PUBLIC SERVICE COMMISSION OF MARYLAND

TEN-YEAR PLAN (2014 – 2023) OF ELECTRIC COMPANIES IN MARYLAND

Prepared for the
Maryland Department of Natural Resources
In compliance with Section 7-201
of the Public Utilities Article, *Annotated Code of Maryland*
August 2014

State of Maryland
Public Service Commission

W. Kevin Hughes, Chairman
Harold D. Williams, Commissioner
Lawrence Brenner, Commissioner
Kelly Speakes-Backman, Commissioner
Anne E. Hoskins, Commissioner

David J. Collins Executive Secretary	Anthony Myers Acting Executive Director	H. Robert Erwin, Jr. General Counsel

6 St. Paul Street
Baltimore, MD 21202
Tel: (410) 767-8000
www.psc.state.md.us

This report was drafted by the Commission's Energy Analysis and Planning Division.

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I. Introduction

This report constitutes the Maryland Public Service Commission's *Ten-Year Plan (2014-2023) of Electric Companies in Maryland*. The Ten-Year Plan is submitted annually by the Commission to the Secretary of the Department of Natural Resources in compliance with § 7-201 of the Public Utilities Article, *Annotated Code of Maryland*. It is a compilation of information pertaining to the long-range plans of Maryland's electric companies. The report also includes discussion of selected developments that may affect these long-range plans. The analysis contained in the Ten-Year Plan uses forecasts provided by Maryland utilities, PJM Interconnection, LLC ("PJM"), and other state and federal agencies.

The 2014 – 2023 Ten-Year Plan provides a forward-looking analysis of the composition of Maryland's electricity and generation profile, as well as pertinent resources for more detailed information and Commission reports. This Plan will cover the following topics as relevant to Maryland:

1. Maryland Load Growth Forecasts;
2. Transmission, Supply, and Generation; and
3. Federal Energy Issues.

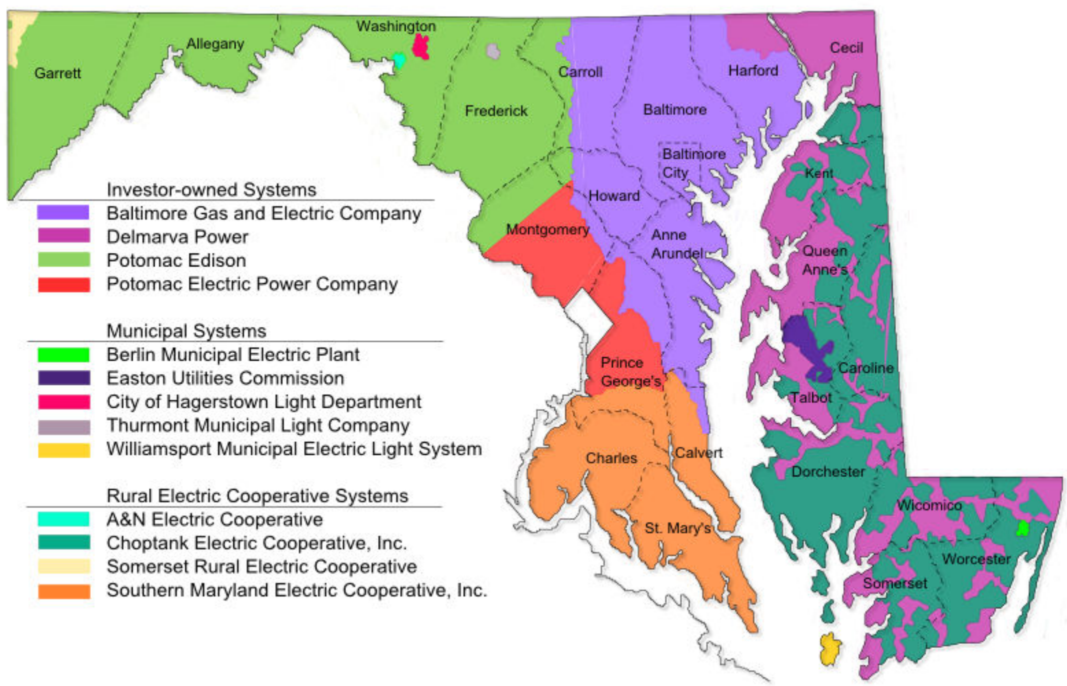
Of special note from these sections are discussions of the future planning implications associated with: the 2013/2014 winter weather on the natural gas market (Section III); the Dominion Cove Point liquefied natural gas facility (Section IV); litigation pertaining to the Federal Energy Regulatory Commission ("FERC") Order 745 (Section V); and the U.S. Environmental Protection Agency's proposal of carbon pollution standards for existing power plants under Section 111(d) of the Clean Air Act (Section V).

Changes to Maryland's capacity and generation profile anticipated by this report may necessitate additional infrastructure investment in the State's distribution network to ensure the safe, reliable, and economic supply of electricity. The Commission exercises its statutory and regulatory power to promote adequate, economical, and efficient delivery of utility services in the State through docketed proceedings. An account of these proceedings, including those dealing with distribution infrastructure investments, is published by the Commission in an annual report every March.

II. Background

Maryland is geographically divided into thirteen electric utility service territories. The four largest are investor-owned utilities ("IOUs"), four are electric cooperatives (two of which serve mainly rural areas of Maryland), and five are electric municipal operations.[1] PJM sub-regions, known as zones, generally correspond with the IOU service territories. PJM zones for three of the four IOUs traverse state boundaries and extend into other jurisdictions.[2] Figure 1 below provides a geographic picture of the Maryland utilities' service territories. Figure 2 depicts the PJM forecast zones of which Maryland is comprised.

Figure 1: Maryland Utilities and their Service Territories in Maryland [3]

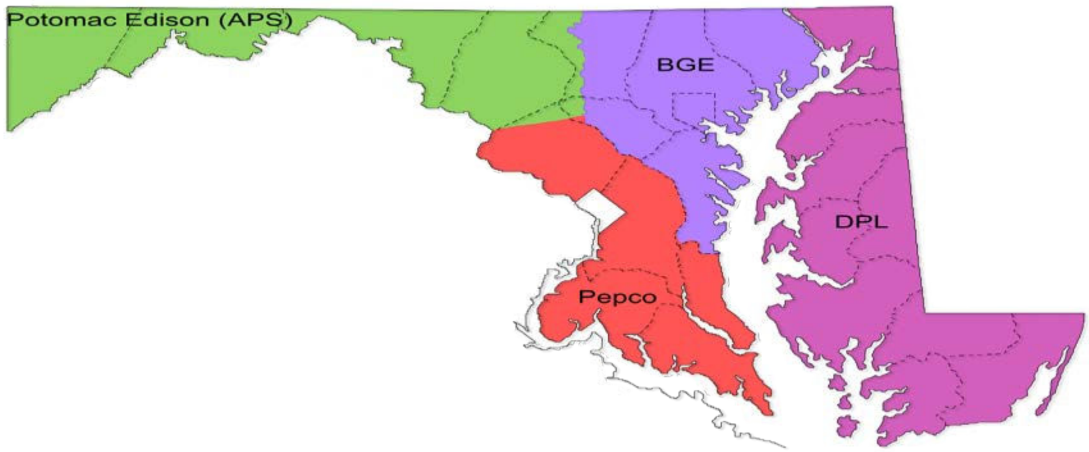


[1] The Commission regulates all Maryland public service companies, as defined by §1-101(x) of the Public Utilities Article, *Annotated Code of Maryland*.

[2] Potomac Electric Power Company ("Pepco"), Delmarva Power and Light Company ("DPL"), and The Potomac Edison Company ("PE") are the three IOUs that extend into other jurisdictions. Pepco, DPL, and PE data are a subset of the PJM zonal data, since PJM's zonal forecasts are not limited to Maryland. The Baltimore Gas and Electric ("BGE") zone, alone, resides solely within the State of Maryland.

[3] *Cumulative Environmental Impact Report 16*, Maryland Department of Natural Resources, Figure 2-12, http://esm.versar.com/pprp/ceir16/Report_2_2_0.htm (last updated February 20, 2012).

Figure 2: PJM Maryland Forecast Zones [4]



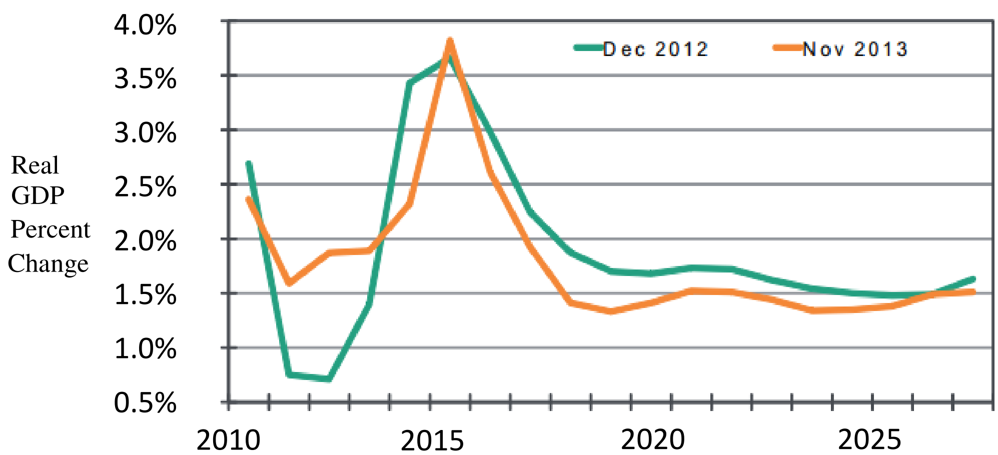
[4] *PJM Load Forecast Report,* PJM (January 2014), http://www.pjm.com/~/media/documents/reports/2014-load-forecast-report.ashx.

III. Maryland Load Growth Forecasts

Each year, PJM presents a Load Forecast Report for its service territory that is derived in part from an independent economic forecast, typically prepared by Moody's Analytics. The economic analysis includes projections related to the expected annual growth of the gross domestic product ("GDP") and can provide insight into possible trends for regional population growth and household disposable income, which in turn can impact energy sector planning.

The PJM forecast typically compares GDP growth projections between the current and previous year – *i.e.* December 2012 to November 2013 load forecasts, as depicted below in Figure 3. The figure shows that GDP projections for PJM's metro areas follow the same general trajectory during the 2014 – 2023 planning period as the previous year's forecast, although at a slightly diminished rate. PJM cites weaker population growth as the main reason that the November 2013 forecast is projecting lower GDP growth than the December 2012 forecast.[5]

Figure 3: Comparison of Real GDP Growth Projections in PJM Metro Areas, December 2012 versus November 2013 [6]



PJM's most recent forecast predicts GDP growth in metro areas will peak at approximately 3.8% in 2015.[7] In the years following the economic downturn, each iteration of the PJM load forecast revised the year in which peak GDP growth would occur until a later year in the forecasted planning period, indicating the likely delay of

[5] PJM Load Forecast Report, PJM, at 11 (January 2014), http://www.pjm.com/~/media/documents/reports/2014-load-forecast-report.ashx.
[6] *Id.* at 12.
[7] *Id.*

economic recovery.[8] On the contrary, Figure 3 shows that the year in which GDP growth is projected to peak (2015) has not been revised from last year's load forecast, illustrating a potentially more stabilized economic outlook. Due to the similar GDP outlook, this section of the Ten-Year Plan will examine instances in which the Maryland utilities' current forecasts differ from the forecasts provided last year.

Load forecasts submitted by the Maryland utilities for the 2014 – 2023 planning period indicate a modest amount of projected annual growth in the number of customers, energy sales, and peak demand throughout Maryland, and are comparable to the forecasts provided over the last several years. However, while the current load forecasts show stronger customer and energy sales growth compared to last year's load forecasts, both summer and winter peak demand growth is projected to occur at a diminished rate versus earlier projections. Table 1 compares the load growth forecasts from the Commission's previous two Ten-Year Plans with the current Ten-Year Plan.

Table 1: Compound Annual Growth Rate Projections – 2012 [9], 2013 [10], and 2014 [11]

Forecasts	Ten-Year Plan 2012 - 2021	Ten-Year Plan 2013 - 2022	Ten-Year Plan 2014 - 2023
Customers Forecasts	0.85%	0.64%	0.73%
Energy Sales Forecasts	1.20%	0.87%	1.29%
Summer Peak Demand Forecasts	1.20%	1.13%	0.90%
Winter Peak Demand Forecasts	1.07%	0.97%	0.81%

A. Customer Growth Forecasts [12]

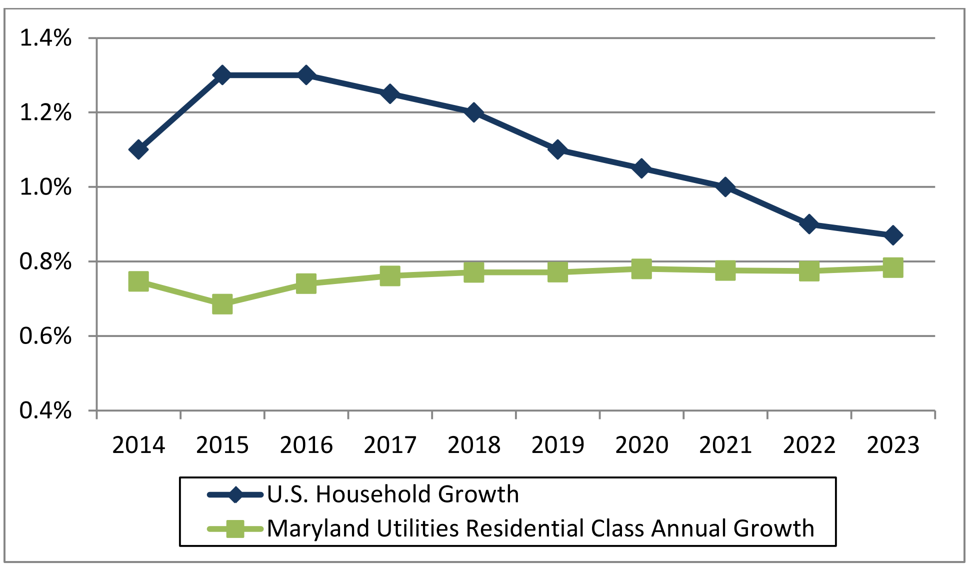
At the close of 2013, approximately 90% of utility customers in Maryland were categorized as residential ratepayers; this group of customers corresponded to a little less than half of the previous year's total retail energy sales.[13] Therefore, growth and usage trends in the residential sector should be closely monitored for their potential ramifications to the Maryland utilities' overall forecasts.

[8] *Ten-Year Plan (2012 - 2021) of Electric Companies in Maryland,* Maryland Public Service Commission, at 3, http://webapp.psc.state.md.us/intranet/Reports/TYP2021.pdf.
[9] *Ten-Year Plan (2012 - 2021) of Electric Companies in Maryland,* Maryland Public Service Commission, http://webapp.psc.state.md.us/intranet/Reports/TYP2021.pdf.
[10] *Ten-Year Plan (2013 - 2022) of Electric Companies in Maryland,* Maryland Public Service Commission, http://webapp.psc.state.md.us/Intranet/Reports/2013_2022%20TYP%20Final%20(4_1_14).pdf.
[11] *See* Appendix Tables 1(a)(i), 2(a)(i), 3(a)(i), 3(a)(iii), and Section III for a complete summary of utility forecasts.
[12] *See* Appendix Table 1(a) for a complete list of utility-by-utility customer growth forecasts.
[13] *See* Appendix Tables 1(b)(i) and 1(b)(ii).

Utility customer growth, particularly in the residential sector, is closely linked to projections regarding household growth. Nationally, the household growth rate is expected to increase over the next few years, which PJM attributes to a short-term increase due to the ongoing economic recovery.[14] PJM's analysis indicates that as the economy recovers, young people who delayed creating new households due to the weak labor market will now do so, and immigration will increase as the U.S. economy improves relative to other countries.[15]

Unlike the national household growth rate projections (which are expected to demonstrate near-term gains), Maryland is projected to lag below the national average for the duration of the planning period. However, towards the latter half of the ten-year planning period, national growth is expected to slow to a rate closer to that projected by Maryland utilities. For the majority of this planning period, the Maryland utilities' forecasts depict a fairly static growth rate. These relatively stable state-specific projections may be attributable to the fact that, in prior years, Maryland's population increased while the national household growth rate experienced a decrease over the same time period.[16,17]

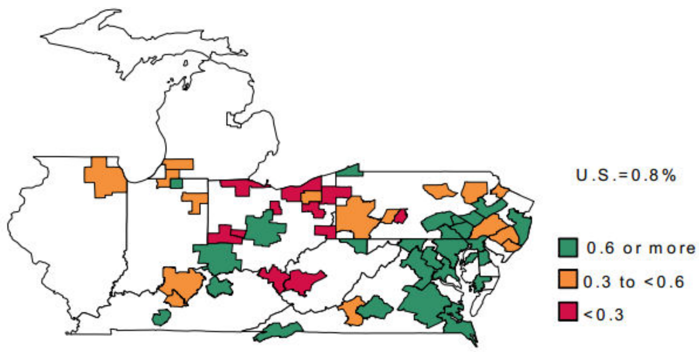
Figure 4: U.S. Household Growth verses Residential Class Growth [18]



[14] PJM Load Forecast Report, PJM, at 7 (January 2014), http://www.pjm.com/~/media/documents/reports/2014-load-forecast-report.ashx.
[15] *Id.*
[16] Maryland Association of Realtors, *The Fiscal Crisis' Impacts on Government Revenues from Maryland Real Estate*, at 1, http://www.mdrealtor.org/Portals/0/docs/ResearchandStatistics/MAR%20Revenue%20Report%202012.pdf
[17] Maryland Department of Planning (July 30, 2014) http://planning.maryland.gov/msdc/Pop_estimate/Estimate_12/chart2.pdf.
[18] The average annual customer growth rates are calculated using the utilities' data responses to the Commission's 2014 data request for the Ten-Year Plan. *See* Appendix Table 1(a) for utility-specific customer growth forecasts, including breakdowns by customer class.

As indicated in the figure above, the utilities' aggregated forecasts signal that Maryland is expected to maintain an annual residential growth rate of between 0.7% and 0.8% for the next ten years. These forecasts are confirmed by Figure 5 below, which reflects the range of PJM household growth projections throughout the PJM footprint. PJM's analysis suggests that favorable demographics, including a highly educated labor force, justify higher growth projections in large metro areas such as Baltimore.[19]

Figure 5: Average Annual Household Growth from 2013 to 2028 [20]



Similar to the utilities' range of *residential* annual growth projections over the ten-year planning period, the Maryland customer growth projection *inclusive of all customer classes* anticipates a compound annual growth rate of 0.73% statewide—a 0.09% increase compared to the growth rate projected by the 2013 – 2022 Ten-Year Plan. Since residential customers represent 90% of current Maryland ratepayers,[21] it is to be expected that the forecasted growth rate across all customer classes is within the range of projected residential growth in Maryland. However, several utilities are forecasting compound annual growth rates that are much higher than the statewide average of 0.73%: the Berlin Municipal Electric Plant ("Berlin"), the Easton Utilities Commission ("Easton" or "EUC"), and SMECO are forecasting the highest compound annual growth rates at 1.05%, 1.31%, and 1.26%, respectively. While these growth rates may appear significantly higher than the statewide average, the specified utilities represent municipal systems and rural electric cooperatives that serve significantly smaller populations than the largest Maryland utilities; together, BGE and Pepco—the State's two largest IOUs—serve approximately 70% of Maryland customers. To put this into perspective, while BGE and Pepco are forecasting lower ten-year compound annual growth rates of 0.65% and 0.91%, respectively, the total combined customer increase for those two utilities is 120,843 customers. This result is significantly greater than the combined projected customer growth of Berlin, Easton, and SMECO, which altogether translates into an incremental 20,605 customers during the same ten-year planning period.

[19] PJM Load Forecast Report, PJM, at 12(January 2014), http://www.pjm.com/~/media/documents/reports/2014-load-forecast-report.ashx.
[20] *Id.*
[21] *See* Appendix Table 1(b)(i).

These compound annual growth rates, as reflected in the table below, translate into a 6.79% increase in the total number of Maryland customers by the end of the ten-year planning period. During this timeframe, Easton, SMECO, Pepco, PE, and BGE are each projecting their overall customer bases to increase by 5% or more.

Table 2: Maryland Customers Forecast (All Customer Classes)[22]

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Total
2014	2,459	1,249,177	52,486	201,444	11,147	17,331	256,397	538,481	158,793	**2,491,542**
2015	2,459	1,255,375	52,797	202,508	11,300	17,411	258,468	543,274	160,844	**2,508,264**
2016	2,471	1,262,574	53,144	203,686	11,454	17,491	260,624	548,178	162,874	**2,526,324**
2017	2,496	1,270,616	53,436	204,832	11,607	17,572	262,552	553,125	164,914	**2,544,977**
2018	2,521	1,279,200	53,668	205,939	11,761	17,653	264,322	558,008	167,054	**2,563,954**
2019	2,546	1,288,112	53,841	207,011	11,914	17,734	265,933	563,007	169,094	**2,583,021**
2020	2,584	1,297,171	53,983	208,050	12,068	17,816	267,513	568,124	171,234	**2,602,372**
2021	2,623	1,306,181	54,095	209,056	12,221	17,898	269,064	573,269	173,444	**2,621,680**
2022	2,662	1,315,154	54,159	210,047	12,375	17,980	270,646	578,641	175,554	**2,641,047**
2023	2,702	1,324,117	54,226	211,022	12,528	18,063	272,113	584,384	177,774	**2,660,756**
Change (2014-2023)	**243**	**74,940**	**1,740**	**9,578**	**1,381**	**732**	**15,716**	**45,903**	**18,981**	**169,214**
Percent Change (2014-2023)	**9.90%**	**6.00%**	**3.32%**	**4.75%**	**12.39%**	**4.22%**	**6.13%**	**8.52%**	**11.95%**	**6.79%**
Compound Annual Growth Rate	**1.05%**	**0.65%**	**0.36%**	**0.52%**	**1.31%**	**0.46%**	**0.66%**	**0.91%**	**1.26%**	**0.73%**

With the exception of Pepco, the customer forecasts provided by these utilities are comparable to the forecasts they provided for the 2013 – 2022 Ten-Year Plan. In total for this planning period, Pepco is projecting the addition of 45,903 customers, of which 99.7% is projected to come from the residential customer class. Pepco's projection for this planning period represents an increase of 21,442 customers compared to its 2013 – 2022 forecast, which is equivalent to 3.98% of Pepco's total 2014 customer base. Pepco attributes this increase over last year's forecast to anticipated higher employment in its service territory.[23]

Pepco's projections regarding residential customer base additions are commensurate to the statewide trends. Overall, the increase in the number of customers across Maryland is primarily driven by growth in the residential class; growth in the residential sector is projected to account for an additional 157,663 customers by 2023, or 93% of total new customers projected. The largest absolute increase in the number of customers is projected to come from BGE's residential customer base, with the addition of 69,319 residential customers forecasted during this planning period.[24] BGE's projected increase in its residential customer base accounts for 44% of the total number of new

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[22] *See* Appendix Table 1(a)(i). Note that A&N, Somerset, Thurmont, and Williamsport did not provide the requested applicable information in response to the Commission's 2014 data request for the Ten-Year Plan.
[23] Pepco forecasts that employment will reach 111% of its pre-recession peak by 2018. July 10, 2014 correspondence Patti Johnson, Manager of Regulatory Affairs.
[24] *See* Appendix Table 1(a).

residential customers across all service territories during the ten-year planning period,[25] a result which is to be expected since BGE serves nearly half of Maryland's residential customers. The increase in residential customers for BGE translates into a compound annual growth rate of 0.65%.[26] This is comparable to PJM's average annual household growth projection of "[a]bove 0.60%" for the BGE service territory, as previously illustrated by Figure 5.

Although several Maryland utilities are projecting a sizeable increase in their customer bases during this planning period, the table below shows that the aggregated utilities' customer forecasts are only 1.71% higher than projections provided during the previous planning period. Table 3 compares the projected percentage increase for each customer class during the planning period for the current and previous Ten-Year Plans. Because a review of the data revealed that the inclusion of BGE's customer forecast in the statewide analysis masked a potential trend in the industrial class, the aggregated utility data is also presented without the data supplied by BGE.

Table 3: Projected Percentage Increase in the Number of Customers by Class, 2014 – 2023 [27, 28]

	All Utilities			Without BGE		
Class	**2013 to 2022**	**2014 to 2023**	**Difference**	**2013 to 2022**	**2014 to 2023**	**Difference**
Residential	5.99%	7.06%	1.07%	6.63%	7.95%	1.32%
Commercial	4.88%	3.80%	-1.08%	5.32%	4.64%	-0.68%
Industrial	5.95%	15.91%	9.96%	7.71%	-0.22%	-7.93%
Other	0.32%	0.81%	0.49%	0.32%	1.95%	1.63%
Resale	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total Customers	**5.88%**	**7.59%**	**1.71%**	**6.50%**	**7.59%**	**1.09%**

The aggregated utility data in the above table reveals that the most significant change between the previous and current Ten-Year Plan forecasts is within the industrial customer class. The reflected increase in the industrial sector is primarily attributable to a change in BGE's reporting methodology, which has the impact of offsetting and masking a large decrease in PE's industrial class projected as part of the 2014 – 2023 planning period. PE updated the historical data for their industrial customer class model, which resulted in a slight decline for the ten-year period reported in 2014 (as opposed to the significant gains projected by PE in previous iterations of the Ten-Year Plan).

