available supply of Tier 2 resources exceeds demand and, as a result, Tier 2 REC prices are significantly lower than Tier 1 non-carve-out REC prices in Maryland. Maryland Tier 2 prices have decreased in the past several years but exhibit minimal volatility and have remained between $0.35-$0.75/MWh since May 2016. Hydro was the only eligible Tier 2 resource in Maryland during this period. Tier 2 REC prices in other states vary due to distinctions in eligible resources. However, prices are consistently lower than Tier 1 non-carve-out RECs. Additionally, Tier 2 REC prices have remained relatively flat since October 2017 in the states depicted in Figure D-6.

[725] Ran Fu, David Feldman and Robert Margolis, *et al.*, *U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017*, National Renewable Energy Laboratory, 2017, nrel.gov/docs/fy17osti/68925.pdf.

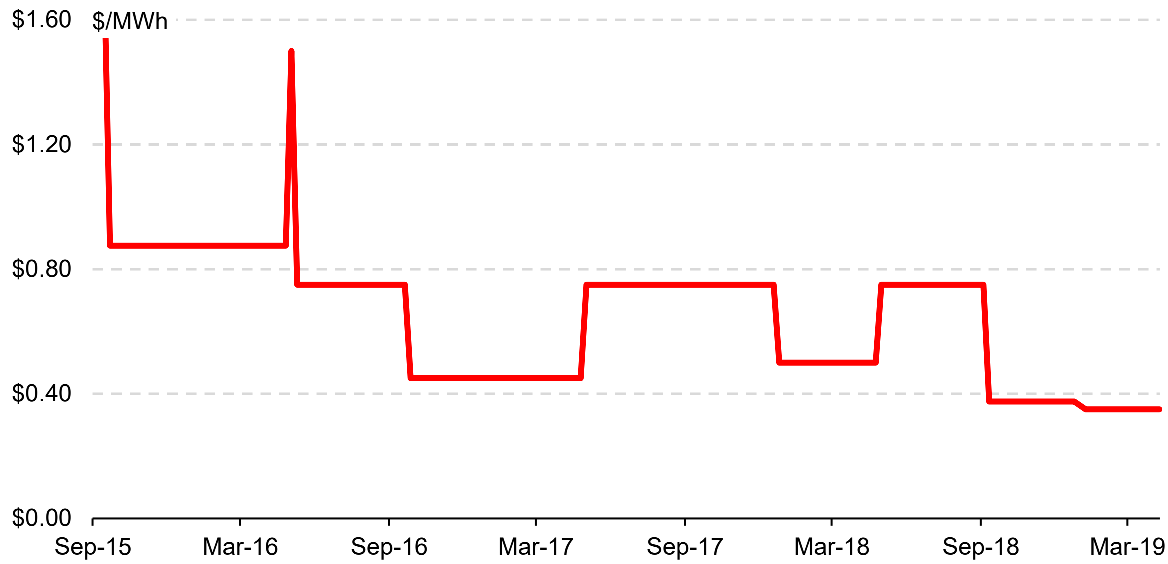

Figure D-5. Tier 2 REC Prices in Maryland, Sep. 1, 2015 – Apr. 12, 2019

Source: Marex Spectrometer, Spectrometer U.S. Environmental

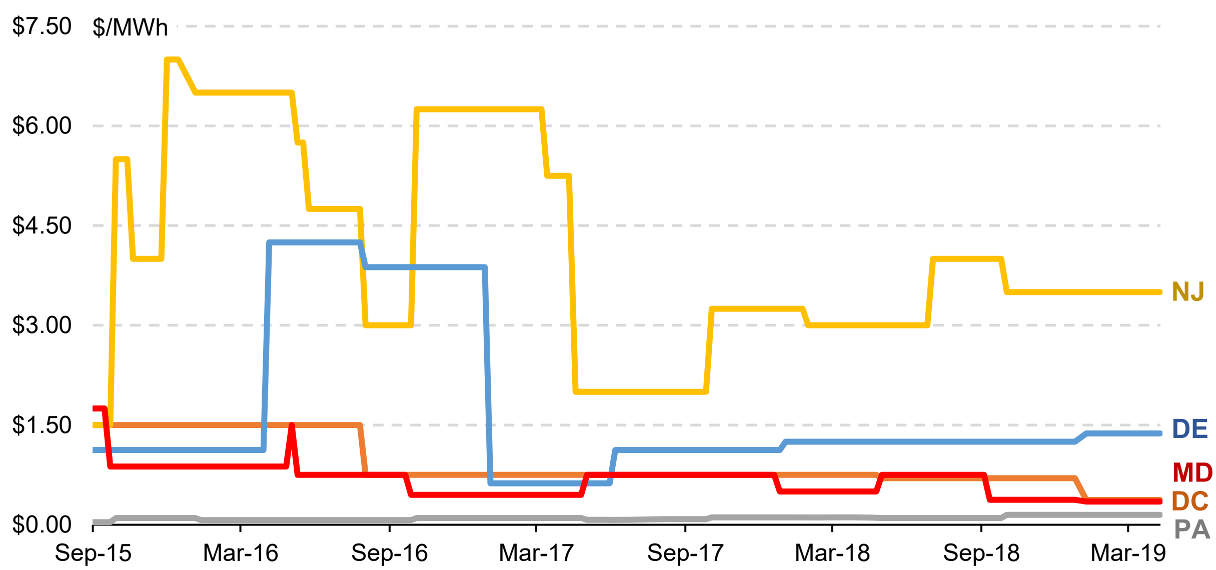

Figure D-6. Tier 2 REC Prices in Select States in PJM, Sep. 1, 2015 – Apr. 12, 2019

Source: Marex Spectrometer, Spectrometer U.S. Environmental.

Appendix E. RPS Compliance Costs in Maryland and PJM

Table E-1. RPS Compliance Costs for Maryland and Select States in PJM

	2010	2011	2012	2013	2014	2015	2016	2017
MARYLAND								
Tier 1 Solar	$5,294,320	$7,810,479	$11,351,367	$21,420,389	$29,388,337	$39,062,714	$45,556,987	$21,276,834
Tier 1 Non-Carve-out	1,925,075	6,289,910	12,453,493	32,664,211	70,677,220	85,070,001	88,234,024	50,099,228
Tier 2	618,310	654,452	665,270	2,751,643	3,991,322	2,619,432	1,441,446	688,040
TOTAL	**$7,837,705**	**$14,754,841**	**$24,470,130**	**$56,836,243**	**$104,056,879**	**$126,752,147**	**$135,232,457**	**$72,064,102**
DELAWARE[1],[2]								
Tier 1 Solar	$339,188	$377,684	$1,497,105	$3,265,575	$5,599,565	$7,465,951	$6,787,614	$8,434,156
Tier 1 Non-Carve-out	1,883,942	7,602,003	13,758,461	18,679,083	8,547,916	8,350,294	9,359,505	11,591,595
Tier 2	89,222	61,593	68,890	(incl. above)	(incl. above)	(incl. above)	(incl. above)	(incl. above)
TOTAL	**$2,312,352**	**$8,041,281**	**$15,324,456**	**$21,944,657**	**$14,147,481**	**$15,816,245**	**$16,147,119**	**$20,025,751**
DISTRICT OF COLUMBIA								
Tier 1 Solar	$1,260,822	$1,999,243	$7,200,414	$14,535,841	$25,144,090	$36,517,225	$44,897,712	$38,570,898
Tier 1 Non-Carve-out	328,484	820,501	1,354,128	2,277,307	2,140,741	1,880,257	2,132,112	3,959,964
Tier 2	130,737	141,527	167,580	118,204	86,961	114,675	134,122	147,732
TOTAL	**$1,720,043**	**$2,961,271**	**$8,722,122**	**$16,931,352**	**$27,371,792**	**$38,512,157**	**$47,163,946**	**$42,678,594**
ILLINOIS[1],[2]								
Tier 1 Solar	n/a	n/a	n/a	no data	no data	no data	$3,516,801	$3,342,768
DG	n/a	n/a	n/a	n/a	no data	no data	no data	no data
Non-Carve-out	$49,093,091	$21,678,004	$5,364,471	$76,696,999	$121,865,211	$143,805,915	$117,865,055	$111,996,712
TOTAL	**$49,093,091**	**$21,678,004**	**$5,364,471**	**$76,696,999**	**$121,865,211**	**$143,805,915**	**$121,381,856**	**$115,339,480**
MICHIGAN[3]								
Tier 1 Solar								
Tier 1 Non-Carve-out								
Tier 2								
TOTAL	**$21,671,155**	**$44,744,881**	**$87,468,316**	**$84,886,287**	**$104,378,259**	**$74,125,866**	**$83,824,849**	**$89,107,452**
NEW JERSEY[1]								
Tier 1 Solar	$108,977,362	$184,634,074	$126,278,551	$106,734,084	$275,743,166	$355,906,173	$461,255,219	$496,030,394
Tier 1 Non-Carve-out	7,254,298	10,635,090	20,148,751	37,650,390	41,686,408	83,489,849	108,682,278	95,359,171
Tier 2	2,148,431	2,380,499	2,618,204	5,193,673	5,490,258	8,430,892	9,777,078	11,856,089
TOTAL	**$118,380,091**	**$197,649,663**	**$149,045,506**	**$149,578,147**	**$322,919,832**	**$447,826,914**	**$579,714,575**	**$603,245,654**
OHIO[4]								
Tier 1 Solar	no data	$8,505,563	$11,295,224	$14,833,991	$17,759,184	$14,772,908	$11,552,928	no data
Tier 1 Non-Carve-out	no data	71,143,716	41,460,813	50,307,092	24,914,747	27,741,181	26,066,897	no data
Tier 2	no data	n/a	n/a	n/a	n/a	n/a	n/a	no data
TOTAL	**no data**	**$79,649,278**	**$52,756,036**	**$65,141,083**	**$42,673,931**	**$42,514,089**	**$37,619,825**	**no data**
PENNSYLVANIA[1],[4]								
Tier 1 Solar	$1,015,379	$4,585,731	$8,165,092	$7,870,764	$11,480,683	$16,079,309	$21,476,534	$22,162,834
Tier 1 Non-Carve-out	2,171,937	7,981,469	22,027,392	44,790,766	60,569,952	78,317,059	105,783,299	98,783,920
Tier 2	246,056	887,970	1,030,665	1,777,911	1,236,729	999,770	1,034,810	1,771,777
TOTAL	**$3,433,372**	**$13,455,170**	**$31,223,149**	**$54,439,441**	**$73,287,364**	**$95,396,138**	**$128,294,643**	**$122,718,531**

Source: EIA State Compliance Reports, unless otherwise indicated.

[1] Compliance year runs from June 1 – May 31; data represent end-year.

[2] Estimated compliance cost data provided by LBNL.

[3] Total costs reported were not broken down by tier.

[4] Compliance cost data vary from LBNL due to differences in REC prices used. LBNL relies upon brokerage trades, while the study used for the final report relies on REC price averages provided in state public utility commission reports.

Table E-2. Total Retail Bills for Maryland and Select States in PJM

	2010	2011	2012	2013	2014	2015	2016	2017
MARYLAND								
Eligible Retail Sales (MWh)	64,068,380	62,157,733	60,887,411	60,879,421	60,839,281	61,248,254	60,106,112	57,879,160
Avg. Retail Rate (¢/kWh)	12.71¢	11.93¢	11.28¢	11.66¢	12.10¢	12.07¢	12.21¢	11.98¢
TOTAL ($Thous.)	**$8,143,091**	**$7,415,418**	**$6,868,100**	**$7,098,540**	**$7,361,553**	**$7,392,664**	**$7,338,956**	**$6,933,923**
DELAWARE								
Eligible Retail Sales (MWh)	7,786,621	8,212,375	7,914,227	7,412,237	7,416,754	7,260,479	7,076,133	6,945,064
Avg. Retail Rate (¢/kWh)	11.97¢	11.48¢	11.06¢	10.90¢	11.22¢	11.17¢	11.09¢	10.90¢
TOTAL ($Thous.)	**$932,059**	**$942,781**	**$875,314**	**$807,934**	**$832,160**	**$810,996**	**$784,743**	**$757,012**
D.C.								
Eligible Retail Sales (MWh)	12,725,218	11,717,815	10,768,938	11,559,203	11,473,299	11,507,583	11,870,230	11,221,610
Avg. Retail Rate (¢/kWh)	13.35¢	12.81¢	11.85	11.85¢	12.11¢	12.07¢	11.73¢	11.80¢
TOTAL ($Thous.)	**$1,698,817**	**$1,501,052**	**$1,276,119**	**$1,369,766**	**$1,389,417**	**$1,388,965**	**$1,392,378**	**$1,324,150**
ILLINOIS								
Eligible Retail Sales (MWh)	79,927,498	111,971,248	115,975,547	125,155,697	125,822,940	122,307,604	120,384,536	125,876,845
Avg. Retail Rate (¢/kWh)	9.13¢	8.97¢	8.40¢	8.26¢	9.36¢	9.40¢	9.38¢	9.49¢
TOTAL ($Thous.)	**$7,297,381**	**$10,043,821**	**$9,741,946**	**$10,337,861**	**$11,777,027**	**$11,496,915**	**$11,292,069**	**$11,945,713**
MICHIGAN								
Eligible Retail Sales (MWh)	103,542,220	96,610,808	102,651,000	103,284,102	103,291,192	103,362,287	103,362,287	103,362,287
Avg. Retail Rate (¢/kWh)	9.88¢	10.40¢	10.98¢	11.21¢	11.03¢	10.76¢	11.05¢	11.28¢
TOTAL ($Thous.)	**$10,229,971**	**$10,047,524**	**$11,271,080**	**$11,578,148**	**$11,393,018**	**$11,121,782**	**$11,421,533**	**$11,659,266**
NEW JERSEY								
Eligible Retail Sales (MWh)	77,418,756	81,349,339	76,935,091	76,273,927	76,512,600	75,390,475	74,199,076	75,031,955
Avg. Retail Rate (¢/kWh)	14.68¢	14.30¢	13.68¢	13.69¢	13.95¢	13.74¢	13.38¢	13.32¢
TOTAL ($Thous.)	**$11,365,073**	**$11,632,955**	**$10,524,720**	**$10,441,901**	**$10,673,508**	**$10,358,651**	**$9,927,836**	**$9,994,256**
OHIO								
Eligible Retail Sales (MWh)	125,942,800	135,154,400	131,205,533	132,149,250	115,026,360	105,575,000	112,430,160	no data
Avg. Retail Rate (¢/kWh)	9.14¢	9.03¢	9.12¢	9.20¢	9.73¢	9.98¢	9.84¢	no data
TOTAL ($Thous.)	**$11,511,172**	**$12,204,442**	**$11,965,945**	**$12,157,731**	**$11,192,065**	**$10,536,385**	**$11,063,128**	
PENNSYLVANIA								
Eligible Retail Sales (MWh)	33,016,464	94,680,993	142,977,002	144,026,130	146,589,566	143,128,607	138,167,579	141,511,559
Avg. Retail Rate (¢/kWh)	10.31¢	10.45¢	9.91¢	9.81¢	10.28¢	10.31¢	10.19¢	10.13¢
TOTAL ($Thous.)	**$3,403,997**	**$9,894,164**	**$14,169,021**	**$14,128,963**	**$15,069,407**	**$14,756,559**	**$14,079,276**	**$14,335,121**

Source: EIA State Compliance Reports.

Table E-3. RPS Ratepayer Impact for Maryland and Select States in PJM as a Percent of Total Retail Bills

	2010	2011	2012	2013	2014	2015	2016	2017
MARYLAND								
Tier 1 Solar	0.07%	0.11%	0.17%	0.30%	0.40%	0.53%	0.62%	0.31%
Tier 1 Non-Carve-out	0.02	0.08	0.18	0.46	0.96	1.15	1.20	0.72
Tier 2	0.01	0.01	0.01	0.04	0.05	0.04	0.02	0.01
TOTAL	**0.10%**	**0.20%**	**0.36%**	**0.80%**	**1.41%**	**1.71%**	**1.84%**	**1.04%**
DELAWARE*								
Tier 1 Solar	0.04%	0.04%	0.17%	0.40%	0.67%	0.92%	0.86%	1.11%
Tier 1 Non-Carve-out	0.20	0.81	1.57	2.31	1.03	1.03	1.19	1.53
Tier 2	0.01	0.01	0.01	(incl. above)				
TOTAL	**0.25%**	**0.85%**	**1.75%**	**2.72%**	**1.70%**	**1.95%**	**2.06%**	**2.65%**
DISTRICT OF COLUMBIA								
Tier 1 Solar	0.07%	0.13%	0.56%	1.06%	1.81%	2.63%	3.22%	2.91%
Tier 1 Non-Carve-out	0.02	0.05	0.11	0.17	0.15	0.14	0.15	0.30
Tier 2	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
TOTAL	**0.10%**	**0.20%**	**0.68%**	**1.24%**	**1.97%**	**2.77%**	**3.39%**	**3.22%**
ILLINOIS*								
Tier 1 Solar	n/a	n/a	n/a	no data	no data	no data	0.03%	0.03%
DG	n/a	n/a	n/a	n/a	no data	no data	no data	no data
Non-Carve-out	0.67%	0.22%	0.06%	0.74%%	1.03%	1.25%	1.04	0.94
TOTAL	**0.67%**	**0.22%**	**0.06%**	**0.74%**	**1.03%**	**1.25%**	**1.07%**	**0.97%**
MICHIGAN								
Tier 1 Solar	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Tier 1 Non-Carve-out	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Tier 2	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
TOTAL	**0.21%**	**0.45%**	**0.78%**	**0.73%**	**0.92%**	**0.67%**	**0.73%**	**0.76%**
NEW JERSEY								
Tier 1 Solar	0.96%	1.59%	1.20%	1.02%	2.58%	3.44%	4.65%	4.96%
Tier 1 Non-Carve-out	0.06	0.09	0.19	0.36	0.39	0.81	1.09	0.95
Tier 2	0.02	0.02	0.02	0.05	0.05	0.08	0.10	0.12
TOTAL	**1.04%**	**1.70%**	**1.42%**	**1.43%**	**3.03%**	**4.32%**	**5.84%**	**6.04%**
OHIO								
Tier 1 Solar	no data	0.07%	0.09%	0.12%	0.16%	0.14%	0.10%	no data
Tier 1 Non-Carve-out	no data	0.58	0.35	0.41	0.22	0.26	0.24	no data
Tier 2	no data							no data
TOTAL	**-**	**0.65%**	**0.44%**	**0.54%**	**0.38%**	**0.40%**	**0.34%**	**-**
PENNSYLVANIA								
Tier 1 Solar	0.03%	0.05%	0.06%	0.06%	0.08%	0.11%	0.15%	0.15%
Tier 1 Non-Carve-out	0.06	0.08	0.16	0.32	0.40	0.53	0.75	0.69
Tier 2	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
TOTAL	**0.10%**	**0.14%**	**0.22%**	**0.39%**	**0.49%**	**0.65%**	**0.91%**	**0.86%**

Source: EIA State Compliance Reports unless otherwise indicated.

*Estimated compliance cost data provided by LBNL.

APPENDIX F. ASSUMPTIONS FOR THE INTERIM REPORT

Among other things, the interim report evaluates whether there is enough planned and operating renewable energy resources to meet current and projected RPS requirements in Maryland and in states within PJM. The final report draws from the interim report in reaching several key findings. Differences from the assumptions made in the interim report, however, may have a significant impact on the analysis in the final report. The following bullets summarize key assumptions from the interim report and review the potential impact of changing these assumptions:

- To forecast electricity sales through 2030 for all states in PJM besides Maryland, the interim report uses historical data from Form EIA-826 – Monthly Electric Utility Sales and Revenue Report with State Distributions, and annualized growth rates obtained from both MISO's *2016 MISO Independent Load Forecast Report* and PJM's 2017 *Load Forecast Report*. The latter also uses respective zonal growth rates to project total retail sales for each PJM member. States for which only a portion of the electricity supply system is within the PJM control area are assumed to have an RPS requirement directly proportional to the amount of service supplied.[726] Likewise, only those renewable energy resources located within the PJM controlled portions of the states in PJM are assumed to be available for meeting those states' RPS requirements.

