PUBLIC SERVICE COMMISSION OF MARYLAND

TEN-YEAR PLAN (2012 – 2021) OF ELECTRIC COMPANIES IN MARYLAND

Prepared for the
Maryland Department of Natural Resources
In compliance with Section 7-201
of the Maryland Public Utilities Article
April 2013

State of Maryland
Public Service Commission

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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 (2012-2021) 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 2012 – 2021 Ten-Year Plan has been reorganized, by comparison with previous Ten-Year Plans, to provide a more 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. The 2012 – 2021 Ten-Year Plan, and future plans, will cover the following topics as relevant to Maryland:

1. Maryland Load Growth;
2. Transmission, Supply, and Generation;
3. Reliability in Maryland;
4. Energy Efficiency and Demand Response;
5. The Environment and Renewables; and
6. Federal Energy Regulatory Commission Issues.

Of special note from these sections are the discussions of the impacts of Demand Side Management on Maryland Load Forecasts (Section I); the implementation of COMAR 20.50.12, which resulted from Rulemaking 43 ("RM 43"), especially as it applies to vegetation management for reliability (Section IV); and the introduction of savings from Advanced Metering Infrastructure and the effects it will have on peak demand (Section V).

Maryland is geographically divided into thirteen electric utility service territories. Four of the largest are investor-owned utilities ("IOUs"), four are electric cooperatives (all 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 Investor-Owned Utilities ("IOU") service territories. PJM zones for three of the four IOUs traverse state bounds and extend into other jurisdictions.[2] The map designated as Figure 1 provides a geographic picture of the utilities' service territories.[3] The map designated as Figure 2 depicts the PJM Maryland forecast zones.

[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, Delmarva Power and Light Company, and the Potomac Edison Company 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 zone, alone, resides solely within the State of Maryland.

[3] The Potomac Edison Company no longer uses its "doing business name" of "Allegheny Power" and any references within the Ten-Year Plan to Allegheny Power should be read as referencing Potomac Edison.

Figure 1: Maryland Utilities and their Service Territories in Maryland [4]