[25] *See* Appendix Table 1(a)(ii). The Utilities project an additional 157,663 residential customers by 2023, of which BGE accounts for 69,319 customers, or 44% of all new residential customers.
[26] *See* Appendix Table 1(a).
[27] *See* Appendix Table 1(a)(i)-(vi) for more information.
[28] The "Other" rate class refers to customers that do not fall into one of the listed classes; street lighting is an example of a rate class included under "Other." The Resale class refers to Sales for Resale which is energy supplied to other electric utilities, cooperatives, municipalities, and Federal and State electric agencies for resale to end use consumers. PE is the only utility with any resale customers; these wholesale customers are PJM, Monongahela Power Company, West Penn Power Company, and Old Dominion Electric Cooperative.

In prior years, BGE separated the customer classes according to the Standard Industrial Classification used by the Federal Government to identify and classify specific categories of business activity.[29] However, this year BGE reported the customers separately according to their individual classes.[30] Despite the differences in reporting, BGE is forecasting roughly the same number of total commercial and industrial ("C&I") customers this year as compared to last year. Furthermore, as reflected in the table below, the total number of actual C&I customers decreased by only 116 customers between years 2012 to 2013, despite the impression of a large projected change attributable to the modified reporting practice.

Table 4: Comparison of BGE's Actual Customers per Class for 2012[31] and 2013[32]

Rate Class	2012	2013	Difference
Residential	1,115,939	1,118,769	2,830
Commerical	119,484	113,008	(6,476)
Industrial	5,559	11,620	6,061
Other	-	300	300
Total Customers	1,240,982	1,243,696	2,714
Total C&I Customers	125,043	124,928	(116)

[29] *The U.S. Small Business Administration, What is a Standard Industrial Classification (SIC) code?,* http://www.sba.gov/content/what-standard-industrial-classification-sic-code, (last visited June 2014).
[30] Response 2-1 to Staff's Second Set of Data Requests for BGE.
[31] *Ten-Year Plan (2013 - 2022) of Electric Companies in Maryland,* Maryland Public Service Commission, http://webapp.psc.state.md.us/Intranet/Reports/2013_2022%20TYP%20Final%20(4_1_14).pdf.
[32] *See* Appendix Table 1(a).

B. Energy Sales Forecast

The Maryland utilities provide forecasts for energy sales and peak load in terms of "Gross of Demand Side Management ("DSM")" and "Net of DSM."[33] In order to provide a more complete look at Maryland energy sales and peak demand forecasts, Sections II.B and II.C discuss the forecasts in "Gross of DSM" terms, which reflect the forecasts *before* the impact of DSM programs. Table 5 shows the energy sales forecast within Maryland (Gross of DSM) for the ten-year planning period, as provided by the utilities. The aggregated forecasts show a compound annual growth rate of 1.29% across all the Maryland service territories for 2014 – 2023, an increase from the 0.87% annual growth rate reported in the 2013 – 2022 Ten-Year Plan.

Table 5: Maryland Energy Sales Forecast (GWh) (Gross of DSM) [34]

	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Total
Change (2014-2023)	2	5,072	324	214	16	18	761	959	558	7,925
Percent Change (2014-2023)	5.16%	15.94%	32.17%	4.89%	5.76%	5.92%	9.78%	6.24%	14.59%	12.23%
Compound Annual Growth Rate	0.56%	1.66%	3.15%	0.53%	0.62%	0.64%	1.04%	0.67%	1.53%	1.29%

The statewide growth rate derived from the utilities' 2014 - 2023 forecasts is 0.42% greater than the rate projected in last year's report, and is driven primarily by the BGE service territory. BGE is forecasting the addition of 5,072 GWh of load during the current ten-year planning period, compared to last year's forecast in which BGE projected the addition of only 2,509 GWh in load over the span of ten years. On the other hand, PE and SMECO are projecting a lower level of growth than anticipated in the 2013 - 2022 report; together, the two utilities are projecting to add 372 fewer GWh in load during this planning period. PE and SMECO projected a similar drop in their customer forecasts between the current and previous Ten-Year Plans.[35]

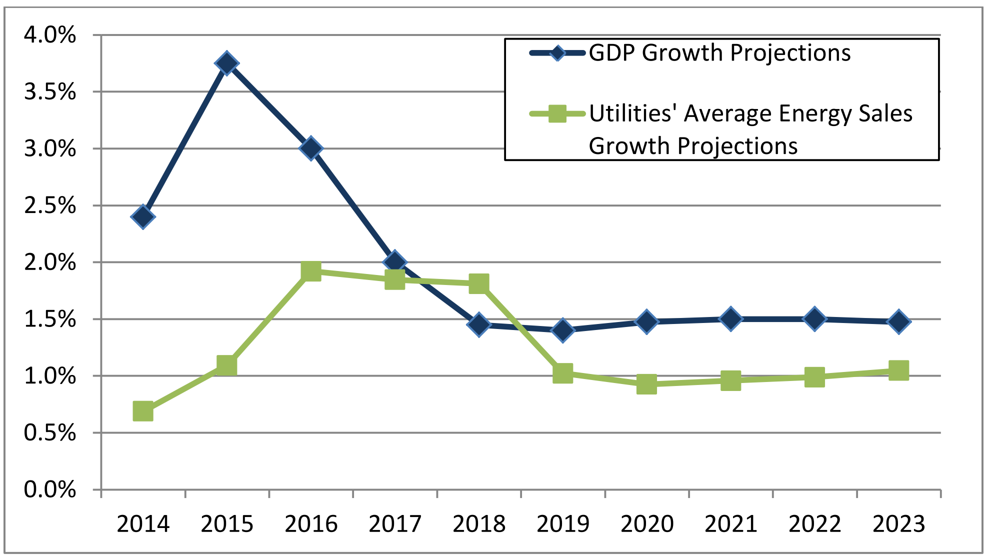
While the table above focuses on Maryland-specific energy sales forecasts, of some interest is a perceived anomaly between the annual growth rate projected by DPL for its Maryland service territory compared to the rate projected by DPL for its system-wide energy sales. DPL is forecasting that energy sales in its Maryland service territory will have a compound annual growth rate of 0.53%; whereas, its system-wide sales are projected to only realize a 0.04% annual growth rate over the same period.[36] DPL

[33] *See* Appendix Table 2(a)(ii) for the Maryland Energy Sales forecast, Net of DSM programs; Appendix Table 3(a)(ii) for the Maryland Summer Peak Demand Forecast, Net of DSM programs; and Appendix Table 3(a)(iv) for the Maryland Winter Peak Demand Forecast, Net of DSM programs.
[34] *See* Appendix Table 2(a) for utility-by-utility energy sales forecasts for the Maryland service territory, available by Gross and Net of DSM. *See* Appendix Table 2(b) for the same information on a system wide basis.
[35] *See* Table 2.
[36] *See* Appendix Table 2(b)(i).

attributes the stronger growth in Maryland to a forecasted increase in total non-farm employment.[37] This reasoning exemplifies the close link between economic projections and energy projections.

The link between economic and energy sales projections is further highlighted by Figure 6 below, which compares the utilities' average energy sales growth rate projections with the PJM GDP growth projections for the next ten years. As shown in the figure, the Maryland utilities' sales forecasts generally follow the pattern of the GDP growth projections, with the notable exception of calendar years 2017 through 2018. Discrepancies between the GDP forecast and the aggregated utilities' energy sales forecasts are investigated, and any discovered discrepancies are discussed below.

Figure 6: Average Annual Energy Sales Growth Rate Projected by the Maryland Utilities as Compared to the PJM November 2013 GDP Growth Projections [38]



One likely discrepancy is that BGE and Choptank are both forecasting a seemingly disproportionate increase in energy sales over the planning period relative to their customer forecasts. This trend is contrary to that reported by other Maryland utilities, which generally predict a percentage increase in energy sales commensurate to that of customer growth. Table 6 below compares the forecasted percentage change for BGE, Choptank, and all other Maryland utilities for these two metrics. As shown in the table below, BGE and Choptank are outliers compared to the other utilities, since both BGE and Choptank are forecasting a much greater percentage change over the planning period in energy sales as compared to the number of customers.

[37] Response 2-7 to Staff's Second Set of Data Requests for DPL.
[38] The average annual energy sales growth rates were calculated using the utilities' data responses to the Commission's 2014 data request for the Ten-Year Plan. *See* Appendix Table 2(a)(i).

Table 6: Percent Change from 2014 to 2023

Utility	Customers	Energy Sales
BGE	6.00%	15.94%
Choptank	3.32%	32.17%
Other Utilities	7.78%	7.91%

BGE attributes the high growth in energy sales to a projected 30% increase in real personal disposable income (a key driver in BGE's residential forecasts) and a 27% increase in Real Gross Metropolitan Product (a key driver for BGE's commercial and industrial forecasts) during the planning period.[39] BGE believes the increased spending power of its customers will have a corresponding impact on the usage per customer, which is why the utility projects energy sales to experience a greater percentage increase than the number of customers between 2014 and 2023. Given the reasoning provided by BGE, it seems reasonable to assume energy sales will grow faster than the number of customers. However, BGE's projected 15.94% increase in energy sales during this planning period is higher than the same metric provided by BGE in 2013 (8.05%) and 2012 (9.79%).

Similar to the past several iterations of the Ten-Year Plan, Choptank continues to forecast the highest compound annual growth rate and overall percentage change in energy sales of all the Maryland utilities. Choptank derives its energy sales projections from its fifteen-year forecast, and attributes its projected 32.17% increase in energy sales during the planning period in part to improving economic conditions. Choptank also cites an anticipated reversal of the trend regarding depressed energy consumption levels by residential and small commercial customers within its service territory; Choptank believes that energy consumption by these customer classes will rebound in conjunction with the economy.[40] Furthermore, Choptank projects that energy sales within its service territory will grow faster than the number of new customers, consistent with its belief that increased spending power of consumers will translate into the expansion of *existing* businesses in an effort to meet the increased demand.[41] Despite the aforementioned line of reasoning, Choptank's forecast also states, "[w]e do not see a robust recovery in the economy for an extended period, thus putting restraints on new business creation and *existing business recovery*." (emphasis added)[42] While this statement undermines Choptank's justification for a significantly accelerated projected growth rate as compared to other Maryland utilities, given the size of Choptank's customer base, it is unlikely that the company's forecast will adversely impact other areas of the Ten-Year Plan.[43]

[39] Real Gross Metropolitan Product ("GMP") or Gross Regional Product ("GRP") is one of several measures of the size of the economy of a metropolitan area. Similar to gross domestic product ("GDP"), GMP is defined as the market value of all final goods and services produced within a metropolitan area in a given period, which usually corresponds to one year.
[40] Response 2-1 to Staff's Second Set of Data Requests for Choptank.
[41] *Id.*
[42] *Id.*
[43] As of December 31, 2013, Choptank's customer base represented approximately 2% of total Maryland utility customers. *See* Appendix Table 1(b)(i).

Although Choptank has provided somewhat conflicting justification for the wide disparity between its customer and energy sales forecasts, it should be noted that Choptank's projections are comparable to a trend exhibited by historical data. As illustrated in the table below, historical data indicates that energy sales within Choptank's service territory have grown at about ten times the rate of its customer base; Choptank's 2014 – 2023 forecast continues this trend, with a projected percentage increase in energy sales growing tenfold compared to the projected percentage increase of its customer base.

Table 7: Choptank's Customer Growth and Energy Sales

Choptank					
		# of Customers	Annual % Change Customers	Energy Sales (GWh)	Annual % Change Energy Sales
Reported Data	2009	52,144	0.45%	938	-0.21%
	2010	52,243	0.19%	1,000	6.61%
	2011	52,264	0.04%	1,001	0.10%
	2012	52,259	-0.01%	956	-4.50%
	2013	52,322	0.12%	971	1.57%
	2009 - 2013 % Change	0.34%		3.52%	
Forecasted in 2014 - 2023 Ten-Year Plan	2014	52,486	0.31%	1,007	3.71%
	2015	52,797	0.59%	1,054	4.67%
	2016	53,144	0.66%	1,101	4.46%
	2017	53,436	0.55%	1,135	3.09%
	2018	53,668	0.43%	1,173	3.35%
	2019	53,841	0.32%	1,209	3.07%
	2020	53,983	0.26%	1,239	2.48%
	2021	54,095	0.21%	1,269	2.42%
	2022	54,159	0.12%	1,300	2.44%
	2023	54,226	0.12%	1,331	2.38%
	2014 - 2023 % Change	3.32%		32.17%	

C. Peak Load Forecasts

PJM's 2014 Load Forecast Report includes long-term projections of peak loads for the entire wholesale market region and each PJM zone.[44, 45] Due to the fact that the PJM zones can extend outside of Maryland, the utilities submit peak demand forecasts restricted to their Maryland service territories as part of the Ten-Year Plan.[46] According to PJM's 2014 Load Forecast Report, the PJM Regional Transmission Organization ("RTO") will continue to be summer peaking during the next 15 years.[47] In 2014, the four PJM zones of which Maryland is comprised are projected to experience their peak demands during the month of July,[48] the same month as the broader PJM Mid-Atlantic Region.[49]

However, Berlin, Choptank, and PE are forecasting their peak demand to occur in the winter in most or all of the forecasted years. PE attributes its winter peak to the high concentration of electric heating.[50] Berlin historically peaks in the winter, although it did have a summer peak in 2012. In further support of its winter peaking projection, Berlin speculates that its proximity to the coastline helps keep the summer temperatures cool enough so that some residents avoid using their air conditioning.[51] The data in Choptank's Ten-Year Plan is taken from its Power Requirements Study, which is prepared by its wholesale power provider, Old Dominion Electric Cooperative. The study forecasts a winter peak for Choptank because a majority of Old Dominion Electric Cooperative's members have begun peaking in the winter due to energy efficiency and demand response programs.[52]

Although SMECO's forecast projects a summer peak in every year of the current planning period (consistent with the PJM Mid-Atlantic Region), over the last ten years SMECO has experienced a winter peak four times (including 2013) and a summer peak

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[44] PJM Load Forecast Report, PJM, at 46, Table B-1 (January 2014), http://www.pjm.com/~/media/documents/reports/2014-load-forecast-report.ashx.
[45] The four PJM zones spanning the Maryland service territory include APS, BGE, DPL, and PEPCO. *See supra* Figure 2 for a map of the Maryland zones. "APS" represents the Allegheny Power Zone, of which PE is a sub-zone.
[46] *See* Appendix Table 3(a) for more information on in-State peak demand forecasts for Maryland utilities, available for summer and winter, and by gross and net of DSM programs. *See* Appendix Table 3(b) for the same information, presented as system wide data for utilities operating in Maryland.
[47]PJM Load Forecast Report, PJM, at 2 (January 2014), http://www.pjm.com/~/media/documents/reports/2014-load-forecast-report.ashx.
[48] *Id.* at 58-59, Table B-5.
[49] *Id.* Three of the Maryland PJM zones (BGE, DPL, and Pepco) are considered to be part of the PJM Mid-Atlantic Region. The fourth Maryland PJM zone (APS) is presented as part of the PJM Western Region data set.
[50] July 8, 2014 correspondence with Kevin Wise, Director of Rates & Regulatory Affairs for FirstEnergy, West Virginia and Maryland.
[51] July 8, 2014 correspondence with Laura Allen, Town Administrator for the Town of Berlin.
[52] July 13, 2014 correspondence with Lisa DeSantis, Manager of Finance & Regulatory Affairs for Choptank.

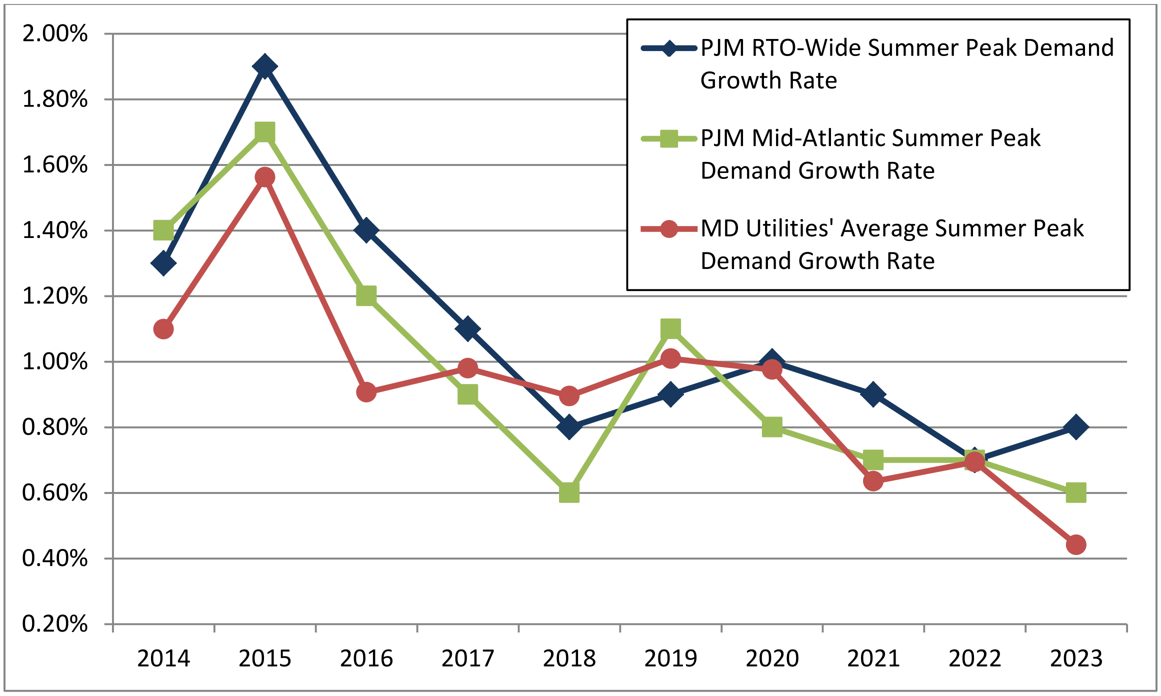
six times.[53] SMECO's current models predict that the Cooperative will have a slightly higher summer peak going forward. However, SMECO believes that this result may change in future iterations of its models, given the high winter peak that the Cooperative experienced this past 2013/2014 winter season.[54]

Figure 7 compares the average of the Maryland utilities' forecasted summer peak demands for their Maryland service territories with summer forecasts for the PJM Mid-Atlantic Region and for the PJM RTO as a whole. As illustrated by the graph, the utilities' average summer peak demand growth rate follows a similar path to the PJM RTO and the PJM Mid-Atlantic Region. In the near-term, the PJM RTO is showing stronger peak demand growth than the Maryland utilities and the PJM Mid-Atlantic Region due to the Dominion Virginia Power zone, which is projected to grow at an average of 2.5% over the next four years.[55]

Also reflected in Figure 7 is a spike in the summer peak demand growth rate projected for the Mid-Atlantic Region in the year 2019. The PJM 2014 Load Forecast report notes that 2019 corresponds to the next Regional Transmission Expansion Plan ("RTEP") study year, which resulted in a projected 2.1% decrease in the PJM RTO summer peak demand forecast in 2019.[56] However, this decrease had different implications in various zones throughout the PJM RTO, and the PJM Mid-Atlantic Region maintained a 1.1% projected summer peak demand growth rate for year 2019.[57] The 2019 spike is muted, although still visible, in the trend-line reflecting the Maryland utilities' average summer peak demand growth rate.

[53] July 15, 2014 correspondence with Eugene Bradford from SMECO.
[54] *Id.*
[55] Dominion includes areas outside of Washington, D.C. which PJM predicts will have strong economic growth. PJM Load Forecast Report, PJM, at 11 (January 2014), http://www.pjm.com/~/media/documents/reports/2014-load-forecast-report.ashx.
[56] *Id.* at 2.
[57] *Id.* at Table B-1.

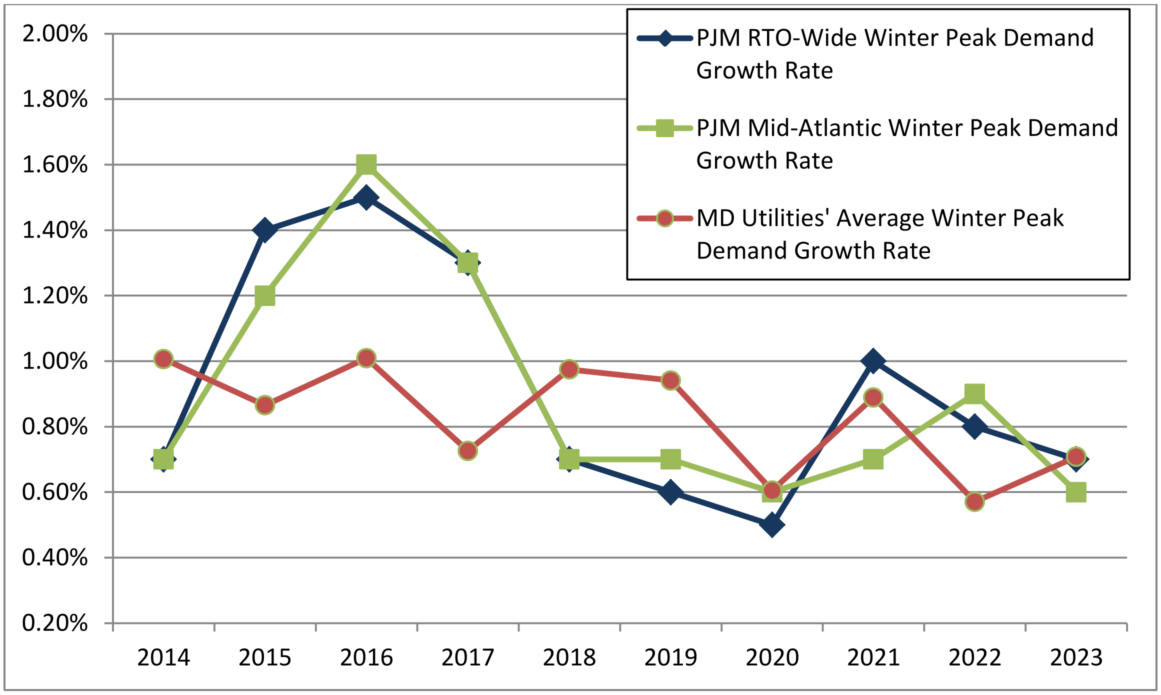
Figure 7: Average of Utilities' Projected Summer Peak Demand Growth Rates (Gross of DSM) Compared to Projected Summer Peak Demand Growth Rates for PJM Mid-Atlantic and PJM RTO [58]



The Maryland utilities also provided peak demand forecasts for the winter season in response to the Ten-Year Plan data request. Figure 8 below depicts an average of the Maryland utilities' forecasted winter peak demands, contrasted with winter peak demand forecasts for the PJM Mid-Atlantic Region and for the PJM RTO. A visual comparison of Figure 7 and Figure 8 illustrates that the aggregated Maryland utilities' winter peak demand forecast does not follow a trajectory comparable to the summer peak demand growth rate projections depicted in Figure 7. The PJM summer peak demand forecasts and the PJM GDP growth forecast follow a pattern of peaking in the near-term before transitioning to a more modest level of projected growth in the second half of the planning period. The Maryland utilities' summer peak demand forecasts also follow this pattern. Since the Maryland utilities' winter peak demand forecasts do not mirror PJM's GDP growth forecast, it may suggest that the utilities believe the economic recovery will have a greater impact on the summer months. All the winter forecasts show a lower level of peak demand growth than their summer counterparts.

[58] The Utilities' average summer peak demand growth rates were calculated using the Utilities' data responses to the Commission's 2014 data request for the Ten-Year Plan. *See* Appendix Table 3(a)(i).

Figure 8: Average of Utilities' Projected Winter Peak Demand Growth Rates (Gross of DSM) Compared to Projected Winter Peak Demand Growth Rates for PJM Mid-Atlantic and PJM RTO [59,60]



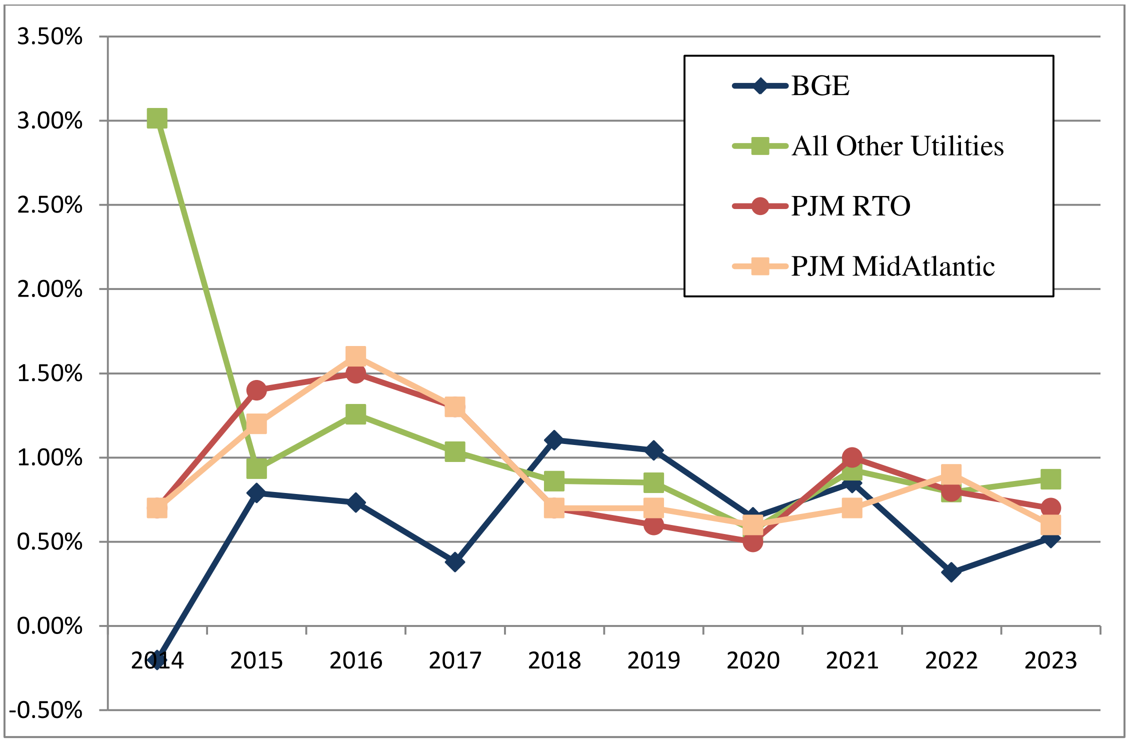
As illustrated by the above graph, the Maryland utilities' average winter peak demand growth rate differs dramatically in 2014 as compared to the PJM projections for that year. This difference is likely due to the January 2014 issuance date of the PJM Load Forecast report, the timing of which prevented the inclusion of actual winter 2014 verified usage data, contrasted with the May 2014 data response by the Maryland utilities for purposes of this report.