- The retail sales projections for Maryland were calculated using the Maryland PSC's 2016-2025 *Ten-Year Plan*.[727] The *Ten-Year Plan* provides "Net of DSM (Demand Side Management)" retail sales projections for 2016-2025 for Maryland-only service areas. An annual growth rate was calculated based on the 2020-2025 retail sales projections (0.2% per year) and was then applied to 2025 retail sales projections to calculate the projections for each year from 2026-2030. Prior to applying the RPS percentages, a 1.9% downward adjustment was made in the retail sales projections to account for IPL sales, which are exempt from the Maryland RPS requirements. The 1.9% figure is an estimate based on historical Maryland PSC data from 2013-2015.

In addition to the above assumptions, the interim report also assumed capacity factors for each renewable energy technology. Any deviations from those capacity factors will affect the available amount of renewable energy generation. These assumptions are summarized below:

- <u>Solar</u> – The NREL Open Energy Information (OpenEI) Transparent Cost Database uses a nationwide capacity factor range of 16% to 30% for solar PV generators, with a median value of 20%.[728] For solar PV, a data set of generation and capacity of solar PV in PJM was compiled from EIA for 2014-2016. The solar PV capacity factor was 18% in 2014, 16% in 2015, and 17% in 2016. The analysis uses an 18% solar PV capacity factor for historical generation (through 2017), and a 22% solar PV capacity factor for future generation (beginning in 2018).[729]

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[726] For example, in Michigan, PJM is estimated to provide approximately 7% of the total electrical demand. Accordingly, this analysis assumes that 7% of the Michigan RPS requirements will be derived from the PJM system, and 93% of the Michigan renewable energy requirement will stem from sales outside of the PJM region.

[727] Public Service Commission of Maryland, *Ten-Year Plan (2016-2025) of Electric Companies in Maryland*, November 2016.

[728] Open Energy Information, "Transparent Cost Database: Capacity Factor," National Renewable Energy Laboratory, en.openei.org/apps/TCDB/#blank.

[729] Improvements in technology, and greater development of solar systems that incorporate tracking, increase the capacity factor over time.

- Wind – The NREL OpenEI Transparent Cost Database uses a nationwide capacity factor range of 26% to 52% for onshore wind generators, with a median value of 38%, and a nationwide capacity factor range of 31% to 45% for offshore wind generators, with a median value of 39%.[730] Generation and data for onshore wind plants in PJM from EIA was compiled for 2014, 2015, and 2016. The capacity factor for wind was 30% in both 2014 and 2015, and 28% in 2016. Based on those values, the final report uses a 30% capacity factor for onshore wind generators through 2017 and assumes an increase to a 35% onshore wind capacity factor beginning in 2018.[731] Offshore wind generators are considered to have a 39% capacity factor, consistent with the NREL median values.

- Hydro – The NREL OpenEI Transparent Cost Database uses a nationwide capacity factor range of 12% to 61% for hydro generators, with a median value of 45%.[732] The interim report includes data that allow the calculation of a capacity factor for a sampling of hydro units under 30 MW. This sampling of units, on average, has a capacity factor of approximately 42%. This analysis assumed a 45% capacity factor for all hydro generators, consistent with the NREL median value.

- Methane – Generation data from 171 units in PJM were available from EIA. Annual plant utilization ranged from less than 1% to over 96%. These compute to an average capacity factor of approximately 55%, which was assumed to apply to LFG facilities in PJM.

- Biomass – The NREL OpenEI Transparent Cost Database uses a nationwide capacity factor range of 70% to 90% for biomass generators, with a median value of 84%.[733] This analysis assumed an 84% capacity factor for biomass generators, consistent with the NREL median value.

- Black Liquor – As with biomass, an 84% capacity factor was used. Economic paper mill production is fully dependent on the ability to recover chemicals and energy from black liquor.

- Waste-to-Energy – Municipal solid waste-to-energy generating units are subject to variation in the quantity and quality of their waste supply (i.e., their fuel). These variations are seasonal, peak with holidays, and are weather-related (for example, rain soaks waste, resulting in lower efficiency in generation). Data for 11 units in the PJM control area were available. Annual plant utilization ranged from less than 1% to over 54%. These compute to an average capacity factor of approximately 27%, which was assumed to apply to waste-to-energy facilities in the PJM control area.

[730] Open Energy Information, "Transparent Cost Database: Capacity Factor," National Renewable Energy Laboratory, en.openei.org/apps/TCDB/#blank.

[731] Improvements in wind energy technology increase the capacity factor over time.

[732] "Open Energy Information, "Transparent Cost Database: Capacity Factor," National Renewable Energy Laboratory, en.openei.org/apps/TCDB/#blank.

[733] Ibid.

Appendix G. Potentially Available Resources in the PJM Generation Interconnection Queue

The PJM Queue tracks proposed generation additions in the PJM region. PJM conducts a myriad of studies to determine whether proposed generation additions can be added to the PJM grid without detrimentally affecting reliability, and what grid upgrades or updates may be necessary to ensure reliability is maintained. Table G-1 identifies the nameplate capacity of active and under-construction, Tier 1 renewable energy projects currently listed in the PJM Queue as of November 2018. The capacity figures are subdivided by the proposed state, energy source, and the year the project entered the PJM Queue. Projects remain in the PJM Queue until either terminated or in-service.

Table G-1. Nameplate Capacity of Active and Under-Construction Tier 1 Renewable Energy Projects in the PJM Queue, as of December 2018 (MW)

Source	Year[1]	MD	DE	IL	IN	KY	MI	NJ	NC	OH	PA	VA	WV	TOTAL
SOLAR[2]	2015	**65**	6	-	-	-	-	-	-	-	-	91	-	**162**
	2016	**780**	219	-	200	180	-	12	595	1,416	30	2,985	-	**6,417**
	2017	**126**	90	673	570	20	100	28	478	2,155	190	2,688	-	**7,118**
	2018	**130**	103	1,890	920	1,131	150	367	960	1,987	1,525	6,510	397	**16,069**
	Subtotal		**1,102**	**2,563**	**1,690**	**1,331**	**250**	**407**	**2,033**	**5,557**	**1,745**	**12,274**	**397**	**29,767**
ONSHORE WIND[3]	2015	**-**	-	150	174	-	-	-	-	-	-	-	-	**324**
	2016	**-**	-	990	200	-	-	-	-	195	67	-	-	**1,452**
	2017	**-**	-	1,205	1050	-	-	-	-	1,907	170	180	160	**4,671**
	2018	**-**	-	5,105	200	-	-	3,831	-	1,110	100	-	115	**10,461**
	Subtotal		**-**	**7,450**	**1,624**	**-**	**-**	**3,831**	**-**	**3,211**	**338**	**180**	**275**	**16,909**
OFFSHORE WIND	2015	**-**	-	-	-	-	-	-	-	-	-	-	-	**-**
	2016	**-**	-	-	-	-	-	-	-	-	-	-	-	**-**
	2017	**-**	-	-	-	-	-	-	-	-	-	-	-	**-**
	2018	**-**	352[4]	-	-	-	-	3,016	-	-	-	2,400	-	**5,768**
	Subtotal		**-**	**-**	**-**	**-**	**-**	**3,016**	**-**	**-**	**-**	**2,400**	**-**	**5,768**
HYDRO	2015	**-**	-	-	-	-	-	-	-	-	-	-	-	**-**
	2016	**-**	-	-	-	-	-	-	-	-	-	-	-	**-**
	2017	**15**	-	-	-	-	-	-	-	-	-	-	-	**15**
	2018	**-**	-	-	-	-	-	-	-	-	-	2	-	**2**
	Subtotal		**15**	-	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**2**	**-**	**17**
BIOMASS	2015	**-**	-	-	-	-	-	-	-	-	-	-	-	**-**
	2016	**4**	-	-	-	-	-	-	-	-	-	-	-	**4**
	2017	**-**	-	-	-	-	-	-	-	-	-	-	-	**-**
	2018	**-**	-	-	-	-	-	-	-	-	-	-	-	**-**
	Subtotal		**4**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**4**
ALL SOURCE TOTAL	2015	**65**	**6**	**150**	**174**	**-**	**-**	**-**	**-**	**-**	**-**	**91**	**-**	**486**
	2016	**784**	**219**	**990**	**400**	**180**	**-**	**12**	**595**	**1,611**	**97**	**2,985**	**-**	**7,873**
	2017	**141**	**90**	**1,878**	**1,620**	**20**	**100**	**28**	**478**	**4,062**	**360**	**2,868**	**160**	**11,805**
	2018	**130**	**455**	**6,995**	**1,120**	**1,131**	**150**	**7,214**	**960**	**3,097**	**1,625**	**8,912**	**512**	**32,301**
	TOTAL	**1,120**	**1,120**	**10,013**	**3,314**	**1,331**	**250**	**7,254**	**2,033**	**8,770**	**2,082**	**14,856**	**672**	**52,465**

Note: Projects in the District of Columbia are not currently reported into the PJM Queue.

[1] Capacity figures for 2018 are inclusive of capacity in the PJM Queue as of November 1, 2018.

[2] Solar category only represents utility-scale solar, including solar plus storage.

[3] Onshore wind category also includes wind plus storage.

[4] Although listed by PJM as located in Delaware, this capacity total is based on two offshore wind projects that are located 17 miles off the coast of Ocean City, Maryland.

Approximately 52,500 MW of potential capacity entered the PJM Queue between 2015-2018. The likelihood that any individual project within the pool of proposed renewable capacity will come online depends on the project phase, meaning how far it has already advanced toward completion. According to PJM, based on historical rates, approximately 16% of all capacity in the PJM Queue is expected to come online as of April 2018.[734] This completion likelihood figure, when combined with the current PJM Queue capacity figures, suggests that PJM has approximately 8,400 MW of renewables capacity forthcoming. This represents nearly a 75% increase above installed renewables capacity in PJM as of December 2017.[735]

[734] Calculated by dividing the total number of in-service projects (slide 8) by the total capacity of all generation applications less active studies (slide 13). David Egan, "PJM Interconnection Queue Status & Statistics Update Database Snapshot on 04/23/2018," presentation to PJM Planning Committee, May 2018, pjm.com/-/media/committees-groups/committees/pc/20180503/20180503-item-11-pjm-interconnection-queue-status-statistics-update.ashx, slides 8 and 13.

[735] Joe Bowring, *2017 State of the Market Report for PJM: MC Special Session*, Monitoring Analytics, LLC, March 2018, pjm.com/-/media/committees-groups/committees/mc/20180322-state-of-market-report-review/20180322-2017-state-of-the-market-report-review.ashx.

APPENDIX H. BIOPOWER TECHNICAL POTENTIAL PROJECTIONS BY FEEDSTOCK

	MD	DE	DC	IL	IN	KY	MI	NJ
Potential Biopower - Capacity (MW)[1]								
Crop Residues[2]	**56.4**	23.4	0	985.1	513.4	125.7	256.2	9.4
Forest Residues[3]	**15.0**	1.0	0	22.0	33.2	128.2	64.3	1.9
Primary Mill Residues[4]	**19.1**	0.2	0	13.4	44.5	77.8	97.9	0.7
Urban Wood and Sec Mill Residues[5]	**65.2**	9.7	0	152.0	101.7	61.5	124.0	109.1
Methane from Manure[6]	**3.6**	2.0	0	32.1	29.9	9.6	14.7	0.1
Methane from Wastewater[7]	**12.2**	2.8	0	66.0	16.6	12.5	38.3	36.8
Methane from Landfills[8]	**12.3**	-	0	80.1	18.9	42.4	15.8	7.1
Methane from Food Waste[9]	**8.9**	1.5	0	20.1	10.1	6.5	14.5	13.3
Total Biomass	**155.7**	34.4	0	1,172.5	692.9	393.1	542.3	121.1
Total Biogas	**36.9**	6.4	0	198.2	75.5	71.0	83.2	57.3
TOTAL Biopower Capacity	**192.7**	**40.7**	**0**	**1,370.7**	**768.3**	**464.1**	**625.6**	**178.4**
Potential Biopower - Generation (MWh)[1]								
Crop Residues[2]	**395,288**	163,805	0	6,903,440	3,598,098	880,554	1,795,519	65,734
Forest Residues[3]	**104,813**	7,291	0	154,395	232,675	898,087	450,668	13,505
Primary Mill Residues[4]	**134,137**	1,687	0	93,696	312,003	545,304	685,751	4,576
Urban Wood and Sec Mill Residues[5]	**457,077**	68,285	0	1,065,420	712,792	431,081	868,751	764,605
Methane from Manure[6]	**25,269**	14,019	0	224,632	209,351	67,503	103,032	719
Methane from Wastewater[7]	**85,213**	19,807	0	462,695	116,132	87,747	268,336	258,127
Methane from Landfills[8]	**86,231**	0	0	561,205	132,591	296,837	110,465	49,426
Methane from Food Waste[9]	**62,171**	10,638	0	140,738	70,703	45,322	101,393	93,455
Total Biomass	**1,091,315**	241,068	0	8,216,951	4,855,568	2,755,026	3,800,689	848,420
Total Biogas	**258,884**	44,464	0	1,389,270	528,777	497,409	583,226	401,727
TOTAL Biopower Generation	**1,350,199**	**285,532**	**0**	**9,606,221**	**5,384,345**	**3,252,435**	**4,383,915**	**1,250,147**

	NC	OH	PA	TN	VA	WV	TOTAL
Potential Biopower - Capacity (MW)[1]							
Crop Residues[2]	156.9	430.9	92.4	109.6	53.6	3.3	**2,816.3**
Forest Residues[3]	233.2	36.0	72.4	102.0	201.9	63.3	**974.4**
Primary Mill Residues[4]	245.3	54.3	94.2	93.7	148.1	88.4	**977.6**
Urban Wood and Sec Mill Residues[5]	123.5	142.8	175.1	74.6	124.0	23.5	**1,286.8**
Methane from Manure[6]	131.4	20.8	4.1	5.1	5.8	0.7	**259.9**
Methane from Wastewater[7]	27.1	45.2	41.7	21.3	21.5	5.4	**347.4**
Methane from Landfills[8]	28.2	64.1	23.8	17.0	17.2	16.7	**343.5**
Methane from Food Waste[9]	14.1	18.6	22.0	10.2	12.6	2.6	**154.9**
Total Biomass	759.0	664.0	434.0	379.9	527.7	178.4	**6,055.0**
Total Biogas	200.8	148.7	91.6	53.6	57.1	25.3	**1,105.6**
TOTAL Biopower Capacity	**959.8**	**812.7**	**525.6**	**433.6**	**584.8**	**203.7**	**7,160.6**
Potential Biopower - Generation (MWh)[1]							
Crop Residues[2]	1,099,862	3,019,454	647,536	768,383	375,835	23,067	**19,736,575**
Forest Residues[3]	1,634,392	252,126	507,390	714,916	1,414,893	443,262	**6,828,413**
Primary Mill Residues[4]	1,719,352	380,746	660,118	656,322	1,037,971	619,457	**6,851,120**
Urban Wood and Sec Mill Residues[5]	865,440	1,000,971	1,226,740	522,847	869,141	164,526	**9,017,676**
Methane from Manure[6]	920,758	145,558	28,752	35,730	40,886	4,913	**1,821,122**
Methane from Wastewater[7]	189,940	316,394	292,404	149,402	150,937	37,585	**2,434,719**
Methane from Landfills[8]	197,864	449,238	166,732	119,308	120,363	116,770	**2,407,030**
Methane from Food Waste[9]	98,591	130,546	153,824	71,461	88,164	18,133	**1,085,139**
Total Biomass	5,319,046	4,653,297	3,041,784	2,662,468	3,697,840	1,250,312	**42,433,784**
Total Biogas	1,407,153	1,041,736	641,712	375,901	400,350	177,401	**7,748,010**
TOTAL Biopower Generation	**6,726,199**	**5,695,033**	**3,683,496**	**3,038,369**	**4,098,190**	**1,427,713**	**50,181,794**

[1] Based on data listed in NREL's Biopower Atlas, up to date as of 2014. Specific feedstock sources (cited below) were used to estimate tons/yr as part of the energy output calculations.

[2] USDA, National Agricultural Statistics Service 2012 Census of Agriculture.

[3] USDA, Forest Service's Timber Product Output database, 2012.

[4] Ibid.

[5] U.S. Census Bureau, 2012 County Business Patterns. U.S. Census Bureau (2012 population data); BioCycle Journal: "State of Garbage in America," January 2008; and County Business Patterns 2012.

[6] USDA, National Agricultural Statistics Service, 2007 Census.

[7] EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011 and data from the EPA Clean Watersheds Needs Survey (2008).

[8] EPA LMOP database (April 2013).

[9] U.S. Census Bureau's County Business Patterns 2012 and the Homeland Security Infrastructure Program (HSIP) 2012.

APPENDIX I. CLEAN PEAK STANDARD IMPLEMENTATION

A wide variety of implementation options apply when designing a CPS policy. These include the selected "peak time," the allocation method for CPCs, how CPS and RPS credits are bundled, and which resources are eligible for the credit, among other factors.[736] The following list summarizes some of the potential options:

- *Type of standard:* Whether peak load contribution is based on total energy (i.e., kWh of energy) or total capacity (i.e., kW of demand) produced during a designated window.
- *Peak*: Whether the "peak" only includes times with high overall demand, high ramping requirements, or some other measurement that indicates system reliability concerns.
- *Baseline*: Whether the CPS measures resource compliance in relation to net load or gross load.
- *Location*: Whether the initial target is set based on local (e.g., utility) or system-wide (e.g., capacity zone) peak.
- *Peak window*: Whether the peak period includes more or less hours, or can change over time as grid conditions evolve.
- *CPC allocation*: Whether credit assignment depends on average or total metered output during peak times, or otherwise accounts for capacity contribution.
- *Joint CPS and RPS resources*: Whether resources that are eligible for both the CPS and RPS (or other related programs, such as demand response) may receive multiple credits or incentives.
- *Resource qualification*: Whether the pool of eligible resources includes traditional thermal (e.g., natural gas peaking turbines); variable resources (e.g., wind or solar output during peak periods); energy storage (e.g., a battery charged with grid power); and/or demand-side resources (e.g., demand response, energy efficiency).
- *Applicable area*: Whether resources must be located in-state to qualify for the credit.

Other considerations include the compensation period (i.e., length of the credited benefit), how credits are retired, eligibility of CPS resources for other programs and incentives, how targets are set over time, and timelines for implementation.

[736] These, and other related options, are described in: Strategen Consulting, "Evolving the RPS: Implementing a Clean Peak Standard," March 2018, static1.squarespace.com/static/571a88e12fe1312111f1f6e6/t/5abbee3c1ae6cf7814660b92/1522265663845/RPS_report_Lon.pdf.

Appendix J. 2014 PJM Renewable Integration Study – Summary and Assessment

J-1. Introduction and Summary

Between 2011-2014, a team of energy analysts and consultants led by General Electric's Energy Consulting Group completed the *PJM Renewable Integration Study* (PRIS).[737] PJM initiated the PRIS to comprehensively assess the impacts of increased penetrations of wind and solar generation in particular on the operation of the PJM grid, with the following principal objectives:

- Determine, for the PJM balancing area, the operational, planning, and energy market effects of large-scale integration of wind and solar power as well as mitigation and facilitation measures available to PJM; and
- Make recommendations to PJM for the implementation of such mitigation and facilitation measures.