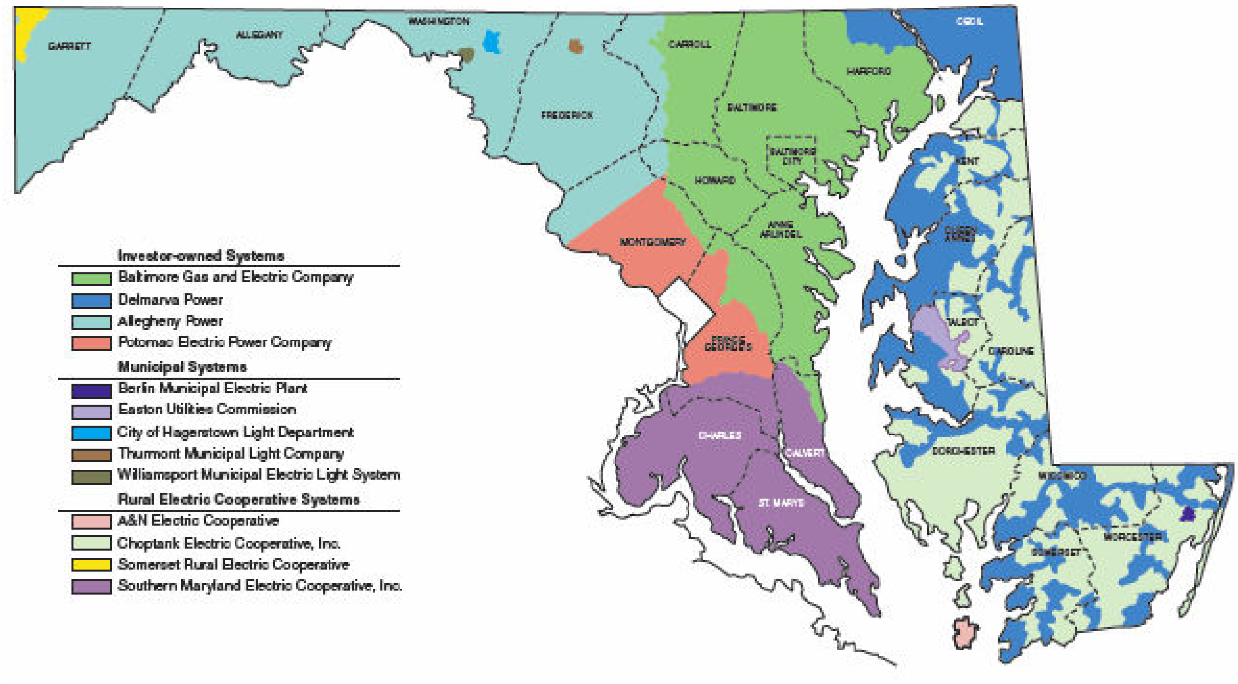
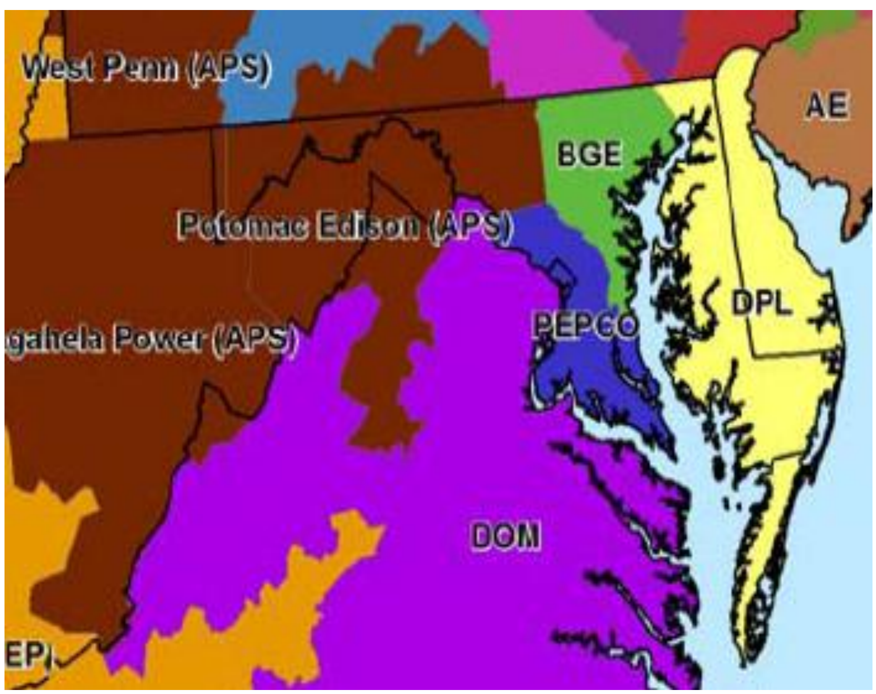


Figure 2: PJM Maryland Forecast Zones [5]



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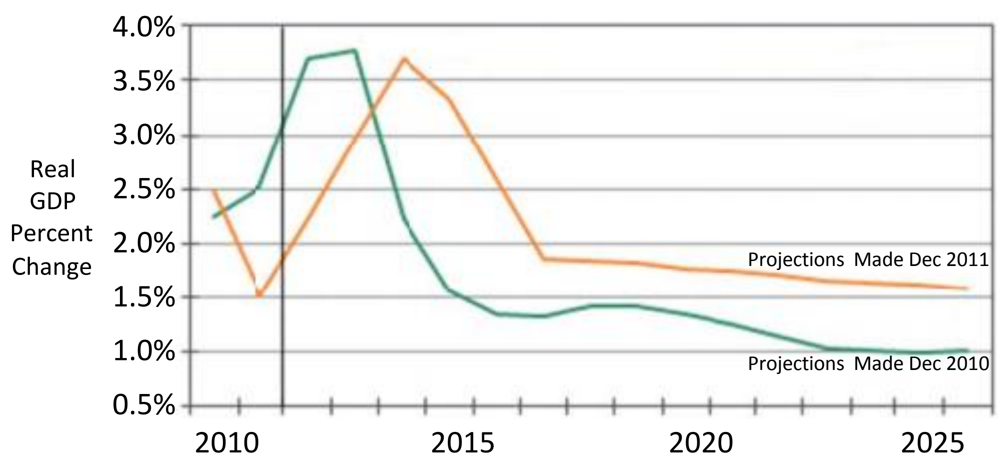
[4] *Cumulative Environmental Impact Report 15*, MD. DEP'T OF NATURAL RES., Figure 2-12, http://esm.versar.com/pprp/ceir15/Report_2_3.htm (last updated Feb. 25, 2010).
[5] *PJM Load Forecast Report,* PJM (Jan. 2012), https://pjm.com/~/media/documents/reports/2012-pjm-load-report.ashx.