With the exception of 2014, the variance between the Maryland utilities' average winter peak demand growth from that of the PJM RTO and Mid-Atlantic Region is attributable to the impact of the BGE zone. Specifically, the BGE transmission zone shows a low level of growth in the near-term relative to the PJM Mid-Atlantic Region, prior to peaking in 2018.[61] To illustrate this, Figure 9 below compares PJM's forecasted winter peak demand growth rates with the BGE forecast shown separately. BGE's projected low level of near-term growth explains why the average of the remaining Maryland utilities' projected winter peak demand growth rates is lower than that of the PJM RTO and Mid-Atlantic Region forecasts (as depicted in Figure 8), since BGE

[59] PJM Load Forecast Report, PJM, Table B-1 (January 2014), http://www.pjm.com/~/media/documents/reports/2014-load-forecast-report.ashx.
[60] The Utilities' average winter peak demand growth rates were calculated using the Utilities' data responses to the Commission's 2014 data request for the Ten-Year Plan. *See* Appendix Table 3(a)(iii).
[61] Per a July 15, 2014 correspondence with Arpita Kumari, Principal Load Forecasting Analyst, from BGE, BGE confirmed that its winter peak demand forecast is based on PJM's forecast.

accounts for approximately 47% of Maryland's total winter peak demand. It is unclear as to why BGE's level of growth varies from that of the other utilities, especially from 2014 through 2019.

Figure 9: Average of Utilities' Projected Winter Peak Demand Growth Rates (Gross of DSM) Compared to Projected Winter Peak Demand Growth Rates for PJM Mid-Atlantic and PJM RTO[62,63]



As shown in the below tables, the ten-year forecasted Maryland growth rates of summer and winter peak demand (gross of DSM) are 0.90% and 0.81%, respectively.[64] This translates into expected summer peak demand (gross of DSM) for the Maryland service territory of 16,025 MW in the year 2023 and an expected winter peak demand (gross of DSM) for Maryland of 13,514 MW in the year 2023.[65] Compared to the previous Ten-Year Plan, the forecasted summer peak demand growth rate and the forecasted winter peak demand growth rate declined 0.23% and 0.16%, respectively.

[62] The Utilities' average winter peak demand growth rates were calculated using the Utilities' data responses to the Commission's 2013 data request for the Ten-Year Plan. *See* Appendix Table 3(a)(iii).
[63] PJM Load Forecast Report, PJM, Table B-1 (January 2014), http://www.pjm.com/~/media/documents/reports/2014-load-forecast-report.ashx.
[64] *See* Appendix Table 3(a).
[65] *See* Appendix Table 3(a)(i) and 3(a)(iii).

Table 8: Maryland Summer Peak Demand Forecast (MW) (Gross of DSM) [66]

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Total
Change (2014-2023)	1	633	38	91	10	6	154	176	133	1,241
Percent Change (2014-2023)	9.90%	8.69%	15.38%	9.11%	13.49%	9.52%	9.75%	4.91%	14.32%	8.39%
Compound Annual Growth Rate	1.05%	0.93%	1.60%	0.97%	1.42%	1.02%	1.04%	0.53%	1.50%	0.90%

Table 9: Maryland Winter Peak Demand Forecast (MW) (Gross of DSM) [67]

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Total
Change (2014-2023)	(1)	391	16	78	4	(6)	148	192	127	948
Percent Change (2014-2023)	-3.74%	6.56%	5.63%	8.22%	6.19%	-8.82%	9.02%	6.94%	15.08%	7.53%
Compound Annual Growth Rate	-0.42%	0.71%	0.61%	0.88%	0.67%	-1.02%	0.96%	0.75%	1.57%	0.81%

Figures 10 and 11 compare the current and historical peak demand growth rates for the four PJM zones of which Maryland is comprised. As illustrated by the figures, in all but one case, the zones are projecting a lower level of growth than forecasted during the previous planning period. This trend corresponds to the utilities' peak demand forecasts, summarized in Tables 7 and 8 above, which also declined relative to the previous planning period. As previously mentioned, PJM attributes the decline in long-term economic prospects to slower population growth.[68] PJM's 2014 Load Forecast Report states, "[t]he November 2013 forecast is weaker for long-term growth in metro areas in the PJM service territory than the forecast from December 2012. Growth in key variables - output, employment and households - is somewhat more subdued because of weaker population gains."[69] Figure 12 shows that the decline in peak demand growth rates is reflected by the PJM RTO and PJM Mid-Atlantic Region projections as well.

[66] *Id.*
[67] *Id.*
[68] PJM Load Forecast Report, PJM, at 11 (January 2014), http://www.pjm.com/~/media/documents/reports/2014-load-forecast-report.ashx.
[69] *Id.*

Figure 10: Comparison of Maryland PJM Zone Ten-Year Summer Peak Load Growth Rates as Reported in PJM Load Forecast Reports of 2011, 2012, 2013 and 2014 [70]

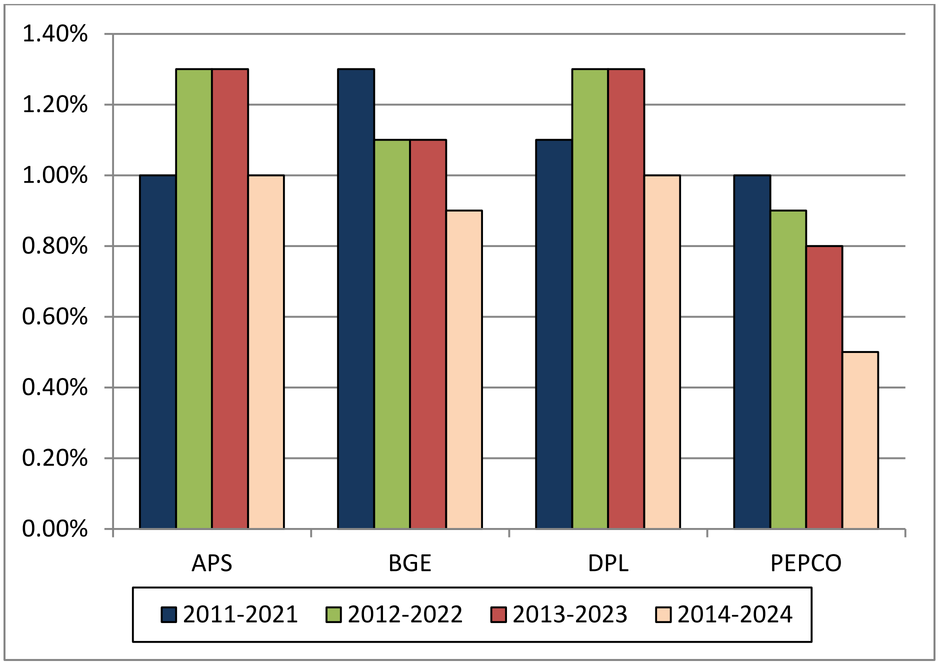
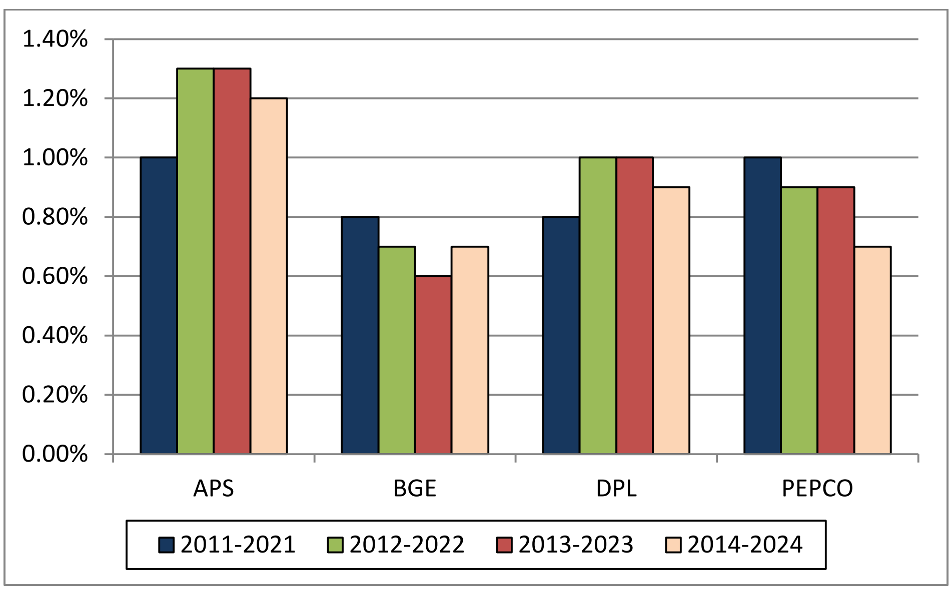
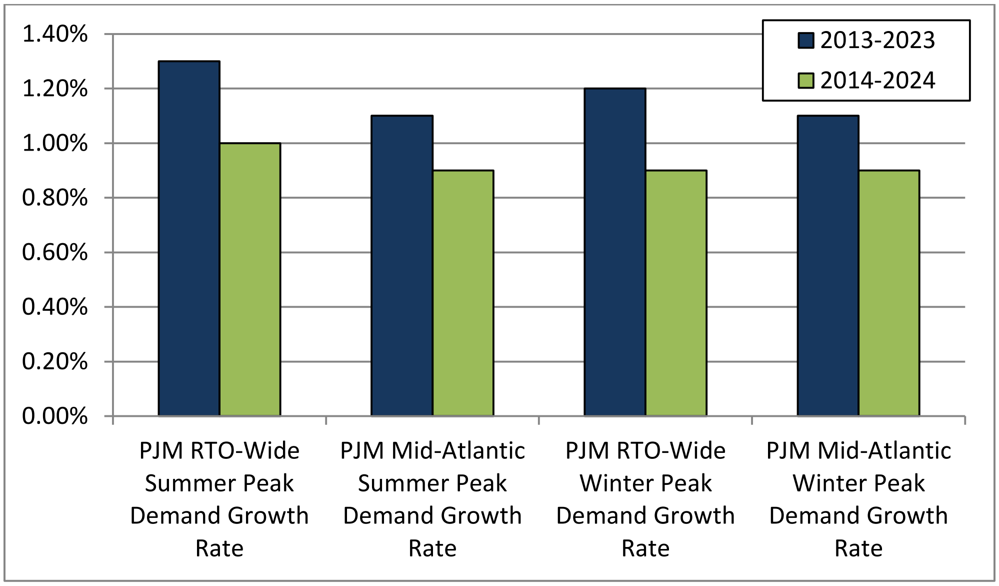


Figure 11: Comparison of Maryland PJM Zone Ten-Year Winter Peak Load Growth Rates as Reported in PJM Load Forecast Reports of 2011, 2012, 2013, and 2014[71]



[70] *See PJM Load Forecast Report,* PJM Table B-1 (Jan. 2012), https://pjm.com/~/media/documents/reports/2012-pjm-load-report.ashx; *PJM Load Forecast Report,* PJM Table B-1 (Jan. 2011), http://www.pjm.com/sitecore%20modules/web/~/media/documents/reports/2011-pjm-load-report.ashx; and *PJM Load Forecast Report,* PJM Table B-1 (Jan. 2010), http://www.pjm.com/sitecore%20modules/web/~/media/documents/reports/2010-load-forecast-report.ashx.
[71] *Id.*

Figure 12: Comparison of PJM Ten-Year Peak Load Growth Rates as Reported in PJM Load Forecast Reports of 2013 and 2014[72]



D. Impact of Demand Side Management

DSM programs result in lower growth of both energy sales and peak demand. To evaluate the impact of DSM programs, this section reflects the Maryland utilities' energy sales forecasts *after* the benefits of DSM programs are included ("net of DSM"). For purposes of this section, only the five utilities participating in EmPOWER Maryland are evaluated: BGE, DPL, PE, Pepco, and SMECO ("the Participating Utilities").[73] According to the Participating Utilities' Ten-Year Plan forecasts, the DSM programs will save a total of 44,478 GWh over the planning period. These savings will be achieved by reducing the annual rate of growth in energy sales and peak demand.

Figure 13 below shows the impact of the Participating Utilities' DSM programs on the compound annual growth rates of their respective energy sales projections over the duration of the ten-year planning period. BGE is forecasting the largest energy savings due to its DSM programs, most notably from its residential Behavior-Based Program[74] and its conservation voltage reduction ("CVR") program. Together, these two programs represent 64% of BGE's forecasted savings.[75] Conversely, PE is forecasting the lowest level of savings due to DSM programs. This is because PE is projecting only limited

[72] *Id.*
[73] See The EmPOWER Maryland Report to the General Assembly for more information on the energy efficiency and demand response programs associated with EmPOWER Maryland.
[74] BGE's Behavior Based Program is under BGE's Smart Grid initiative, not EmPOWER Maryland, but it is included towards this goal.
[75] The Behavior Based Program and the CVR Program each represent 32% of BGE's forecasted energy savings due to DSM programs, resulting in a cumulative 64% savings differential.

growth in savings from 2014 to 2016, and then holds the 2016 savings level constant for the remainder of the planning period. In other words, PE is projecting energy sales and peak demand to increase throughout the planning period, while projecting a comparable increase in savings from DSM programs for only two years. Similarly, SMECO also forecasts no increase in DSM savings after 2016. The spectrum of projections from the Participating Utilities can be attributed partially to being amid planning for the 2015-2017 Empower Maryland programs and awaiting the new goals beyond 2015 to support reductions in energy consumption and peak demand.

Figure 13: Impact of the Participating Utilities' DSM Programs on the Ten-Year Energy Sales Compound Annual Growth Rate [76]

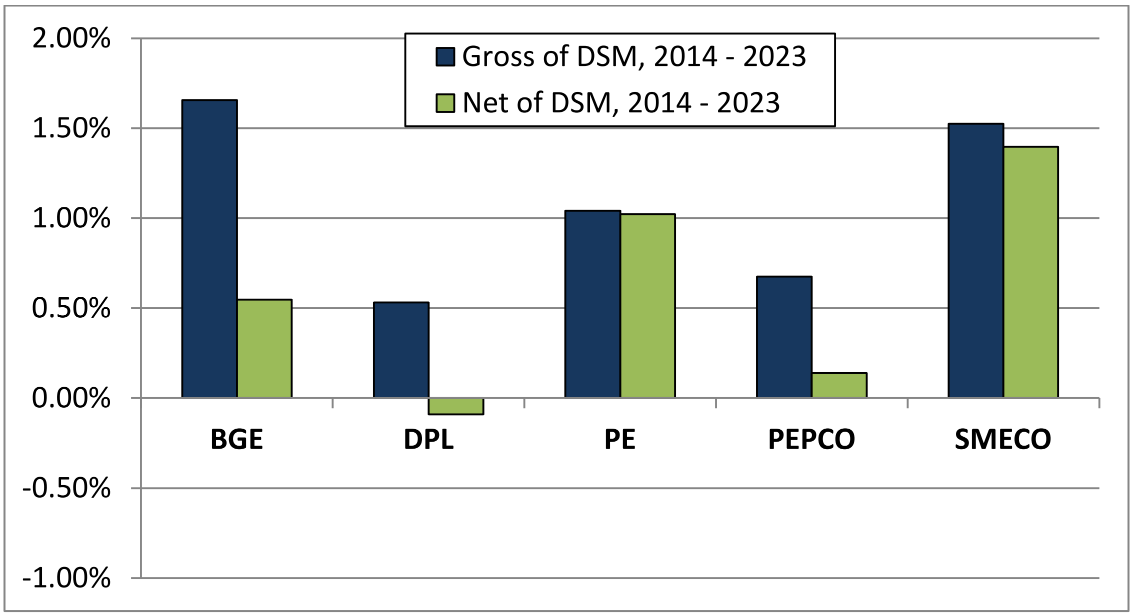
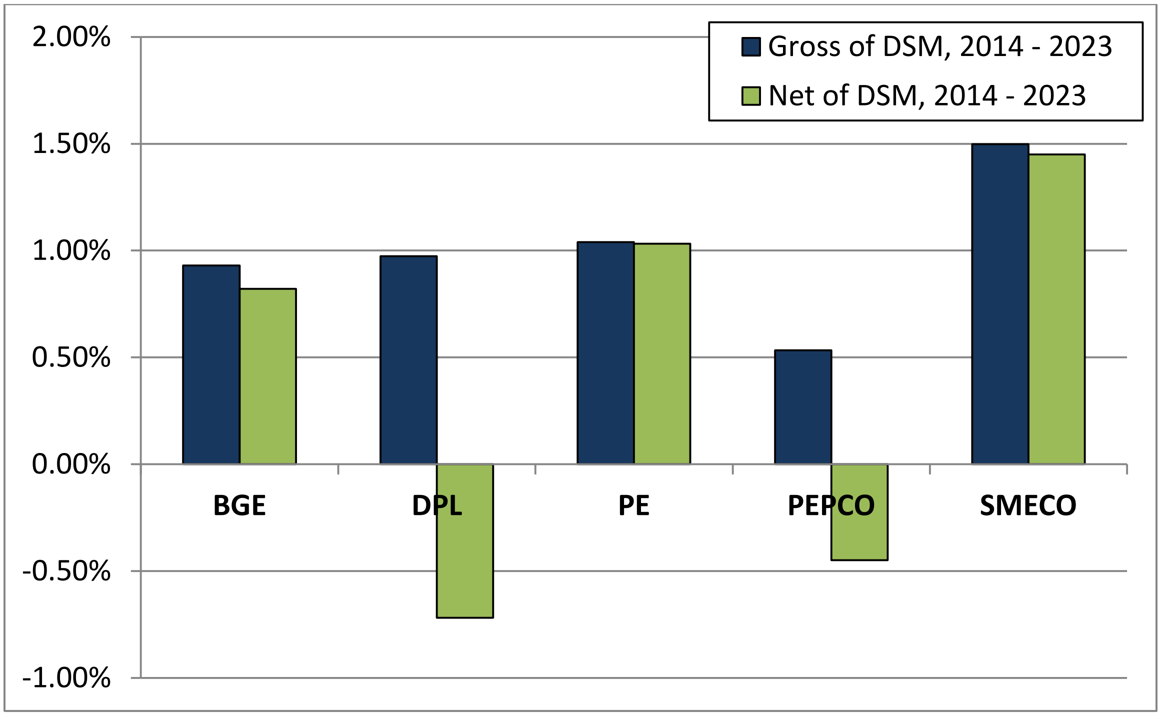


Figure 14 details the impact of the DSM programs on the Participating Utilities' 2014 peak demand forecasts as compared to their respective 2023 projections. As noted above, all of the Participating Utilities' programs are expected to experience an increased differential in peak demand growth attributable to DSM programs; however, Pepco and DPL are projecting the largest demand savings to accrue during the planning period attributable to the DSM programs. Both utilities are forecasting that summer peak demand will be lower in 2023 than in 2014 due to their DSM programs, despite forecasted growth in the number of customers during the planning period of 8.52% and 4.75%, respectively, and a summer peak demand growth rate between 2014-2023 of 4.91% and 9.11%, respectively. Both Pepco and DPL are forecasting large increases in the effectiveness of their EmPOWER programs over the next several years.

[76] *See* Appendix Table 2(a)(i) and 2(a)(ii) for the data used to make this Figure.

Figure 14: Impact of the Participating Utilities' DSM Programs on the Ten-Year Summer Peak Load (MW) [77]



The tables below compare the growth in DSM savings across the Participating Utilities from 2014 to 2018. Both DPL and Pepco assume a constant level of savings post-2018. Table 10 shows the growth in demand savings from DSM programs due to energy efficiency and conservation ("EE&C"), while Table 11 shows the growth in total demand savings attributable to DSM programs. As shown below, DPL and Pepco are forecasting a much larger increase in demand savings than the other Participating Utilities. This is why both utilities predict their 2023 peak demand (net of DSM) will be lower than their 2014 peak demand (net of DSM).

Table 10: Average Annual Increase in Demand Savings due to DSM Programs from 2014 to 2018 for EE&C Programs[78]

Description	DPL	Pepco	BGE	PE	SMECO
Average Annual MW Savings Increase due to DSM Programs	28.3%	25.9%	16.2%	2.8%	9.3%

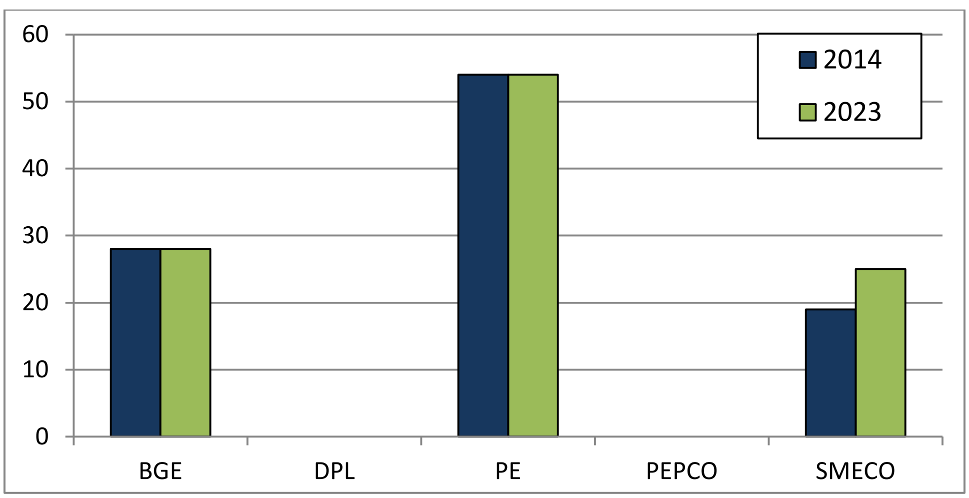
[77] *See* Appendix Table 2(a)(i) and 2(a)(ii) for the data used to make this Figure.
[78] Responses to the Commission's Ten-Year Plan Data Requests.

Table 11: Average Annual Increase in Demand Savings due to DSM Programs from 2014 to 2018 for All DSM Programs [79]

Description	DPL	Pepco	BGE	PE	SMECO
Average Annual MW Savings Increase due to DSM Programs	29.9%	12.0%	3.6%	2.9%	4.7%

None of the Participating Utilities are forecasting a significant reduction in *winter* peak demand due to the DSM programs, since the majority of DSM programs focus on summer peak demand reduction opportunities. While Pepco and DPL operate similar energy efficiency programs as the other Participating Utilities, the Companies did not project any DSM program savings for the winter peak load. Figure 15 illustrates that both BGE and PE are projecting a steady peak load reduction in the winter throughout the planning period. BGE's projected winter peak demand savings are attributable to its Residential DLC program (i.e., hot water heaters), while PE and SMECO reported savings from several EE&C programs. SMECO developed the winter savings forecast after working with its measurement and verification ("M&V") contractor, Navigant.[80]

Figure 15: The Impact of the Participating Utilities' DSM Programs on the Ten-Year Winter Peak Load (MW)[81]



[79] *Id.*
[80] In a July 15, 2014 correspondence with Eugene Bradford from SMECO, SMECO noted that its forecast is a rough estimate and not intended to meet rigorous M&V requirements.
[81] *See* Appendix Tables 3(a)(i) and 3(a)(ii) for data used to derive this graph.

E. Future Planning Implications Associated with the 2013/2014 Winter Weather Impact on the Natural Gas Market

The 2013/2014 winter season brought prolonged periods of bitterly cold temperatures to Maryland and surrounding regions. The extremely cold weather caused an increase in energy use and challenged the electricity and natural gas sectors. Eight of the ten highest winter demand days for electricity on the PJM system occurred in January 2014. The January 6 – 8, 2014 Polar Vortex brought many challenges to PJM, which experienced low reserves, as well as a higher number of forced generator outages when compared to a typical January.[82] Although the harsh winter weather experienced in January 2014 was an anomaly compared to the typical weather experienced in the region in recent years, the bitterly cold temperatures prompted PJM to improve its operating strategies as well as recognize the impact of limitations of the natural gas and electric system coordination. As a result of the experiences with the winter weather, PJM has taken steps to influence new policies to improve the transparency and flexibility of the natural gas markets.