The PRIS is a complex study that applied industry standard grid modeling and analysis tools to assess a very large electrical and geographic footprint, with hundreds of pages of report documentation and over a dozen briefings on various elements of the study. This appendix provides a summary of the assumptions, approach, major findings, and recommendations of the PRIS, as well as an update on the current state of generation in PJM relative to scenarios analyzed, and selected updates of relevance to interpretation of the study.

The study findings indicate that the PJM system, with adequate transmission expansion and additional regulating reserves, will not have any significant issues operating with up to 30% of its energy provided by wind and solar generation.[738] Other major findings of the PRIS include the following:

- Only incremental improvements in PJM practices are needed, as PJM's current energy scheduling practices already incorporate recommendations from previous renewable integration studies.
- PJM system production costs should drop progressively with higher levels of renewable energy penetration. However, variable O&M costs to coal and natural gas units may increase.
- Coal and natural gas generation is reduced as part of scenarios with higher renewable energy penetration. This should result in lower air pollution and GHG emissions.
- Scenarios with 30% renewable energy penetration will require 1-2 GW of additional regulation capacity beyond what was available in 2011, due to the variability of renewable energy resources. However, additional reserves are not needed for contingency or uncertainty scenarios.
- Up to $14 billion in new and upgraded transmission lines may be needed to support 30% renewable energy penetration, depending on the spatial distribution of new renewable energy systems.

[737] PJM Interconnection, LLC, *Renewable Integration Study Reports*, pjm.com/committees-and-groups/subcommittees/irs/pris.aspx.

[738] PRIS, Executive Summary.

- Better wind and solar energy forecasts are needed in order to more efficiently dispatch power plants.
- Using energy storage systems to meet the additional regulation requirements should help to lower overall production costs for PJM.

Trends over the six years since the PRIS began demonstrate that PJM has been moving toward higher levels of renewable energy generation, increasing from about 2% of system load in 2011 to just over 5% of PJM's generation mix in 2018.[739] In the near term, it is therefore most relevant to focus on the conclusions made in the PRIS for how PJM can respond to 14% penetration or 20% penetration. Trends in solar PV installation, as well as the slow pace of development of offshore wind projects (at least to date), suggest that PJM may be moving toward the "high solar, best onshore" (HSBO) scenarios from the PRIS, where renewable energy generation primarily comes from high solar penetration in conjunction with the best possible onshore wind resources.

While the broad conclusions from the PRIS are still relevant for understanding how PJM should respond to future trends over the next few years, it is important to note that the PRIS did not anticipate other recent developments that will affect PJM's readiness for renewable energy integration, including much slower actual and projected electric load growth, and the sharp decline in natural gas prices, which has radically altered market economics for coal and nuclear power plants. Additional studies since the PRIS, including a 2017 PJM study on the implications of changes in the generation resource mix on system reliability, highlight the need to assure sufficient flexible generation capacity in the resource mix to provide reserves and ancillary services needed to accommodate increasing levels of variable renewable energy generation.

The first objective of this appendix is to provide a distilled summary of the PRIS that sufficiently represents the assumptions, approaches, results, and recommendations from the study that are useful for understanding how the study relates to Maryland's assessment of its current and future renewable energy policies, in terms of regional grid integration considerations. The second objective is to identify market and industry changes since the PRIS was published, and highlight how these changes relate to interpretation of study outcomes.

J-2. Study Assumptions and Structure

The following qualifiers clarify the focus and boundaries of the PRIS effort:

- The PRIS was not a detailed, near-term planning study on any specific issue or mitigation. The target year was 2026, which was used to estimate the PJM annual load profile used in the study scenarios. The PRIS was not intended to specifically serve as a forecast for expected conditions in 2026; this was simply the latest year evaluated by the PRIS.
- The cost-benefit economics of renewable energy resources, including the capital investment required to install additional wind and solar infrastructure, were beyond the scope of the study and were not investigated. The study assumed that the penetration of renewable energy resources would increase and investigated how the PJM system would be affected.

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[739] Monitoring Analytics, LLC, *2018 State of the Market for PJM*, March 2019, monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-sec3.pdf.

- The impact of renewable energy on production cost savings was investigated, but the analysis did not address potential secondary impacts to the capacity market such as increased retirements due to non-economic performance or any need for generators to recover more in the capacity market because of lower revenues in the energy market.

Major assumptions of the PRIS included:

<u>Study Horizon and Economics</u>

- The load energy and peak demand in 2026 were projected based on the annual growth assumptions for energy as of 2011; however, the hourly load shape was based on the historical years of the hourly patterns of the renewable energy which, for all the scenarios, was based on the year 2006.
- 2026 data were updated based on PJM input on coal retirement/gas repowering and new capacity builds, both in the PJM Queue, plus future generic thermal generator additions to maintain PJM reserve margin targets. The generation capacity mix, excluding wind and solar plants, remained unchanged across all the scenarios studied.
- All units were economically committed and dispatched while respecting existing and new transmission limits, generator cycling capabilities, and minimum turndowns, with exceptions made for any must-run unit or units with operational constraints.
- The inflation rate was assumed to be 2% per year.

<u>Network and Operations</u>

- The entire Eastern Interconnection system was simulated.
- PJM was represented as one power pool, modeled as a nodal market, with a number of areas or zonal pricing zones.
- Because a large capacity of renewable energy resources could potentially lead to surplus energy during certain hours of the year, rules were developed to simulate the order in which generation assets should be curtailed. First, thermal plants were curtailed in the simulation, with the exception of must-run units. Once all of these were curtailed, renewable energy resources were then curtailed. Nuclear power plants were also treated as must-run and were not curtailed in the simulation.[740]
- Existing operating reserve practice was used for the Reference Case, but statistical analysis was used to modify reserves for scenarios with higher penetration of renewable energy resources.

The GE Energy Consulting team completed the study's requirements through four distinct tasks:

- Task 1: Wind and Solar Profile Development
- Task 2: Scenario Development and Analysis
- Task 3: Operational Impact Analysis and Market Analysis
- Task 4: Mitigation, Facilitation, and Report

[740] PRIS, Task 3A Part D, Production Cost Analysis.

This appendix consolidates the summary of the PRIS into the following two sections, including cases considered; highlights of methods, results, and recommendations; along with relevant developments since the 2011-2014 time frame of the PRIS. Section J-3 addresses Tasks 1 and 2, focusing on development of the analysis scenarios, while Section J-4 addresses Tasks 3 and 4, covering the study method, findings, and recommendations.

J-3. PRIS Analysis Scenarios (Tasks 1 and 2)

Task 2 of the PRIS focused on the development of 10 scenarios to describe the potential penetration of renewable energy resources into the PJM market by 2026 (see Table J-4 later in this section for specific details on each scenario):

- A Reference Case with 2% renewable energy penetration.
- A 14% renewable energy penetration Base Case, which reflected state RPS targets as of 2011. This scenario is referred to as the "14% RPS" case throughout the PRIS, but it is important to bear in mind that this scenario does not reflect current RPS targets.
- Four scenarios with 20% renewable energy penetration, but with different spatial distributions of generation (different ratios of solar PV, onshore wind, and offshore wind).
- Four scenarios with 30% renewable energy penetration, but with different spatial distributions of generation (different ratios of solar PV, onshore wind, and offshore wind).

All 10 scenarios rely on the 2011 load forecast for PJM, which projected a total system load of 969,596 GWh in 2026. Percentage amounts refer to the amount of this load (percentage of total energy rather than the percentage of installed capacity) that will be supplied by renewable energy systems under each scenario. Note that energy produced by non-wind and non-solar renewable energy systems is assumed to stay constant throughout every scenario, at about 1.5%, or 14,500 GWh.

After the original development of these 10 scenarios, additional modeling was performed for some sensitivities, including low load scenarios, low natural gas price scenarios, and scenarios where wind and solar production can be perfectly forecasted.

J-3.1. Renewable Energy Profiles (Task 1)

To develop a library of plausible future renewable energy projects for scenario development in Task 2, Task 1 developed power output profiles (wind energy and solar energy generated every 10 minutes) for a large set of *theoretical* potential new wind and solar PV installations throughout PJM. This included all wind and solar projects in the PJM Queue as of 2011 as well as a considerable number of additional theoretical projects. Task 1 was completed by AWS Truepower, which has since been purchased and integrated into UL LLC. AWS Truepower used three years of weather data (2004, 2005, and 2006) to build the library of power output profiles.[741]

The library of power output profiles developed included:

[741] PRIS, Task 1.

- Wind: 302 theoretical onshore wind plants (108.12 GW); 4,269 theoretical offshore wind plants (85.38 GW);[742] and the 254 wind plants in the 2011 PJM Queue (40.99 GW).
    - *For Maryland:* Nine theoretical onshore sites (1.11 GW); 354 theoretical offshore sites (7.08 GW); and eight wind projects from the PJM Queue (0.72 GW).
- Centralized Solar PV: 1,745 theoretical centralized solar PV plants (63.81 GW) and the 354 centralized solar PV plants in the 2011 PJM Queue (4.08 GW).
    - *For Maryland:* 73 theoretical sites (2.27 GW) and nine projects from the PJM Queue (0.12 GW).
- Distributed Solar PV: Estimates of the amount of distributed solar PV generation that could potentially be installed for 948 cities across PJM (51.85 GW).
    - *For Maryland:* 44 cities identified that could potentially contribute 3.48 GW of distributed solar in total.

J-3.2. PRIS Scenarios (Task 2)

J-3.2.1. Reference Case (2% Renewable Energy)

The Reference Case is the "do nothing" or "business as usual" case that assumes that the only wind and solar plants that will be active in 2026 will be those wind and solar plants that were installed as of January 1, 2012, and that all planning and construction of renewable energy projects ceased as of that date. Note that since the study began in 2011, the Reference Case used the PJM Queue as of June 2, 2011 to predict which additional power plants were likely to come online during the second half of 2011. All other projects in the PJM Queue were ignored for the Reference Case.

According to the Task 2 report, as of 2011, the majority of installed wind capacity in PJM was located in Illinois, Indiana, and Pennsylvania, while the majority of the existing solar was located in New Jersey. The Reference Case is used as a starting point to evaluate the changes due to increased wind and solar generation. Under this case, no additional investment or mitigation is needed in PJM—but state RPS standards will not be met.

For Maryland, the Reference Case included 250 MW of onshore wind and zero MW of centralized or distributed solar PV systems, although it is unclear exactly which Maryland renewable energy projects the PRIS considered to be "in service" as of 2011. Other data sources suggest that Maryland has yet to surpass 200 MW of wind installed as of 2017,[743] and that Maryland already had 37.1 MW of solar PV installed as of the end of 2011.[744]

The Reference Case assumes that across all of PJM:

- 5,122 GW of onshore wind power plants will produce 16,785 GWh of energy; and

[742] Offshore wind sites in this case are an analytical construct representing approximately 20-MW increments of resource potential, which should not be construed as any expectation on specific project size. Most eventual commercial offshore wind projects would be scaled in the hundreds of megawatts.

[743] American Wind Energy Association, "Wind Energy in Maryland," awea.org/Awea/media/Resources/StateFactSheets/Maryland.pdf.

[744] Larry Sherwood, *U.S. Solar Market Trends 2008*, Interstate Renewable Energy Council, 2009, irecusa.org/wp-content/uploads/2014/09/Solar-Market-Trends-2008.pdf.

- 72 MW of solar power plants will produce 122 GWh of energy.

J-3.2.2. Base Case (14% Renewable Energy)

The 14% Base Case is a scenario in which every state is able to simultaneously meet their respective RPS targets. The RPS targets for 2026, as they existed in 2011, were used in the PRIS. Maryland's historical RPS level of 20% was used.

Starting from the Reference Case, all additional qualifying projects that were in the PJM Queue as of June 2, 2011 were assumed to be completed by 2026. The qualifying PJM Queue projects had either a Facility Study Agreement (FSA) or Interconnection Service Agreement (ISA) in place. However, additional wind and solar plants above and beyond the PJM Queue were still needed in order to create a scenario that met all of the RPS targets, and these additional generating facilities were strategically chosen from the "library" of likely renewable energy development sites identified in the Task 1 Report. The RPS targets used by GE in the PRIS are provided in Table J-1.

Table J-1. 2026 RPS Targets Used to Develop the PRIS 14% Base Case

Year 2026	Required Energy from State Requirement									
State	Load (GWH)	%RE	%Other	%Wind	%Solar	Renewable Energy (GWh)	Projected Other Source Renewable Energy (GWh)	Net Additional Renewable (GWh)	Wind (GWh)	Solar (GWh)
Delaware	15,509	25.0%	3.1%	21.5%	3.5%	3,877	484	3,393	2,850	543
Indiana	24,971	0.0%	0.0%	0.0%	0.0%	0	0	0	0	0
Kentucky	8,567	0.0%	0.0%	0.0%	0.0%	0	0	0	0	0
Ilinois	126,569	25.0%	3.1%	23.5%	1.5%	31642.25	3,953	27,689	25,790	1,899
Maryland	83,979	20.0%	2.5%	15.5%	2.0%	16,796	2,098	14,697	13,018	1,680
Michigan	4,682	10.0%	1.2%	10.0%	0.0%	468.201	58	410	410	0
New Jersey	100,159	22.5%	2.8%	14.4%	5.3%	22,536	2,816	19,720	14,404	5,316
North Carolina	9,193	6.3%	0.8%	6.1%	0.2%	574.5625	72	503	484	18
Ohio	196,943	12.5%	1.6%	12.0%	0.5%	24,618	3,076	21,542	20,558	985
Pennsylvania	194,329	8.0%	1.0%	7.5%	0.5%	15546.32	1,942	13,604	12,632	972
Tennessee	2,341	0.0%	0.0%	0.0%	0.0%	0	0	0	0	0
Virginia	149,566	7.5%	0.9%	7.5%	0.0%	11217.45	1,401	9,816	9,816	0
Washington DC	11,537	20.0%	2.5%	17.5%	2.5%	2,307	288	2,019	1,731	288
West Virginia	41,251	12.5%	1.6%	12.5%	0.0%	5156.375	644	4,512	4,512	0
PJM 14%	**969,596**	**13.9%**	**1.5%**	**11.2%**	**1.2%**	**134,739**	**14,500**	**120,239**	**108,539**	**11,700**
PJM 20%	**969,596**	**20.0%**	**1.5%**	**15.50%**	**3.0%**	**193,919**	**14,500**	**179,419**	**150,331**	**29,088**
PJM 30%	**969,596**	**30.0%**	**1.5%**	**23.5%**	**5.0%**	**290,879**	**14,500**	**276,379**	**227,899**	**48,480**

Source: PRIS, Task 2.

In total, the Base Case assumes that 11.2% of PJM load will be met by a combination of onshore and offshore wind sites; that 1.2% of PJM load will be met with centralized and distributed solar PV sites; and that the use of other types of renewable energy will remain constant at 1.5% of PJM load.

The Base Case implies that there will be significant growth in wind power, above and beyond the PJM Queue, including offshore wind sites in New Jersey, Delaware, and Virginia (see Table J-2). Wind growth in Maryland was expected to be modest, with only an additional 130 MW of wind added to the capacity used in the Reference Case. Most of these Maryland wind sites were assumed to be located in the Allegheny Mountains west of Cumberland (see Figure J-1). The Base Case assumed that no offshore wind projects in Maryland would be in service by 2026.

Table J-2. Wind Summary, PRIS 14% Base Case

14% Base Case	Onshore						Offshore						Total Wind		
	Queue			Additional			Queue			Additional			14% Base Case		
States	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF	MW	GWH	CF
Delaware							450	1,340	0.34	550	1,653	0.34	1,000	2,993	0.34
Illinois	7,589	26,743	0.40	4,204	15,553	0.42							11,793	42,296	0.41
Indiana	4,051	12,629	0.36	3,054	10,971	0.41							7,105	23,600	0.38
Maryland	380	1,191	0.36										380	1,191	0.36
Michigan	200	633	0.36										200	633	0.36
New Jersey							1,099	3,241	0.34	901	2,757	0.38	2,000	5,999	0.34
North Carolina	374	840	0.26										374	840	0.26
Ohio	3,498	10,488	0.34	1,624	5,233	0.37							5,122	15,721	0.35
Pennsylvania	1,866	5,448	0.33	614	1,988	0.37							2,480	7,436	0.34
Virginia	38	113	0.34							1,000	3,038	0.35	1,038	3,151	0.35
West Virginia	1,237	3,812	0.35	345	1,110	0.37							1,582	4,922	0.36
Total	19,233	61,897	0.37	9,841	34,855	0.40	1,549	4,582	0.34	2,451	7,447	0.35	33,074	108,782	0.38

Source: PRIS, Task 2.

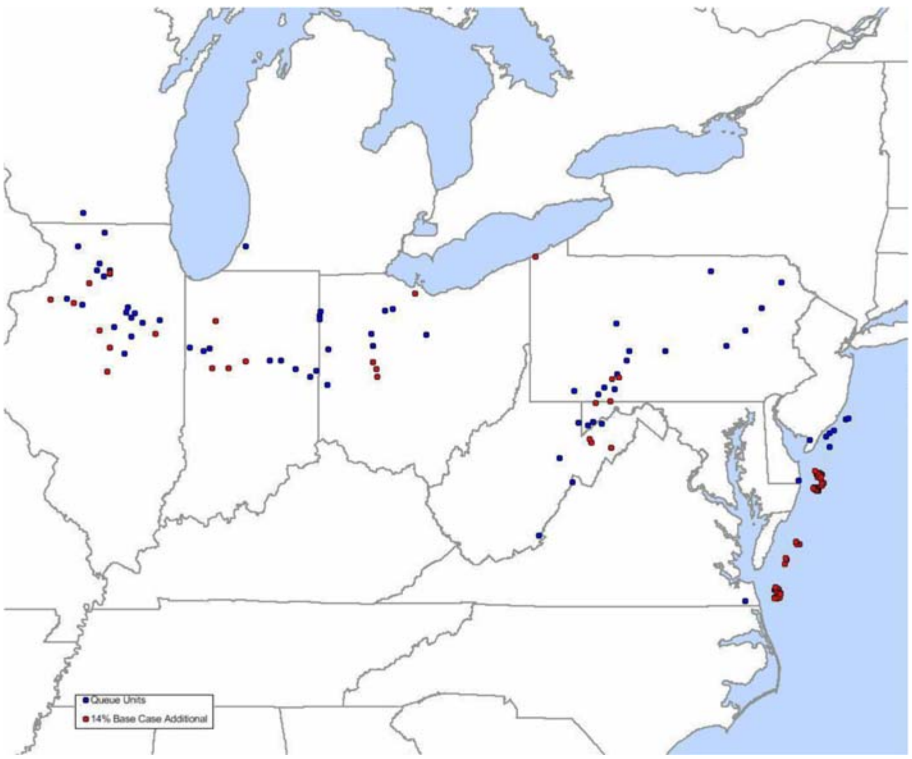


Figure J-1. Wind Sites, PRIS 14% Base Case

Source: PRIS, Task 2.

The Base Case assumed that New Jersey would be the leader in installing new solar PV, for both centralized and distributed systems. Although very few Maryland projects were in the PJM Queue as of 2011, the PRIS determined that the largest amount of additional centralized capacity needed should be installed in Maryland. In total, under the 14% Base Case, Maryland ranks third among PJM states in installed solar capacity (see Table J-3 and Figure J-2).