II. Maryland Load Growth Forecasts

Overall, the load forecasts indicate a modest amount of growth in the number of customers, energy sales, and peak demand throughout Maryland for the 2012 through 2021 planning period. The analysis uses forecasts provided by Maryland utilities, PJM Interconnection, LLC ("PJM"), and other state and federal agencies.

Each year, PJM presents a load forecast 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"). Figure 3 compares the GDP growth projections in PJM's 2011 load forecast with projections contained in PJM's 2012 load forecast. Because the national economy's performance in 2011 was below expectations, PJM's 2012 load forecast reflects delayed projections related to the timing and growth rate of economic recovery (measured by the percent change in GDP).[6] In the 2011 load forecast report (relying on projections made in December 2010), PJM expected strong economic growth to occur during 2012 and 2013; however, in the 2012 load forecast, PJM revised its projections to show this growth instead occurring during 2013 and 2014.[7] PJM's forecast for the ten-year period covered by this Plan shows that GDP growth will steadily increase through 2014, peaking at approximately 3.7% before gradually returning to an annual GDP growth rate in the range of 1.5 – 2.0%.[8] The implications of these revised GDP growth projections are reflected in revisions to load growth forecasts that are discussed in further detail throughout this section.

Figure 3: Comparison of Real GDP Growth Projections, December 2010 versus December 2011 [9,10]