On January 21, 2014, the BGE and Pepco service territories experienced a loss of 1,783 MW of generation capacity. In an effort to reduce the load placed on these territories, PJM called on demand response resources. Many demand response resources answered the PJM requests, even though they were not obligated to respond because the requests were made outside of the mandatory June – September compliance window. On January 7, 2014, in response to PJM's directive to implement mandatory load management with short lead times, DPL called a Demand Response event for heat pumps.[83] Although DPL attempted to shed load by calling on the heat pumps, no load reduction was realized. This may be attributable in part to the less efficient operation of some heat pumps in extremely cold temperatures; even though the heat pump compressor is shut off, the equipment goes into an electric resistant heat mode and continues to act as a heat source. BGE also called a number of demand response events in January for water heaters. Unlike DPL's attempt with calling the heat pumps, BGE called a total of 17 water heater load reduction events that resulted in an average energy load reduction of 101.72 MWh, with the highest peak load reduction at 55 MW.[84]

The second half of January 2014 brought another series of storms that caused scheduling constraints in the natural gas markets, which largely contributed to operational challenges and high operating reserve costs. In order to assure that natural gas would be delivered to certain generators when they needed to be in service, generators were required to schedule gas deliveries necessary to sustain operations a full day in advance, and in some instances 72 hours ahead, at extremely high prices. These gas commitments

[82] PJM's "Analysis of Operation Events and Market Impacts during the January 2014 Cold Weather Events" (May 8, 2014) at 4.
[83] Although DPL responded to PJM's directive for demand reduction, the Company was not required to respond because it was made outside of the mandatory compliance window.
[84] Over the course of the events called, the load reductions ranged from 15.58 MWh to 243.79 MWh. The difference in load reductions experienced was based upon the length and time of the event.

were at odds with the day-ahead and real-time commitments in the wholesale electricity markets. During this time period, spot natural gas prices increased significantly.

The cold weather in January had a significant impact on the natural gas market. The extremely cold temperatures greatly increased energy usage, directly impacting the supply and prices in the natural gas market. Natural gas prices soared, resulting in delivery prices over $100/MMBtu, which in turn produced electric prices for supply production of over $1,000/MWh, exceeding PJM's offer cap on market pricing.[85] Although natural gas prices have decreased since January 2014, prices are still well above natural gas prices during the same period in 2013. The natural gas futures contract for September 2014 averaged $4.58/MMBtu, which is a 15% increase from the September 2013 average of $3.97/MMBtu. Natural gas prices depend on a number of factors including economic growth and resource recovery rates.[86] Additionally, anticipated growth in demand for natural gas from the electric power[87] and industrial sectors[88] will put upward pressure on prices in 2015 – 2018.[89]

In addition to high prices, natural gas storage levels fell below the 5-year average of 2,479 Billion cubic feet ("Bcf") in January 2014. Currently, gas stocks are estimated to reach 3,424 Bcf at the end of October; however, those estimates are still below the storage levels at the same time in 2013. Low storage levels will put more pressure on energy companies to replenish the country's gas supply to meet future demand. Hot summer weather can also have an effect on natural gas inventories. Warmer than normal temperatures can cause an increase in the demand for air conditioning, which in turn increases the power sector's demand for natural gas.

Overall, with the increasing reliance on natural gas, prices are expected to continue to rise. The increase in natural gas prices could potentially be higher than current projections if natural gas reserves are not able to meet sufficient levels. As previously stated, natural gas prices are dependent on a number of direct and indirect factors (*i.e.* supply, demand, weather, etc.); therefore, the increased demand for natural

[85] Under PJM's Tariff and Operating Agreement, generally, suppliers are prohibited from submitting offers in excess of $1000/MWh. However, when gas prices increased in the winter of 2014, PJM noticed a substantial amount of energy was offered at a price of $999/MWh, indicating that the costs were constrained by the offer cap. On January 24, 2014 FERC granted PJM's request for a temporary tariff waiver to permit generators to recover the difference between the cost-based offers and the PJM market clearing price. The waiver allowed individual generators to recover their costs above the market clearing price as uplift.

[86] The U.S. Energy Information Administration's Annual Energy Outlook 2014 Report, projects the Henry Hub spot price for natural gas in 2040 as $7.65/MMBtu.

[87] According to the EIA's Annual Energy Outlook 2014, low natural gas prices make natural gas an attractive fuel for serving increased load in the electric power sector. Additionally, natural gas is the fuel most often used to replace coal fired generation as it is retired.

[88] The EIA's Annual Energy Outlook 2014, states that the energy intensive industries in the industrial sector will take advantage of relatively low gas prices in the future as industrial out put grows.

[89] The U.S. Energy Information Administration Annual Energy Outlook 2014, pg MT-21; http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf.

gas and this year's lower-than-average reserves could be quite influential on future electricity prices.

IV. Transmission, Supply, and Generation

In order to ensure a safe, reliable, and economic supply of electricity in Maryland, an appropriate balance of generation, DSM, imports, and transmission must be achieved. While importation and DSM offer ancillary benefits to managing the power supply, it is critical that local generation is established and maintained to mitigate the risk to Maryland's long-term reliability.

For purposes of the Ten-Year Plan, the congestion costs and the role of transmission infrastructure in planning processes are discussed in Section IV.A; Section IV.B focuses on the state-specific impact of Maryland's status as a net importer of electricity. Information related to the Commission's concerns about the capacity, composition, and advanced age of Maryland's current generation profile[90] is discussed in Section IV.C. Lastly, section IV.D discusses the role of PJM's Reliability Pricing Model ("RPM") in maintaining existing generation and in encouraging new sources of capacity required to maintain reliability within PJM.

Maryland depends on regional transmission and importation by the PJM market system. All load serving entities in PJM are required to ensure that they have sufficient capacity contracts to provide reliable electric service during periods of peak demand. As of 2012, Maryland's net summer generating capacity was approximately 12,215 MW.[91] Maryland's peak demand forecast for 2014, net of utility demand-side management and energy conservation measures, is approximately 13,428 MW.[92] Maryland's summer peak demand has grown faster than the State's net summer generating capacity over the last several years. In 2010, Maryland was able to meet 96.3% of its summer peak demand with in-State generation, versus only 87.7% in 2012.[93,94] This is consistent with the trend in Maryland energy imports discussed in more detail in Part B of this section.

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[90] *In the Matter of Whether New Generating Facilities are Needed to Meet Long-Term Demand for Standard Offer Service*, Case No. 9214**,** Order No. 84815 (April 12, 2012) at 19. The Commission found that the CPV bid for an in-service date of June 1, 2015 resulted in the best price for SOS ratepayers.

[91] The U.S. Energy Information Administration ("EIA"), State Electricity Profile: Maryland; http://www.eia.gov/electricity/state/Maryland/.

[92] *See* Appendix Table 3(a)(ii).

[93] The EIA's most recent data available is from 2012.

[94] *Ten-Year Plan (2010 – 2019) Of Electric Companies in Maryland,* Maryland Public Service Commission, at 7.
http://webapp.psc.state.md.us/Intranet/Reports/2010-2019%20Ten%20Year%20Plan.pdf.

A. Regional Transmission[95]

PJM in its 2013 Regional Transmission Expansion Plan ("RTEP") authorized more than 700 electric transmission improvement projects at a cost of over $7 billion.[96] The development of the RTEP takes into account the total effects of system trends, which are often driven by federal and state public policy decisions. The planning process takes into consideration: generating plant deactivations largely driven by environmental regulations; new generating plants to be powered by natural gas, wind and solar; and the impacts of demand resources and energy efficiency programs.[97] The large number of projects approved as part of the 2013 RTEP is driven, in part, by a number of upcoming power plant retirements and the increasing penetration of wind energy in the region.[98]

1. Regional Transmission Congestion

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities as well as the cost and geographical distribution of facilities. Congestion occurs when available, least-cost energy cannot be delivered to all load because of inadequate transmission facilities, thereby causing the price of energy in the constrained area to be higher than in an unconstrained area.[99] PJM's Locational Marginal Pricing ("LMP") system is designed to reflect the value of energy at a specific location and time of delivery, thus measuring the impact of congestion throughout the PJM system.

As shown in Table 12, the declining trend in congestion costs reversed direction in 2013; this trend reversal is likely due to an increased frequency in congestion. Total congestion costs for the PJM RTO increased by 28% ($147.9 million) between 2012 and 2013, whereas, the total PJM congestion costs decreased by 47% ($470 million) between calendar years 2011 and 2012.[100]

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[95] *See* Appendix Table 4 for a full list of transmission enhancements proposed by Maryland utilities.
[96] *Book 1: PJM 2013 RTEP State Summaries*, PJM, at 2, (December 31, 2013), http://pjm.com/~/media/documents/reports/2013-rtep/2013-rtep-book-1.ashx.
[97] *Book 1: PJM 2013RTEP State Summaries*, PJM, at 5, (December 31, 2013), http://pjm.com/~/media/documents/reports/2013-rtep/2013-rtep-book-1.ashx
[98] PJM News Release, "PJM Grid Operator Plans Billions in Transmission Improvements to Massive Generator Fuel Shift," http://www.pjm.com/~/media/about-pjm/newsroom/2013-releases/20130307-rtep_report_published.ashx.
[99] Monitoring Analytics, *State of the Market Report for PJM - 2013*, PJM, at 293, (March 14, 2013), http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2012/2012-som-pjm-volume2.pdf.
[100] Monitoring Analytics, *State of the Market Report for PJM - 2012*, PJM, at 459, Tables G-1 & G-2 (March 13, 2014), http://monitoringanalytics.com/reports/PJM_State_of_the_Market/2013/2013-som-pjm-volume2-appendix.pdf.

Table 12: PJM Total Annual Zonal Congestion Costs, 2011 – 2013 [101]

PJM Control Zone	2011 Total Annual Zonal Congestion Costs ($ million)	2012 Total Annual Zonal Congestion Costs ($ million)	2013 Total Annual Zonal Congestion Costs ($ million)
Allegheny Power (Potomac Edison)	$143.90	$52.50	$92.80
Baltimore Gas and Electric	$50.50	$34.40	$38.20
Delmarva Power	$38.80	$14.80	$18.10
Potomac Electric Power	$71.10	$12.50	$65.90
Maryland Zones Total	**$304.30**	**$114.20**	**$215.00**
PJM RTO Total Annual Zonal Congestion Costs ($ Million)	**$999.00**	**$529.00**	**$676.90**
Percent Attributed to MD Zones	**30.5%**	**21.6%**	**31.8%**
Change in Costs for PJM RTO From Previous Year		**-47.0%**	**28.0%**
Change in Costs for MD Zones From Previous Year		**-62.5%**	**88.3%**

The APS control zone continues to experience congestion causing higher prices in the BGE, Pepco, and DPL control zones. Additionally, there is an interface pricing flaw between PJM and Midcontinent Independent System Operator ("MISO"), which may be causing an overstatement of congestion costs.[102,103]

2. Regional Transmission Upgrades

The Commission recognizes the need to maintain and improve the transmission system within Maryland in order to ensure safe, reliable, and economic electricity service to the State's ratepayers. As with increases in local generating capacity and the reduction of system load, transmission expansions and improvements can reduce congestion and LMP differences among zones; such improvements may also support reliability requirements and mitigate economic concerns. On a jurisdictional basis, Maryland experienced higher real-time, average LMP[104] than any other jurisdiction in PJM for calendar year 2013, and was second only to the District of Columbia in 2012.[105]

[101] Monitoring Analytics, *State of the Market Report for PJM - 2013*, PJM, at 424, Tables G-1 & G-2 (March 14, 2013), http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2012/2012-som-pjm-volume2.pdf.

[102] *See* MISO Assessment of Interface Pricing Issues raised by MISO IMM and WPPI Energy (January 24, 2014), www.miso-pjm.com/~/media/committees-groups/stakeholder-meetings/pjm-miso-joint-common/20140124/20140124-item-05-miso-assessment-on-interface-pricing.ashx.

[103] For more information regarding congestion costs, see IV.D. of this report.

[104] The Locational Marginal Pricing ("LMP") system is the mechanism PJM uses to reflect the value of energy at a specific location and time of delivery, which accounts for congestion costs.

[105] Monitoring Analytics, *State of the Market Report for PJM - 2013*, PJM, at 426, Table C-17 (March 13, 2014), http://monitoringanalytics.com/reports/PJM_State_of_the_Market/2013/2013-som-pjm-volume2-appendix.pdf.

In 2013, to ensure the smooth operation of the transmission system within the PJM service territory, the PJM Board and PJM's 2013 RTEP approved over 700 individual bulk electric system baseline and network upgrades, totaling $2.8 billion and $4.3 billion, respectively.[106] PJM's 2013 RTEP process was designed to support reliable electricity flows and ensure the power supply system meets national reliability standards through year 2028. Two main drivers behind the 2013 RTEP were generation retirements and the changing fuel mix. Natural gas is rapidly increasing its share of the PJM system wide fuel mix, due to low natural gas prices and environmental regulations, while older generating units with higher carbon intensity are retiring. Renewable energy is also becoming an increasingly important part of PJM's fuel mix; as part of the $7 billion in upgrades, PJM approved more than $97 million in transmission upgrades to ensure energy from wind, solar, and other similar generators can be utilized.[107]

The authorized transmission upgrades to improve system reliability could potentially also alleviate some congestion costs in Maryland, since a portion of the transmission upgrades approved by the PJM Board in 2013 are located in Maryland and the District of Columba.[108] PJM's 2013 RTEP authorized ten transmission upgrades for Maryland and the District of Columbia, with each costing more than $5 million.[109] Together, the upgrades cost approximately $179.2 million.[110]

The Edison Electric Institute, in its *Transmission Projects: At A Glance* report, highlighted six ongoing transmission upgrades within Maryland. The six ongoing projects highlighted by Edison Electric Institute total approximately $469 million and are highlighted below.[111]

- <u>Conastone – Graceton – Raphael Road Project:</u> This project consists of constructing and building 29 miles of 230kV lines between Conastone, Graceton, and Raphael Rd. The improvement will create double-circuit connections between the substations; increasing circuit capabilities. The project costs approximately $111 million, with an in-service date of June 2017.
- <u>Ritchie to Buzzard Point N-1-1 Compliance Project:</u> This project consists of converting an 11 mile stretch of 138 kV circuit into 230 kV circuit between Pepco's Ritchie Substation in Seat Pleasant, Maryland, and Pepco's Buzzard Point Substation in southwest Washington, D.C. The project is designed to help Pepco meet NERC standards and to account for 240 MW of retired combustion turbines at the Buzzard Point substation. The project costs approximately $100

[106] *Book 1: PJM 2013RTEP State Summaries*, PJM, at 2, (February 28, 2014), http://pjm.com/~/media/documents/reports/2013-rtep/2013-rtep-book-1.ashx.
[107] *Id.*
[108] PJM's RTEP report treats Maryland and the District of Columbia as one region.
[109] *Book 5: PJM 2013 RTEP State Summaries*, PJM, at 138, (February 28, 2014), http://pjm.com/~/media/documents/reports/2013-rtep/2013-rtep-book-5.ashx.
[110] *Id.*
[111] Edison Electric Institute, *Transmission Projects at a Glance* (March 2014), *available at*: http://www.eei.org/issuesandpolicy/transmission/Documents/Trans_Project_lowres_bookmarked.pdf.

million, and the first phase is expected to be completed by June 1, 2014. The second phase is expected to be completed by June 1 2018.[112]

- Southern Delmarva Projects: This series of projects, which consists of upgrades to existing structures and new construction, span the entire Pepco Holdings, Inc. service territory; however, emphasis has been placed on the Southern Delmarva zone. The projects are designed to improve reliability and strengthen the transmission system in this growing region. The project is expected to cost approximately $151 million and has in-service dates between now and 2017.[113] Much of Choptank's service territory is located in the project area for these upgrades. As noted above, Choptank is forecasting the highest energy sales growth rates of any Maryland utility. These projects will help alleviate any congestion or other transmission issues stemming from Choptank's forecasted growth.
- Burtonsville-Bowie-Oak Grove Transmission Project: This project consists of reconductoring two 21 mile long, 230 kV circuits from Pepco's Burtonsville Substation in Laurel, Maryland, to Pepco's Oak Grove Substation, in Upper Marlboro, Maryland. The project includes upgrading equipment at each substation. This project is designed to allow Pepco to meet PJM's Generation Deliverability Common Mode Outage standards.[114] The project costs approximately $50 million and is expected to be completed by June 2016.[115]
- Oak Grove-Aquasco Transmission Project: This project consists of reconductoring an 18 mile long, 230 kV circuit from Pepco's Oak Grove Substation, in Upper Marlboro, Maryland, to Pepco's Aquasco Substation, in Aquasco, Maryland. The project also involves upgrading equipment at each substation. This project is designed to allow Pepco to meet PJM's Generation Deliverability Common Mode Outage standards. The project costs approximately $27 million and is expected to be completed by June 2016.[116]
- Burtonsville-Metzerott-Takoma Transmission Project: The project consists of replacing 10 miles of double circuit 230 kV transmission line between the Burtonsville Substation in Laurel, Maryland, and the Takoma Substation, in Takoma, Maryland. The project also includes upgrades at each substation. The project is designed to replace aging infrastructure and to address winter load reliability issues. The project will also increase the transmission capacity into the Takoma and Metzerott areas. The project costs approximately $30 million and is expected to be completed by June 2015. [117]

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[112] *Id.* at 110.
[113] *Id.*.
[114] Common Mode Outages include line faults coupled with a stuck breaker, double circuit powerline outages, faulted circuit breakers and bus faults. PJM uses a procedure very similar to the generator deliverability procedure to study common mode outages.
[115] Edison Electric Institute, *Transmission Projects: At A Glance,* EEI (March 2014), http://www.eei.org/issuesandpolicy/transmission/Documents/Trans_Project_lowres_bookmarked.pdf.
[116] *Id.* at 112.
[117] *Id.* at 113.

A seventh project, the Benning Transmission Project, was completed in 2013. The Benning Transmission Project consisted of two new 5.5 mile, 230 kV underground transmission lines from Benning Station A (Washington, D.C.) to Pepco's Ritchie Substation (Seat Pleasant, Maryland). The project cost approximately $130 million and was designed to allow the retirement of 550 MW of capacity at the Benning station.[118] Appendix Table 4 lists all transmission enhancements identified by the Maryland utilities in response to data requests for the Ten-Year Plan. Together, the 45 identified transmission enhancements in Appendix Table 4 account for over 239 miles of upgrades.

B. Electricity Imports

Maryland continues to be a net importer of electricity, similar to many other states in PJM.[119] As of 2012, 44% of the electricity consumed in the State is imported from other states.[120] As illustrated in the table below, nine of the thirteen PJM states plus the District of Columbia are net importers of electricity. In a nationwide comparison, Maryland is the second largest electricity importer based on percentage of electricity sales.[121] Only the District of Columbia exceeds Maryland in the percentage of electricity sales that are imported. In contrast, the states within the PJM region as of 2012 that exported more electricity in aggregate than consumed within each state are: Illinois, Michigan, Pennsylvania, and West Virginia.[122] Table 13 shows the percentage of retail sales that was imported by Maryland in 2012, along with other net-importing states in the PJM RTO and the country.[123]

[118] Edison Electric Institute, *Transmission Projects: At A Glance,* EEI (March 2014), http://www.eei.org/issuesandpolicy/transmission/Documents/Trans_Project_lowres_bookmarked.pdf.

[119] PJM operates, but does not own, the transmission systems in: (1) Maryland; (2) all or part of 12 other states; and (3) the District of Columbia. With FERC approval, PJM undertakes the task of coordinating the movement of wholesale electricity and provides access to the transmission grid for utility and non-utility users alike. Within the PJM region, power plants are dispatched to meet load requirements without regard to operating company boundaries. Generally, adjacent utility service territories import or export wholesale electricity as needed to reduce the total amount of capacity required by balancing retail load and generation capacity.

[120] *State Electricity Profiles 2012*, U.S. Energy Information Administration, Table 10 (May 1, 2014), http://www.eia.gov/electricity/state/maryland/xls/sept10md.xls.

[121] *Id. See also* Table 13.

[122] *State Electricity Profiles 2012*, U.S. Energy Information Administration, Table 10 for each state (May 1, 2014), http://www.eia.gov/electricity/state/.

[123] EIA is expected to next update this report in May of 2015 at http://www.eia.gov/electricity/state/.

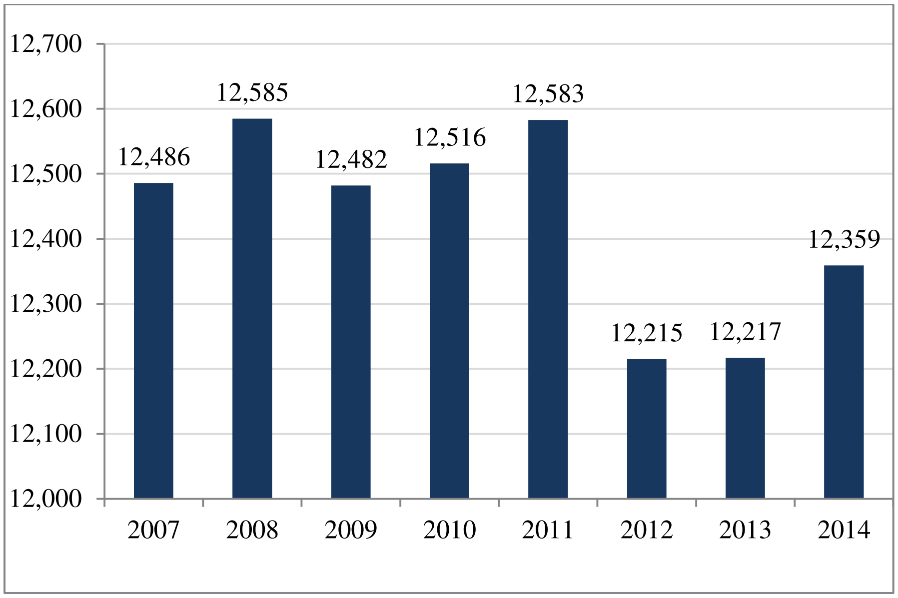
Table 13: State Electricity Imports (Year 2012) (GWh)[124]

State	Retail Sales	Direct Use	Losses	Total Sales, Direct Use and Losses	Domestic Imports	International Imports	International Exports	Net Imports	Percent Retail Sales Imported
D.C.	11,259	-	620	620	(11,984)	-	-	(11,984)	101%
Maryland	61,813	708	3,403	4,111	(29,087)	-	-	(29,087)	44%
Idaho	23,712	591	1,305	1,896	(10,468)	33	20	(10,415)	41%
Virginia	107,795	2,081	5,934	8,015	(46,767)	-	-	(46,767)	40%
Massachusetts	55,313	1,741	3,045	4,786	(23,817)	1,031	77	(22,709)	38%
Delaware	11,519	735	634	1,369	(4,436)	-	-	(4,436)	34%
Tennessee	96,381	2,465	5,306	7,771	(27,945)	-	-	(27,945)	27%
California	259,538	10,750	14,288	25,038	(80,829)	8,573	271	(71,985)	25%
Ohio	152,457	1,454	8,393	9,847	(34,957)	-	-	(34,957)	22%
New Jersey	75,053	1,182	4,132	5,314	(16,284)	-	-	(16,284)	20%
North Carolina	128,085	2,162	7,051	9,213	(22,632)	-	-	(22,632)	16%
Georgia	130,979	4,956	7,211	12,167	(22,900)	-	-	(22,900)	16%
Wisconsin	68,820	2,206	2,789	4,995	(12,155)	-	-	(12,155)	16%
Minnesota	67,989	1,024	3,743	4,767	(15,369)	6,700	437	(8,232)	11%
Colorado	53,685	51	2,956	3,007	(4,981)	-	1	(4,980)	9%
Florida	220,674	5,256	12,149	17,405	(20,455)	-	-	(20,455)	9%
Louisiana	84,731	20,674	4,665	25,339	(7,995)	-	-	(7,995)	7%
Kentucky	89,048	271	4,902	5,173	(5,673)	-	-	(5,673)	6%
Nevada	35,180	83	1,937	2,020	(2,442)	140	2	(2,300)	6%
Indiana	105,173	8,345	5,790	14,135	(6,251)	32	16	(6,203)	5%

Although Maryland continues to be a net importer, one positive trend is the increasing generating capacity in Maryland—up from the low in-State capacity numbers experienced in 2012.[125] In 2007, Maryland resources generated over 50 million MWh in electricity. By 2012, in-State resources generated slightly under 38 million MWh.[126] As Figure 16 illustrates, Maryland generators possessed 12,215 MW of summer peak capacity in 2012. That capacity has increased by 144 MW, to 12,359 MW as of April 2014.[127] Of the new capacity, 26.6 MW is derived from renewable sources, while 115.1 MW came from primarily natural gas-fired resources.

[124] Note the data for State Electricity Imports (Year 2012) from EIA State Electricity Profiles found at http://www.eia.gov/electricity/state/ in table 10, Supply and Disposition of Electricity 1990-2012, for each state.
[125] This decline of in-State capacity was mainly caused by plant closures in 2012. For more information on the plant closures, see section IV.C.1 Conventional Capacity and Generation Profiles, 2012 of this report.
[126] *Electricity Power Industry Generation by Primary Energy Source, 1990-2012 Maryland*, U.S. Energy Information Administration, Table 5 (May 2014), http://www.eia.gov/electricity/state/maryland/xls/sept05md.xls.
[127] *Profile Data*, U.S. Energy Information Administration, Reserves & Supply (June 19, 2014), http://www.eia.gov/electricity/monthly/xls/table_6_02_a.xlsx.

Figure 16: Maryland Capacity Change (MW), 2007 - 2014



The EmPOWER Maryland program, along with other energy efficiency efforts across the State, contributes to a decrease in the peak demand, which reduces the need to increase capacity and generation capabilities. On a per capita basis, Maryland's actual peak demand for 2013 was 2.18 kW.[128] Compared to the per capita peak demand in 2007 of 2.56 kW, there has been a 14.8% decrease over the last 6 years. The State's 2015 goal of 2.17 kW per capita peak demand is well within reach.[129]

[128] *Per Capita Peak Electricity Consumption*, Maryland StateStat, Per Capita Peak Electricity Demand Line Chart (2014), https://data.maryland.gov/Energy-and-Environment/Per-Capita-Peak-Electricity-Demand-Line-Chart/iue3-nwie.