Table J-3. Solar Summary, PRIS 14% Base Case

14% Base Case	Central PV						Distributed PV						Total PV		
	Queue			Additional			Queue			Additional			14% Base Case		
States	MW (AC rating)	GWH	CF	MW (AC rating)	GWH	CF	MW (AC rating)	GWH	CF	MW (AC rating)	GWH	CF	MW (AC rating)	GWH	CF
Delaware	0	0	0.00	150	272	0.21	0	0	0.00	179	271	0.17	329	543	0.19
Illinois	10	16	0.19	376	629	0.19	0	0	0.00	693	949	0.16	1079	1595	0.17
Maryland	40	71	0.20	423	769	0.21	0	0	0.00	545	840	0.18	1008	1680	0.19
North Carolina	5	9	0.21	0	0	0.00	0	0	0.00	6	9	0.18	11	18	0.19
New Jersey	1171	2047	0.20	337	598	0.20	0	0	0.00	1790	2658	0.17	3298	5303	0.18
Ohio	15	22	0.18	272	470	0.20	0	0	0.00	369	492	0.15	655	984	0.17
Pennsylvania	227	399	0.20	48	86	0.21	0	0	0.00	335	486	0.17	609	971	0.18
Virginia	180	317	0.20	0	0	0.00	0	0	0.00	0	0	0.00	180	317	0.20
Washington DC	0	0	0.00	0	0	0.00	0	0	0.00	186	288	0.18	186	288	0.18
Total	**1648**	**2882**	**0.20**	**1606**	**2824**	**0.20**	**0**	**0**	**0.00**	**4102**	**5994**	**0.17**	**7169**	**11412**	**0.18**

Source: PRIS, Task 2.

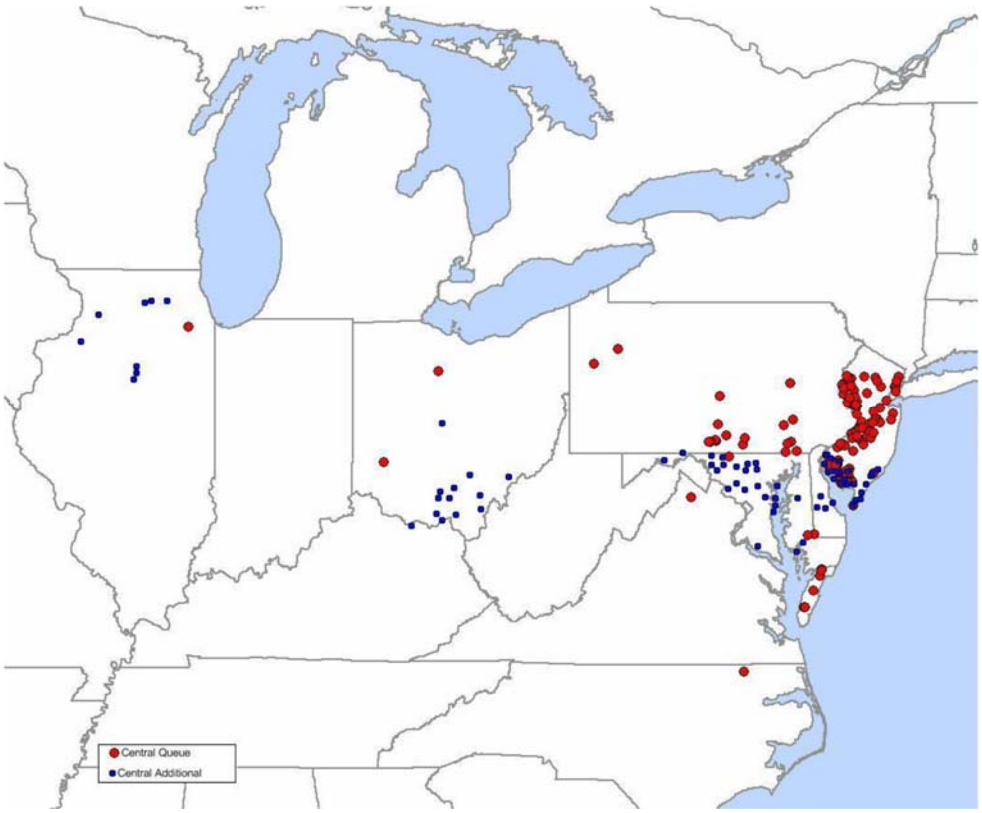


Figure J-2. Centralized Solar Sites, PRIS 14% Base Case

Source: PRIS, Task 2.

J-3.2.3. <u>20% and 30% Renewable Penetration Scenarios</u>

The remaining set of eight scenarios were all developed to enable a detailed evaluation of the operational impacts of incremental wind and solar generation variability and uncertainty on PJM's bulk electric power system. The eight scenarios were developed for different wind and solar penetration build-outs, at either 20% or 30% renewable energy. All eight of these scenarios continue to include 14,500 GWh (~1.5% of the PJM load energy) of other renewable sources that count toward meeting the renewable targets, including biomass plants. Since these other renewable energy resources do not exhibit the variability and uncertainty associated with wind and solar generation, they were blended with the rest of the PJM generation resources.

These eight scenarios include all wind and solar projects that counted towards the Reference and Base Cases and add additional wind and solar sites from the "library" developed as part of Task 1. Some scenarios are more heavily weighted towards solar, offshore wind, onshore wind, etc. and therefore a different set of potential generating facilities is needed to model each scenario. By definition, these eight scenarios go above and beyond the state RPS requirements (as they existed in 2011) to envision a generation expansion future with more wind and solar generation.

Different amounts of additional renewable energy generation, above and beyond what was already accounted for in the 14% Base Case, were added to each of the additional eight scenarios (see below and Table J-4). Focusing specifically on changes in the mix of generation located in Maryland, the scenarios are:

1. **20% Low offshore wind, best onshore wind (LOBO):** No additional wind added in Maryland relative to the 14% Base Case, but 182 MW of solar PV added. Totals of 380 MW onshore wind, zero MW offshore wind, and 1,190 MW of solar PV in Maryland. In this scenario, all additional onshore wind sites were assumed to be constructed in Illinois, which has the best wind resources in PJM.
2. **20% Low offshore wind, dispersed onshore wind (LODO):** Maryland renewable energy generation is unchanged from the LOBO scenario. Additional onshore wind sites are spread out between Illinois, Indiana, Ohio, Pennsylvania, and West Virginia.
3. **20% High offshore wind, best onshore wind (HOBO):** 40 MW of offshore wind are added in Maryland, but onshore wind in Maryland is reduced to 180 MW. Solar PV remains the same (1,190 MW in Maryland).
4. **20% High solar, best onshore wind (HSBO):** No additional wind added in Maryland relative to the 14% Base Case (380 MW onshore), but considerably more solar PV at 3,215 MW.
5. **30% Low offshore wind, best onshore wind (LOBO):** No additional wind added in Maryland relative to the 14% Base Case (380 MW onshore), and a total of 2,854 MW solar PV.
6. **30% Low offshore wind, dispersed onshore wind (LODO):** No additional wind added in Maryland relative to the 14% Base Case (380 MW onshore), and a total of 2,854 MW solar PV.
7. **30% High offshore wind, best onshore wind (HOBO):** 1,520 MW of offshore wind are added in Maryland, while onshore wind remains at 380 MW and solar PV remains at 2,854 MW.
8. **30% High solar, best onshore wind (HSBO):** No additional wind added in Maryland relative to the 14% Base Case (380 MW onshore), but considerably more solar PV, at 4,699 MW.

Table J-4. List of All PRIS Study Scenarios

Scenario	Renewable Penetration in PJM	Wind/Solar (GWh)	Wind + Solar Siting	Comments
2% BAU	Reference	Existing wind + solar	Existing Plants (Business as Usual)	Benchmark Case for Comparing Scenarios
14% RPS	Base Case 14%	109 / 11	Per PJM Queue & RPS Mandates	Siting based on PJM generation queue and existing state mandates
20% LOBO	20%	150 / 29	Low Offshore + Best Onshore	Onshore wind selected as best sites within all of PJM
20% LODO	20%	150 / 29	Low Offshore + Dispersed Onshore	Onshore wind selected as best sites by state or region
20% HOBO	20%	150 / 29	High Offshore + Best Onshore	High offshore wind with best onshore wind
20% HSBO	20%	121 / 58	High Solar + Best Onshore	High solar with best onshore wind
30% LOBO	30%	228 / 48	Low Offshore + Best Onshore	Onshore wind selected as best sites within all of PJM
30% LODO	30%	228 / 48	Low Offshore + Dispersed Onshore	Onshore wind selected as best sites by state or region
30% HOBO	30%	228 / 48	High Offshore + Best Onshore	High offshore wind with best onshore wind
30% HSBO	30%	179 / 97	High Solar + Best Onshore	High solar with best onshore wind

Source: PRIS, Final Project Review.

Note: BAU = Business as usual (Reference Case).

J-3.3. 2017-2018 PJM Updates Affecting the PRIS Development Scenarios

This subsection assesses changes in load growth, generation mix, and market conditions since the PRIS was issued in 2014. It is important to note that the PRIS was not intended to be a study forecasting market trends and conditions. Instead, the PRIS was designed to test the operation and reliability of the PJM grid under assumed scenarios of combinations of onshore wind, offshore wind, distributed solar PV, and central (utility-scale) solar PV. Put another way, the PRIS was meant to highlight potentially difficult operating periods or areas of concern for PJM to plan and prepare for.

J-3.3.1. <u>Reduced PJM Load Projection and RPS Target Basis</u>

In the PRIS, GE determined that since the total system load in 2026 was projected to be 969,596 GWh, a grand total of 134,774 GWh of renewable energy would be needed for the 14% Base Case.

However, PJM total electric loads have not grown as fast as the load forecast from 2011 anticipated. For 2017, 808,229 GWh of energy was produced in PJM;[745] and as of January 2018, annual net energy for 2018 was projected to be slightly lower, at 806,725 GWh.[746] According to the PJM January 2018 load forecast, annual net energy use for 2026 is

[745] Joe Bowring, *2017 State of the Market Report for PJM: MC Special Session*, Monitoring Analytics, LLC, March 2018, pjm.com/-/media/committees-groups/committees/mc/20180322-state-of-market-report-review/20180322-2017-state-of-the-market-report-review.ashx.

[746] PJM Resource Adequacy Planning Department, *PJM Load Forecast Report – January 2018*, pjm.com/-/media/library/reports-notices/load-forecast/2018-load-forecast-report.ashx?la=en, Table E-1.

projected to be 828,788 GWh, or about 85% of the 2026 load projection used in the PRIS. Assuming these trends continue, less renewable energy capacity will be needed to reach the 14% Base Case target level—14% of the 2026 forecast is now 116,030 GWh. Figure J-3 illustrates these shifts in the PJM 2026 load and the reduced 14% renewable energy target level.

It should also be noted that state RPS targets have not remained constant. The District of Columbia and three states (Illinois, Maryland, and New Jersey) have raised their RPS requirements since the PRIS was issued, while the RPS requirements in West Virginia were repealed in 2015.[747] Other state RPS requirements continue to increase until their penultimate end point. Therefore, the total amount of renewable energy generation needed to meet current RPS targets applicable to the PJM footprint will likely vary from the 14% level specified in the PRIS.

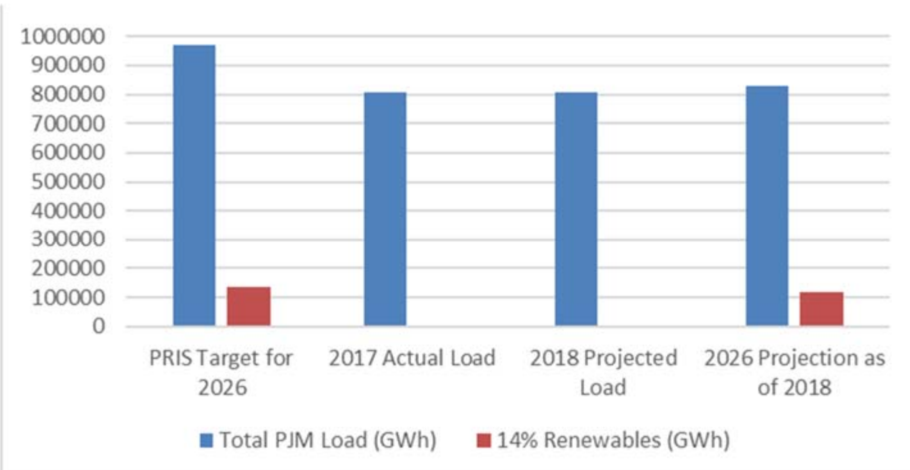


Figure J-3. Projected PJM Load, 2026

J-4. Analytical Approach and Results (Tasks 3 and 4)

The inputs, modeling, and analysis methods used by the PRIS are described in this section. Figure J-4 provides a diagram illustrating the analytic elements, outputs, and process relationships of the study.

[747] John Eick, "West Virginia Becomes First State to Repeal RPS," American Legislative Exchange Council, 2015, alec.org/article/west-virginia-becomes-first-state-repeal-rps/.

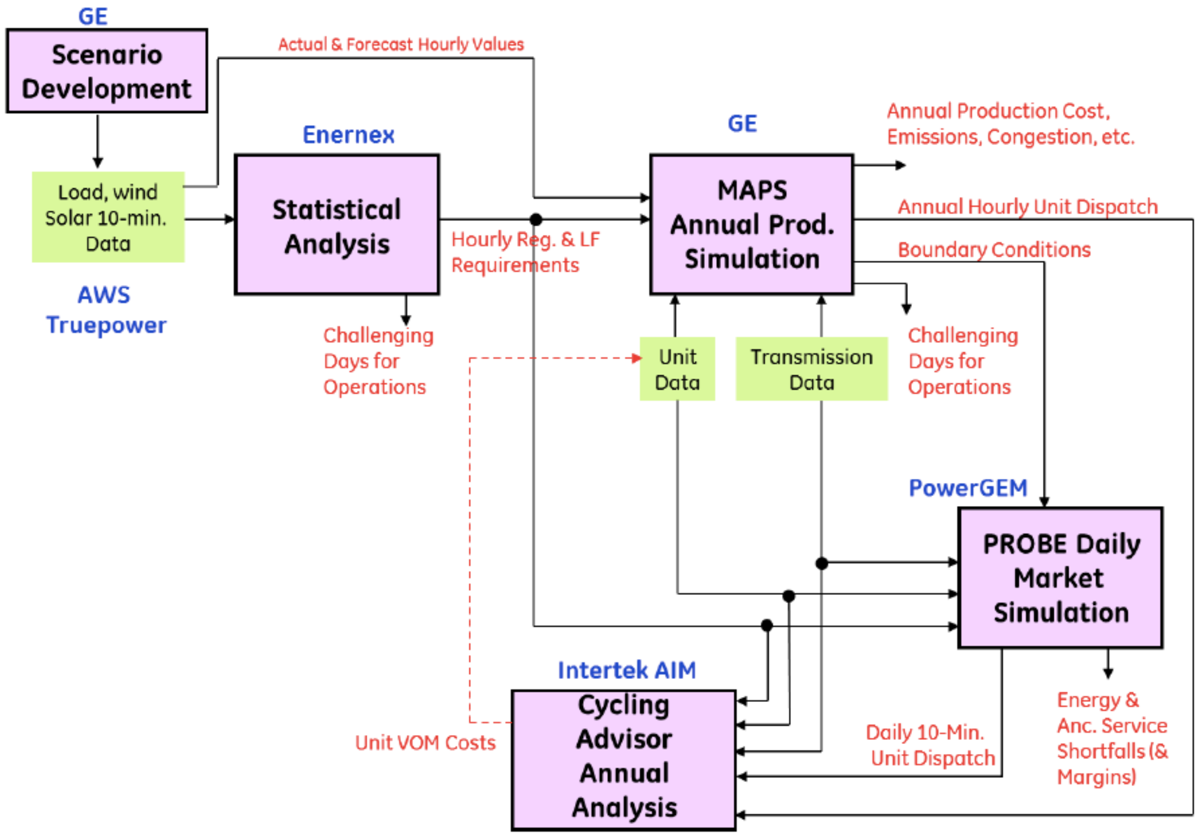


Figure J-4. PRIS Overview

Source: PRIS, Task 3A, Part A.

J-4.1. Primary Study Inputs[748]

J-4.1.1. Plant Characteristics

Individual thermal power plants are represented as multi-block units with constant heat rates for each block, along with other operating, economic, and environmental parameters. The operating reserve capability of each thermal unit is based on the unit's ramp rate and type, and is equal to some fraction of its total capacity. Three types of hydro resources are modeled: pondage hydro, pumped storage hydro, and fixed hourly pattern hydro. Fuel and O&M costs of hydro resources are assumed to be zero, and fixed and capital costs are not addressed since these costs do not impact economic dispatch. Wind and solar resources are assumed to have zero fuel and O&M costs, and hence are assumed to be available at no cost in the dispatch stack. The hourly generation is a model output that accounts for any necessary curtailment.

J-4.1.2. Load Projections

PJM load projections are based on PJM's 2011 *Load Forecast Report*. Since the historical wind and solar data from 2004-2006 are used for the analysis, for consistency, the load shapes used are also from the same years. The load shapes are then energy-scaled to the 2026 annual energy forecast for each zone. Load for the rest of the Eastern Interconnection is based on the Ventyx Velocity Suite's "Historical and Forecast Demand by Zone,"

[748] PRIS, Task 3A, Part A.

aggregated to the GE's Multi-Area Production Simulation (MAPS) pool levels, which are roughly equivalent to the North American Electric Reliability Corporation (NERC) sub-regions. Individual control area historical load shapes were then energy-scaled using a pool-level scaling factor. Note that load forecasts as of 2018 anticipate much lower PJM loads in 2026 than were assumed by the PRIS.

All wind and solar units were modeled as hourly load modifiers that follow a predefined hourly generation pattern. Figure J-5 shows how the hourly net load (load minus wind minus solar) profile for the HSBO case becomes increasingly variable with increasing renewable energy penetration levels, requiring substantial changes in daily grid balancing operations. Note, in particular, the decreases in net load between the Reference Case and the 30% HSBO scenario in Figure J-5. Operationally, the net load will drive the decisions and algorithms for deployment of controllable resources (e.g., conventional generating units, energy transactions with neighboring markets and areas, and demand response).

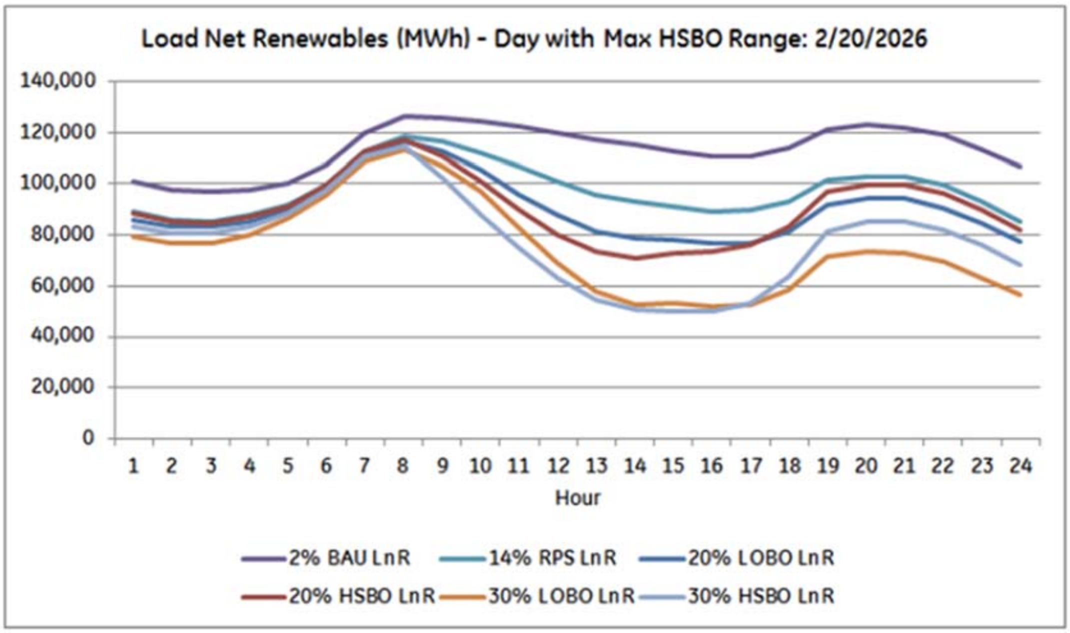


Figure J-5. Hourly Net Load Profile Under Different PRIS Scenarios

J-4.1.3. Fuel and Emissions Price Projections

Monthly natural gas prices for the PRIS were based on the Henry Hub prices from the AEO 2012, with "basis differentials" reflecting the time- and location-dependent variations in the cost of natural gas. Annual coal prices were also based on data from the AEO 2012, adjusted to account for transportation costs. Oil price projections were based on the Ventyx Velocity Suite NYMEX Forecast. Projected nuclear fuel prices were taken from Ventyx Energy Velocity™.[749] The PRIS scenarios assume that all operating plants will have appropriate control technology (i.e., compliance by all plants) and hence, all emission prices are assumed to be $0/ton for criteria pollutants such as SOx and NOx, and for GHGs such as CO_2.