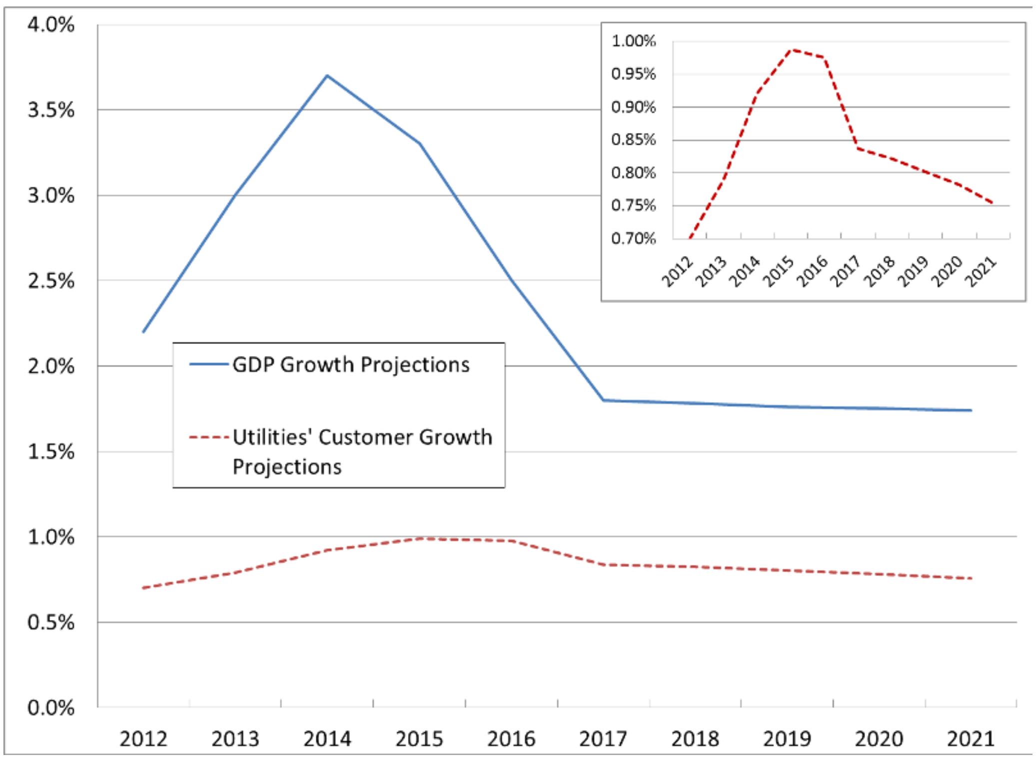


[6] *See PJM Load Forecast Report,* PJM 4 (Jan. 2012), https://pjm.com/~/media/documents/reports/2012-pjm-load-report.ashx (citing a summary of the Dec. 2011 U.S. forecast completed by Moody's Analytics).
[7] *Id.* at 7.
[8] *Id.*
[9] The lighter colored line (yellow in colored copies) represents projections made in December 2011.
[10] *PJM Load Forecast Report,* PJM 7 (Jan. 2012), https://pjm.com/~/media/documents/reports/2012-pjm-load-report.ashx.

A. Customer Growth Forecasts [11]

As discussed above, the 2012 PJM load forecast projects a steady and fairly rapid percent increase in GDP growth through 2014. Although the GDP growth rate peaks in the 2014 timeframe, the projections indicate that the PJM service territory will continue to grow in proportion to the higher GDP growth rates through 2017.[12] The customer growth forecasts provided by the Maryland electric utilities ("the Utilities") reflect a similar pattern of growth, as depicted by the inset of Figure 4 below.

Figure 4: Average of Utilities' Projected Annual Customer Growth Rates Compared to the PJM 2012 GDP Growth Projections [13]



Comparatively to PJM's GDP growth projections, the Utilities' customer forecasts indicate a rapid percent increase in customer growth peaking in the 2014-2015 timeframe, with higher growth rate projections continuing through 2017.

[11] *See* Appendix 1(a) for a complete list of utility-by-utility customer growth forecasts.
[12] *See* Figure 1.
[13] The average annual customer growth rates are calculated using the utilities' data responses to the Commission's 2012 data request for the Ten-Year Plan. *See* Appendix 1(a) for utility-specific customer growth forecasts, including breakdowns by customer class.

Over the ten-year planning period, the Utilities' projections result in a compound annual growth rate of 0.85%. The Easton Utilities Commission ("EUC") and Southern Maryland Electric Cooperative, Inc. ("SMECO") are forecasting the highest compound annual growth rates at 1.77% and 1.63%, respectively. Baltimore Gas and Electric Company ("BGE") and Potomac Electric Power Company ("Pepco"), which together serve approximately 70% of Maryland customers, are forecasting ten-year compound annual growth rates of 0.88% and 0.52%, respectively.

Table 1: Maryland Customers Forecast (All Customer Classes)[14]

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Total
2012	2,396	1,244,585	52,504	200,631	10,993	17,548	255,095	534,416	154,963	**2,473,131**
2013	2,396	1,252,824	52,840	202,543	11,202	17,629	258,019	537,633	157,573	**2,492,659**
2014	2,408	1,263,163	53,401	204,511	11,411	17,710	260,763	542,037	160,203	**2,515,607**
2015	2,420	1,275,698	54,096	206,511	11,620	17,792	263,374	546,086	162,843	**2,540,440**
2016	2,444	1,289,211	54,832	208,472	11,829	17,875	265,650	549,417	165,483	**2,565,214**
2017	2,469	1,300,616	55,480	210,398	12,038	17,957	267,599	551,902	168,223	**2,586,682**
2018	2,493	1,312,121	56,020	212,324	12,247	18,040	269,331	554,403	170,963	**2,607,942**
2019	2,531	1,323,728	56,477	214,236	12,456	18,124	270,951	556,562	173,803	**2,628,868**
2020	2,569	1,335,438	56,894	216,143	12,665	18,208	272,450	558,411	176,653	**2,649,431**
2021	2,607	1,347,252	57,299	218,043	12,874	18,292	273,853	559,911	179,293	**2,669,424**
Change (2012-2021)	**211**	**102,667**	**4,795**	**17,412**	**1,881**	**744**	**18,758**	**25,495**	**24,330**	**196,293**
Percent Change (2012-2021)	**8.82%**	**8.25%**	**9.13%**	**8.68%**	**17.11%**	**4.24%**	**7.35%**	**4.77%**	**15.70%**	**7.94%**
Compound Annual Growth Rate	**0.94%**	**0.88%**	**0.98%**	**0.93%**	**1.77%**	**0.46%**	**0.79%**	**0.52%**	**1.63%**	**0.85%**