[129] To find more information on the EmPOWER Maryland program, refer to the EmPOWER Maryland Energy Efficiency Act Report located here: http://webapp.psc.state.md.us/Intranet/Reports/2014%20EmPOWER%20Maryland%20Energy%20Efficiency%20Act%20Standard%20Report.PDF.

C. Maryland Capacity and Generation Profiles

The capacity and generation profiles of in-State resources must be comprehensively analyzed for both short- and long-term reliability planning purposes, due to the uncertain future of coal-fired generation.[130] In Case No. 9214, the Commission observed that the State's reliability risk is further heightened because neighboring states that export electricity into Maryland also have at-risk coal-fired generation.[131]

1. Conventional Capacity and Generation Profiles, 2012[132]

Coal-fired power plants aged 31 years or more comprise 83% of the electric generating capacity in Maryland; of this, 62.7% is considered at-risk as defined by PJM.[133] Tables 14 and 15 below show the electric generating capacity in Maryland, as well as the age of plants by fuel.[134]

Table 14: Maryland Summer Peak Capacity Profile, 2012 [135]

Primary Fuel Type	Capacity	
	Summer (MW)	Percent Of Total
Coal	4,757.0	38.9%
Oil and Gas	4,861.4	39.8%
Nuclear	1,716.0	14.0%
Hydroelectric	590.0	4.8%
Other and Renewables	290.9	2.4%
Total	**12,215.3**	**100.0%**

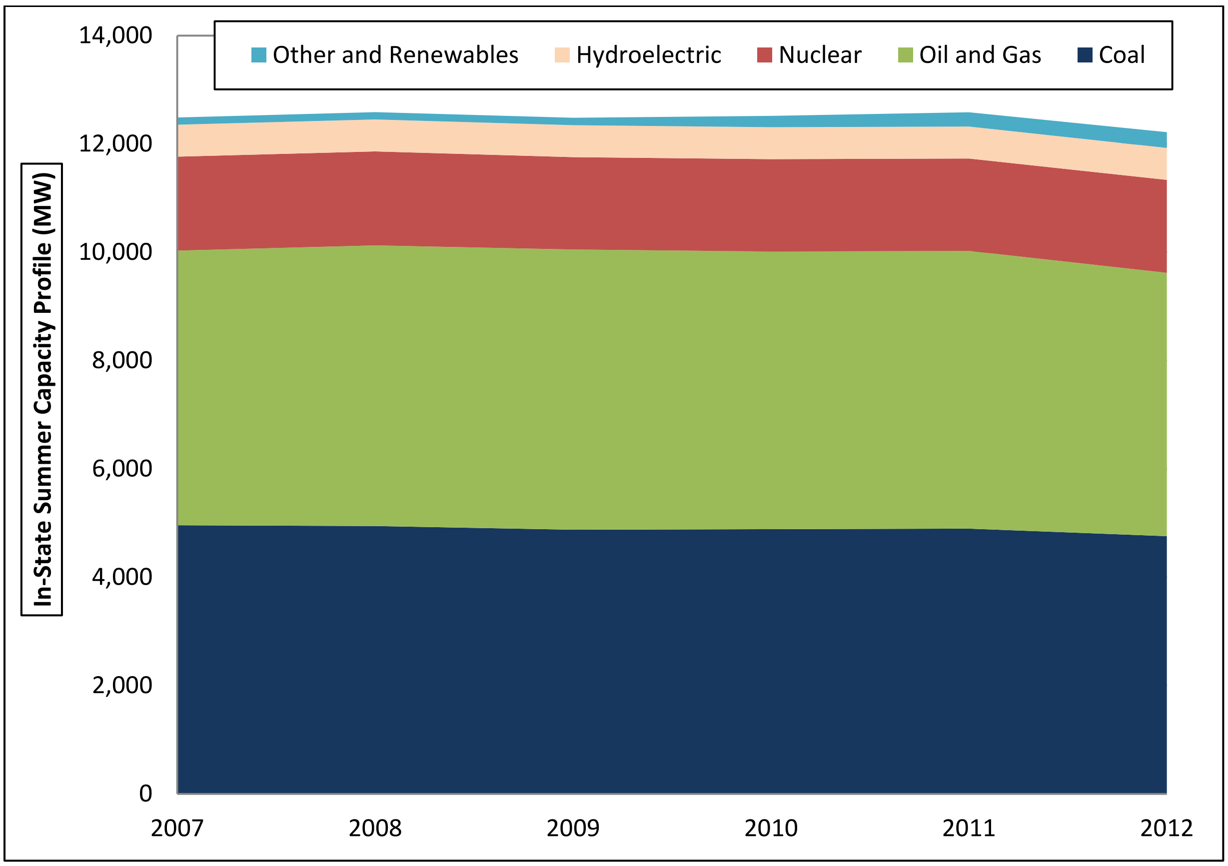
[130] The uncertainty stems from the economic pressure on coal as a result of decreasing natural gas prices, as well as from regulations promulgated by the U.S. Environmental Protection Agency.
[131] Order No. 84815 (April 12, 2012) at 19.
[132] The 2013 data is not scheduled for release by the U.S. Energy Information Administration until September 2014.
[133] PJM categorizes coal generation more than 40 years old and less than 400 MW as at "high-risk" of retirement. Case No. 9214 *In the Matter of Whether New Generating Facilities are Needed to Meet Long-Term Demand for Standard Offer Service*, PJM Comments (January 13, 2012) at 11-12.
[134] *See* Appendix Table 5 for a complete list of Maryland generation capacity in 2012.
[135] *Report EIA-860: "GenY12" Excel*, U.S. Energy Information Administration (last visited June 25, 2014), http://www.eia.gov/cneaf/electricity/page/eia860.html.

Table 15: Age of Maryland Generation by Fuel Type, 2012 [136]

Primary Fuel Type	Age of Plants, By Percent			
	1-10 Years	11-20 Years	21-30 Years	31+ Years
Coal	0%	6%	11%	83%
Oil and Gas	7%	24%	12%	57%
Nuclear	0%	0%	0%	100%
Hydroelectric	0%	0%	0%	100%
Other and Renewables	76%	11%	13%	0%

Maryland's summer peak capacity profile decreased by 368 MW in 2012 compared to 2011. This is a sharp decrease when compared to the past several years, during which Maryland's summer peak capacity has remained fairly stable.[137]

Figure 17: Maryland Summer Capacity Profile, 2007 - 2012



[136] *Id.*
[137] Maryland's Summer Peak Capacity was 12,583 MW in 2011, 12,516 MW in 2010, and 12,590 MW in 2008.

Contributing to the decline were two plant closures in 2012: The R. Paul Smith Power Station (115 MW); and RG Steel Sparrows Point (152 MW). According to FirstEnergy, the owner of the R. Paul Smith Power Station, the former coal-fired plant located in Williamsport was closed due to the U.S. Environmental Protection Agency Mercury and Air Toxics Standards.[138] When FirstEnergy announced the closure of R. Paul Smith, it also shut down five other coal-fired plants located in Ohio and Pennsylvania for the same reason.[139] RG Steel, which owned Sparrows Point, declared bankruptcy, closed the mill, and sold its assets and generating station to a group of investors.[140]

Maryland's generating profile differs from its capacity profile. Coal and nuclear facilities typically generate an overwhelming majority of all electricity produced in Maryland, even though these resources represent a little over half of in-State capacity.[141] Conversely, oil and natural gas facilities, which operate as mid-merit or peaking units that come on-line when needed, generate less than 14% of the electric energy produced in Maryland while representing 39.8% of in-State capacity.[142] Table 16 summarizes Maryland's 2012 in-State generation profile according to fuel source.[143]

Table 16: Maryland Generation Profile, 2012 [144]

Primary Fuel Type	Generation	
	Annual (MWh)	Percent Of Total
Coal	16,184,773	42.8%
Oil & Gas	5,194,514	13.7%
Nuclear	13,579,266	35.9%
Hydroelectric	1,656,539	4.4%
Other & Renewables	1,194,651	3.2%
Total	**37,809,744**	**100.0%**

138 "FirstEnergy, Citing Impact of Environmental Regulations, Will Retire Six Coal-Fired Power Plants," FirstEnergy Press Release, January 26, 2012. (last visited June 25, 2014) https://www.firstenergycorp.com/content/fecorp/newsroom/news_releases/firstenergy_citingimpactofenvironmentalregulationswillretiresixc.html.

139 *Id.*

140 Bathon, Michael, "RG Steel Sells Sparrows Point, Other Assets for $94 Million," Bloomberg News, August 15, 2012. (last visited June 25, 2014) http://www.bloomberg.com/news/2012-08-16/rg-steel-sells-sparrows-point-other-assets-for-94-million-1-.html.

141 *See supra* Table 12. Coal facilities represented 38.9% of the in-State capacity in 2012, while nuclear facilities represented 14.0% of capacity. Therefore, coal and nuclear facilities combined for almost 53% of Maryland's generating capacity profile in 2012.

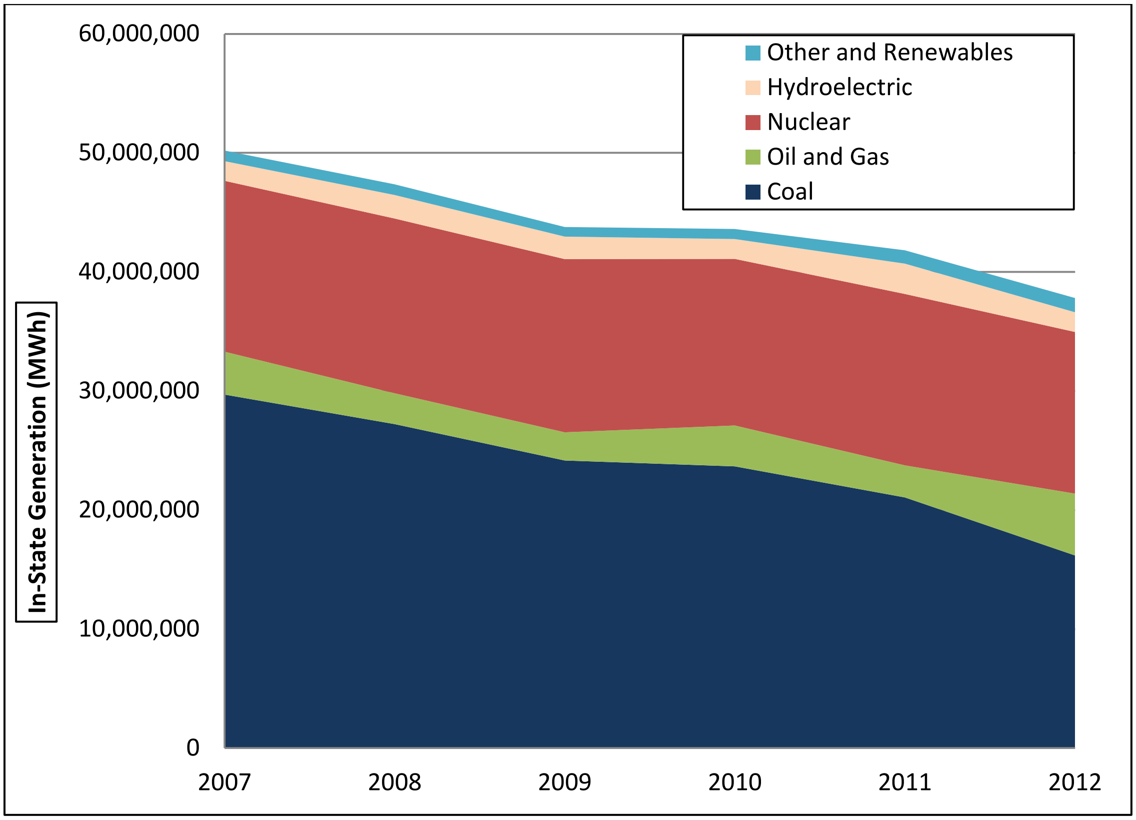
142 *Id.*

143 At the time of this report, data for 2013 was not available. According to the United States Energy Information Administration website, the next data release is scheduled for May 2015. *See* http://www.eia.gov/electricity/state/.

144 *State Electricity Profiles 2012*, U.S. Energy Information Administration, Table 5 (May 1, 2014), http://www.eia.gov/electricity/state/maryland/xls/sept05md.xls.

Unlike the stability historically exhibited by Maryland's summer capacity profile, the percentage of in-State generation derived from various fuel sources continues to evolve. Between 2007 and 2012, in-state coal generation decreased by approximately 13,500 GWh, causing the percentage of in-state generation derived from coal to decrease from 59% in 2007, to roughly 43% in 2012.

Figure 18: Maryland Generation Profile, 2007 – 2012



The standard life expectancy for coal generation facilities is approximately 40 years, though extensions can often be granted for up to 60 years. This assessment places a significant percentage of total Maryland coal generation capacity at or near the end of its normal operational life, a fact made especially concerning considering that coal generation facilities provided over 40% of the in-State generation in 2012. If operational extensions for Maryland coal generation units are not made, the need for additional in-State resources will be further necessitated to avoid potential reliability concerns.

PJM currently registers 13,419 MW of capacity resources requesting deactivation within the RTO. Prior to December 2, 2013, there was only one pending request for deactivation in Maryland: Riverside 6, a 118 MW plant in BGE's transmission zone, which was deactivated on June 1, 2014. On June 30, 2014, a total of 1,300 MW of capacity requested deactivation with dates ranging from June 1, 2015 to May 31, 2018.[145] The plants with pending deactivation requests are Riverside 4 (BGE zone, 76 MW), Dickerson (Pepco zone, 546 MW), and Chalk Point (Pepco zone, 678 MW). PJM states that the reliability analysis for Riverside 4 is complete; while the reliability analysis for Dickerson and Chalk Point is underway.

NRG Energy, Inc. operates both the Dickerson plant and the Chalk Point plant. Dickerson is located in Montgomery County and Chalk Point is located in Prince George's County. NRG Energy, Inc. cites the impact of cheap natural gas and the high cost of emissions-reducing equipment as reasons for requesting deactivation.[146] Once the two plants are deactivated, the number of in-State coal plants will be reduced to six facilities. As previously noted in Table 14, Maryland currently has 4,757 MW of coal capacity. These two NRG plants represent approximately 26% of that capacity. The two NRG plants are also the subject of a lawsuit filed by the Maryland Department of the Environment over water pollution.[147]

The retirement of older coal-fired plants will not be unusual in coming years. In 2012, the U.S. Energy Information Administration ("EIA") estimated that 27 GW of coal-fired capacity would retire over the next five years,[148] representing about 8.5% of the United State's total coal fleet capacity.[149] In addition, the EIA predicted that 2012 would constitute the largest amount of retirements in U.S. history to occur over a one-year time period (until 2015, when the EIA estimates nearly 10 GW of coal-fired plants will retire). The EIA attributes the upcoming retirements to five main reasons:

- slower demand growth leading to less need for the smaller, older, and less efficient coal plants;
- the low cost of natural gas due to shale gas production;
- the availability of efficient natural gas combined cycle power plants which are currently under-utilized;
- the advanced age of many coal-fired plants; and
- environmental and compliance costs associated with the Mercury and Air Toxics Standards and other federal regulations. [150]

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[145] *Future Deactivations,* PJM (last visited June 30, 2014), http://www.pjm.com/planning/generation-retirements/~/media/planning/gen-retire/pending-deactivation-requests.ashx.
[146] Hopkins, Jamie Smith, "Coal-fired units at 2 Md. power plants slated to retire," the Baltimore Sun, December 6, 2013, http://articles.baltimoresun.com/2013-12-06/business/bs-bz-coal-plants-to-retire-20131206_1_dickerson-plant-power-plants-two-plants.
[147] In the United Stated District Court for the District of Maryland, Case 1:13-cv-01685-MJG.
[148] "27 Gigawatts of Coal-fired Capacity to Retire Over Next Five Years," U.S. Energy Information Administration, July 27, 2012, http://www.eia.gov/todayinenergy/detail.cfm?id=7290.
[149] *Id.*
[150] *Id.*

Outside of the State, but within the four transmission zones that include Maryland, there is only one plant requesting deactivation - McKee in the DPL zone, which accounts for 34 MW of capacity.[151] PJM completed a reliability analysis and identified no reliability impacts associated with the May 31, 2017 scheduled deactivation of McKee.[152]

2. Proposed Conventional Generation Additions[153]

In Case No. 9214, the Commission approved a request for proposals ("RFP") for new generation to be issued by Maryland electric distribution companies after determining that "the issuance of the RFP is in the best interest of Maryland ratepayers and may promote the long-term electric reliability of the State."[154] Subsequently, the Commission awarded the bid to CPV Maryland, LLC to build a 661 MW natural gas-fired combined cycle facility in Charles County located in the Southwestern Mid-Atlantic Area Council ("SWMAAC") sub-region of PJM, with an in-service date of June 1, 2015.[155] In deciding to order new generation, the Commission focused on several findings: (1) the long-term demand for electricity in Maryland, specifically in the SWMAAC zone, compels the order of new generation;[156] (2) Maryland's status as a net importer renders the State very dependent on transmission projects; (3) the uncertain impact of future EPA regulations could greatly impact our State's and the region's aging coal fleet; and (4) the PJM Reliability Pricing Model ("RPM") has been unsuccessful in attracting appreciable new generation.[157]

On September 30, 2013, the United States District Court for the State of Maryland ruled the Commission's CPV Maryland, LLC Order unconstitutional.[158] The District Court found that, "while there exist legitimate ways in which states may secure the development of generation facilities, states may not do so by dictating the ultimate price received by the generation facility for its actual wholesale energy and capacity sales in the PJM Markets without running afoul of the Supremacy Clause."[159] On June 2, 2014 the United States Court of Appeals for the Fourth Circuit affirmed the District Court's

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[151] *Future Deactivations,* PJM (last visited June 30, 2014), http://www.pjm.com/planning/generation-retirements/~/media/planning/gen-retire/pending-deactivation-requests.ashx.
[152] *Id.*
[153] *See* Appendix Table 6 for a complete list of new conventional generation proposed in Maryland.
[154] *In the Matter of Whether New Generating Facilities are Needed to Meet Long-Term Demand for Standard Offer Service*, Case No. 9214, Mail Log No. 134480, pp. 2 (Sept. 29, 2011).
[155] *In the Matter of Whether New Generating Facilities are Needed to Meet Long-Term Demand for Standard Offer Service*, Case No. 9214, Order No. 84815 (April 12, 2012). The Commission found that the CPV bid for an in-service date of June 1, 2015 resulted in the best price for SOS ratepayers. *Id.* at 26.
[156] *Id.* at 29.
[157] *Id.* at 18 - 23.
[158] *Memorandum of Decision, PPL EnergyPlus, LLC, vs The Maryland Public Service Commission,* Civil Action No. MJG-12-1286, September 30, 2013.
[159] *Id.* at 111.

decision, adding that the Generation Order "presents a direct and transparent impediment to the functioning of the PJM markets, and is therefore preempted."[160]

Notwithstanding the District Court and Circuit Court of Appeals decisions, CPV Maryland, LLC cleared the May 2014 PJM Base Residual Auction as a capacity resource for the 2017/2018 delivery year. Additionally, CPV announced in early August 2014 that the project secured financing from 15 lenders and that it would begin construction on the Waldorf plant in September 2014.

In addition to the CPV natural gas-fired combined cycle facility, Table 17 shows the proposed new conventional generation additions within Maryland for the next ten years. Notably, nearly all of the proposed conventional generation is natural gas fired. There is no proposed new coal or nuclear generation in the Maryland service territory. The largest of the proposed projects are the natural gas generating stations located in Charles, Cecil, and Prince George's counties. Seven of the facilities listed below, totaling 3,716 MW, are currently under construction; the remaining projects are still under study.[161]

Table 17: Proposed New Conventional Generation in Maryland (MW)[162]

Transmission Owner	Fuel Type	In-Service Date Range	Total Capacity (MW)
APS	natural gas	2014	4
BGE	natural gas	2015	256
DPL	natural gas and oil	2014	12
ODEC	natural gas	2016 - 2017	2,161
PEPCO	natural gas	2015 - 2018	4,920
		Total (MW):	**7,353**

[160] United States Court for the Fourth Circuit, *PPL EnergyPlus, LLC v. Douglas* Nazarian, Opinion No. 13-2419, pg. 27.
[161] Of this total, 309 MWs is scheduled to become operational in 2015; 2,246 MWs in 2016; 327 MWs in 2017; and 834 MWs in 2018.
[162] *Generation Queues: Active (Maryland)*, PJM (last visited June 20, 2014), http://www.pjm.com/planning/generation-interconnection/generation-queue-active.aspx.

3. Renewable Generation and Proposed Additions[163]

The Commission recognizes the importance renewable generation plays in meeting Maryland's energy needs while also addressing environmental concerns. Renewable energy resources located in Maryland generated 2,768,332 MWh of electricity in 2013, as shown below in Table 18. The largest sources of non-hydroelectric renewable energy were the Baltimore Refuse Energy Company facility and the Montgomery County Resource Recovery facility. Both facilities use municipal solid waste ("MSW") and represent discretely dispatchable energy resources; in 2013, the MSW facilities generated 327,537 MWh and 312,589 MWh, respectively.

Table 18: Maryland Generation (MWh) from Renewable Sources, 2013 [164][165]

Primary Fuel Source	2013 Generation (MWh)	Percent of Total In-State Renewable Generation
Hydroelectric	1,531,447	55.32%
Other Biomass	390,559	14.11%
Wind	317,976	11.49%
Other	303,222	10.95%
Wood	144,840	5.23%
Solar	80,288	2.90%
Other Gases	0	0.00%
Total	**2,768,332**	**100.00%**

Based on the PJM queue, Maryland's renewable generation capacity is planned to increase by an estimated 656 MW over the next few years as shown in the table below. However, this does not account for smaller renewable generators, notably residential solar; these smaller renewable generators are not required to obtain PJM interconnection status, but simply require interconnection with the local utility.[166]

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[163] Maryland's Renewable Portfolio Standard has helped incent a significant amount of new renewable generation capacity in Maryland via Renewable Energy Credits ("RECs") and the Alternative Compliance Payments submitted to the Strategic Energy Investment Fund. RECs are the environmental attributes of renewable generation, and are separate from the actual electricity generation from Maryland's renewable resources. More details can be found at the *Renewable Energy Standard Report;* available at*: http://webapp.psc.state.md.us/Intranet/psc/Reports_new.cfm.*

[164] *Monthly Generation Data by State*, U.S. Energy Information Administration, EIA-923 Report (August 11, 2014), http://www.eia.gov/electricity/data/state/.

[165] *See* Appendix Table 7 for unit by unit reporting as provided by the Maryland utilities.

[166] The 2014 in-service dates refers to the initial in-service date and does not account for any delays. *Generation Queues: Active (Maryland)*, PJM (last visited June 30, 2014), http://www.pjm.com/planning/generation-interconnection/generation-queue-active.aspx.

Table 19: Proposed New Renewable Generation in Maryland

Transmission Owner	Fuel Type	In-Service Date Range	Total Capacity (MW)
APS	Wind	2014 - 2015	90
	Biomass	2016	49
	Solar	2015	20
BGE	Solar	2014 - 2015	22
	Methane	2014	4
DPL	Wind	2014 - 2015	279
	Biomass	2014	20
	Solar	2014 - 2017	172
		Total (MW):	**656**

Additionally, the amount of solar resources in Maryland will continue to increase due to a suite of State policy initiatives: the RPS solar carve-out requires interconnection to the distribution network serving Maryland; net metering incentives; tax incentives; and grants administered by the Maryland Energy Administration ("MEA"). The increasing renewable generation penetration may have the potential to impact the grid, and the Commission will continue to monitor the successful integration of these renewables.

4. Future Planning Considerations Associated with the Dominion Cove Point Liquefied Natural Gas Facility

On April 1, 2013, Dominion Cove Point LNG, LP ("DCP") filed an application with the Commission for a Certificate of Public Convenience and Necessity ("CPCN") pursuant to § 7-207 and § 7-208 of the Public Utilities Article ("PUA") of the Maryland Annotated Code. The CPCN request was to construct 130 MW of generating capacity at its existing liquefied natural gas ("LNG") facility. The current LNG terminal site is located in Calvert County, Maryland, and is designed to receive imported LNG from tanker ships. DCP is now seeking to expand the existing terminal into a bi-directional import and export LNG facility, for which DCP is seeking regulatory approval from the Federal Energy Regulatory Commission ("FERC"). While the total project proposed by DCP includes both the generating station and the liquefaction project, the requested CPCN pertained solely to the construction of the 130 MW generating station.

On May 30, 2014, after more than one year of filings, testimony, and hearings, the Commission conditionally approved DCP's CPCN in Order No. 86372.[167] In addition to adopting all air and water quality permitting conditions required by the State environmental agencies, as well as conditions related to traffic, noise, esthetics, and forest conservation, the Commission instituted several new conditions. The Commission found

[167] Case No. 9318, Order No. 86372 (May 30, 2014).

in its review of the CPCN for the proposed 130 MW electric generating station that the project, as proposed, would not provide net benefits to Maryland citizens. Therefore, the Commission focused on actions that will advance and protect the environmental and economic interests of Maryland citizens by imposing new conditions, some of which may impact energy sector planning in both the near and long-term.