[749] ABB purchased Ventyx after the PRIS was published. ABB now refers to the Ventyx data and software as "ABB Ability™ Velocity Suite. *See:* new.abb.com/enterprise-software/energy-portfolio-management/market-intelligence-services/velocity-suite for more information.

J-4.2. Modeling, Analysis, and Results

J-4.2.1. Transmission Modeling[750]

The PRIS simulation models included the full configuration of the Eastern Interconnection transmission grid, including all the major transmission lines, transmission system buses, and line constraints. Also included were all of the major thermal and contingency constraints with summer and winter ratings applied, and other operational constraints. For inter-regional transmission, transmission "hurdle rates" were sourced from the Eastern Interconnection Planning Collaborative (EIPC) study.[751]

The Transmission Modeling task explicitly identified transmission constraints from both reliability and congestion standpoints and developed transmission overlays that identified new or upgraded transmission lines needed to resolve the constraints. For the 14% Base Case, the estimated cost of the transmission overlay is $3.7 billion, involving more than 750 miles of new and upgraded transmission (see Table J-5). About 71% ($2.6 billion) of the transmission overlay was needed to provide an outlet for 20 GW of western wind projects in the ComEd and American Electric Power (AEP) service areas to eastern load centers. Another 18% ($0.7 billion) was needed to provide an outlet for 4 GW of offshore wind in Delaware, Maryland, New Jersey, and Virginia. The remaining 11% of transmission upgrades were dispersed throughout the PJM footprint.

Table J-5. Summary of New Transmission Lines and Upgrades for PRIS Scenarios

Scenario	765 kV New Lines (Miles)	765 kV Upgrades (Miles)	500 kV New Lines (Miles)	500 kV Upgrades (Miles)	345 kV New Lines (Miles)	345 kV Upgrades (Miles)	230 kV New Lines (Miles)	230 kV Upgrades (Miles)	Total (Miles)	Total Cost (Billion)	Total Congestion Cost (Billion)
2% BAU	0	0	0	0	0	0	0	0	0	$0	$1.9
14% RPS	260	0	42	61	352	35	0	4	754	$3.7	$4.0
20% Low Offshore Best Onshore	260	0	42	61	416	122	0	4	905	$4.1	$4.0
20% Low Offshore Dispersed Onshore	260	0	42	61	373	35	0	49	820	$3.8	$4.9
20% High Offshore Best Onshore	260	0	112	61	363	122	17	4	939	$4.4	$4.3
20% High Solar Best Onshore	260	0	42	61	365	122	0	4	854	$3.9	$3.3
30% Low Offshore Best Onshore	1800	0	42	61	796	129	44	74	2946	$13.7	$5.2
30% Low Offshore Dispersed Onshore	430	0	42	61	384	166	44	55	1182	$5.0	$6.3
30% High Offshore Best Onshore	1220	0	223	105	424	35	14	29	2050	$10.9	$5.3
30% High Solar Best Onshore	1090	0	42	61	386	122	4	4	1709	$8	$5.6

Source: PRIS, Task 3A, Part C.

[750] PRIS, Task 3A, Part C.

[751] EIPC, "Post-DOE: 2015-present," eipconline.com/project-overview.

The 14% Base Case transmission overlay was used as the starting point transmission model for all 20% and 30% scenarios. Expanded transmission overlays were developed for the 20% and 30% scenarios based on any identified reliability and congestion issues in those models. Differing mixes of offshore wind, distributed solar, etc. resulted in different transmission constraints. While costs are similar between the 14% Base Case and the four 20% scenarios, costs become increasingly higher in the four 30% scenarios. This is related to the high concentration of wind power needed, either in Illinois and Indiana (for LOBO) or from offshore wind sites (for HOBO). Because a large amount of solar PV resources is expected to be distributed (and located in relatively urban areas), scenarios with higher amounts of solar PV are not expected to need as much investment in transmission upgrades.

The transmission model for the PRIS was built by starting from the PJM Regional Transmission Expansion Plan (RTEP) models. Based on these models, GE added in the additional load and generation needed for each of the 10 scenarios developed under Task 2. New transmission lines were iteratively added to the model to resolve constraints until congestion costs between two nodes were no more than $5/MWh, averaged across the year. In some scenarios, this means that significant congestion costs still remain, even after accounting for the proposed new lines.

J-4.2.2. <u>Statistical Analysis and Reserves</u>[752]

PRIS Task 3A, Part B consisted of a statistical analysis of the load and renewable energy generation patterns used in modeling the 10 PRIS scenarios, as well as a separate study on the increased levels of regulation capacity (reserves) needed to manage variable generation in each of the 10 PRIS scenarios.

The main purpose of the statistical analysis section was to display and analyze the trends and patterns inherent in the forecasted electric load data as well as in wind and PV generation forecasts. These data were then used in the production simulation, but the statistical analysis by itself only serves to characterize the data. Information presented in this section includes identification of the peak load hour of the year; charts showing the variation in load and generation by season and month; load duration curves; and information on the frequency of short-term load and duration changes (e.g., how often does generation change by +/- 1 GW over a 10-minute period in the 30% HSBO scenario?). PJM's large geographic footprint is of significant benefit for integrating wind and solar generation, and greatly reduces the magnitude of variability-related challenges as compared to smaller balancing areas.

With increasing levels of wind and solar generation, it will be necessary for PJM to carry higher levels of regulation to respond to the inherent variability and uncertainty in the output of those resources. Statistical analysis of wind, PV, and load data was employed to determine how much additional regulation capacity would be required to manage renewable variability in each of the study scenarios. The regulation requirement for wind and solar was combined with the regulation requirement for load (a percentage of peak or valley load MW, per PJM rules) to calculate a total regulation requirement value, as listed in Table J-6. It was determined that due to the size and geographic spread of the PJM system, no additional primary reserves (synchronized or non- synchronized) or secondary reserves would be required to cover the forecast uncertainty.

[752] PRIS, Task 3A, Part B.

Table J-6. Additional Regulation Capacity Required for PRIS Study Scenarios

Regulation	Load Only	2% BAU	14% RPS	20% HOBO	20% LOBO	20% LODO	20% HSBO	30% HOBO	30% LOBO	30% LODO	30% HSBO
Maximum (MW)	2,003	2,018	2,351	2,507	2,721	2,591	2,984	3,044	3,552	3,191	4,111
Minimum (MW)	745	766	919	966	1,031	1,052	976	1,188	1,103	1,299	1,069
Average (MW)	1,204	1,222	1,566	1,715	1,894	1,784	1,958	2,169	2,504	2,286	2,737
% Increase Compared to Load		1.5%	30.1%	42.4%	57.3%	48.2%	62.6%	80.2%	108.0%	89.8%	127.4%

Source: PRIS, Task 3A, Part B

BAU = Business as usual (Reference Case).

J-4.2.3. Production Simulation[753]

Production simulation analysis was performed with GE's MAPS model to evaluate hour-by-hour grid operation of each scenario with different wind and load profiles, with modeling of market and operational procedures based on consultation with PJM. The output of the simulation included hourly production costs, LMPs, transmission flows and congestion, environmental emissions, and other detailed information. The MAPS simulation was also used to identify challenging days for further sub-hourly analysis using PowerGEM's Portfolio Ownership & Bid Evaluation (PROBE) model, along with the boundary conditions (i.e., hourly flows between PJM and its neighbors).

The MAPS production simulations were conducted in one-hour time steps, and the real-time adjustments of generation to compensate for variations in the balancing area net demand were not modeled explicitly. Instead, the responsive generation necessary in a given hour to regulate the net demand of the balancing area was represented as constraints on the unit commitment and economic dispatch algorithms in the production model. Constraints for each scenario, accounting for the additional variability and short-term uncertainty introduced by wind generation, were developed by statistical analysis using PowerGEM's Transmission Adequacy and Reliability Assessment (TARA) program.

Study Results: Production Simulation

- PJM system production costs drop progressively with higher levels of renewable energy penetration. (Production Costs = variable system costs [fuel, variable O&M, and emission tax/allowance costs] and startup costs, but not fixed costs or capital costs of wind and solar energy.) See Figure J-6.
- Coal and gas generation are reduced under all scenarios; on average, delivered renewable energy displaced PJM coal-fired generation, PJM gas-fired generation, and PJM imports roughly equally.
- Emissions of criteria pollutants and GHGs are reduced.
- The transmission system would handle all resulting power transfers; all tie-line transmission limits were modeled.
- Higher penetrations of renewable energy (20% and 30%) create operational patterns (primarily with gas generation) that are significantly different than what is common today.

[753] PRIS, Task 3A, Part D.

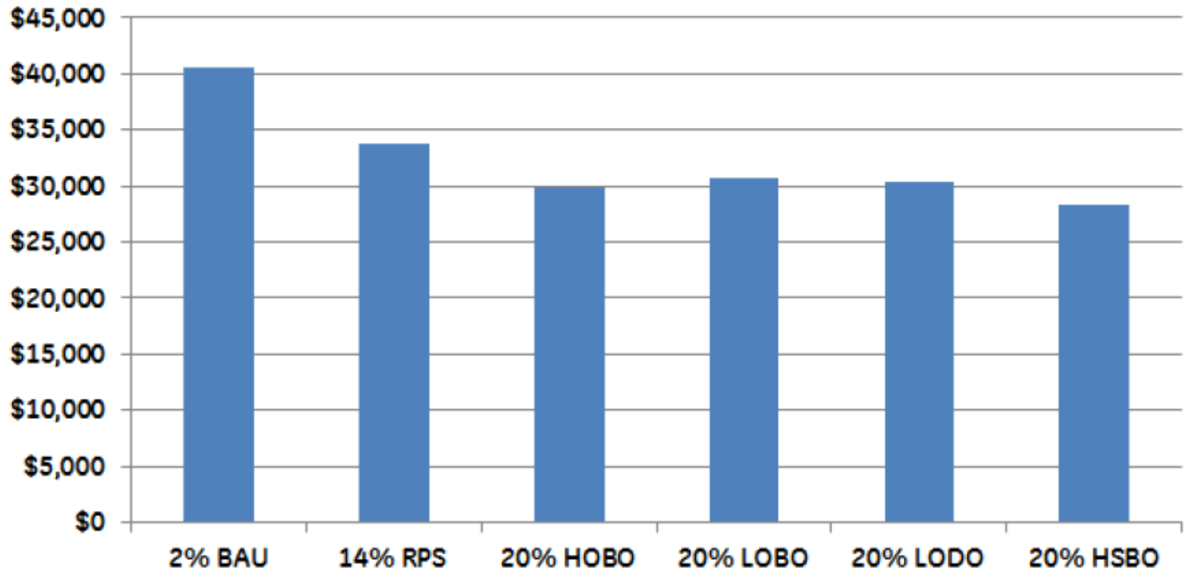


Figure J-6. PJM System Production Costs, PRIS Scenarios

Source: PRIS, Task 3A, Part D

Note: BAU = Business as usual (Reference Case).

J-4.2.4. Sub-hourly Simulation[754]

Sub-hourly simulation analysis with the PROBE model was used to quantify grid performance trends and to investigate potential mitigation measures in the 10-minute time frame. PROBE used the same inputs as MAPS to simulate challenging days identified by the statistical analysis and the hourly production simulation. The PROBE market simulation analyzed potential short-term operational issues created by each integration scenario, closely following PJM current market rules including detailed modeling of various ancillary market requirements.

[754] PRIS, Task 3A, Part E.

Study Results: Sub-hourly Analysis

Overall: The study findings, in general, support that the PJM system, with adequate transmission and ancillary services in the form of regulation, will not have any significant issues absorbing the higher levels of renewable energy penetration considered in the study.

- "Adequate Transmission" is the additional transmission overlay added to the system to keep the congestion down to a target level, as developed under Transmission Modeling.
- "Adequate Regulation" is the additional regulation required to mitigate the wind and solar variability, as described in Section 3.2.2, "Resource-Specific Technical and Economic Potential."
- No additional primary (synchronized or non-synchronized) or secondary reserves were needed for contingency or forecast uncertainty.
- In general, all the simulations of challenging days revealed successful operation of the PJM real-time market, with no unserved load and minimal renewable energy curtailment.
- The level of difficulty for real-time operations largely depends on the day-ahead unit commitment.

J-4.2.5. Renewable Capacity Valuation Analysis[755]

This analysis involved calculating the loss of load expectation (LOLE), in days per year for each scenario for the year 2026, using the GE Multi-Area Reliability Simulation (MARS) model. The analysis quantified the impact of wind and solar generation on overall reliability measures, as well as the capacity values of the renewable energy resources. Neighboring systems were not modeled in this portion of the analysis, to concentrate the analysis on the capacity value of renewable energy generation within the PJM system. Thus, only the PJM load profiles and generation characteristics impacted the capacity value of the renewable energy generation.

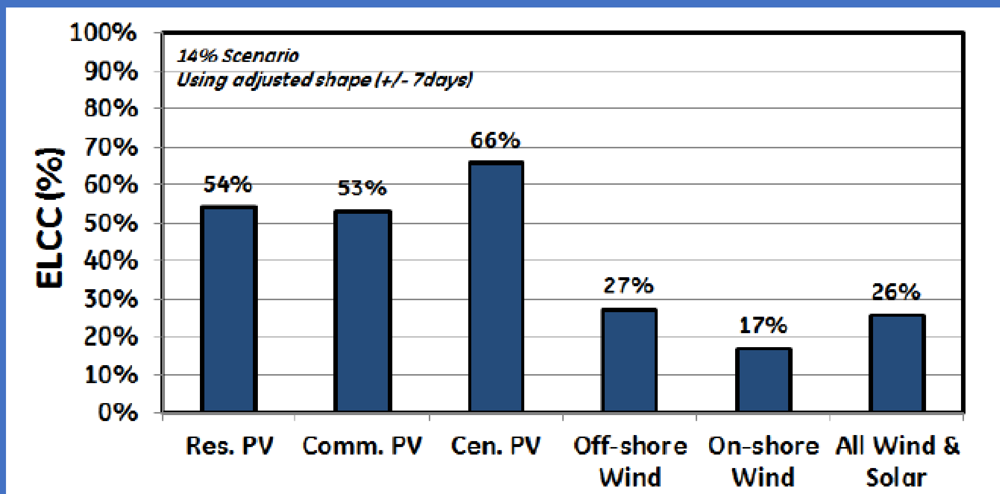
The analyses in the final report are based on the effective load carrying capability (ELCC) of wind/solar resources, a method that provides an estimation of the capacity value of a resource by focusing primarily on the resource output during the hours that carry more capacity adequacy-related reliability risk. To test the impact of different profile years, in addition to the 2006 profile year, the load and wind profiles from 2004-2005 were used in the Reference Case, 14% Base Case, 20% LOBO, and 30% LOBO Scenarios. Differences in operational and economic performance were relatively small.

The capacity value analysis did not address possible secondary impacts to the capacity market such as increased retirements due to non-economic performance, or whether generators must receive more revenue from the capacity market because of decreased revenues in the energy market.

[755] PRIS, Task 3A, Part F.

Study Results: ELCC

- ELCC values vary as the resource penetration levels change, and therefore a range is provided for each resource type. The ELCC values for each resource in the 14% Base Case are provided in the figure below.
- The study recommends that PJM consider an annual or bi-annual capacity valuation adjustment for the different classes of renewable energy resources.



ELCC for Different Resources in the 14% Base Case

J-4.2.6. Unit Cycling Impact Analysis[756]

Unit cycling analysis was performed to provide estimates of cycling related wear-and-tear costs and variable O&M costs. Intertek AIM's proprietary unit commitment model Cycling Advisor was used to derive the incremental variable O&M costs of power plant operation by utilizing its ability to model unit cycling damage. Cycling Advisor used the hourly MW dispatch and other inputs such as fuel costs, variable O&M costs, equipment damage costs, unit startup costs, and emission amounts from MAPS. The Loads Model (LM) was also used to evaluate the damage and damage cost due to cycling at an hourly and a 10-minute operating profile.

[756] PRIS, Task 3A, Part G.

Study Results: Cycling Impact Analysis

- CCGTs perform the majority of the on/off cycling in the scenarios, with the coal units performing the load-follow cycling.
- Increased cycling of coal and combined cycle units result in higher cycling variable operations and maintenance (VOM) costs, and reduced baseload VOM costs.
- For scenarios that experience increased emissions due to cycling, the increases are dominated by supercritical coal emissions.
- NOx and SOx rates increase at low loads for coal and decrease for gas plants.
- Load-follow cycling is the primary contributor of cycling-related emissions.
- Including the effects of cycling in emissions calculations does not significantly change the level of emissions for scenarios with higher levels of renewable energy generation. However, on/off cycling and load-following ramps do increase emissions over steady state levels.

J-4.2.7. Market Analysis and Mitigation Options[757]

This study task quantified the market impacts under different scenarios to help identify potential improvements to PJM's market design and procedures that could facilitate higher levels of renewable energy generation in PJM. Hourly MAPS simulations provided market-related information such as annual bid production cost, average LMP, annual congestion cost, and annual emissions. The sub-hourly PROBE simulations determined the impact of renewables on the imbalance market, with particular focus on quick start capacity committed in the real-time dispatch.

Uncertainties in the load and renewable energy resource availability were modeled by modified load forecast and unit availability between day-ahead and real-time runs. Multiple sub-hourly PROBE simulations were performed for selected days to study the impact of better and shorter-term renewable forecasts and unit commitment, which included the following sub-hourly sensitivity simulations over previously considered selected challenging days:

- 4-hour-ahead wind and solar forecast and unit commitment;
- Perfect wind and solar day-ahead forecast; and
- Reduced wind and solar forecast error.

Sensitivity cases for low natural gas prices and high carbon prices were also considered, in order to evaluate the impact on short-term operations.

The Mitigations component of this task included investigation of changes to the infrastructure, and accompanying practices, that could improve system performance. An overview of best practices from other markets was completed by review of the industry and academic literature, focusing on several well-known variable energy integration issues. As PJM's energy scheduling practices at the time of the PRIS already incorporated recommendations from previous renewable energy integration studies, simulations were performed to consider the impact of better renewable energy forecasts and meeting reserve requirements by non-thermal resources (such as energy storage), to determine whether

[757] PRIS, Tasks 3B & 4.

additional mitigation measures were required. Additional analysis included accounting for the cycling costs in the dispatch of generation, and consideration of limited ramp-rate capabilities of existing power plants.

Study Results: Market Analysis and Mitigations

- Use of wind and solar forecasts for mid-term (e.g. 4-hour-ahead) unit commitment and regulation services can yield reduced operating costs:
  - Operating-Day Recommitment Process
    - With present practices, wind and solar forecast errors are compensated by re-dispatch of committed generation and commitment of combustion turbine (CT) units in the real-time market.
    - System efficiency could be improved with a short-term (4- to 6-hour) economic recommitment process during the operating day, based on a 4- to 6-hour-ahead wind + solar forecast.
  - Dynamic Procurement of Regulation
    - The amount of "additional" regulation required can be optimized each hour to be the "right" amount for the wind + solar generation in that hour, based on the short-term wind + solar forecast for that hour.
- Benefits of Energy Storage for Regulation Reserve – A reduction in regulation reserve requirements by using energy storage caused a small drop in PJM total production cost. (However, benefits of the full range of service offerings of energy storage in PJM were not evaluated.)