The compound annual growth rates discussed above in Table 1 translate into a 7.94% increase in the total number of Maryland customers by the end of the ten-year planning period. Overall, this increase in the number of customers is largely driven by growth in the residential class; residential class growth is projected to account for an additional 174,000 customers by 2021. However, the Utilities project that the commercial class will experience the greatest *percentage* increase of any individual customer class during the ten-year planning period, with Utilities projecting the addition of approximately 22,000 more commercial customers by 2021. Table 2 shows a breakdown of the projected percent increase over the ten-year planning period for each customer class:

[14] *See* Appendix 1(a)(i). Note that A&N, Somerset, Thurmont, and Williamsport did not provide the requested applicable information in response to the Commission's 2012 data request for the Ten-Year Plan.

Table 2: Projected Percentage Increase in the Number of Customers by Class, 2012 – 2021[15, 16]

Residential	7.85%
Commercial	8.83%
Industrial	6.19%
Other	1.70%
Resale	0.00%
Total Customers	**7.94%**

The largest percentage increase across any customer class is projected by Choptank; the Choptank Electric Cooperative is forecasting a 44.24% increase in the number of commercial customers over the ten-year planning period.[17] Choptank cites improving economic conditions and its small customer base as the reason for the significant percentage increase. Choptank expects the percentage change in the number of small businesses to be as high as 6.4 to 7.2% in some years.[18]

The largest absolute increase in the number of customers is projected to come from BGE's residential customer base, with an additional 92,000 residential customers forecast between 2012 and 2021.[19] BGE's projected increase in its residential customer base accounts for over half of the total number of new residential customers across all service territories during the ten-year planning period,[20] a result which may be anticipated since BGE serves nearly half of Maryland's residential customers.

[15] *See* Appendix 1(a)(i)-(vi) for more information.
[16] 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. Potomac Edison 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.
[17] *See* Choptank Electric Cooperative, *2012 Power Requirements Study - Fifteen-Year Forecast* (provided by Lisa Wothers, Manager of Finance & Regulatory Affairs for the Choptank Electric Cooperative) (on file with the Commission's Technical Staff).
[18] *Id.*
[19] *See* Appendix 1(a).
[20] *See* Appendix 1(a)(ii). The Utilities project an additional 173,996 residential customers by 2021, of which BGE accounts for 92,485 customers—or 53.15% of all new residential customers.

B. Energy Sales Forecast

For purposes of the Ten-Year Plan, the Utilities submitted both their 2011 actual energy sales[21] and their projected energy sales for 2012 – 2021.[22] The Appendix includes examples of how the 2011 utility energy sales translated into a typical monthly electric bill for Maryland customers, broken down according to season, customer class, and utility.[23]

Table 3 shows the energy sales forecast within Maryland (Gross of DSM[24]) for the ten-year planning period, as provided by the Utilities. The forecast shows a compound annual growth rate of 1.20% across all the Maryland service territories for 2012 – 2021.