One of the additional conditions of the CPCN approval involves modification of a proposed condition pertaining to low-income bill assistance. Under the modification condition, DCP must contribute $400,000 annually for each of the 20 years the terminal is under contract to operate to the Maryland Energy Assistance Program ("MEAP"), or other low-income energy assistance programs as determined by the Commission. The Commission required this provision to offset the potential impact of higher natural gas prices resulting from exports at the DCP facility. The Maryland Energy Assistance Program, administered by the Office of Home Energy Programs, provides assistance with home heating bills for qualifying residents. As of 2011, over 80,000 households have been helped through this program.[168]

A second condition of the CPCN approval requires DCP to contribute $40 million over 5 years to the Maryland Strategic Energy Investment Fund ("SEIF"), administered by the Maryland Energy Administration. The Commission directed that the DCP contribution be used solely for the purpose of: investing in the development of renewable and clean energy resources; the implementation of greenhouse gas reduction or mitigation programs; and the deployment cost-effective energy efficiency and demand response programs.[169] As of 2012, SEIF-funded programs have helped residents across the State reduce over 58,000 MWh in annual energy, install 2,900 renewable energy systems in Maryland homes, and complete over 3,400 energy retrofits for low-to-moderate income families.[170] The additional funding from DCP may go towards funding long-term strategic energy programs such as the Multi-Family Housing Retrofits for Low and Moderate Income Families Program, the EmPOWERing Clean Energy Communities Program, the Residential Clean Energy Grants Program, and the Commercial Clean Energy Grants Program.

While the Maryland Public Service Commission approved the DCP CPCN request, subject to the order's 179 licensing conditions, other agencies remain actively engaged in aspects of the approval process for the larger DCP project. In the federal arena, the FERC and the Department of Energy ("DOE") are responsible for issuing decisions regarding DCP's proposed expansion of its existing LNG terminal. The export of liquefied natural gas is regulated by DOE, while the FERC regulates the construction of new liquefied natural gas terminals and pipelines. On October 7, 2011, DOE conditionally issued authority for DCP to export LNG to countries with free trade

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[168] Maryland Energy Administration, *Clean Energy Accomplishments FY 2009, 2010, and 2011*, http://energy.maryland.gov/documents/SEIFAccomplishmentsbook_FY09FY10andFY11.pdf (2012).
[169] Order No. 86372 at 74.
[170] Maryland Energy Administration, *EmPOWERing Maryland Clean Energy Programs FY 2012,* http://energy.maryland.gov/documents/FY12ProgramBook.pdf (July 2011).

agreements, up to 1 Bcf/day.[171] On September 11, 2013, DOE issued comparable authority to DCP for the export of LNG to countries with non-free trade agreements, up to 0.77 Bcf/day.[172]

The FERC staff released an Environmental Assessment for the Cove Point Liquefaction Project on May 15, 2014.[173] In that assessment, the FERC staff concluded that "approval of the proposed Project, with appropriate mitigating measures, would not constitute a major federal action significantly affecting the quality of the human environment."[174] The comment period on the Environmental Assessment closed to the public on June 16, 2014, but remained open for comment by any federal agencies until August 13, 2014.[175] The FERC is expected to issue a final decision after the August 13, 2014 comment deadline.

The Maryland Commission tied its conditional approval of the DCP CPCN to the licensing conditions, in addition to all applicable Maryland and federal laws and standards. Therefore, construction can not begin on the 130 MW generating station and the expansion of the LNG terminal until the FERC issues its final approval on the DCP liquefaction project. Within 90 days of the commencement of construction of the 130 MW generating station, DCP is required to make the first of its funding contributions to SEIF and MEAP.[176]

D. PJM's Reliability Pricing Model

As a means of ensuring reliability of the electric system in the RTO, PJM annually conducts a long-term planning process that compares the potential available generation capacity located within the RTO and the import capability of the RTO against the estimated demand of customers within the RTO. Consequently, the model projects the amount of generation and transmission required to maintain the reliability of the electric grid within PJM. The amount of capacity procured in PJM's Reliability Pricing Model ("RPM") is roughly based upon a forecast of the peak load projected by PJM for a particular year, plus a reserve margin. The RPM works in conjunction with PJM's RTEP to ensure reliability in the PJM region for future years.

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[171] DOE, *DOE/FE ORDER NO. 3019*, http://www.fossil.energy.gov/programs/gasregulation/authorizations/Orders_Issued_2011/ord3019.pdf (October 7, 2011).
[172] DOE, *DOE/FE ORDER NO. 3331*, http://www.fossil.energy.gov/programs/gasregulation/authorizations/Orders_Issued_2013/ord3331.pdf (September 11, 2013).
[173] FERC Office of Energy Projects, *Environmental Assessment for the Cove Point Liquefaction Project,* http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=13546268 (May 15, 2014).
[174] *Id.* at 1.
[175] FERC, *NOTICE OF SCHEDULE FOR ENVIRONMENTAL REVIEW OF THE PROPOSED COVE POINT LIQUEFACTION PROJECT*, http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=13482760 (March 12, 2014).
[176] Order No. 86372 at 74,

Using this information, PJM evaluates offers from generators and other resources three years in advance to be available for a one-year delivery period running from June through May (up to three years for new generation) through the Base Residual Auction ("BRA").[177] Once PJM completes its RTEP and conducts the RPM BRA, PJM is in a position to evaluate the reliability of its system. PJM must operate the transmission system to meet reliability criteria established by the FERC and administered by the North American Electric Reliability Corporation ("NERC").

However, the Commission noted in Case No. 9214 that "[s]ince its inception in 2007, RPM has brought no new generation to Maryland, in spite of the fact that clearing prices for capacity in SWMAAC have averaged almost double those of the non-constrained portions of PJM."[178] Furthermore, the Mid-Atlantic Advisory Council ("MAAC") LDA, which includes SWMAAC, has experienced significant volatility in Net Zonal Load[179] capacity prices as a result of the past ten BRAs. The historical pattern suggests that future BRA results could vary significantly from year to year and must be closely monitored.

Table 20: PJM BRA Capacity Prices by Zone[180]

Delivery Year	APS ($/MW-day)	BGE ($/MW-day)	DPL ($/MW-day)	PEPCO ($/MW-day)	RTO Price ($/MW-day)
2012/2013	$16.74	$133.42	$171.27	$133.42	$16.46
2013/2014	$27.73	$226.15	$245.09	$247.14	$27.73
2014/2015	$125.94	$135.25	$142.99	$135.25	$125.94
2015/2016	$134.62	$165.78	$165.78	$165.78	$136.00
2016/2017	$59.37	$118.89	$118.89	$118.89	$59.37
2017/2018	$119.81	$119.92	$119.92	$119.92	$120.00

PJM noted that the 2017/2018 capacity prices were slightly higher than the previous delivery year due to several factors. First, two new RPM design elements were included in the 2017/2018 RPM BRA. Capacity Import Limits were established on the amount of external generation capacity that can be reliably committed to PJM.[181] These limits resulted in fewer cleared imports of capacity from outside of the RTO, resulting in

[177] Reliability Pricing Model, PJM Markets & Operations (last visited July 1, 2014), http://www.pjm.org/markets-and-operations/rpm.aspx.
[178] *In the Matter of Whether New Generating Facilities are Needed to Meet Long-Term Demand for Standard Offer Service*, Case No. 9214, Order No. 84815 (April 12, 2012), pp. 22.
[179] The Zonal Net Load capacity price reflects the BRA resource clearing price and credits from any transmission capacity transfer rights.
[180] *PJM RPM Auction User Information: Delivery Year*, PJM Markets & Operations (Delivery Years 2013-2018), http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx.
[181] *2017/2018 RPM Base Residual Auction Results,* PJM, at 2 (May 23, 2014), http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2017-2018-base-residual-auction-report.ashx.

increased capacity prices. Maximum limits on the procurement of the more limited capacity product types were also put into place in this auction.[182] These limits allowed for greater variety in the types of demand resources clearing in the auction, including more "annual" and "extended summer" products than in the past. Second, there was a decrease in the quantity of external generation capacity procured and the total quantity of DR procured by 39% and 12%, respectively.[183] Finally, the expected net energy market revenues were lower than anticipated due to reduced demand and low natural gas prices, thereby increasing the need to cover fixed costs on the capacity prices.[184] Depending on the zone, this increase could be slight, like that for BGE, DPL, and Pepco at approximately 1%, or significant, like that for APS of 102%.

Other important occurrences during the 2017/2018 BRA include the highest increase in capacity procured from new generation since the inception of RPM in 2007. Most of this new generation came from gas-fired combined cycle generation downstream of the west-to-east transmission constraints.[185] There were also several facilities that were initially scheduled for deactivation that instead changed fuel types and reactivated, further increasing new generation capacity.

As demonstrated in Table 20 above, the RTO capacity price doubled between the 2016/2017 and 2017/2018 delivery years. This increase is attributable to three main factors. *First*, the increased cost of complying with new environmental regulations raised the capacity price. *Second*, the new limits set on demand response programs that operate exclusively in the summer, as well as limits pertaining to generation imports also yielded a higher capacity price. *Finally*, there was a decrease in total imports and demand response in the most recent auction.[186] These variables outweighed the increase in new generation capacity offered in the 2017/2018 BRA, thereby resulting in higher capacity prices. The capacity prices for the APS Zone also doubled between the 2016/2017 and 2017/2018 delivery years. This zone appears to follow the trend of the broader RTO. Historically, demand response programs in the Maryland service territory have not been cost effective in the APS Zone due to the relatively low capacity prices. The higher prices in the APS Zone may indicate that a demand response program could be cost effective in the future.

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[182] *Id.*
[183] *Id.*
[184] *Id.*
[185] *Id.*
[186] RTO Insider, *Capacity Prices Jump Following Rule Changes*, http://www.rtoinsider.com/pjm-capacity-auction-analysis/ (May 27, 2014).

V. Federal Energy Issues

As transmission, wholesale electricity, and bulk power system standards have a significant impact on Maryland's energy infrastructure, the Commission recognizes the importance of tracking energy policy made at the federal level and forecasting what impact those changes may have on Maryland ratepayers.

A. FERC Order 745

FERC Order 745 established a compensation method for demand response resources participating in organized wholesale energy markets, which are administered by RTOs and Independent System Operators ("ISO") such as PJM.[187] In Order 745, the FERC asserted that the Energy Policy Act of 2005 required the elimination of unnecessary barriers to the participation of demand response in wholesale energy markets. Specifically, the FERC determined in its Order that RTOs and ISOs must pay demand response resources the market price for energy, also known as the locational marginal price ("LMP"). The demand response resource must be paid LMP if two criteria are met: 1) if the resource has the ability to balance supply and demand as an alternative to a generation resource; and, 2) if dispatch of that resource is cost-effective, as determined by a net benefits test outlined by the FERC. A demand response resource would meet this net benefits test if the benefit to customers from the reduced LMP derived from the dispatch of demand response resources exceeds the cost of otherwise paying those resources LMP.

On May 23, 2014, a panel of the United States Court of Appeals for the District of Columbia Circuit issued a 2-1 decision vacating FERC Order 745 in its entirety. While demand response resources will still be able to participate in PJM's capacity market following the court's decision, these resources will no longer be allowed to bid into the energy markets. This could have a chilling effect on the continuing roll-out of demand response in Maryland; however, any impact may be mitigated since the D.C. Circuit court ruling does not directly affect the capacity market. The D.C. Circuit ruled that "[b]ecause FERC's rule entails direct regulation of the retail market—a matter exclusively within state control—it exceeds the Commission's authority."[188] Moreover, the majority held that Order 745 was arbitrary and capricious, since it did not engage the argument raised by dissenting FERC Commissioner Moeller; specifically, that Order 745 will result in unjust and discriminatory rates. Senior Circuit Judge Edwards issued a dissenting opinion, stating that "FERC had jurisdiction to issue Order 745 because demand response is not unambiguously a matter of retail regulation under the Federal Power Act and because the demand response resources subject to the rule directly affect wholesale electricity prices".[189]

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[187] Docket No. RM10-17-000; *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745 (March 15, 2011).
[188] *Electric Power Supply Association v. FERC*, D.C. Cir. Nos. 11-1486, et al., p. 14.
[189] *Id.*at 27.

PJM's capacity market model, the RPM, creates long-term price signals to attract needed investments in reliability in the PJM region. These resources include not only generating plants, but also demand response resources, energy efficiency, and transmission facilities. Prior to the May 23, 2014 D.C. Circuit decision, a demand response resource could participate not just as a capacity resource in PJM markets, but as an energy resource as well. The Court's decision does not directly affect demand response resource bids into the capacity market, and a majority of the demand response resource revenues come from participation in the PJM capacity market.[190] In a press release issued May 27, 2014, EnerNOC, one of the largest providers of demand response in the U.S., explained that the energy payments at risk because of the D.C. court's decision pertaining to FERC Order 745 represented a mere 2% of the company's revenues over the past three years. However, the reasoning of the Court's decision, if it stands, could be applied in future cases to markets other than just the energy markets, such as the capacity market.

In addition to the Maryland Commission, the FERC has petitioned the full U.S. Court of Appeals for the District of Columbia Circuit to rehear *en banc* the panel's May 23, 2014 decision. In response, on July 18, 2014 the D.C. Circuit Court of Appeals ordered the petitioners in the case to file a joint response to the FERC's petition for rehearing *en banc*. If the Court agrees to a rehearing, or if the decision is appealed to the United States Supreme Court, the FERC's rules could remain in effect through this period of further litigation. Given the ensuing litigation process, it may be some time before the final results of this decision are known. In the interim, the Commission intends to monitor the docket and adopt positions consistent with our State policies pertaining to demand response and energy efficiency programs.

If ultimately upheld, the D.C. court's decision could negatively affect certain EmPOWER Maryland programs, including: BGE's Peak Rewards, PHI's Energy Wise Rewards, SMECO's CoolSentry Load Management, and certain other energy efficiency and behavior-based programs that rely on Advanced Metering Infrastructure. While the majority of revenues used to fund Maryland utilities' programs flows from the PJM capacity market, BGE, in particular, has received significant revenue from bidding these resources into the energy market. However, since a final court decision may be significantly delayed, the May 23, 2014 D.C. court decision should have no meaningful short-term affects on EmPOWER programs.

[190] 2014 Demand Response Operations Markets Activity Report: June 2014; Figure 12, p. 13.

B. Section 111(d) of the Clean Air Act

On June 2, 2014, the U.S. Environmental Protection Agency ("EPA") released its proposed Carbon Pollution Standards for Existing Power Plants.[191] Using a 2012 baseline, the EPA proposal seeks to cut carbon dioxide emissions nationwide 30% from 2005 levels by 2030.[192] The EPA proposal stems from a June 25, 2013 Presidential memorandum directing the EPA to issue greenhouse gas standards for existing power plants under Section 111(d) of the Clean Air Act.[193] Section 111(d) grants the EPA the authority to issue emission guidelines for existing stationary sources based on a determination of the Best System of Emission Reduction ("BSER").[194] In crafting each state's goal, the EPA mapped out the BSER for existing sources considering four building blocks. These building blocks were applied uniformly to every state on the basis of each state's individual 2012 generation profile. The four building blocks consist of the following elements: (1) heat rate improvements; (2) higher utilization of natural gas combined cycle units; (3) a shift to renewable generation with low- or zero-carbon emissions; and (4) increased utilization of demand-side energy efficiency. The EPA is receiving comments on its proposal through October 16, 2014, and is expected to issue the final rule by June 1, 2015. If a state chooses to pursue single-state reduction strategies, state implementation plans must be submitted to the EPA by June 30, 2016; the deadline is extended by one year for states pursuing a multi-state implementation plan.[195]

Maryland's carbon intensity rate (lbs/MWh) ascribed to it by the EPA translates into a 37% reduction in carbon intensity from the power sector by 2030.[196] In 2005, Maryland generated 83.3 million metric tons of CO_2 from fossil fuel-fired generating units.[197] By 2011, Maryland realized its lowest level of emissions from fossil fuel sources since 1983 when in-State emissions for 2011 fell to 63.8 million metric tons of CO_2, a decrease of 23% compared to 2005 levels.[198,199] Over the same period, national CO_2 emissions decreased by 10%.

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[191] *Q&A: EPA Regulation of Greenhouse Gas Emissions from Existing Power Plants.* Center for Climate and Energy Solutions. http://www.c2es.org/federal/executive/epa/ghg-standards-for-new-power-plants.
[192] *Id.*
[193] *Id.*
[194] McMahan, Tim. Wood, Tom. *What To Expect From The EPA's Upcoming Greenhouse Gas Regulations.* North American WindPower (May 29, 2014), http://www.nawindpower.com/e107_plugins/content/content.php?content.13025.
[195] *Id.*
[196] *Carbon Pollution Standards Map.* Center for Climate and Energy Solutions. http://www.c2es.org/federal/executive/epa/carbon-pollution-standards-map.
[197] *State CO2 Emissions.* U.S. Energy Information Administration. Release date: February 25, 2014. http://www.eia.gov/environment/emissions/state/state_emissions.cfm.
[198] *Id.*
[199] A major driver of the reduction was the Maryland Healthy Air Act, which became effective on July 16, 2007. *The Maryland Healthy Air Act.* Maryland Department of the Environment. http://www.mde.md.gov/programs/Air/ProgramsHome/Pages/air/md_haa.aspx

Maryland is one of the nine states currently participating in the Regional Greenhouse Gas Initiative ("RGGI"), the first market-based regulatory program in the United States to reduce greenhouse gas emissions. In its proposal, EPA explicitly recognized RGGI as a viable compliance pathway to meet the proposed goals. As such, Maryland continues to investigate a compliance pathway consistent with the EPA 111(d) guidelines that will leverage the market-based regional cooperation already established through the RGGI program and appropriately recognize progress already achieved in the RGGI region. Future iterations of the Ten-Year Plan will discuss the possible implications of a multi-state implementation plan on Maryland's electricity sector planning efforts.

VI. Conclusion

A number of open and continuing issues will affect planning for electric regulatory policy in the near and medium term. The Maryland capacity and generation profile is expected to diversify during the planning period due to anticipated natural gas-fired and renewable resource additions. New and developing regulations promulgated by the EPA may also spur changes to the in-State fuel mix, as well as that of the broader PJM RTO. Additionally, a shift in energy production is projected for the State, as evidenced by the planned Dominion Cove Point liquefied natural gas facility. Furthermore, the Maryland utilities will continue to encounter the effects of extreme weather and its impact on the generation of and peak demand for electricity in the State of Maryland. In response to these, and other developments, the 2015 - 2024 Ten-Year Plan will review and assess the impacts that the above-mentioned issues will have on Maryland's long-term electricity resource planning.

Appendices to the 2014-2023 Maryland Public Service Commission's Ten-Year Plan

*All data in the following appendices was derived from the Utilities' responses to Staff's Data Request submitted on May 1, 2014 and returned by May 30, 2014.

Appendix Table 1(a): Maryland Customer Forecasts

Appendix Table 1(a)(i): All Customer Classes (# of customers)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2014	2,459	1,249,177	52,486	201,444	11,147	17,331	256,397	538,481	158,793	2,834	994	**2,491,542**
2015	2,459	1,255,375	52,797	202,508	11,300	17,411	258,468	543,274	160,844	2,834	994	**2,508,264**
2016	2,471	1,262,574	53,144	203,686	11,454	17,491	260,624	548,178	162,874	2,834	994	**2,526,324**
2017	2,496	1,270,616	53,436	204,832	11,607	17,572	262,552	553,125	164,914	2,834	994	**2,544,977**
2018	2,521	1,279,200	53,668	205,939	11,761	17,653	264,322	558,008	167,054	2,834	994	**2,563,954**
2019	2,546	1,288,112	53,841	207,011	11,914	17,734	265,933	563,007	169,094	2,834	994	**2,583,021**
2020	2,584	1,297,171	53,983	208,050	12,068	17,816	267,513	568,124	171,234	2,834	994	**2,602,372**
2021	2,623	1,306,181	54,095	209,056	12,221	17,898	269,064	573,269	173,444	2,834	994	**2,621,680**
2022	2,662	1,315,154	54,159	210,047	12,375	17,980	270,646	578,641	175,554	2,834	994	**2,641,047**
2023	2,702	1,324,117	54,226	211,022	12,528	18,063	272,113	584,384	177,774	2,834	994	**2,660,756**
Change (2014-2023)	**243**	**74,940**	**1,740**	**9,578**	**1,381**	**732**	**15,716**	**45,903**	**18,981**	**-**	**-**	**169,214**
Percent Change (2014-2023)	**9.90%**	**6.00%**	**3.32%**	**4.75%**	**12.39%**	**4.22%**	**6.13%**	**8.52%**	**11.95%**	**0.00%**	**0.00%**	**6.79%**
Compound Annual Growth Rate	**1.05%**	**0.65%**	**0.36%**	**0.52%**	**1.31%**	**0.46%**	**0.66%**	**0.91%**	**1.26%**	**0.00%**	**0.00%**	**0.73%**

<u>Note:</u> A&N and Somerset did not report applicable information for this table.

Appendix Table 1(a)(ii): Residential (# of customers)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2014	2,024	1,123,998	47,475	174,959	8,719	14,762	224,867	490,803	143,689	2,449	846	**2,234,591**
2015	2,024	1,129,530	47,768	175,900	8,837	14,836	226,648	495,579	145,500	2,449	846	**2,249,915**
2016	2,034	1,136,071	48,104	176,917	8,956	14,910	228,521	500,464	147,300	2,449	846	**2,266,572**
2017	2,054	1,143,434	48,381	177,910	9,075	14,985	230,200	505,392	149,100	2,449	846	**2,283,826**
2018	2,075	1,151,342	48,590	178,872	9,194	15,060	231,745	510,263	151,000	2,449	846	**2,301,436**
2019	2,096	1,159,594	48,746	179,809	9,313	15,135	233,153	515,250	152,800	2,449	846	**2,319,190**
2020	2,127	1,168,024	48,880	180,720	9,431	15,211	234,540	520,357	154,700	2,449	846	**2,337,285**
2021	2,159	1,176,449	48,983	181,606	9,550	15,287	235,903	525,495	156,700	2,449	846	**2,355,426**
2022	2,191	1,184,870	49,037	182,483	9,669	15,363	237,296	530,860	158,600	2,449	846	**2,373,664**
2023	2,224	1,193,317	49,093	183,348	9,788	15,440	238,589	536,560	160,600	2,449	846	**2,392,254**
Change (2014-2023)	**200**	**69,319**	**1,618**	**8,389**	**1,069**	**678**	**13,723**	**45,756**	**16,911**	**-**	**-**	**157,663**
Percent Change (2014-2023)	**9.90%**	**6.17%**	**3.41%**	**4.79%**	**12.26%**	**4.59%**	**6.10%**	**9.32%**	**11.77%**	**0.00%**	**0.00%**	**7.06%**
Compound Annual Growth	**1.05%**	**0.67%**	**0.37%**	**0.52%**	**1.29%**	**0.50%**	**0.66%**	**1.00%**	**1.24%**	**0.00%**	**0.00%**	**0.76%**

<u>Note:</u> A&N and Somerset did not report applicable information for this table.

Appendix Table 1(a): Maryland Customer Forecasts

Appendix Table 1(a)(iii): Commercial (# of customers)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2014	302	113,167	4,748	25,971	2,428	2,523	28,363	47,584	15,100	336	125	**240,647**
2015	302	113,641	4,755	26,096	2,463	2,529	28,660	47,600	15,340	336	125	**241,847**
2016	304	114,077	4,763	26,258	2,498	2,535	28,945	47,619	15,570	336	125	**243,030**
2017	307	114,510	4,778	26,412	2,532	2,541	29,193	47,636	15,810	336	125	**244,181**
2018	310	114,923	4,801	26,557	2,567	2,547	29,415	47,648	16,050	336	125	**245,280**
2019	313	115,306	4,818	26,695	2,602	2,553	29,615	47,660	16,290	336	125	**246,313**
2020	317	115,646	4,826	26,824	2,636	2,559	29,809	47,671	16,530	336	125	**247,279**
2021	322	115,938	4,835	26,945	2,671	2,565	29,997	47,678	16,740	336	125	**248,152**
2022	327	116,191	4,845	27,061	2,706	2,571	30,188	47,685	16,950	336	125	**248,984**
2023	332	116,400	4,856	27,171	2,740	2,577	30,363	47,728	17,170	336	125	**249,799**
Change (2014-2023)	**30**	**3,233**	**108**	**1,199**	**312**	**54**	**2,001**	**144**	**2,070**	**-**	**-**	**9,151**
Percent Change (2014-2023)	**9.90%**	**2.86%**	**2.27%**	**4.62%**	**12.85%**	**2.14%**	**7.05%**	**0.30%**	**13.71%**	**0.00%**	**0.00%**	**3.80%**
Compound Annual Growth	**1.05%**	**0.31%**	**0.25%**	**0.50%**	**1.35%**	**0.24%**	**0.76%**	**0.03%**	**1.44%**	**0.00%**	**0.00%**	**0.42%**

Note: A&N and Somerset did not report applicable information for this table.

Appendix Table 1(a)(iv): Industrial (# of customers)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2014	113	11,721	23	239	0	46	2,845	0	4	10	14	**15,014**
2015	113	11,914	23	239	0	46	2,837	0	4	10	14	**15,199**
2016	113	12,136	23	237	0	46	2,833	0	4	10	14	**15,416**
2017	114	12,382	23	236	0	46	2,833	0	4	10	14	**15,663**
2018	116	12,647	23	236	0	46	2,837	0	4	10	14	**15,933**
2019	117	12,926	23	235	0	46	2,839	0	4	10	14	**16,214**
2020	118	13,216	23	233	0	46	2,839	0	4	10	14	**16,503**
2021	120	13,510	23	232	0	46	2,839	0	4	10	14	**16,798**
2022	122	13,811	23	231	0	46	2,837	0	4	10	14	**17,098**
2023	124	14,117	23	230	0	46	2,836	0	4	10	14	**17,403**
Change (2014-2023)	**11**	**2,396**	**-**	**(9)**	**-**	**-**	**(9)**	**-**	**-**	**-**	**-**	**2,389**
Percent Change (2014-2023)	**9.90%**	**20.45%**	**0.00%**	**-3.84%**	**N/A**	**0.00%**	**-0.32%**	**N/A**	**0.00%**	**0.00%**	**0.00%**	**15.91%**
Compound Annual Growth	**1.05%**	**2.09%**	**0.00%**	**-0.43%**	**N/A**	**0.00%**	**-0.04%**	**N/A**	**0.00%**	**0.00%**	**0.00%**	**1.65%**

Note: A&N and Somerset did not report applicable information for this table.