Topics for Future Study

- Impacts of reduced energy revenues for conventional power plants
  - Investigate the potential consequences of reduced capacity factors and energy revenues on the conventional generation fleet in PJM.
- Flexibility improvement for conventional power plants
  - Investigate possible methods to enhance limited ramping or cycling capabilities at existing coal or gas units.
- Expanding system flexibility through active power controls on wind and solar plants
  - Investigate how wind and solar plants could contribute to frequency response, and work toward interconnection requirements that ensure PJM will continue to meet its grid-level performance targets.

J-5. PRIS Relevance to Maryland RPS Considerations

The PRIS provides quantifiable insights into grid system operational requirements and impacts associated with the postulated set of renewable energy scenarios. The credibility of the PRIS derives from its high-resolution modeling of prospective renewable energy generation along with detailed models of PJM generation, transmission, and distribution assets, as analyzed using industry standard grid analysis tools to quantify cost, reliability, and operational impacts. At a higher level, the results from the PRIS are important for understanding how PJM could respond to theoretical future scenarios where renewable energy generation makes up a much larger share of the energy mix (both for PJM as a whole as well as specifically for Maryland). The broad trends suggest that only incremental improvements are needed to prepare for significant renewable penetration. Nevertheless, it is important to recognize that developments in the PJM system over the last six years suggest that actual conditions in 2026 are likely to differ in significant ways from all 10 of the scenarios modeled by the PRIS.

J-5.1. 14% Base Case Observations

The 14% Base Case is of most relevance to current RPS considerations within PJM. After six years of the 15-year study horizon, PJM renewable energy penetration levels have risen from 2% to 5%. Although RPS targets have changed in some states and jurisdictions, the 14% Base Case still comes close to reflecting what PJM would look like if all states met their RPS targets.

Primary implications of the PRIS for the 14% Base Case to bear in mind for RPS considerations are as follows:

- $3.7 billion in transmission system enhancements (additions and upgrades) are required to address reliability and congestion constraints.
- A 30% increase in regulating reserve capacity (from 1,204 MW to 1,566 MW) is required to address added variability (though potentially reduced through use of shorter-term forecast information). The PRIS assumed that thermal power plants would provide this regulating reserve but also examined the impact of small amounts of energy storage across PJM.
- The PJM system will not have any significant issue absorbing the higher levels of renewable energy penetration considered in the study. All simulations of challenging days revealed successful operation of the PJM real-time market.
- Energy production costs should fall as renewable penetration increases.
- Carbon taxes might accelerate the shift from coal to natural gas, especially when combined with low natural gas prices.
- Coal and natural gas power plants will have to cycle much more often in order to compensate for renewable energy variability, marginally increasing the O&M costs for these power plants.

Renewable energy growth to date has followed a different pattern than assumed under the PRIS – distributed solar capacity additions are outpacing the assumed rate, while wind capacity additions are a little lower than assumed. On the positive side, transmission investment requirements for the 14% Base Case would likely be reduced with this higher level of distributed solar growth in comparison with wind growth, but those cost savings may be partly offset by higher regulation requirements given stronger correlation of solar energy production (see further explanation in Section J-5.2) in comparison with wind. In addition, as discussed in more detail in Section J-5.4, the PJM thermal generation portfolio has undergone a more rapid increase in natural gas generation that assumed in the PRIS. Both of these trends are significant changes. Therefore, while general observations from the PRIS are still useful as applicable to the integration of renewable energy in PJM, specific impact quantifications (e.g., transmission and regulation needs, production cost reductions, emissions savings) should be viewed with caution, for the 2026 14% Base Case and the other scenarios.

J-5.2. 20% Scenario Observations

Of the four 20% scenarios analyzed, current trends in renewable energy development—including the growth in solar and the challenges facing offshore wind development—suggest that the "High Solar + Best Onshore" (HSBO) scenario appears to be the most relevant for understanding what the generation mix in PJM is most likely to resemble once PJM eventually reaches 20% renewable energy. Compared to the other 20% scenarios, this HSBO scenario was projected to result in greater energy production cost savings. This scenario also required less investment in new transmission lines ($3.9 billion) than the other scenarios, which assumed heavy construction of offshore wind, given the more distributed nature of solar PV installations throughout the PJM territory.

However, this scenario would have more sub-hourly changes in solar energy production and thus requires more added regulation reserves than any of the other 20% scenarios, a maximum of 2,984 MW. This increase in needed reserves also increases the cycling costs for natural gas power plants.

J-5.3. 30% Scenario Observations

For the most part, the trends observed in the 20% scenarios are also seen in the corresponding 30% scenarios, but at a greater level. Once again, the "High Solar + Best Onshore" (HSBO) scenario is likely to be the most relevant for future consideration. Compared to the 20% HSBO scenario, the 30% HSBO scenario requires more than twice the transmission investment ($8 billion), and over 1 GW of additional regulation reserves are needed. The 30% HSBO scenario involves the largest amount of renewable energy curtailment of any of the 10 scenarios analyzed, mostly due to increased local congestion.[758] The 30% HSBO scenario is one of the best scenarios for emissions reductions, but load-weighted LMP does not decrease as much as it does in the 30% "High Offshore + Best Onshore" (HOBO) scenario.[759]

J-5.4. Further Developments in PJM Affecting Operations with Renewable Energy

J-5.4.1. <u>2017 PJM Reliability Study</u>

In March 2017, PJM issued a report entitled *PJM's Evolving Resource Mix and System Reliability*,[760] which analyzed a large range of PJM's future generation and system scenarios. In light of recent trends in PJM, including low natural gas prices and increasing renewable energy penetration, this study evaluated how system reliability would be affected by different hypothetical mixes of power generation than the current resource mix.

PJM's 2017 study concluded that:

> *A marked decrease in operational reliability was observed for portfolios with significantly increased amounts of wind and solar capacity (compared to the expected near-term resource portfolio), suggesting de facto performance-based upper bounds on the percent of system capacity from these resource types. Additionally, most portfolios with solar unforced capacity shares of 20% or greater were classified infeasible because they resulted in LOLE criterion violations at night. Nevertheless, PJM could maintain reliability with unprecedented levels of wind*

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[758] PRIS, Final Project Review.

[759] Ibid.

[760] PJM Interconnection, *PJM's Evolving Resource Mix and System Reliability*, March 2017, pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx; and the Appendix at: pjm.com/~/media/library/reports-notices/special-reports/20170330-appendix-to-pjms-evolving-resource-mix-and-system-reliability.ashx.

and solar resources, assuming a portfolio of other resources that provides a sufficient amount of reliability services.

In contrast with the PRIS, which looked at the specific impacts associated with specific (albeit frequently hypothetical) power plants, the 2017 PJM study focused more on attempting to quantify the benefits associated with particular types of power plants – regardless of their specific hourly generation or geographic location. While the PRIS considered the penetration of renewables as a percentage of the total *energy* delivered per year, the 2017 PJM study focused on renewables as a percentage of the total *capacity* available to meet peak demand and provide reserves.

In the 2017 PJM study, each type of power plant (i.e., coal, natural gas combustion turbines, nuclear, solar, wind, etc.) was assigned a value for "Generator Reliability Attributes" – scores describing how well, for example, that type of power plant is able to provide frequency response, reactive power capability, fuel assurances, etc. Next, different portfolios (or scenarios) were developed for the total resource mix needed to meet PJM's demand. For example, one portfolio might posit that PJM's total peak demand (i.e., total capacity requirements) could be met using 10% wind, 10% solar, 50% natural gas, and 30% coal. Using the Generator Reliability Attributes associated with wind, solar, natural gas, and coal, a "Composite Reliability Index" was calculated for each portfolio, which is essentially a weighted average describing the reliability of that portfolio. Each hypothetical portfolio could thereby be compared to the current resource mix in PJM, which was used as a baseline.

Over 100 different alternative portfolios were analyzed and then ranked by Composite Reliability Index (CRI). The portfolios scoring highest ("most desirable") tended to be close to the current baseline for PJM – a generation mix consisting of relatively low renewable energy penetration, steady coal and/or nuclear baseload, and considerable natural gas production. The lowest scoring portfolios were those portfolios that met PJM's capacity demands using large amounts of wind and solar generation and minimal coal and nuclear capacity. Some of the portfolios analyzed are shown in Figure J-7.

While the 2017 PJM study appears to be cautioning planners against large-scale renewable energy integration, it is important to recognize some differences between the scenarios analyzed by the PRIS (which GE concludes are all feasible, assuming some incremental improvements are made) and the portfolios analyzed in this 2017 PJM study. The portfolios in the 2017 PJM study with "significantly increased amounts of wind and solar capacity" (left side of Figure J-7) are portfolios where the amount of renewable energy generated each year is likely to be above and beyond even the 30% scenarios analyzed in the PRIS. In actuality, the scenarios from the PRIS all fall somewhere in the middle of Figure J-7. One of the major conclusions of the PRIS is the need to maintain adequate regulation reserves in PJM, and the PRIS acknowledges the need for new thermal generation to be installed in order to supply those reserve requirements. Therefore, even under the scenarios in the PRIS where 30% of *total energy* comes from renewable sources, a considerable amount of non-renewable *capacity* will need to exist to provide reserves and ancillary services.

By contrast, the most infeasible scenarios in the 2017 PJM study (left side of Figure J-7) essentially represent a future where the majority of thermal power plants have been retired, rather than keeping them available to help meet peak demand and to provide ancillary services. It seems likely that the authors of the PRIS would agree with the conclusions of the 2017 PJM study; expanding solar and wind capacity without maintaining adequate reserve capacity from other types of power plants would create an unreliable and highly variable power system.

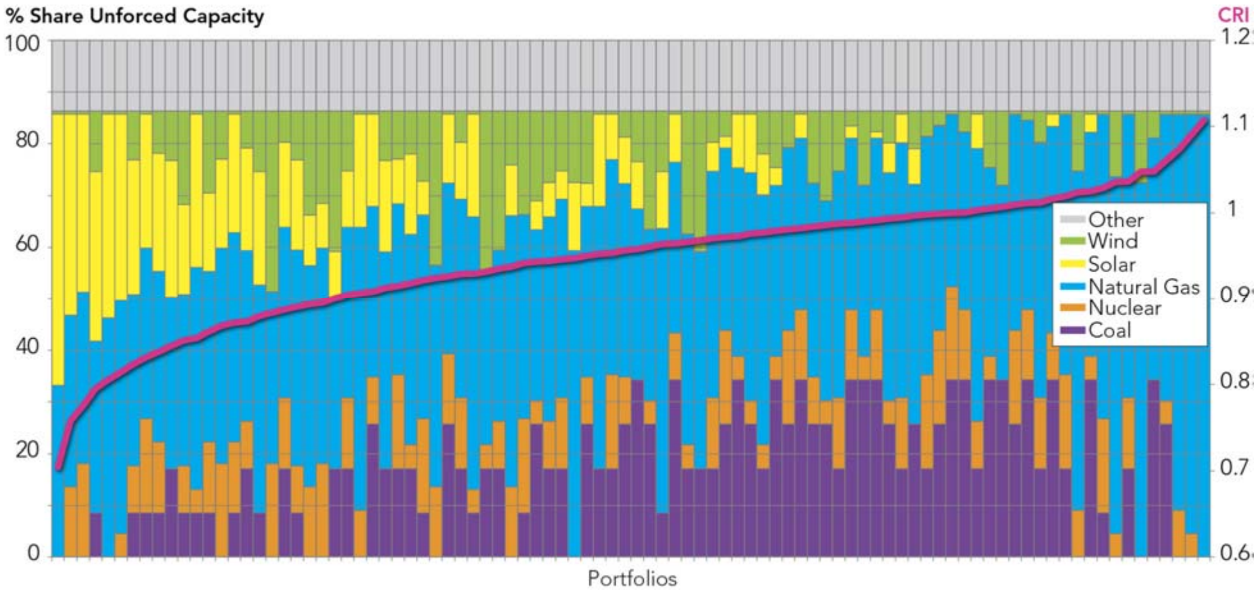

Figure J-7. Portfolio Composition and Composite Reliability Index

Source: PJM, *PJM's Evolving Resource Mix and System Reliability*, March 2017, pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx.

J-5.4.2. PJM Committee and Subcommittee Actions

PJM convenes three standing committees, 18 subcommittees, and many other task forces, forums, and groups focused on a range of their technical and business needs. Of foremost relevance to renewable energy integration is the Intermittent Resources Subcommittee, but the Market Implementation Committee and other subcommittees such as Load Analysis and Distributed Energy Resources also address topics that are changing how PJM is managing renewable energy on its network. Topics of significance include:

Intermittent Resources Subcommittee

- Requiring real-time meteorological data for solar plants greater than 3 MW.
- Adopting ride-through requirements from latest Smart Inverter Standards.
- Incorporation of solar resources into the PJM *Load Forecast Report*.
- Understanding lessons learned from unusual events like the 2017 solar eclipse and events in other power markets around the world.

Load Analysis Subcommittee

- Updating load forecasts, including simulating weather and tracking economic trends.
- Tracking the impact of distributed solar power on system peak loads.

Distributed Energy Resources Subcommittee

- Resolving issues related to how BTM distributed resources can participate in the PJM market, including demand response and ancillary services.

Market Implementation Committee

- Developing a compliance filing in response to FERC Order 841 (issued February

2018), "Electric Storage Participation in Markets Operated by Regional Transmission Operators and Independent System Operators."

J-5.5. Natural Gas Prices and Capacity Market Trends

As discussed briefly in Section J-4.1.3, one of the most significant changes in the PJM market since 2011 has been the unexpectedly high growth of natural gas generation capacity, due in large part to increased U.S. production of natural gas and falling natural gas prices.[761] In turn, this appears to have made it more difficult for coal and nuclear power plants to compete in the PJM market. This trend has been particularly evident in PJM's annual capacity auctions (see Figure J-8); the 2021-2022 capacity auction (held in May 2018)[762] included 1,000 MW more natural gas than was included in the previous auction, while nuclear power capacity clearing the auction fell by over 7,000 MW. Coal appears to have temporarily recovered from a slow and steady decline in cleared capacity. Note that, with respect to this figure, wind capacity is adjusted to 13% of nameplate and solar PV capacity is adjusted to 38% of nameplate.

When power plants fail to clear the capacity auction, it often implies that a power plant will no longer be economically viable to operate, which in turn leads owners to begin planning for power plant retirement and decommissioning. As of June 2018, 9,227.8 MW of generation in PJM have announced plans to retire by 2021.[763]

The accelerated changeover from coal to natural gas is similar to, but larger than, one of the sensitivities examined by the PRIS – the low natural gas price sensitivity (prices have actually been even lower than this low sensitivity). This sensitivity was found to reduce customer energy prices and to reduce GHG emissions, especially when coupled with the growth of renewable energy. Given today's capacity market trends, should PJM reach the 14% Base Case, the non-renewable energy generation mix will likely be tilted toward natural gas rather than coal or nuclear power. Given the generally higher flexibility of most natural gas plants for ramping and startup, increased natural gas capacity will facilitate integrating large amounts of renewables into PJM.

[761] U.S. Energy Information Administration, *Annual Energy Outlook 2018*, eia.gov/outlooks/aeo/pdf/AEO2018.pdf.

[762] PJM Interconnection, LLC News Release, "PJM's Capacity Auction Attracts Diverse, Competitive Resources to Maintain a Reliable Grid," May 2018, pjm.com/-/media/about-pjm/newsroom/2018-releases/20180523-rpm-results-2021-2022-news-release.ashx.

[763] Monitoring Analytics, LLC, *2018 State of the Market for PJM*, March 2019, monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018q2-som-pjm-sec1.pdf, Section 1 – Introduction.

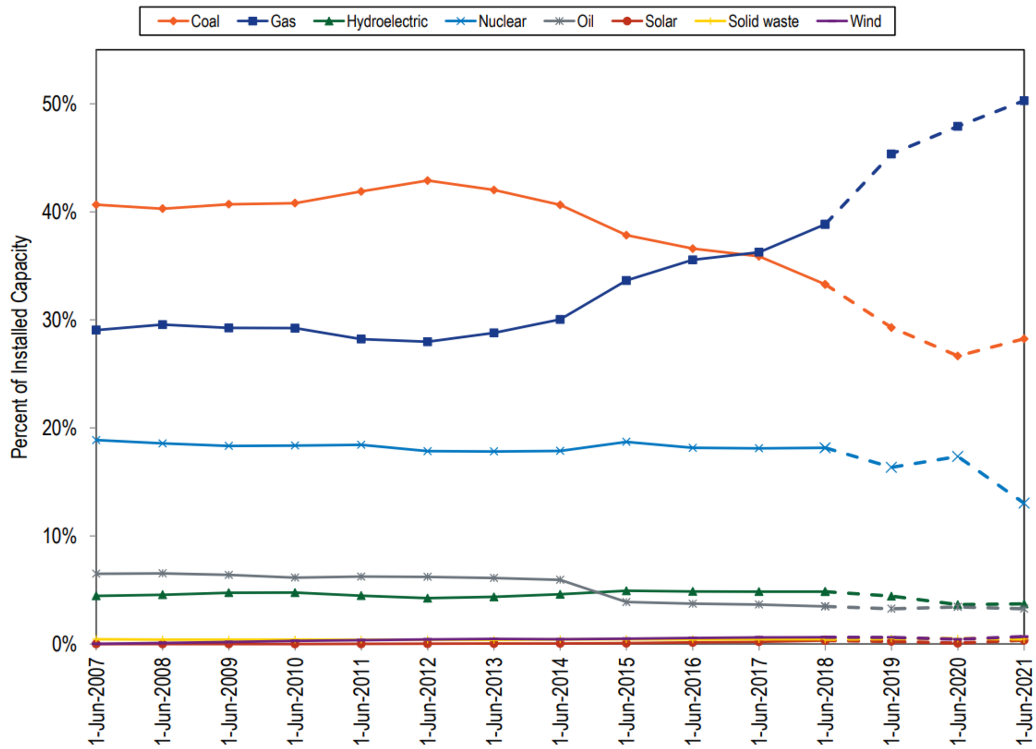

Figure J-8. Percent of Installed Capacity for PJM, by Fuel Source

Source: Monitoring Analytics, LLC, *2018 State of the Market for PJM*, March 2019, monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018q2-som-pjm-sec5.pdf, Section 5 – Capacity.

APPENDIX K. GLOSSARY

Advanced Metering Infrastructure (AMI). An integrated network of digital hardware and software, which enables the collection, measurement, storage, and analysis of detailed, time-based information and the transmittal of such information between customers, utilities, and other third-party providers.

Alternative Compliance Payment (ACP). Payments that serve as a method to penalize load-serving entities (LSEs) that do not comply with the Renewable Portfolio Standard (RPS), and to provide suppliers an option for compliance with RPS's in lieu of purchasing Renewable Energy Credits (RECs). This can occur in instances of REC scarcity or unavailability.

Ancillary services. Those services that are necessary to support the transmission of capacity from generation resources to customer loads while maintaining reliable operation of the transmission system. Such services include frequency and voltage regulation, load following and ramping, black start, and spinning and non-spinning reserve capacity.

***Annual Energy Outlook* (AEO).** Annual U.S. Energy Information Administration (EIA) publication that presents yearly projections and analysis of energy topics.

Balance of system (BOS). All the components of a solar photovoltaic (PV) system other than the modules.