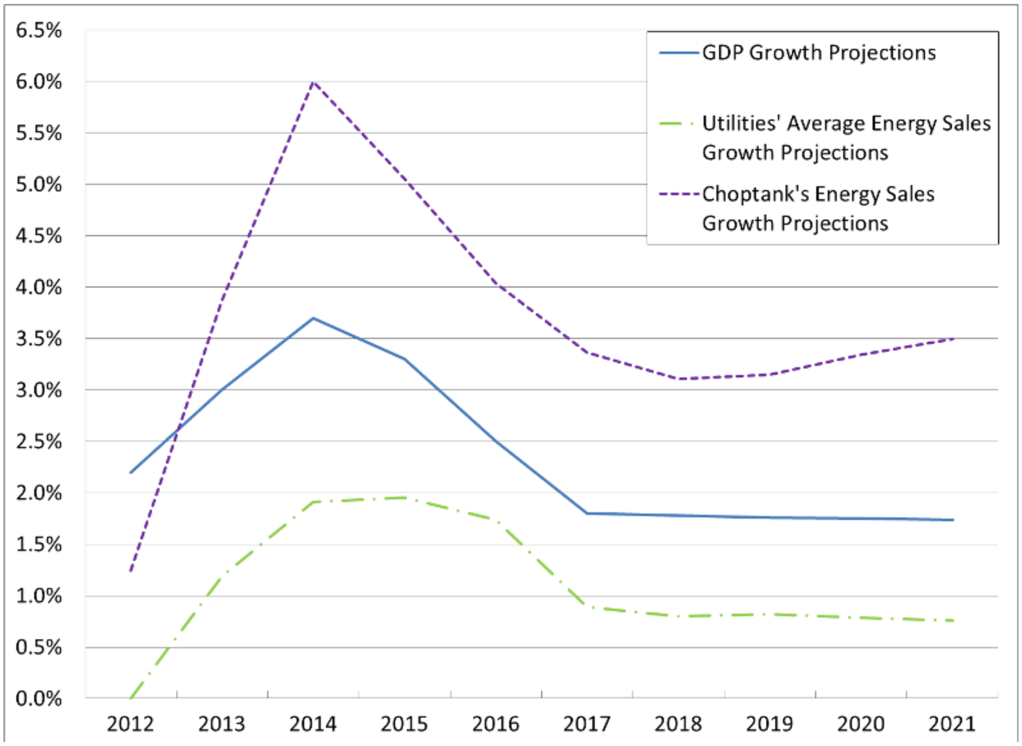
Table 3: Maryland Energy Sales Forecast (GWh) (Gross of DSM) [25]

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Total
Change (2012-2021)	5	3,066	421	809	21	(4)	1,095	1,103	717	**7,232**
Percent Change (2012-2021)	11.79%	9.79%	41.50%	19.03%	7.72%	-1.26%	14.50%	7.25%	19.78%	**11.37%**
Compound Annual Growth Rate	1.25%	1.04%	3.93%	1.95%	0.83%	-0.14%	1.52%	0.78%	2.03%	**1.20%**

Across all of the Utilities during the planning period, Choptank is forecasting the highest compound annual growth rate at 3.93%, which is driven by the anticipated large increase in the number of small businesses previously discussed in Section II.A. Although Choptank is projecting energy usage per business to increase less than 1.0% per year, the net effect of new businesses drives a high growth rate for the entire class.[26] As seen in Figure 5 below, the pattern of annual growth for Choptank individually, as well as the pattern of annual growth averaged across all of the Utilities, creates a similar pattern to that of GDP growth projections for the PJM service territory.

[21] *See* Appendix 1(b)(ii) for a breakdown of actual 2011 energy sales by customer class for every reporting utility in the Maryland service territory.
[22] *See* Appendix 2(a) for a utility-by-utility list of energy sales forecast for the Maryland service territories.
[23] *See* Appendix 3(a) for a breakdown by utility, customer class, and season of a customer's typical monthly electric bill in Maryland, for utility sales only. *See* Appendix 3(b) for a similar breakdown, covering both utility and distribution sales.
[24] In previous years, the Ten-Year Plan referred to energy sales and peak demand in Net of DSM terms, meaning *after* the benefits of DSM programs were included. In this Ten-Year Plan, the format has been changed to reflect energy sales *before* the effects of DSM programs. This approach provides a more complete look at Maryland energy sales and peak demand forecasts. The effects of DSM programs are further detailed in Section II.D and Section V of this Plan.
[25] *See* Appendix 2(a) for utility-by-utility energy sales forecasts for the Maryland service territory, available by Gross and Net of DSM. *See* Appendix 2(b) for the same information on a system wide basis.
[26] *See* Choptank Electric Cooperative, *2012 Power Requirements Study - Fifteen-Year Forecast,* 14 (provided by Lisa Wothers, Manager of Finance & Regulatory Affairs for the Choptank Electric Cooperative) (on file with the Commission's Technical Staff).