Appendix Table 1(a): Maryland Customer Forecasts

Appendix Table 1(a)(v): Other (# of customers)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2014	20	291	240	274	0	0	320	93	0	39	9	**1,287**
2015	20	290	251	274	0	0	321	95	0	39	9	**1,300**
2016	20	289	254	274	0	0	322	96	0	39	9	**1,303**
2017	20	288	254	273	0	0	323	96	0	39	9	**1,304**
2018	21	287	254	273	0	0	323	96	0	39	9	**1,303**
2019	21	286	254	273	0	0	323	97	0	39	9	**1,302**
2020	21	285	254	273	0	0	323	97	0	39	9	**1,301**
2021	21	284	254	273	0	0	323	97	0	39	9	**1,300**
2022	22	283	254	273	0	0	322	97	0	39	9	**1,299**
2023	22	282	254	273	0	0	321	97	0	39	9	**1,297**
Change (2014-2023)	**2**	**(9)**	**14**	**(1)**	**-**	**-**	**2**	**3**	**-**	**-**	**-**	**10**
Percent Change (2014-2023)	**9.90%**	**-3.09%**	**5.83%**	**-0.53%**	**N/A**	**N/A**	**0.55%**	**3.33%**	**N/A**	**0.00%**	**0.00%**	**0.81%**
Compound Annual Growth	**1.05%**	**-0.35%**	**0.63%**	**-0.06%**	**N/A**	**N/A**	**0.06%**	**0.36%**	**N/A**	**0.00%**	**0.00%**	**0.09%**

Note: A&N and Somerset did not report applicable information for this table.
Note: The "Other" rate class refers to customers that do not fall into one of the listed classes; street lighting is an example of a rate class included under "Other."

Appendix Table 1(a)(vi): Resale (# of customers)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2014	0	0	0	0	0	0	3	0	0	0	0	**3**
2015	0	0	0	0	0	0	3	0	0	0	0	**3**
2016	0	0	0	0	0	0	3	0	0	0	0	**3**
2017	0	0	0	0	0	0	3	0	0	0	0	**3**
2018	0	0	0	0	0	0	3	0	0	0	0	**3**
2019	0	0	0	0	0	0	3	0	0	0	0	**3**
2020	0	0	0	0	0	0	3	0	0	0	0	**3**
2021	0	0	0	0	0	0	3	0	0	0	0	**3**
2022	0	0	0	0	0	0	3	0	0	0	0	**3**
2023	0	0	0	0	0	0	3	0	0	0	0	**3**
Change (2014-2023)	-	-	-	-	-	-	-	-	-	-	-	-
Percent Change (2014-2023)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**0.00%**	**N/A**	**N/A**	**N/A**	**N/A**	**0.00%**
Compound Annual Growth	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**0.00%**	**N/A**	**N/A**	**N/A**	**N/A**	**0.00%**

Note: A&N and Somerset did not report applicable information for this table.
Note: The "Resale" class refers to "Sales for Resale", which is energy supplied to other electric utilities, cooperatives, municipalities, and Federal and State electric agencies for resale to end-use consumers. PE is the only utility with any resale customers; these wholesale customers are PJM, Monongahela Power Company, West Penn Power Company and Old Dominion Electric Cooperative.

Appendix Table 1(b): 2013 Customer Numbers and Energy Sales

Appendix Table 1(b)(i): Customer Class Breakdown as of December 31, 2013 (# of customers)

	System Wide						Maryland					
Utility	Residential	Commercial	Industrial	Other	Sales for Resale	Total	Residential	Commercial	Industrial	Other	Sales for Resale	Total
Berlin	2,032	298	113	20	-	**2,462**	2,032	298	113	20	-	**2,462**
BGE	1,118,769	113,008	11,620	300	-	**1,243,696**	1,118,769	113,008	11,620	300	-	**1,243,696**
Choptank	47,332	4,724	23	242	-	**52,322**	47,332	4,724	23	242	-	**52,322**
DPL	443,843	59,539	469	643	-	**504,494**	174,110	25,889	239	275	-	**200,513**
Easton	8,227	2,325	-	-	-	**10,552**	8,227	2,325	-	-	-	**10,552**
Hagerstown	14,689	2,518	46	-	-	**17,253**	14,689	2,518	46	-	-	**17,253**
PE	341,064	44,045	4,826	645	4	**390,583**	223,537	27,693	2,845	328	2	**254,404**
PEPCO	721,437	73,982	13	116	-	**795,548**	486,127	47,487	12	88	-	**533,714**
SMECO	140,733	14,735	4	350	-	**155,821**	140,733	14,735	4	350	-	**155,821**
Thurmont	2,449	336	10	39		**2,834**	2,449	336	10	39		**2,834**
Williamsport	846	125	14	9	-	**993**	846	125	14	9	-	**993**
Total	**2,841,420**	**315,634**	**17,138**	**2,363**	**4**	**3,176,559**	**2,218,850**	**239,138**	**14,925**	**1,649**	**2**	**2,474,564**

<u>Note:</u> A&N and Somerset did not report applicable information for this table.
<u>Note:</u> "System wide" includes the entire distribution system of a utility, which may extend beyond the Maryland service territory into Washington, D.C., Delaware, and parts of West Virginia. The affected utilities include DPL, PE, and Pepco.

Appendix Table 1(b)(ii): Utilities' 2013 Energy Sales by Customer Class (GWh)

	System Wide						Maryland					
Utility	Residential	Commercial	Industrial	Other	Sales for Resale	Total	Residential	Commercial	Industrial	Other	Sales for Resale	Total
Berlin	25	3	13	0	-	**42**	25	3	13	0	-	**42**
BGE	13,077	3,035	14,339	317	-	**30,768**	13,077	3,035	14,339	317	-	**30,768**
Choptank	670	209	91	1	-	**971**	670	209	91	1	-	**971**
DPL	5,088	5,136	2,220	48	-	**12,492**	2,136	1,704	408	12	-	**4,260**
Easton	108	156	-	-	-	**264**	108	156	-	-	-	**264**
Hagerstown	156	96	47	-	-	**299**	156	96	47	-	-	**299**
PE	5,039	2,892	2,425	22	1,397	**11,775**	3,244	2,049	1,612	16	1,386	**8,306**
PEPCO	7,884	16,746	625	75	-	**25,331**	5,827	8,232	396	73	-	**14,528**
SMECO	2,131	1,274	33	7	-	**3,445**	2,131	1,274	33	7	-	**3,445**
Thurmont	38	16	25	1	-	**80**	38	16	25	1	-	**80**
Williamsport	9	3	7	0	-	**20**	9	3	7	0	-	**20**
Total	**34,225**	**29,567**	**19,826**	**471**	**1,397**	**85,487**	**27,421**	**16,778**	**16,971**	**427**	**1,386**	**62,984**

<u>Note:</u> A&N and Somerset did not report applicable information for this table.
<u>Note:</u> "System wide" includes the entire distribution system of a utility, which may extend beyond the Maryland service territory into Washington, D.C., Delaware, and parts of West Virginia. The affected utilities include DPL, PE, and Pepco.

Appendix Table 2(a): Energy Sales Forecast by Utility (Maryland Service Territory Only)

Appendix Table 2(a)(i): Maryland Energy Sales Forecast, Gross of DSM (GWh)

	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Total
2014	42	31,831	1,007	4,377	271	304	7,783	15,374	3,826	**64,823**
2015	40	31,965	1,054	4,431	273	306	7,943	15,583	3,928	**65,532**
2016	40	32,636	1,101	4,502	275	308	8,056	15,850	4,014	**66,791**
2017	41	33,373	1,135	4,572	276	310	8,147	16,097	4,064	**68,024**
2018	41	34,155	1,173	4,631	278	312	8,220	16,322	4,116	**69,256**
2019	42	34,725	1,209	4,612	280	314	8,290	16,316	4,169	**69,964**
2020	42	35,293	1,239	4,590	282	316	8,331	16,287	4,223	**70,612**
2021	43	35,841	1,269	4,579	283	318	8,396	16,275	4,277	**71,289**
2022	44	36,367	1,300	4,581	285	320	8,468	16,291	4,330	**71,994**
2023	44	36,904	1,331	4,591	287	322	8,544	16,333	4,384	**72,748**
Change (2014-2023)	**2**	**5,072**	**324**	**214**	**16**	**18**	**761**	**959**	**558**	**7,925**
Percent Change (2014-2023)	**5.16%**	**15.94%**	**32.17%**	**4.89%**	**5.76%**	**5.92%**	**9.78%**	**6.24%**	**14.59%**	**12.23%**
Compound Annual Growth Rate	**0.56%**	**1.66%**	**3.15%**	**0.53%**	**0.62%**	**0.64%**	**1.04%**	**0.67%**	**1.53%**	**1.29%**

Note: A&N and Somerset did not report applicable information for this table.

Appendix Table 2(a)(ii): Maryland Energy Sales Forecast, Net of DSM (GWh)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Total
2014	42	31,436	1,006	4,203	271	304	7,442	14,656	3,625	**62,994**
2015	40	31,219	1,053	4,195	273	306	7,555	14,671	3,686	**63,007**
2016	40	31,505	1,100	4,204	275	308	7,668	14,745	3,737	**63,590**
2017	41	31,845	1,133	4,212	276	310	7,759	14,798	3,787	**64,170**
2018	41	32,207	1,172	4,209	278	312	7,832	14,829	3,839	**64,727**
2019	42	32,390	1,208	4,190	280	314	7,902	14,823	3,892	**65,048**
2020	42	32,571	1,237	4,168	282	316	7,943	14,794	3,946	**65,308**
2021	43	32,731	1,267	4,157	283	318	8,008	14,782	4,000	**65,597**
2022	44	32,870	1,299	4,159	285	320	8,080	14,798	4,053	**65,916**
2023	44	33,019	1,330	4,169	287	322	8,156	14,840	4,107	**66,283**
Change (2014-2023)	**2**	**1,583**	**324**	**(34)**	**16**	**18**	**714**	**185**	**482**	**3,289**
Percent Change (2014-2023)	**5.16%**	**5.03%**	**32.21%**	**-0.81%**	**5.76%**	**5.92%**	**9.59%**	**1.26%**	**13.29%**	**5.22%**
Compound Annual Growth	**0.56%**	**0.55%**	**3.15%**	**-0.09%**	**0.62%**	**0.64%**	**1.02%**	**0.14%**	**1.40%**	**0.57%**

Note: A&N and Somerset did not report applicable information for this table.

Appendix Table 2(b): Energy Sales Forecast by Utility (System Wide)

Appendix Table 2(b)(i): System Wide Energy Sales Forecast, Gross of DSM (GWh)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Total
2014	42	31,831	1,007	12,527	271	304	14,564	26,721	3,826	**91,102**
2015	40	31,965	1,054	12,639	273	306	14,808	26,927	3,928	**91,949**
2016	40	32,636	1,101	12,742	275	308	14,998	27,220	4,014	**93,341**
2017	41	33,373	1,135	12,828	276	310	15,154	27,495	4,064	**94,684**
2018	41	34,155	1,173	12,866	278	312	15,287	27,742	4,116	**95,979**
2019	42	34,725	1,209	12,770	280	314	15,418	27,750	4,169	**96,685**
2020	42	35,293	1,239	12,654	282	316	15,508	27,732	4,223	**97,297**
2021	43	35,841	1,269	12,576	283	318	15,629	27,735	4,277	**97,980**
2022	44	36,367	1,300	12,555	285	320	15,760	27,776	4,330	**98,745**
2023	44	36,904	1,331	12,569	287	322	15,892	27,852	4,384	**99,593**
Change (2014-2023)	**2**	**5,072**	**324**	**42**	**16**	**18**	**1,328**	**1,131**	**558**	**8,491**
Percent Change (2014-2023)	**5.16%**	**15.94%**	**32.17%**	**0.33%**	**5.76%**	**5.92%**	**9.12%**	**4.23%**	**14.59%**	**9.32%**
Compound Annual Growth Rate	**0.56%**	**1.66%**	**3.15%**	**0.04%**	**0.62%**	**0.64%**	**0.97%**	**0.46%**	**1.53%**	**1.00%**

Note: A&N and Somerset did not report applicable information for this table.
Note: "System wide" includes the entire distribution system of a utility, which may extend beyond the Maryland service territory into Washington, D.C., Delaware, and parts of West Virginia. The affected utilities include DPL, PE, and Pepco.

Appendix Table 2(b)(ii): System Wide Energy Sales Forecast, Net of DSM (GWh)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Total
2014	42	31,436	1,006	12,328	271	304	14,218	25,962	3,625	**89,201**
2015	40	31,219	1,053	12,377	273	306	14,411	25,975	3,686	**89,349**
2016	40	31,505	1,100	12,417	275	308	14,595	26,074	3,737	**90,060**
2017	41	31,845	1,133	12,441	276	310	14,748	26,155	3,787	**90,745**
2018	41	32,207	1,172	12,418	278	312	14,882	26,209	3,839	**91,366**
2019	42	32,390	1,208	12,322	280	314	15,013	26,217	3,892	**91,685**
2020	42	32,571	1,237	12,205	282	316	15,103	26,199	3,946	**91,909**
2021	43	32,731	1,267	12,127	283	318	15,224	26,202	4,000	**92,204**
2022	44	32,870	1,299	12,106	285	320	15,355	26,243	4,053	**92,582**
2023	44	33,019	1,330	12,121	287	322	15,487	26,318	4,107	**93,043**
Change (2014-2023)	**2**	**1,583**	**324**	**(208)**	**16**	**18**	**1,269**	**356**	**482**	**3,842**
Percent Change (2014-2023)	**5.16%**	**5.03%**	**32.21%**	**-1.69%**	**5.76%**	**5.92%**	**8.93%**	**1.37%**	**13.29%**	**4.31%**
Compound Annual Growth Rate	**0.56%**	**0.55%**	**3.15%**	**-0.19%**	**0.62%**	**0.64%**	**0.95%**	**0.15%**	**1.40%**	**0.47%**

Note: A&N and Somerset did not report applicable information for this table.
Note: "System wide" includes the entire distribution system of a utility, which may extend beyond the Maryland service territory into Washington, D.C., Delaware, and parts of West Virginia. The affected utilities include DPL, PE, and Pepco.

Appendix Table 3(a): Peak Demand Forecasts (Maryland Service Territory Only)

Appendix Table 3(a)(i): Maryland Summer, Gross of DSM Programs (MW)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Total
2014	11	7,283	247	997	70	63	1,575	3,593	926	**14,785**
2015	11	7,399	247	1,016	72	64	1,604	3,634	950	**15,016**
2016	11	7,455	250	1,029	73	65	1,629	3,653	969	**15,152**
2017	11	7,549	255	1,037	74	65	1,645	3,664	982	**15,300**
2018	11	7,627	260	1,046	75	66	1,659	3,680	994	**15,437**
2019	11	7,714	264	1,055	76	67	1,674	3,706	1,007	**15,593**
2020	11	7,791	269	1,066	77	67	1,686	3,739	1,020	**15,745**
2021	11	7,836	275	1,074	78	68	1,697	3,753	1,033	**15,845**
2022	12	7,886	280	1,082	79	69	1,713	3,770	1,046	**15,955**
2023	12	7,916	285	1,088	80	69	1,729	3,769	1,059	**16,025**
Change (2014-2023)	**1**	**633**	**38**	**91**	**10**	**6**	**154**	**176**	**133**	**1,241**
Percent Change (2014-2023)	**9.90%**	**8.69%**	**15.38%**	**9.11%**	**13.49%**	**9.52%**	**9.75%**	**4.91%**	**14.32%**	**8.39%**
Compound Annual Growth Rate	**1.05%**	**0.93%**	**1.60%**	**0.97%**	**1.42%**	**1.02%**	**1.04%**	**0.53%**	**1.50%**	**0.90%**

Note: A&N, Somerset, Thurmont, and Williamsport did not report applicable information for this table.

Appendix Table 3(a)(ii): Maryland Summer, Net of DSM Programs (MW) [200], [201]

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Total
2014	11	6,608	236	906	70	63	1,527	3,075	846	**13,361**
2015	11	6,653	237	855	72	64	1,550	3,041	860	**13,361**
2016	11	6,658	240	837	73	65	1,574	2,986	873	**13,336**
2017	11	6,721	246	823	74	65	1,590	2,922	886	**13,356**
2018	11	6,857	251	808	75	66	1,605	2,864	898	**13,453**
2019	11	6,922	256	817	76	67	1,619	2,889	911	**13,587**
2020	11	6,995	260	827	77	67	1,632	2,923	924	**13,735**
2021	11	7,038	266	835	78	68	1,643	2,937	937	**13,833**
2022	12	7,085	272	843	79	69	1,659	2,953	950	**13,940**
2023	12	7,113	278	849	80	69	1,675	2,953	963	**14,010**
Change (2014-2023)	**1**	**505**	**42**	**(57)**	**10**	**6**	**148**	**(122)**	**117**	**649**
Percent Change (2014-2023)	**9.90%**	**7.64%**	**17.80%**	**-6.29%**	**13.49%**	**9.52%**	**9.69%**	**-3.97%**	**13.83%**	**4.86%**
Compound Annual Growth Rate	**1.05%**	**0.82%**	**1.84%**	**-0.72%**	**1.42%**	**1.02%**	**1.03%**	**-0.45%**	**1.45%**	**0.53%**

Note: A&N, Somerset, Thurmont, and Williamsport did not report applicable information for this table.

[200] Berlin reported to Staff 6.8MW of DSM savings per year. This was attributed to the town generating 6.8MW of fossil fuel generation from generators that they own, operate, and dispatch, independent of PJM.
[201] Choptank's DSM programs include: a voluntary program among the consumers to drop load during "beat the peak" alerts; a legacy A/C & water heater switch program; and the availability of experimental interruptible rates, in which a few consumers are still enrolled.

Appendix Table 3(a): Peak Demand Forecasts (Maryland Service Territory Only)

Appendix Table 3(a)(iii): Maryland Winter, Gross of DSM Programs (MW)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Total
2014	14	5,956	284	944	58	68	1,642	2,762	841	**12,593**
2015	12	6,003	267	958	59	60	1,670	2,789	860	**12,702**
2016	13	6,047	265	971	59	60	1,688	2,826	878	**12,830**
2017	13	6,070	271	982	59	60	1,705	2,850	890	**12,923**
2018	13	6,137	275	989	60	61	1,718	2,869	904	**13,049**
2019	13	6,201	282	995	60	61	1,732	2,888	916	**13,172**
2020	13	6,241	285	998	61	61	1,742	2,898	929	**13,252**
2021	13	6,294	289	1,008	61	62	1,756	2,919	943	**13,370**
2022	13	6,314	294	1,014	61	62	1,772	2,937	955	**13,446**
2023	14	6,347	300	1,021	62	62	1,790	2,954	968	**13,541**
Change (2014-2023)	**(1)**	**391**	**16**	**78**	**4**	**(6)**	**148**	**192**	**127**	**948**
Percent Change (2014-2023)	**-3.74%**	**6.56%**	**5.63%**	**8.22%**	**6.19%**	**-8.82%**	**9.02%**	**6.94%**	**15.08%**	**7.53%**
Compound Annual Growth Rate	**-0.42%**	**0.71%**	**0.61%**	**0.88%**	**0.67%**	**-1.02%**	**0.96%**	**0.75%**	**1.57%**	**0.81%**

Note: A&N, Somerset, Thurmont, and Williamsport did not report applicable information for this table.

Appendix Table 3(a)(iv): Maryland Winter, Net of DSM Programs (MW)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Total
2014	14	5,946	274	944	58	68	1,587	2,762	822	**12,500**
2015	12	5,993	257	958	59	60	1,615	2,789	839	**12,607**
2016	13	6,037	255	971	59	60	1,634	2,826	853	**12,731**
2017	13	6,060	262	982	59	60	1,650	2,850	865	**12,825**
2018	13	6,127	266	989	60	61	1,663	2,869	879	**12,951**
2019	13	6,191	273	995	60	61	1,678	2,888	891	**13,074**
2020	13	6,231	277	998	61	61	1,687	2,898	904	**13,155**
2021	13	6,284	281	1,008	61	62	1,702	2,919	918	**13,272**
2022	13	6,304	286	1,014	61	62	1,717	2,937	930	**13,349**
2023	14	6,337	293	1,021	62	62	1,736	2,954	943	**13,445**
Change (2014-2023)	**(1)**	**391**	**19**	**78**	**4**	**(6)**	**148**	**192**	**121**	**945**
Percent Change (2014-2023)	**-3.74%**	**6.58%**	**6.93%**	**8.22%**	**6.19%**	**-8.82%**	**9.33%**	**6.94%**	**14.72%**	**7.56%**
Compound Annual Growth Rate	**-0.42%**	**0.71%**	**0.75%**	**0.88%**	**0.67%**	**-1.02%**	**1.00%**	**0.75%**	**1.54%**	**0.81%**

Note: A&N, Somerset, Thurmont, and Williamsport did not report applicable information for this table.

Appendix Table 3(b): Peak Demand Forecasts (System Wide)

Appendix Table 3(b)(i): System Wide Summer, Gross of DSM (MW)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2014	11	7,283	247	4,181	70	63	2,893	6,870	926	15	4	**22,564**
2015	11	7,399	247	4,261	72	64	2,937	6,948	950	15	4	**22,908**
2016	11	7,455	250	4,314	73	65	2,980	6,985	969	15	4	**23,121**
2017	11	7,549	255	4,351	74	65	3,007	7,005	982	15	4	**23,317**
2018	11	7,627	260	4,388	75	66	3,032	7,037	994	15	4	**23,508**
2019	11	7,714	264	4,427	76	67	3,057	7,086	1,007	15	4	**23,728**
2020	11	7,791	269	4,470	77	67	3,079	7,150	1,020	15	4	**23,953**
2021	11	7,836	275	4,504	78	68	3,099	7,177	1,033	15	4	**24,101**
2022	12	7,886	280	4,538	79	69	3,125	7,208	1,046	15	4	**24,262**
2023	12	7,916	285	4,562	80	69	3,152	7,207	1,059	15	4	**24,360**
Change (2014-2023)	**1**	**633**	**38**	**381**	**10**	**6**	**258**	**337**	**133**	**-**	**-**	**1,797**
Percent Change (2014-2023)	**9.90%**	**8.69%**	**15.38%**	**9.11%**	**13.49%**	**9.52%**	**8.93%**	**4.91%**	**14.32%**	**0.00%**	**0.00%**	**7.96%**
Compound Annual Growth Rate	**1.05%**	**0.93%**	**1.60%**	**0.97%**	**1.42%**	**1.02%**	**0.95%**	**0.53%**	**1.50%**	**0.00%**	**0.00%**	**0.85%**

Note: A&N and Somerset did not report applicable information for this table.
Note: "System wide" includes the entire distribution system of a utility, which may extend beyond the Maryland service territory into Washington, D.C., Delaware, and parts of West Virginia. The affected utilities include DPL, PE, and Pepco.

Appendix Table 3(b)(ii): System Wide Summer, Net of DSM (MW)[202]

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2014	11	6,682	236	3,940	70	63	2,844	6,324	846	15	4	**21,035**
2015	11	6,712	237	3,947	72	64	2,882	6,327	860	15	4	**21,130**
2016	11	6,723	240	3,946	73	65	2,925	6,290	873	15	4	**21,165**
2017	11	6,783	246	3,963	74	65	2,951	6,235	886	15	4	**21,233**
2018	11	6,887	251	3,979	75	66	2,976	6,193	898	15	4	**21,355**
2019	11	6,949	256	4,018	76	67	3,002	6,242	911	15	4	**21,550**
2020	11	7,026	260	4,061	77	67	3,023	6,306	924	15	4	**21,774**
2021	11	7,071	266	4,095	78	68	3,044	6,333	937	15	4	**21,922**
2022	12	7,121	272	4,129	79	69	3,070	6,364	950	15	4	**22,085**
2023	12	7,151	278	4,153	80	69	3,096	6,363	963	15	4	**22,184**
Change (2014-2023)	**1**	**469**	**42**	**213**	**10**	**6**	**252**	**39**	**117**	**-**	**-**	**1,149**
Percent Change (2014-2023)	**9.90%**	**7.02%**	**17.80%**	**5.42%**	**13.49%**	**9.52%**	**8.87%**	**0.61%**	**13.83%**	**0.00%**	**0.00%**	**5.46%**
Compound Annual Growth Rate	**1.05%**	**0.76%**	**1.84%**	**0.59%**	**1.42%**	**1.02%**	**0.95%**	**0.07%**	**1.45%**	**0.00%**	**0.00%**	**0.59%**

Note: A&N and Somerset did not report applicable information for this table.
Note: "System wide" includes the entire distribution system of a utility, which may extend beyond the Maryland service territory into Washington, D.C., Delaware, and parts of West Virginia. The affected utilities include DPL, PE, and Pepco.

[202] Berlin reported to Staff 6.8MW of DSM savings per year. This was attributed to the town generating 6.8MW of fossil fuel generation from generators that they own, operate, and dispatch, independent of PJM.