Behind-the-meter (BTM). A renewable energy system designed to produce power for on-site use in a home, business, or facility.

Biomass. A non-hazardous, organic material that is available on a renewable or recurring basis and has been segregated from inorganic waste material. Biomass contains stored energy from the sun absorbed through photosynthesis that, when burned, is released as heat. Biomass can be burned directly or converted to bioliquids or biogas that can be burned as fuels.

Black liquor. A byproduct of the paper production process, alkaline spent liquor, that can be used as a source of energy. Alkaline spent liquor is removed from the digesters in the process of chemically pulping wood.

Blast furnace gas (BFG). A byproduct of blast furnaces that is generated when the iron ore is reduced with coke to metallic iron. BFG can be used to produce energy at waste-to-energy plants.

Bond yield. The measure of the profit realized from a bond investment.

Business-as-usual. Reflects the modeler's set of assumptions about what is likely to happen over the modeling time frame in the absence of policy changes.

Bypassable charge. A volumetric-based charge that covers the utility's costs associated with a specific program that a customer can avoid if they choose to opt out of the program.

Capacity. The capability to generate electrical power, typically expressed in megawatts (MW).

Capacity auction. An auction in which generators submit bids that specify the amount of capacity being offered and the price sought to obtain a commitment to supply that capacity. Through this process, capacity is secured to satisfy the capacity requirements for a particular delivery year.

Capacity factor. The ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period.

Capacity market. A market construct that pays utilities and other electricity suppliers to commit generation for delivery years into the future in order to meet customer demand, plus a reserve amount.

Capital cost. The cost to construct a power generating facility, including field development, engineering, legal, regulatory, equipment, space, and other one-time costs.

Carbon dioxide (CO_2). A GHG that is produced through burning fossil fuels, municipal solid waste (MSW), and biological materials, as well as through certain chemical reactions. Carbon content refers to the measure of the concentration of carbon dioxide (CO_2).

Carbon dioxide equivalent (CO_2e). The common unit used to describe different greenhouse gases (GHGs).

Carve-out. A requirement that a certain percentage of an RPS be met specifically with a particular type of energy generation.

Certificate of Public Convenience and Necessity (CPCN). A regulatory compliance certificate that gives a utility an applicant permission to construct a facility such as a power plant or transmission line.

Clean Peak Standard. A requirement that a certain percent of delivered electricity during a predetermined peak period must come from clean energy resources.

Clearing price. The equilibrium (i.e., market clearing), monetary value of a commodity or security that is determined by the bid-ask process of buyers and sellers.

Code of Maryland Regulations (COMAR). The official compilation of all administrative regulations issued by Maryland state agencies.

Combined cycle (CC). An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more combustion turbines (CTs). The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a conventional steam turbine in the production of electricity.

Combined heat and power (CHP). A cogeneration plant that simultaneously produces electricity and recovers useful thermal energy from a single source.

Combustion turbine (CT). A generating unit that consists of an internal-combustion engine that converts the chemical energy of a liquid fuel into mechanical fuel through internal combustion. Also known as a gas turbine, the unit is typically used during peak periods because of its quick response capability and relatively high running costs.

Community solar. A solar PV system that is shared by multiple customers who receive credit on their electricity bills for their share of the power produced.

Compliance year. A period of time during which an electric utility seeks to establish RPS compliance.

Compound Annual Growth Rate (CAGR). The constant interest rate that would be required for compound interest to grow an investment from its beginning balance to its ending balance.

Congestion. Describes a situation where power cannot be moved from where it is being produced to where it is needed for use because the transmission system does not have sufficient capability to carry the electricity.

Consumer Price Index (CPI). A measure of the average change in the price level over time of a weighted average market basket of goods and services.

Control area. The service territory of an regional transmission organization (RTO) or independent system operator (ISO).

Cost-Benefit. Relating to a process that estimates the strengths and weaknesses of transactions, projects, investments, etc. by assessing the relation between the cost of the undertaking and the value of the resulting benefits.

Day-ahead energy market. A financial market where participants purchase and sell energy at fixed, day-ahead prices for the following day.

Debt/equity ratio. The relative proportion of debt to equity used to finance a company's investments.

Decommissioning. The act of withdrawing a generator from service and, as needed or required, restoring or remediating the site where the generator was located.

Degradation. The decline in the systems output of a generator over time.

Demand. The amount of power that must be supplied to a customer or an aggregate of customers (i.e., a load), typically expressed in MW.

Demand charge. The price paid by a ratepayer for each unit of power drawn on the electric grid. Demand charges are typically applied to the maximum demand for a 15-minute interval during a billing period and expressed in dollars per kilowatt-hour (kWh).

Demand response (DR). Refers to the shift of demand from periods of peak system demand to non-peak periods. The shift or reduction in demand is typically in response to time-of-use (TOU) rates or other forms of financial incentives.

Demand-side management (DSM). The reduction or curtailment of energy consumption from end-use equipment or processes, often to reduce customer load during peak demand and/or during times of supply constraint.

Depreciation. The reduction in value of an asset due to wear and tear over time.

Discount rate. The interest rate for determining the present value of a future payment or series of payments.

Dispatch (merit order or economic). The practice of utilizing least-cost generation first to serve load. For example, PJM operation stacks generator bids from lowest to highest and uses the energy generation facilities in least-cost order.

Dispatchable generation. Generation capable of varying output in response to grid operator control instruction.

Distributed energy resources (DERs). Small or modular electrotechnologies that are typically geographically dispersed and are installed and operated at the subtransmission or distribution level.

Distributed generation (DG). Generating resources located close to or on the same site as the facility using the power.

Distribution. The latter stage of the transmission and distribution (T&D) process in which electricity is delivered from transmission providers to end-users. Also refers to distribution lines, which carry electricity at a lower voltage (i.e., less than 69 kV) than a transmission line.

Distribution System Plan (DSP). The process of advance planning to ensure the reliable operation of the distribution grid.

Eastern Interconnection. North America is comprised of two major and three minor alternating current power grids or "interconnections." The Eastern Interconnection 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 operating at an average of 60 Hz.

Economic life. The period over which an asset remains useful to the owner.

Economic resource potential. The resource that is economically viable when economic constraints such as cost of energy are factored in.

Economies of scale. The increase in savings that comes from a proportionate increase in the level of production.

Electric cooperative (Coop). A nonprofit, customer-owned electric company that distributes electricity in a rural area.

Electric distribution company. A company that delivers electricity to a customer's home or business through its system of poles, power lines, and other equipment.

Electricity/energy supplier. An entity that sells electricity to customers (and, in Maryland, is licensed to do so by the Maryland Public Service Commission [PSC]).

Emissions allowance. A representation of an incremental amount of emissions (e.g., one ton of CO_2) that an entity may produce.

Emissions rate. Ratio of emissions per unit of output (e.g., tons/MWh of CO_2).

EmPOWER Maryland. Enacted into law with the passage of House Bill (HB) 374, the EmPOWER Maryland Energy Efficiency Act of 2008 is an initiative that aims to achieve reductions in Maryland's per capita electricity consumption and peak demand relative to historical electricity demand.

Energy. The capability a physical system has in order to do work (potential energy) or the conversion of this capability into motion (kinetic energy).

Energy efficiency. Energy efficiency programs are aimed at reducing the electricity consumption used by specific end-use systems, typically by substituting technologically more advanced equipment to produce the same level of end-use services (e.g., lighting, heating, motor drive) with less electricity.

Energy market. Commodity market that deals specifically with the trade and supply of energy.

Energy storage. The capture of energy produced at one time for use at a later time.

Energy supplier. An entity that sells electricity to customers (and, in Maryland, is licensed to do so by the Maryland PSC).

Energy use. A measure of electrical power used over a period of time, usually expressed in kWh or MWh.

Environmental impact. The effect on the natural environment, including land alteration, disruption to wildlife, emissions from combustion, and toxic byproducts or remains.

Environmental justice. *(from EPA)* The fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation and enforcement of environmental laws, regulations, and policies.

Federal Energy Regulatory Commission (FERC). An independent federal commission responsible for regulating wholesale electric power transactions, the siting of hydro and natural gas facilities, and the interstate transmission and sale of natural gas for resale.

Financing costs. The interest and other costs involved in the borrowing of money to build or purchase assets. Also referred to as borrowing costs.

Fixed operations and maintenance (O&M) costs. Costs associated with a system after it is installed that do not vary directly with plant power generation, and consist of wages and wage-related overheads for the permanent plant staff, routine equipment maintenance, and other fees.

Fossil fuel. An energy source, such as coal, natural gas, or petroleum, that is formed in the earth's crust from decayed organic material.

Frequency. The rate of waves of electric current.

Fuel diversity. The mix of fuels used to generate electricity in a specified region.

Fuel security. The uninterrupted availability of fuel sources.

Generation. The process of producing electrical energy.

Geothermal electric. A type of power generation that uses steam at temperatures of several hundred degrees Fahrenheit from below the earth's surface to produce electricity.

Geothermal heat pump. A type of geothermal power generation that takes advantage of the difference between the temperature of the subsurface soil and the above-ground air to move heat for end-uses such as water heating and space cooling and heating.

Green goods and services (GGS). A U.S. Bureau of Labor Statistics term for jobs and businesses that produce goods and provide services that benefit the environment or conserve natural resources.

Greenhouse gas (GHG). Gases that absorb infrared radiation, trap heat within the atmosphere, and emit radiation in all directions, resulting in the general warming of the planet's surface temperature. These include CO_2, methane (CH_4), and fluorocarbons.

Grid. A network of generators, transformers, T&D lines, substations, and end-users that comprise the physical utility electric power supply and T&D systems.

Gross Domestic Product (GDP). The total dollar value of goods and services produced for a country over a specific time period.

Heat rate. A measure of system thermal efficiency commonly stated as British thermal units (Btu) per kWh (i.e., the amount of fuel that is required to produce a certain amount of output).

Henry Hub. A natural gas pipeline on the Louisiana Gulf Coast that acts as the delivery point for the natural gas futures contract on the New York Mercantile Exchange (NYMEX).

Hosting capacity. The capability of a system to accommodate DERs.

Hydroelectric power generation (hydropower). Energy created by flowing water that is captured and turned into electricity.

Independent system operator (ISO). Former power pools that formed into ISOs as a way to provide non-discriminatory access to transmission as well as open access to retail and wholesale supply. An ISO, regulated by the FERC, serves as an independent, third-party coordinator and operator of the transmission system within a defined area, typically within one state, and ensures the reliability of the electric system.

Industrial Process Load (IPL). The consumption of electricity in support of industrial processes.

Inflation-adjusted. The act of adjusting for the time period's inflation rate (i.e., the rate at which the average price level of a commodity or service increases over a period of time).

Input-output modeling (I-O). A form of macroeconomic analysis that observes interdependencies between economic sectors as a series of inputs of source materials and outputs of finished goods or services. The I-O method is typically used to estimate the impacts of economic shocks throughout the economic sectors.

Integrated Resource Plan (IRP). A long-term, comprehensive utility planning framework that creates a portfolio of least-cost supply-side and demand-side resources to meet future load requirements.

Interconnection. The physical connection between an electricity source and the electric power grid. Interconnection can also be defined as two or more electric systems having a common transmission line that permits a flow of energy between them. This physical connection allows for the sale or exchange of energy.

Interest rate. The percentage of the loan principal charged by the lender as interest to the borrower, typically expressed as an annual percentage.

Intermittent resource. An electric generating plant with output controlled by the natural variability of the energy resource (e.g., wind, sun, or flow of water) rather than dispatched based on system requirements.

Internal rate of return (IRR). The discount rate at which the net present value (NPV) of all the cash flows (both positive and negative) from a project or investment equal zero. The IRR is a metric used to estimate the profitability of potential projects or investments.

Investment Tax Credit (ITC). A federal solar tax credit that allows the owner, investor, or producer of a residential or commercial solar system to deduct a certain percent of the cost of installing the system from their taxes.

Investor-owned utility (IOU). A for-profit, privately-owned utility company.

Landfill gas. A type of biogas that is produced by anaerobic bacteria in municipal solid waste (MSW) landfills.

Lawrence Berkeley National Laboratory (LBNL). A U.S. Department of Energy (DOE) national laboratory located in California.

Levelized cost. *(from EIA)* The present value of the total cost of building and operating a generating plant over its economic life, converted to equal annual payments. Costs are levelized in real dollars (i.e., adjusted to remove the impact of inflation).

Levelized Avoided Cost of Energy (LACE). NPV of the benefits of energy output over the cycle life of an energy facility, usually represented as a function of the energy rating (i.e., $/MWh). Calculated by summing the total, time-value adjusted energy and capacity cost of the grid resources that the new generator displaces (i.e., generation that is avoided), and dividing by the total potential energy output of the new energy facility.

Levelized Cost of Energy (LCOE). NPV of the cost of energy output over the cycle life of an energy facility, usually represented as a function of the energy rating (i.e., $/MWh). Calculated by summing the total, time-value adjusted capital and operating cost, and dividing by the total potential energy output of the energy facility. A related term, Levelized Avoided Cost of Energy (LACE), is created by replacing costs with benefits (e.g., the value of energy services provided or the energy output).

Life cycle cost. The total discounted dollar cost of owning, operating, maintaining, and disposing of a generation, transmission, or distribution asset over a period of time.

Liquidity. The degree to which an asset can be bought or sold in the market without changing the asset's price.

Load-serving entity (LSE). Provider of electric service, including competitive retailers, to retail customers.

Locational Marginal Price (LMP). A method of setting prices in an ISO/RTO market whereby prices at specific locations on the grid are determined by the marginal price of generation of power available to that specific location. Prices vary from location to location based on transmission congestion and losses.

***Long-Term Electricity Report for Maryland* (LTER).** A report from the Maryland Power Plant Research Program (PPRP) that provides a comprehensive assessment of approaches to meet the long-term electricity needs of Marylanders through clean, reliable, and affordable power.

Loss of load expectation (LOLE). The estimated number of hours in the year in which daily peak demand is more than the available generation capacity.

Maryland Board of Public Works. A three-member body consisting of the Governor, Comptroller, and Treasurer of the State of Maryland that oversees many aspects of the state's finances.

Maryland Clean Energy Jobs Act (CEJA) (Senate Bill 516). Legislation passed by the Maryland General Assembly in May 2019 that increased the Maryland RPS to 50% of the total retail electricity sales in Maryland by 2030.

Maryland Department of Natural Resources (DNR). A government agency charged with maintaining natural resources in Maryland, including state parks, public lands, state forests, state waterways, wildlife and recreation areas.

Maryland General Assembly. The state legislature of the State of Maryland.

Maryland Healthy Air Act (HAA). A Maryland law that imposed strict annual and seasonal nitrogen oxides (NOx), sulfur dioxide (SO_2), and mercury emissions limits on seven coal-burning power plants in Maryland. The HAA also required that Maryland participate in the Regional Greenhouse Gas Initiative (RGGI).

Methane (CH_4). A GHG emitted during the production and transport of fossil fuels as well as from livestock, agricultural practices, and the decay of organic MSW.

Microgrid. A combination of co-located resources that can operate as one entity that: (1) interacts with the greater electric grid (if available); or (2) is an autonomous power system that is not connected with a large power system (i.e., in "island" mode).

Million British thermal units (MMBtu). Equal to one million British thermal units, which measures the energy (heat) content of fuel. MMBtu is typically the standard unit of measurement for natural gas.

Multiplier. A factor used to increase the credit value of RECs for designated resources to further incentivize their use for RPS compliance.

Municipal Solid Waste (MSW). Garbage that can be used to produce energy at waste-to-energy plants. MSW is considered biomass when it consists of organic material, such as food scraps, paper, and cardboard.

Municipal utility (Muni). An electric company owned and operated by a municipality serving residential, commercial, and/or industrial customers, usually within the boundaries of the municipality.

National Renewable Energy Laboratory (NREL). A DOE national laboratory located in Colorado that specializes in research and development related to renewable energy and energy efficiency technologies.

Negative price period. Period of time during which the cost of energy on the wholesale energy market falls below zero and power suppliers have to pay their wholesale customers to purchase electric energy. This may occur when electricity demand is low, but power generation exceeds demand.

Net energy import. The total zonal consumption minus the total in-zone generation. A positive result represents a need to import energy, while a negative result represents the ability to export energy.

Net metering. A billing system that measures the flow of energy into and out of the energy grid by customers who generate their own electricity through a single, bi-directional meter. The system allows these customers to sell the excess electricity generated by their DG systems back to their electric utility, usually at retail rates.

Net present value (NPV). The current value of all future cash flows generated by a project over a period of time.

New York Mercantile Exchange (NYMEX). The largest commodity futures exchange in the world, located in New York City.

Nitrogen oxides (NOx). A group of seven gases and compounds composed of nitrogen and oxygen that are produced from the burning of fossil fuels. NOx reacts with water molecules in the atmosphere to produce acid rain.

Nominal price. The price paid for a product or service at the time of the transaction. Nominal prices are those that have not been adjusted to remove the effect of changes in the purchasing power of the dollar; they reflect buying power in the year in which the transaction occurred.

Non-bypassable charge. A volumetric-based charge that is applied to all customer bills. Revenues from the non-bypassable charge are used to support certain programs, such as assistance to low-income customers or support of energy efficiency or renewable energy technologies.

Non-dispatchable generation. Generation not capable of varying output in response to grid operator control instruction. (See Intermittent resources.)

Non-spinning reserve. Offline generation capacity that can be ramped to capacity and synchronized to the grid within 10 minutes of a dispatch instruction by the ISO/RTO, and that is capable of maintaining that output for at least two hours.

Non-wires alternative (NWA). An electric grid investment or project that can replace the need for traditional T&D through a combination of distributed energy, energy storage, energy efficiency, demand response, and grid software and controls.

North American Electric Reliability Corporation (NERC). A nonprofit corporation established to develop and maintain mandatory reliability standards for the bulk electric system, with the fundamental goal of maintaining and improving the reliability of electric power. NERC consists of eight regional reliability entities covering the interconnected power regions of the contiguous United States, Canada, and Mexico.

Nuclear Regulatory Commission (NRC). An independent agency of the United States responsible for regulating the nuclear power industry.

Off-peak energy price. The energy price for a period of relatively low system demand. These periods often occur in daily, weekly, and seasonal patterns; these off-peak periods differ for each individual electric utility. For the PJM energy market, off-peak periods are all NERC holidays (i.e., New Year’s Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) and weekend hours, plus weekdays from the hour ending at midnight until the hour ending at 7:00 a.m.

Off-peak period. Those hours or other periods defined by North American Energy Standards Board (NAESB) business practices, contracts, agreements, or guides as periods of lower electrical demand.

Offshore renewable energy credit (OREC). RECs awarded specifically to offshore wind energy resources.

On-peak energy price. The energy price for periods of relatively high system demand. These periods often occur in daily, weekly, and seasonal patterns; these on-peak periods differ for each individual electric utility. For the PJM Energy Market, on-peak periods are weekdays, other than NERC holidays, and from the hour ending at 8:00 a.m. until the hour ending at 11:00 p.m.

Output. The energy (kWh or MWh) produced by a power plant.

Overnight Capital Cost. The present value cost that would be paid as a lump sum up front to completely pay for the construction of a power generation plant right away (i.e., overnight). Used as a metric of how economically feasible the building of a power generation plant would be at current prices.

Peak demand. The maximum instantaneous power draw from end-user loads over a designated period of time (e.g., a year, a month, or a season).

Peak shaving. The process of reducing consumption of electricity during the periods when the utility experiences peak demand.

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 Generation Attribute Tracking System (PJM-GATS). Online data system that tracks environmental attributes of generation in PJM control area and is used by states to measure compliance with RPS or environmental disclosure requirements.

PJM Generation Interconnection Queue (PJM Queue). Lists the current status of requests for the interconnection of new generating facilities in PJM. Interconnection applicants must undergo a series of studies to ensure they can be connected to PJM's grid without negatively affecting electric power reliability.