Figure 5: Average Annual Energy Sales Growth Rate Projected by the Utilities as Compared to the PJM 2012 GDP Growth Projections[27]



C. Peak Load Forecasts

PJM's 2012 Load Forecast Report includes long-term forecasts of peak loads for the entire wholesale market region and each PJM sub-region (i.e., zone) – including the four sub-regions in which Maryland resides.[28,29] Although the PJM zones generally correspond to the service territories of Maryland's four IOUs, three of the zones traverse State boundaries; the BGE zone alone resides solely within the Maryland service territory. Additionally, the PJM zones encompass adjacent municipal and rural electric cooperatives. Because of this PJM structure, the Utilities submit peak demand forecasts restricted to their Maryland service territories as part of the Ten-Year Plan.[30]

[27] The average annual energy sales growth rates were calculated using the utilities' data responses to the Commission's 2012 data request for the Ten-Year Plan. *See* Appendix 2(a)(i).

[28] *PJM Load Forecast Report,* PJM 40, Table B-1 (Jan. 2012), https://pjm.com/~/media/documents/reports/2012-pjm-load-report.ashx.

[29] 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 the Potomac Edison Company is a sub-zone.

[30] *See* Appendix 4(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 4(b) for the same information, presented as system wide data for utilities operating in Maryland.

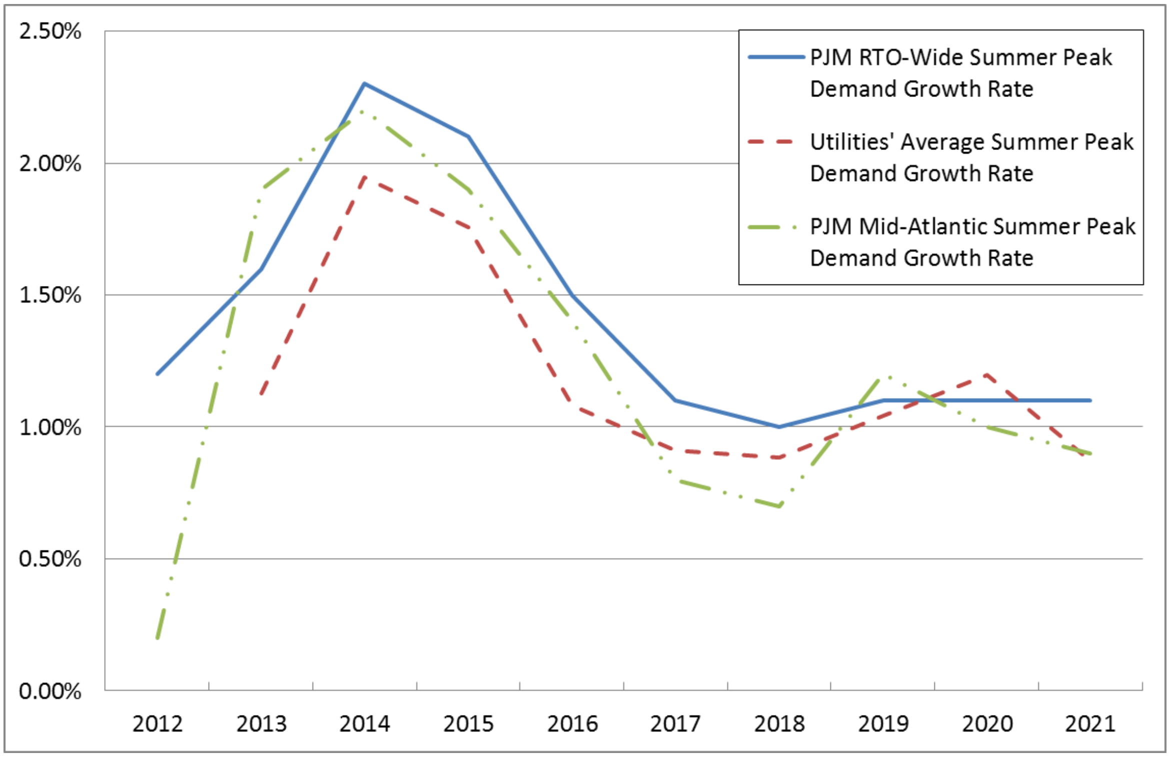
According to PJM's 2012 Load Forecast Report, the PJM RTO will continue to be summer peaking during the next 15 years.[31] In 2012, the four PJM zones which comprise Maryland all experienced their peak demands during the month of July,[32] as did the PJM Mid-Atlantic Region.[33] PJM monthly peak forecasts for years 2013 and 2014 project that peak demand will continue to occur during the month of July in each of the Maryland PJM zones.[34]