Appendix Table 3(b): Peak Demand Forecasts (System Wide)

Appendix Table 3(b)(iii): System Wide Winter, Gross of DSM (MW)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2014	14	5,956	284	3,383	58	68	3,185	5,479	841	19	5	**19,293**
2015	12	6,003	267	3,435	59	60	3,230	5,533	860	19	5	**19,482**
2016	13	6,047	265	3,482	59	60	3,260	5,605	878	19	5	**19,692**
2017	13	6,070	271	3,519	59	60	3,288	5,654	890	19	5	**19,848**
2018	13	6,137	275	3,544	60	61	3,313	5,692	904	19	5	**20,022**
2019	13	6,201	282	3,566	60	61	3,338	5,729	916	19	5	**20,190**
2020	13	6,241	285	3,579	61	61	3,357	5,749	929	19	5	**20,298**
2021	13	6,294	289	3,613	61	62	3,382	5,791	943	19	5	**20,472**
2022	13	6,314	294	3,635	61	62	3,408	5,825	955	19	5	**20,592**
2023	14	6,347	300	3,661	62	62	3,438	5,859	968	19	5	**20,734**
Change (2014-2023)	**(1)**	**391**	**16**	**278**	**4**	**(6)**	**252**	**380**	**127**	**-**	**-**	**1,441**
Percent Change (2014-2023)	**-3.74%**	**6.56%**	**5.63%**	**8.22%**	**6.19%**	**-8.82%**	**7.92%**	**6.94%**	**15.08%**	**0.00%**	**0.00%**	**7.47%**
Compound Annual Growth Rate	**-0.42%**	**0.71%**	**0.61%**	**0.88%**	**0.67%**	**-1.02%**	**0.85%**	**0.75%**	**1.57%**	**0.00%**	**0.00%**	**0.80%**

<u>Note:</u> A&N and Somerset did not report applicable information for this table.
<u>Note:</u> "System wide" includes the entire distribution system of a utility, which may extend beyond the Maryland service territory into Washington, D.C., Delaware, and parts of West Virginia. The affected utilities include DPL, PE, and Pepco.

Appendix Table 3(b)(iv): System Wide Winter, Net of DSM (MW)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2014	14	5,946	274	3,383	58	68	3,130	5,479	822	19	5	**19,199**
2015	12	5,993	257	3,435	59	60	3,175	5,533	839	19	5	**19,387**
2016	13	6,037	255	3,482	59	60	3,205	5,605	853	19	5	**19,592**
2017	13	6,060	262	3,519	59	60	3,233	5,654	865	19	5	**19,749**
2018	13	6,127	266	3,544	60	61	3,257	5,692	879	19	5	**19,923**
2019	13	6,191	273	3,566	60	61	3,283	5,729	891	19	5	**20,091**
2020	13	6,231	277	3,579	61	61	3,301	5,749	904	19	5	**20,200**
2021	13	6,284	281	3,613	61	62	3,327	5,791	918	19	5	**20,374**
2022	13	6,304	286	3,635	61	62	3,353	5,825	930	19	5	**20,494**
2023	14	6,337	293	3,661	62	62	3,382	5,859	943	19	5	**20,637**
Change (2014-2023)	**(1)**	**391**	**19**	**278**	**4**	**(6)**	**252**	**380**	**121**	**-**	**-**	**1,438**
Percent Change (2014-2023)	**-3.74%**	**6.58%**	**6.93%**	**8.22%**	**6.19%**	**-8.82%**	**8.04%**	**6.94%**	**14.72%**	**0.00%**	**0.00%**	**7.49%**
Compound Annual Growth Rate	**-0.42%**	**0.71%**	**0.75%**	**0.88%**	**0.67%**	**-1.02%**	**0.86%**	**0.75%**	**1.54%**	**0.00%**	**0.00%**	**0.81%**

<u>Note:</u> A&N and Somerset did not report applicable information for this table.
<u>Note:</u> "System wide" includes the entire distribution system of a utility, which may extend beyond the Maryland service territory into Washington, D.C., Delaware, and parts of West Virginia. The affected utilities include DPL, PE, and Pepco.

Appendix Table 4: Transmission Enhancements, by Service Territory

Transmission Owner	Voltage (kV)	Length (miles)	No. of Circuits	Start Date	Comp. Date	In-Service Date	Purpose	Start location County	Start location Terminal	End Location County	End Location Terminal
BGE	115	3.3	1	Apr-10	May-14	Jun-14	Baseline Transmission Reliability	Baltimore County	Deer Park	Baltimore County	Northwest
BGE	115	3	2	Jun-08	Dec-16	Dec-16	Distribution Adequacy	Baltimore City	Westport	Baltimore City	Wilkens
BGE	115	1	1	Sep-09	Jun-17	Jun-17	Baseline Transmission Reliability	Baltimore City	Orchard St	Baltimore City	Constitution St
BGE	115	0.2	2	Jun-12	Jun-18	Jun-18	Baseline Transmission Reliability	Baltimore City	Coldspring	Baltimore City	Camp Small
BGE	115	4.27	2	Jan-12	Jun-18	Jun-18	Distribution Adequacy	Baltimore City	Hazelwood	Baltimore City	Loch Raven
BGE	115	3	1	Jun-13	Jun-18	Jun-18	Baseline Transmission Reliability	Anne Arundel	Waugh Chapel	Anne Arundel	Bestgate
BGE	115	3	1	Jun-13	Jun-18	Jun-18	Baseline Transmission Reliability	Harford	Joppatowne	Harford	Raphael Rd
BGE	230	8.6	1	Jan-11	Jun-17	Jun-17	Baseline Transmission Reliability	Harford	Conastone	Harford	Graceton
BGE	230	13.7	1	Jan-09	Jun-17	Jun-17	Baseline Transmission Reliability	Harford	Graceton	Harford	Bagley
BGE	230	6.1	2	Apr-07	Jun-17	Jun-17	Baseline Transmission Reliability	Harford	Raphael Rd	Harford	Bagley
BGE	230	4	2	Jan-10	Jun-20	Jun-20	Baseline Transmission Reliability	Baltimore County	Northwest	Baltimore County	Hanover Pike
DPL	138/230	N/A	N/A	Oct-10	May-13	May-13	Baseline Transmission Reliability	Cecil	Cecil	Cecil	Cecil
DPL	138/230	N/A	N/A	Jun-12	May-13	May-13	Baseline Transmission Reliability	Caroline	Steele	Caroline	Steele
DPL	138	N/A	N/A	Apr-12	Apr-14	Apr-14	Baseline Transmission Reliability	Worcester	138th Street	Worcester	SVC site @138th Street
DPL	69	2.61	1	Jan-12	Dec-13	Dec-13	Baseline Transmission Reliability	Worcester	Ocean Bay	Worcester	Maridel
DPL	138	12.33	1	Aug-13	Jun-14	Jun-14	Baseline Transmission Reliability	New Castle	Townsend	Queen Annes	Church
DPL	138	25.9	1	Jan-12	Jun-15	Jun-15	Baseline Transmission Reliability	Queen Annes	Wye Mills	Queen Annes	Church
DPL	138	5.22	1	Mar-11	Jun-15	Jun-15	Baseline Transmission Reliability	Cecil	Cecil	New Castle	Glasgow
DPL	69	19.13	1	Apr-13	May-16	May-16	Baseline Transmission Reliability	Accomack (VA)	Wattsville	Worcester	Kenney
DPL	69	N/A	N/A	Sep-13	Dec-14	Dec-14	Baseline Transmission Reliability	Talbot	Easton	Talbot	Easton
DPL	69	8.74	1	Feb-13	May-15	May-15	Supplemental Transmission Reliability	Worcester	Worcester	Worcester	Ocean City
DPL	69	4.42	1	Dec-13	May-16	May-16	Supplemental Transmission Reliability	Dorchester	Vienna	Wicomico	Sharptown
DPL	138	30.91	1	May-13	May-18	May-18	Baseline Transmission Reliability	Wicomico	Piney Grove	Accomack (VA)	Wattsville
PEPCO	230	5.01	4	Jan-11	Apr-14	Apr-14	Baseline Transmission Reliability	Prince George's	Oak Grove	Prince George's	Ritchie
PEPCO	230	10.98	1	Jan-12	Mar-13	Mar-13	Baseline Transmission Reliability	Prince George's	Ritchie	DC	Buzzard Point
PEPCO	230	10.83	1	Jun-13	Nov-14	Nov-14	Baseline Transmission Reliability	Prince George's	Ritchie	DC	Buzzard Point
PEPCO	230	8.84	2	Jan-13	Jun-15	Jun-15	Transmission Owner Indentified Reliability	Prince George's	Burtonsville	Prince George's	Takoma

Appendix Table 4 (Continued): Transmission Enhancements, by Service Territory

								Start location		End Location	
Transmission Owner	Voltage (kV)	Length (miles)	No. of Circuits	Start Date	Comp. Date	In-Service Date	Purpose	County	Terminal	County	Terminal
PE	138	12.7	1	Jul-05	May-13	May-13	Baseline Transmission Reliability	Frederick	Catoctin	Carroll	Carroll
PE	138	0.1	2	Jul-05	Jul-05	Jul-05	Accommodate for Generator Interconnection	Allegany	Dans Mountain (new)	Allegany	Carlos Junction-Ridgeley
PE	138	0.1	1	Jul-05	Jul-05	Jul-05	Accommodate for Generator Interconnection	Garrett	Four Mile Ridge (new)	Preston, WV	Hazelton
PE	138	0.1	1	Jul-05	Jul-05	Jul-05	Accommodate for Generator Interconnection	Garrett	Four Mile Ridge (new)	Mineral, WV	Ridgeley
PE	500	2.7	1	Jul-05	Jul-05	Jul-05	Baseline Transmission Reliability	Frederick	VA State Line	Frederick	Doubs
PE	138	0	1	Jul-05	Jul-05	Jul-05	Baseline Transmission Reliability	Berkeley, WV	Nipetown	Washington	Reid
PE	230	0	1	Jul-05	Jul-05	Jul-05	Baseline Transmission Reliability	Frederick	Doubs	Frederick	Lime Kiln (Section 207)
PE	230	0	1	Jul-05	Jul-05	Jul-05	Baseline Transmission Reliability	Frederick	Doubs	Frederick	Lime Kiln (Section 231)
PE	138	0	1	Jul-05	Jul-05	Jul-05	Baseline Transmission Reliability	Washington	Paramount	Washington	Reid
PE	138	0	1	Jul-05	Jul-05	Jul-05	Baseline Transmission Reliability	Washington	Halfway	Washington	Paramount
PE	138	0	1	Jul-05	Jul-05	Jul-05	Baseline Transmission Reliability	Washington	Reid	Washington	Paramount
PE	138	0.1	2	Jul-05	Jul-05	Jul-05	Distribution Adequacy	Garrett	Altamont (new)	Preston, WV	Albright
PE	138	0.1	1	Jul-05	Jul-05	Jul-05	Distribution Adequacy	Garrett	Mt. Zion	Garrett	Altamont (new)
SMECO	230	10	2	Jul-05	Jul-05	Jul-05	Reliability	Calvert	Sollers Wharf Sw. St.	St. Mary's	Hewitt Rd. Sw. St
SMECO	69	4.3	1	Jul-05	Jul-05	Jul-05	Reliability	Calvert	Sunderland	Calvert	Huntingtown
SMECO	69	6.8	1	Feb-14	Jul-05	Jul-05	Capacity / Reliability	Charles	Hawkins Gate	Charles	Westlake
SMECO	69	4	2	Jul-05	Jul-05	Jul-05	Capacity	Charles	Hawkins Gate	Charles	Wooded Glen
SMECO	69	3	1	Jul-05	Jul-05	Jul-05	Capacity	Charles	Wooded Glen	Charles	Dorchester

Appendix Table 5: List of Maryland Generators, as of December 31, 2012

Owner / Operator	Plant Name	County	Capacity Statistics (MW)		
			Nameplate	Summer	% Summer
A & N Electric Coop	Smith Island	Somerset	1.7	1.6	0.0%
AES WR Ltd Partnership	AES Warrior Run Cogeneration Facility	Allegany	229.0	180.0	1.5%
American Sugar Refining, Inc.	Domino Sugar Baltimore	Baltimore City	17.5	17.5	0.1%
BP Piney & Deep Creek LLC	Deep Creek	Garrett	20.0	18.0	0.1%
Calpine Mid-Atlantic Generation LLC	Crisfield	Somerset	11.6	10.4	0.1%
Calvert Cliffs Nuclear PP LLC	Calvert Cliffs Nuclear Power Plant	Calvert	1,828.7	1,716.0	14.0%
Constellation Solar Horizons LLC	Mount Saint Mary's	Frederick	13.7	13.7	0.1%
Constellation Solar Maryland, LLC	McCormick & Co. Inc. at Belcamp	Hartford	1.4	1.4	0.0%
Covanta Montgomery, Inc.	Montgomery County Resource Recovery	Montgomery	67.8	54.0	0.4%
Criterion Power Partners LLC	Criterion Wind Project	Garrett	70.0	70.0	0.6%
Eastern Landfill Gas LLC	Eastern Landfill Gas LLC	Baltimore	3.0	3.0	0.0%
Easton Utilities Comm	Easton	Talbot	33.6	31.9	0.6%
Easton Utilities Comm	Easton 2	Talbot	38.8	37.0	
Energy Recovery Operations, Inc	Harford Waste to Energy Facility	Harford	1.2	1.1	0.0%
Exelon Generation	Notch Cliff	Baltimore	144.0	116.7	8.0%
Exelon Generation	Riverside	Baltimore	257.2	228.0	
Exelon Generation	Gould Street	Baltimore City	103.5	97.0	
Exelon Generation	Philadelphia	Baltimore City	82.8	60.9	
Exelon Generation	Westport	Baltimore City	121.5	115.8	
Exelon Generation	Perryman	Harford	404.4	353.6	
Exelon Power	Conowingo	Harford	530.8	572.0	4.7%
FC Landfill Energy	FC Landfill Energy	Frederick	2.2	2.0	0.0%
GenOn	Chalk Point LLC	Prince Georges	2,647.0	2,248.0	36.9%
GenOn	Morgantown Generating Plant	Charles	1,548.0	1,423.0	
GenOn	Dickerson	Montgomery	930.0	833.0	
GSA Metropolitan Service Center	Central Utility Plant at White Oak	Montgomery	22.9	22.9	0.2%
Howard County - Maryland	Alpha Ridge LFG	Howard	1.0	1.0	0.0%
IKEA Property Inc	IKEA College Park 411	Prince George's	1.0	1.0	0.0%
Industrial Power Generating Company LLC	Wicomico	Wicomico	5.4	5.4	0.0%
LES Operations Services LLC	Millersville LFG	Anne Arundel	3.2	3.0	0.0%
Maryland Environmental Service	Eastern Correctional Institute	Somerset	5.8	4.6	0.0%
NAEA Rock Springs LLC	NAEA Rock Springs LLC	Cecil	772.6	658.0	5.4%
Naval Facilities Engineering Command	Goddard Steam Plant	Charles	12.4	10.0	0.1%
NewPage Corp-Luke	Luke Mill	Allegany	65.0	60.0	0.5%
NRG Solar Arrowhead LLC	FedEx Field Solar Facility	Prince George's	2.0	2.0	0.0%
NRG Vienna Operations Inc	Vienna Operations	Dorchester	180.6	168.9	1.4%
Panda-Brandywine LP	Panda Brandywine LP	Prince Georges	288.8	230.0	1.9%
Power Choice/Pepco Energy Serv	NIH Cogeneration Facility	Montgomery	22.0	21.2	0.2%
Prince George's County	Brown Station Road Plant I	Prince Georges	2.7	2.4	0.0%
Prince George's County	Brown Station Road Plant II	Prince Georges	4.0	3.2	
Raven Power Holdings	Brandon Shores	Anne Arundel	1,370.0	1,273.0	21.7%
Raven Power Holdings	Herbert A Wagner	Anne Arundel	1,058.5	975.9	
Raven Power Holdings	C P Crane	Baltimore	415.8	399.0	
Roth Rock Wind Farm LLC	Roth Rock Wind Farm LLC	Garrett	40.0	40.0	0.4%
Roth Rock Wind Farm LLC	Roth Rock North Wind Farm, LLC	Garrett	10.0	10.0	
SCE Engineers	Montgomery County Oaks LFGE Plant	Montgomery	2.4	2.3	0.0%
SMECO Solar LLC	Herbert Farm Solar	Charles	5.5	5.5	0.0%
Solo Cup Co	Solo Cup Co	Baltimore	11.2	11.2	0.1%
Town of Berlin - (MD)	Berlin	Worcester	9.0	9.0	0.1%
Trigen Inner Harbor East, LLC	Inner Harbor East Heating	Baltimore City	2.1	2.1	0.0%
Trigen-Cinergy Solutions College Park	UMCP CHP Plant	Prince Georges	27.4	20.8	0.2%
Washington Gas Energy Services, Inc.	Kent County-Kennedyville	Kent	1.0	1.0	0.0%
Washington Gas Energy Services, Inc.	Kent County - Worton Complex	Kent	1.0	1.0	
Washington Gas Energy Services, Inc.	Perdue Salisbury Photovoltaic	Wicomico	1.0	1.0	0.0%
Washington Gas Energy Services, Inc.	Rock Hall	Kent	1.0	1.0	0.0%
Wheelabrator Environmental Systems	Wheelabrator Baltimore Refuse	Baltimore City	64.5	61.3	0.5%
Worcester County Renewable Energy LLC	Worcester County Renewable Energy	Worcester	2.0	2.0	0.0%
			13,521.2	**12,215.3**	**100.0%**

Appendix Table 6: Proposed New Conventional Generation in Maryland
PJM Queue Effective Date: June 20, 2014

Transmission Owner	Project Name	County Location	PJM Queue Status	PJM Queue #	Fuel Type	Project Capacity (MW)	Projected In-Service Date
APS	Damascus-Mt. Airy 34.5kV	Frederick	Under Study	Y3-029	natural gas	4	2014 Q1
BGE	Perryman	Harford	Under Construction	S32	natural gas	256	2015 Q4
DPL	Crisfield 25kV	Somerset	Under Study	Y2-108	oil	12	2013 Q2
ODEC	Rock Spring 500kV	Cecil	Under Construction	Y1-065	natural gas	834	2018 Q2
ODEC	Rock Springs 500kV	Cecil	Under Study	Y3-102	natural gas	1,000	2017 Q2
ODEC	Rock Springs 500kV	Cecil	Under Construction	Z1-041	natural gas	327	2017 Q2
PEPCO	Burches Hill-Brandywine 230kV	Prince George's	Under Study	X3-087	natural gas	894	2017 Q2
PEPCO	Burches Hill-Chalk Point 500kV	Prince George's	Under Construction	X4-035	natural gas	736	2016 Q2
PEPCO	Burches Hill-Chalk Point 500kV	Prince George's	Under Study	Z1-052	natural gas	800	2017 Q1
PEPCO	Burches Hill-Brandywine 230kV	Prince George's	Under Study	Z2-060	natural gas	927	2018 Q2
PEPCO	Kelson Ridge 230kV	Charles	Under Construction	X4-006	natural gas	785	2016 Q2
PEPCO	Morgantown-Oak Grove	St. Charles	Under Construction	V3-017	natural gas	725	2016 Q2
PEPCO	White Oak	Montgomery	Under Construction	W4-010	natural gas	53	2015 Q4

Appendix Table 7: Existing Renewable Generation in Maryland Reported by the Utilities As of December 31, 2013

Company	Project Name	Site Location	Fuel Type	Net Capacity (MW)	2013 Net Generation (MWh)	In Service Date
Berlin	Flexera - South Moon Sales, Inc. (South Moon Under)	Berlin, MD	Solar - Photovoltaic	0.0276 MW	16	Sep-11
Berlin	218007 (C. Hunter)	Berlin, MD	Solar - Photovoltaic	0.00893 MW	6	Jun-12
BGE	KC Brighton LLC / Brighton Dam	Laurel, MD	Hydro, runoff from water treatment plant	N/A - energy only	1,220	Jan-86
BGE	BRESCO (Baltimore Refuse Energy Co.)	Baltimore, MD	Refuse with natural gas	57 MW	327,537	Nov-84
DPL	INGENCO (Industrial Power Generating Company)	Salisbury, Wicomico County, MD	Methane	6 MW (6 MW Energy)	Est. 0	Jul-07
DPL	Worcester (Worcester County Renewable Energy, LLC)	Worchester County, MD	Methane	0 MW (2 MW Energy)	Est. 0	Jul-12
DPL	Chesapeake Renewable Energy (Chesapeake Renewable Energy, LLC)	Pocomoke City, MD	Solar	0 MW (4 MW Energy)	5,366	Dec-12
PEPCO	PG Landfill Gas, CVC-982 (Pringe George's County)	Upper Marlboro, MD	Landfill Gas	4-0.875 MW (landfill gas), connected to 4.16 kV units on 13.8 kV feeder	13,095	2003 Q4
PEPCO	PG Correction, CVC-946 (Pringe George's County)	Upper Marlboro, MD	Landfill Gas	3-0.875 MW (landfill gas), connected to 13.8 kV	9,078	1985 Q2
PEPCO	Gude Landfill, CVC-941 (Northeast MD Waste Disposal Authority)	Rockville, MD	Landfill Gas	1-1.025 MW (landfill gas), connected to 480V unit on 13.8 kV feeder	16,287	2009 Q3
PEPCO	Oaks Landfill, CVG-991 (Northeast MD Waste Disposal Authority)	Laytonsville, MD	Landfill Gas	2-1.2 MW (landfill gas), connected to 480 V units of 13.8 kV feeder	8,248	2009 Q3
PEPCO	Montgomery County Resource Recovery Facility (Covanta Montgomery, Inc)	Dickerson, MD	Solid Waste	55 MW	312,589	1995 Q3
PE	Westvaco 138kV (Luke Paper Company)	Westvaco 138 kV	Black Liqour	0 MW	8	2009 Q1
PE	Garrett County (Synergics Roth Rock Wind Energy, LLC)	Garrett County	Wind	6.5 MW	50	2011 Q1
PE	Emmitsburg 34.5 kV (Constellation Solar Horizons, LLC)	Emmitsburg 34.5 kV	Solar	5.32 MW	14	2012 Q2
PE	Lappans 34.5 kV (Maryland Solar, LLC)	Lappans 34.5 kV	Solar	7.6 MW	20	2012 Q4
PE	Kelso Gap 138 kV (Criterion Power Partners, LLC)	Kelso Gap 138 kV	Wind	0 MW	100	2010 Q4
PE	Kelso Gap 138 kV (Criterion Power Partners, LLC)	Kelso Gap 138 kV	Wind	0 MW	14	2010 Q4
PE	Reichs Ford Landfill (Northeast Maryland Waste Disposal Authority (NMWDA) & Frederick County Government)	Reichs Ford Landfill	Methane	2 MW	2	2010 Q2
SMECO	Herbert Solar Farm (SMECO Solar LLC)	7761 Leonardtown Rd	Solar	5.5 MW	8,774	Nov-12

Appendix Table 8: Proposed New Renewable Generation in Maryland PJM Queue
Effective Date: June 20, 2014

Transmission Owner	Project Name	County Location	PJM Queue Status	PJM Queue #	Fuel Type	Project Capacity (MW)	Projected In-Service Date
APS	Balenger Sewage-Thomas Bakery 34.5kV	Frederick	Under Study	Y2-096	biomass	49	2016 Q3
APS	Four Mile Ridge Wind 138kV	Garrett	Under Construction	U2-030	wind	60	2014 Q4
APS	Kelso Gap 138kV	Garrett	Under Construction	T16	wind	30	2015 Q4
APS	Ridgeley-Frostburg 138kV	Allegheny	Under Study	Z2-038	solar	20	2015 Q4
BGE	Ashton 480V	Montgomery	Under Construction	Y3-074	hydro	-	2014 Q3
BGE	Friendship Manor	Howard	Under Construction	Y1-045	solar	2	2013 Q3
BGE	Otter Point 34.5kV	Baltimore	Under Construction	Y2-100	methane	4	2013 Q2
BGE	Perryman Solar	Harford	Under Construction	Y2-117	solar	20	2015 Q4
DPL	Chestertown East 25kV	Kent	Under Study	Z2-074	solar	10	2016 Q2
DPL	Chestertown-Millington 69kV	Kent	Under Study	Y3-033	wind	129	2015 Q3
DPL	Chestertown West 25kV	Kent	Under Study	Z2-073	solar	10	2016 Q2
DPL	Church 25kV	Queen Anne's	Under Study	Z1-081	solar	6	2017 Q1
DPL	Church 25kV	Kent	Under Study	Z2-097	solar	10	2016 Q2
DPL	Church Hill 69kV	Queen Anne	Under Construction	X3-066	solar	6	2014 Q2
DPL	Dorchester 12kV	Dorchester	Under Study	Y1-080	solar	3	2013 Q4
DPL	Loretto-Kings Creek 138kV	Somerset	Under Study	X1-096	wind	150	2014 Q4
DPL	Lynch East 25kV	Kent	Under Study	Z2-075	solar	6	2016 Q2
DPL	Lynch West 25kV	Kent	Under Study	Z2-096	solar	10	2016 Q2
DPL	Pocomoke	Somerset	Under Study	T144	biomass	20	2010 Q1
DPL	Rockawalkin 69kV	Wicomico	Under Study	Y3-058	solar	15	2015 Q2
DPL	Stockton 1 69kV	Worcester	Under Study	Z1-076	solar	14	2015 Q4
DPL	Stockton 2 69kV	Worcester	Under Study	Z1-077	solar	10	2015 Q4
DPL	Todd 69kV	Anne Arundel	Under Study	X3-008	solar	20	2017 Q2
DPL	West Cambridge-Vienna 69kV	Dorcester	Under Study	X3-015	solar	20	2012 Q4
DPL	Worcester 25kV	Worcester	Under Study	W3-160	solar	10	2011 Q1
DPL	Worcester North 25kV	Worcester	Under Study	Z2-077	solar	6	2016 Q2
DPL	Worcester South 25kV	Worcester	Under Study	Z2-076	solar	6	2016 Q2
DPL	Wye Mills 69kV	Talbot	Under Study	Y1-079	solar	10	2013 Q2