PJM Interconnection, LLC. A federally regulated RTO that manages the wholesale electricity market and transmission system in a region encompassing the District of Columbia and all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia.

Power Plant Research Program (PPRP). A part of the Maryland DNR, the 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.

Power Purchase Agreement (PPA). A bilateral contract in which the seller generates electricity for the buyer to purchase.

Production cost. All costs associated with the O&M of a power plant, including fixed and variable O&M, capital costs, etc.

Production tax credit (PTC). A production-based federal tax incentive that provides income tax credits or deductions at a specified amount for eligible renewable energy facilities.

Public Utility Regulatory Policies Act (PURPA). Act passed by the U.S. Congress in 1978 to encourage the development of renewable resources by obligating regulated monopoly electric utilities to purchase electricity from qualifying facilities (QFs) at avoided cost rates. Avoided cost is the marginal cost that the electric utility would incur if it were to generate the electricity itself or purchase it from another source.

Pumped hydro storage. A type of hydropower and energy storage that takes power sent from the grid and spins the turbines backwards, which causes the turbines to pump water from a river or lower reservoir to an upper reservoir where the power is stored. To use the power, the water is released from the upper reservoir back down into the river or lower reservoir, spinning the turbines forward and activating generators to produce electricity.

Ramp (or ramping). The rate, expressed in either MW per minute or MW per hour, that a generator changes its output over time. Ramping can be further defined as "ramping up" (increasing output) or "ramping down" (decreasing output).

Rate of return. The ratio of net operating income earned by a utility, calculated as a percentage of its rate base.

Ratepayer. The end-use customer of a utility.

Real price. A price that has been adjusted to remove the effect of changes in the purchasing power of the dollar. Real prices, which are expressed in constant dollars, reflect buying power relative to a base year.

Real-time market. The competitive generation market controlled and coordinated by the ISO/RTO that allows market participants to buy and sell wholesale electricity on demand.

REC futures. Refers to REC futures contracts (i.e., contractual agreements to buy and sell RECs at a future date).

Refuse-derived fuel. A fuel produced from waste products that can be used to produce energy at waste-to-energy plants. Refuse-derived fuel can be considered biomass when derived from MSW biomass.

Regional Greenhouse Gas Initiative (RGGI). An initiative of 10 Northeastern and mid-Atlantic states to reduce CO_2 emissions from electric power plants by means of a cap-and-trade system. RGGI is the first mandatory, market-based CO_2 emissions reduction program in the United States.

Regional Transmission Expansion Plan (RTEP). An annual planning process from PJM that identifies transmission system upgrades and enhancements within PJM that may be necessary to maintain electric power reliability.

Regional transmission organization (RTO). An RTO controls and operates the transmission facilities that are held by a region's utilities. An RTO is independent of the transmission facility owners. Maryland resides within the PJM RTO.

Reliability. The ability of an electric production system to deliver electricity to customers within accepted standards and in the amount desired.

Reliability Pricing Model (RPM). A PJM-run capacity market that develops a long-term (three-year) pricing signal for capacity resources and requirements from LSEs to serve electric demand.

ReliabilityFirst Corporation (RFC). One of eight FERC-approved regional reliability organizations in North America overseen by NERC. RFC is a not-for-profit company whose goal is to preserve and enhance electric service reliability and security for the interconnected electric systems within its territory. The RFC territory is situated within the Eastern Interconnection and covers all or portions of Maryland, New Jersey, Pennsylvania, Delaware, Virginia, West Virginia, Ohio, Michigan, Kentucky, Tennessee, Indiana, Illinois, Wisconsin, and the District of Columbia.

Renewable energy. Sources of energy that are continually being replenished, such as energy from the sun (solar), wind, geothermal, and hydro.

Renewable energy credit (REC). A credit that represents 1 MWh of renewable energy generation and the corresponding environmental, social, and non-power qualities of the renewable electricity generation. RECs can be bundled(i.e., tied to the purchase of the physical electricity of the renewable energy resource) or unbundled (i.e., sold separately from the underlying physical electricity).

Renewable Portfolio Standard (RPS). A state-mandated energy portfolio standard that requires LSEs operating within the state to designate that a specific portion of retail electricity supply sold to in-state customers comes from eligible energy sources, primarily renewable energy resources. Alternative names for RPS programs include; low-carbon portfolio standard, clean energy standard, and alternative energy portfolio standard.

Reserve margin. The amount of unused capacity of an electric power system available to meet certain contingencies, such as unexpected outages of power plants or higher-than-projected demand for electricity.

Resilience. The capacity of an energy system to tolerate disturbances or unexpected events, and to continue to deliver energy services to end-users.

Resource adequacy. The ability of utilities and LSEs to satisfy forecasted future loads reliably.

Retail choice. Permitting end-use customers to contract directly with suppliers for their electric or natural gas service, while T&D companies provide for delivery of the service. Also known as retail competition, electric restructuring, or restructuring.

Retail rate. The final price paid by end-use customers.

Self-generator. A generating facility that consumes most or all of the electricity it produces to meet on-site power demand.

Smart inverter. Power electronics that are capable of having two-way communications with the grid and can conduct grid-supportive applications related to voltage, frequency, communications and controls.

Social Cost of Carbon (SCC). A measure of the economic harm expressed as the dollar value of the total damages from emitting one ton of CO_2 into the atmosphere.

Solar photovoltaic (PV). Solar PV technologies use semiconducting materials to convert sunlight directly into electricity.

Solar renewable energy credit (SREC). REC awarded specifically to solar energy resources.

Solar Thermal System. Solar thermal technologies that capture the heat energy from the sun and use it for heating and/or the production of electricity.

Spinning reserves. The online reserve capacity that is synchronized to meet electric demand within 10 minutes of dispatch instruction by the ISO/RTO.

Standard offer service (SOS). Electricity supply service sold by electric utility companies to a customer who doess not choose an alternative electricity supplier.

Stranded costs. Costs accumulated by an electric utility company through infrastructure investments or PPAs that are no longer commercially viable after changes in regulatory or market conditions.

Sulfur dioxide (SO_2). A colorless gas or liquid that is produced from the burning of fossil fuels and the smelting of mineral ores that contain sulfur.

SWOT (Strengths, Weaknesses, Opportunities, Threats) analysis. Analysis framework for identifying and analyzing the internal and external factors (the strengths, weaknesses, opportunities, and threats) that can have an impact on the viability of a project.

Technical Resource Potential. The portion of a theoretical resource that can be captured using a specific technology.

Technology forcing. A policy or strategy that establishes a requirement to be met at some future point in time that cannot be met with existing technology, or at least not at an acceptable cost.

Time-of-use (TOU). Refers to a price structure for electric energy that is specific to the time (season, day of week, time of day) when the energy is purchased. TOU rates charge higher rates during peak hours of the day in an effort to shift peak period demand to off-peak hours.

Time-varying rates. A pricing schedule where the price per kWh of electricity is higher during peak periods and lower during off-peak periods.

Transformer. An electrical device that transfers electrical energy between two or more circuits through electromagnetic induction.

Transmission. The beginning stage of the T&D process in which electricity is delivered from a power generating plant to various substations or entities that serve loads. Also refers to transmission lines that carry electricity over large distances at a high voltage (69 kilovolts [kV] and above) with minimum losses and distortion.

Turbine. A mechanical device that uses a wheel or rotor to produce power. The device is designed to revolve by a fast-moving flow of water, steam, gas, air, or other fluid.

U.S. Energy Information Administration (EIA). An independent agency within the DOE that develops surveys, collects energy data, and conducts analytical and modeling analyses of energy issues.

U.S. Environmental Protection Agency (EPA). A federal agency that sets and enforces rules and standards that protect the environment and control pollution.

Useful life. The estimated length of time (in years) that a depreciable fixed asset remains functional. Also referred to as project life or cycle life.

Utility-scale. Refers to large generation projects that exceed 1 MW in capacity.

Variable operations and maintenance (O&M) cost. Costs associated with a system after it is installed that tend to vary in near direct proportion to the output of the unit, and include costs associated with equipment outage maintenance, utilities, chemicals, and other consumables. Fuel costs are determined separately and are not included in O&M costs.

Vertically integrated utility. A utility that owns and controls all levels of the supply chain: generation, transmission, and distribution.

Vintage. Refers to the length of time RECs are eligible.

Volt. A unit of electric potential energy; 1 kV = 1,000 volts.

Voltage. The pressure that guides power or makes electric charges move in an electrical conductor. Commonly referred to as electromotive force.

Waste-to-energy. The process of generating energy from various types of waste, including MSW, industrial waste, and commercial waste.

Watt. The electrical unit of power or rate of doing work. 1 kW = 1,000 watts; 1 MW = 1,000,000 watts; 1 GW = 1,000,000,000 watts.

Watt-hour. An electric energy unit of measure that is equal to one watt of power supplied or taken steadily from an electric circuit for one hour.

Weighted average cost of capital (WACC). The average after-tax cost of a company's various capital sources (i.e., the ROE and return on debt), in which each category of capital is proportionately weighted.

Wholesale energy market. A financial market that allows for the purchase and sale of large quantities of the electricity produced by different energy resources between utility companies and energy suppliers.

Wholesale energy price. The price at which energy is sold by energy suppliers, in a wholesale energy market, to energy distributers, who buy power for resale to end-use customers.

Wind power (or wind energy). The process of using wind turbines to convert the kinetic energy into electric power.

Wood waste. A type of biomass that includes discarded wood products resulting from wood processing, typically from lumber mills and paper mills.

Zero-Emission Credit (ZEC). A credit provided to eligible zero-emissions facilities that represents 1 MWh of zero-emissions generation. Existing ZEC programs provide ZECs only to nuclear power generation.

Appendix L. List of Acronyms

2d Cir.	U.S. Court of Appeals for the Second Circuit
7th Cir.	U.S. Court of Appeals for the Seventh Circuit
ACC	Arizona Corporation Commission
ACP	Alternative Compliance Payment
AEO	*Annual Energy Outlook* report
AEP	American Electric Power
AEPS	Alternative Energy Portfolio Standard
AERLP	Alternative Energy Revolving Loan Program
Ameren	Ameren Illinois
AMI	Advanced Metering Infrastructure
APEEP	Air Pollution Emission Experiments and Policy
ATB	Annual Technology Baseline
AVERT	AVoided Emissions and geneRation Tool
AWEA	American Wind Energy Association
BEA	U.S. Bureau of Economic Analysis
BEI	Baltimore Energy Initiative
BFG	Black furnace gas
BGE	Baltimore Gas and Electric Company
BHI	Beacon Hill Institute
BLS	U.S. Bureau of Labor Statistics
Blue Chip	*Blue Chip Economic Indicators*
BOEM	Bureau of Ocean Energy Management
BOS	Balance of system
BRA	Base Residual Auction
BTM	Behind-the-meter
C-PACE	Commercial Property Assessed Clean Energy Program
C&I	Commercial & Industrial
CAGR	Compound Annual Growth Rate
CAISO	California ISO
CARES	Clean and Renewable Energy Standard
CARIS	Congestion Assessment and Resource Integration Study
CASPR	Competitive Auctions with Sponsored Policy Resources ()
CC	Combined cycle
CCGT	Combined cycle gas turbine
CEF	Clean Energy Fund
CEHPAC	Children's Environmental Health and Protection Advisory Council
CEJA	Clean Energy Jobs Act
CEJSC	Commission on Environmental Justice and Sustainable Communities
CES	Clean Energy Standard
Ch. 393	Chapter 393 of the Acts of the Maryland General Assembly of 2017
Ch. 757	Chapter 757 of the Acts of the Maryland General Assembly of 2019
CH_4	Methane
CHP	Combined Heat and Power
CIP	Copenhagen Infrastructure Partners
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
COBRA	CO-Benefits Risk Assessment
COMAR	Code of Maryland Regulations
ComEd	Commonwealth Edison
CPC	Clean peak certificate
CPCN	Certificate of Public Convenience and Necessity

CPI	Consumer Price Index
CPS	Clean Peak Standard
CPV	Competitive Power Ventures
CRI	Composite Reliability Index
CSP	Concentrating Solar Power
CT	Combustion Turbine Unit
DC or D.C.	District of Columbia
DCEO	Illinois Department of Commerce and Economic Opportunity
DEEP	Department of Energy & Environmental Protection
DER	Distributed energy resource
DG	Distributed generation
DNR	Maryland Department of Natural Resources
DOE	U.S. Department of Energy
DOER	Massachusetts Department of Energy Resources
DOI	U.S. Department of the Interior
DOJ	U.S. Department of Justice
Dominion	Dominion Energy, Inc.
DPL	Delmarva Power & Light Company
DPV	Distributed solar
DR	Demand response
DSIRE	Database of State Incentives for Renewables & Efficiency®
DSM	Demand-side management
DSP	Distribution System Plan
eGRID	Emissions & Generation Resource Integrated Database
EEI	Edison Electric Institute
EFI	Energy Futures Initiative
EIA	U.S. Energy Information Administration
EIPC	Eastern Interconnection Planning Collaborative
EJ	Environmental justice
ELCC	Effective load carrying capability
EO	Executive Order
EPA	U.S. Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
EV	Electric vehicle
EY	Energy year
FEJA	Future Energy Jobs Act
FERC	Federal Energy Regulatory Commission
FES	FirstEnergy Solutions Corporation
FIP	Feed-in Premium
FIT	Feed-in Tariff
FLIGHT	Facility Level Information on GreenHouse gases Tool
FRR	Fixed Resource Requirement
FSA	Facility Study Agreement
FTE	Full-time equivalent
GDP	Gross Domestic Product
GE	GE Energy Consulting
GGS	Green goods and services
GHG	Greenhouse gas
GW	Gigawatt
GWh	Gigawatt-hour
GWP	Global warming potential
HAA	Maryland Healthy Air Act
HB	House Bill
HOBO	High Offshore + Best Onshore
Hope Creek	Hope Creek Nuclear Generating Station
HR	House Resolution

HSBO	High Solar + Best Onshore
HUD	U.S. Department of Housing and Urban Development
Hydro	Hydroelectric power
I-O	Input-output modeling
ICC	Illinois Commerce Commission
IEA	International Energy Agency
IEPA	Illinois Environmental Protection Agency
IMPLAN	IMpact analysis for PLANning
IOU	Investor-owned utility
IPA	Illinois Power Agency
IPL	Industrial Process Load
IREC	Interstate Renewable Energy Council
IRENA	International Renewable Energy Agency
IRP	Integrated Resource Plan
IRR	Internal rate of return
ISA	Interconnection Service Agreement
ISO	Independent system operator
ISO-NE	Independent System Operator of New England
ITC	Federal Investment Tax Credit
IWG	Interagency Working Group
JEDI	Jobs and Economic Development Impacts
kW	Kilowatt
kWh	Kilowatt-hour
kWh-RE	Kilowatt-hour of renewable energy
LBNL	Lawrence Berkeley National Laboratory
LCOE	Levelized Cost of Energy
LCPS	Low Carbon Portfolio Standard
LFG	Landfill gas
LIPA	Long Island Power Authority
LM	Loads Model
LMI	Low- and moderate-income
LMP	Locational Marginal Price
LOBO	Low Offshore + Best Onshore
LODO	Low Offshore + Dispersed onshore
LOLE	Loss of load expectation
LSE	Load-serving entity
LTER	*Long-term Electricity Report for Maryland*
M-RETS	Midwest Renewable Energy Tracking System
MACEJ	Maryland Advisory Council on Environmental Justice
MACRS	Modified Accelerated Cost-Recovery System
MAPS	Multi-Area Production Simulation
MARS	Multi-Area Reliability Simulation
MassCEC	Massachusetts Clean Energy Center
MATS	Mercury and Air Toxics Standard
MCCC	Maryland Commission on Climate Change
MCEC	Maryland Clean Energy Center
MDE	Maryland Department of the Environment
MD-PACE	Maryland Property Assessed Clean Energy Program
MDA	Maryland Department of Agriculture
MDV-SEIA	Maryland-District of Columbia-Delaware-Virginia group of SEIA
MEA	Maryland Energy Administration
MES	Maryland Environmental Service
MidAmerican	MidAmerican Energy Company
MIRECS	Michigan Renewable Energy Certification System
MISO	Midcontinent Independent System Operator
MMBtu	Million British thermal units

MMT	Million metric tons
MT	Metric tons
MOPR	Minimum Offer Price Rule
MSW	Municipal solid waste
MT	Metric tons
MW	Megawatt
MWh	Megawatt-hour
MWh-RE	Megawatt-hour of renewable energy
NAICS	North American Industry Classification System
NASEO	National Association of State Energy Officials
NCCETC	North Carolina Clean Energy Technology Center
NERC	North American Electric Reliability Corporation
NIPSCO	Northern Indiana Public Service Company
NJDEP	New Jersey Department of Environmental Protection
NJDRC	New Jersey Division of Rate Counsel
NJPBU	New Jersey Board of Public Utilities
NOx	Nitrogen oxides
NPD	Nonpowered dams
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NSD	New stream-reach development
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
NYSERDA	New York State Energy Research & Development Authority
O&M	Operations and maintenance
OAQDA	Ohio Air Quality Development Authority
OCC	Overnight capital cost
OHEP	Office of Home Energy Programs
OLS	New Jersey Office of Legislative Services
OpenEI	Open Energy Information
OREC	Offshore renewable energy credit
ORNL	Oak Ridge National Laboratory
OSW	Offshore wind
PACE	Property Assessed Clean Energy
PBR	Performance-based regulation
PC	Public Conference
Pepco	Potomac Electric Power Company
PFS	PACE Financial Servicing, LLC
PJM	PJM Interconnection, LLC
PJM-APS	PJM-Allegheny Power Systems
PJM-GATS	PJM's Generation Attribute Tracking System
PJM-MidE	PJM-Mid-Atlantic East
PJM-SW	PJM-Mid-Atlantic Southwest
PJM Queue	PJM Generation Interconnection Queue
PM2.5	Particulate matter 2.5
POU	Publicly-owned utility
PPA	Power Purchase Agreement
PPRP	Power Plant Research Program
PRA	Planning Resource Auction
PRIS	*PJM Renewable Integration Study*
PROBE	Portfolio Ownership & Bid Evaluation
PSC	Public Service Commission
PSEG	Public Service Enterprise Group
PTC	Federal Production Tax Credit
PUCO	Public Utilities Commission of Ohio
PURA	Public Utilities Regulatory Authority

PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaic
QF	Qualifying facility
R-PACE	Residential Property Assessed Clean Energy Program
REC	Renewable energy credit/certificate
REP	Renewable Energy Program
RETI	Renewable Energy Transmission Initiative
REV	Reforming the Energy Vision
RFC	ReliabilityFirst Corporation
RFP	Request for proposal
RGGI	Regional Greenhouse Gas Initiative
RLF	Revolving loan fund
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standard
RTEP	Regional Transmission Expansion Plan
RTO	Regional transmission organization
Salem	Salem Nuclear Power Plant
SALP	State Agency Loan Program
SAM	System Advisor Model
SB	Senate Bill
SCC	Social cost of carbon
SEIA	Solar Energy Industries Association
SEIF	Strategic Energy Investment Fund
SO_2	Sulfur dioxide
SOS	Standard offer service
SOx	Sulfur oxides
SPE	Special purpose entity
SREC	Solar renewable energy credit
SWOT	Strengths, weaknesses, opportunities and threats analysis
TARA	Transmission Adequacy and Reliability Assessment
TOU	Time-of-use
TRG	Techno-resource group
TWh	Terawatt-hour
United	United Illuminating Co.
UPV	Utility-scale PV
USC	Universal Service Charge
VOM	Variable operations and maintenance
WACC	Weighted average cost of capital
WEA	Wind Energy Area
ZEC	Zero-emission credit
ZES	Zero Emission Standard

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