Figure 6 depicts an average of the Utilities' forecasted summer peak demands for their Maryland service territories, contrasted with summer forecasts for the PJM Mid-Atlantic region and for the PJM RTO as a whole. As the graph illustrates, both the average of the Utilities' summer peak demand growth rates and the PJM Mid-Atlantic summer peak demand growth rate generally trend below the summer peak demand growth rate of the PJM RTO. Peak demand for the RTO as a whole is expected to grow at a faster rate than Maryland in part because of strong economic growth in the Dominion Virginia Power zone, which includes areas outside of Washington, D.C.[35]

Also reflected in Figure 6 is a spike in the summer peak demand growth rate projected by the Maryland Utilities in the year 2020, pronounced in comparison to the flat growth projected for the RTO as a whole in that year. One possible explanation for this spike in peak demand growth in the years 2019 to 2020 stems from the role of demand side management ("DSM") programs in the Maryland PJM zones. The impact of DSM programs is discussed further in Section II.D and throughout Section V.

[31] *PJM Load Forecast Report,* PJM 2 (Jan. 2012), https://pjm.com/~/media/documents/reports/2012-pjm-load-report.ashx.
[32] *Id.* at 52-53, Table B-5.
[33] *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.
[34] *Id.*
[35] *Id.* at 8.

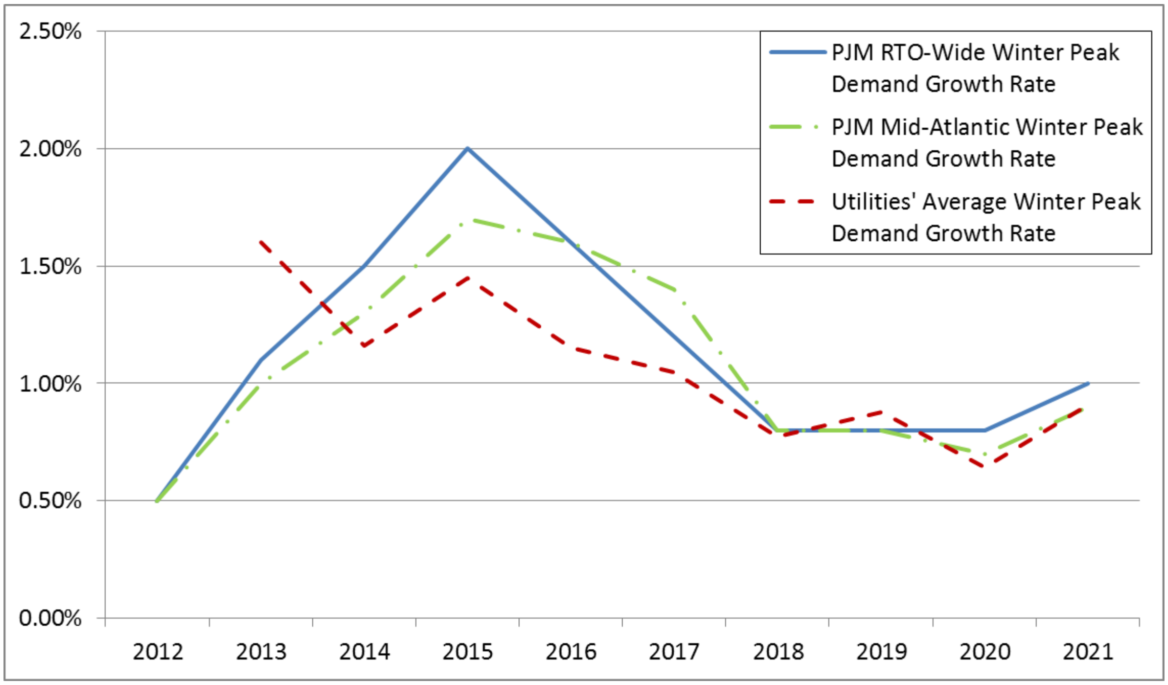
Figure 6: Average of Utilities' Projected Summer Peak Demand Growth Rates (Gross of DSM) Compared to Projected Summer Peak Demand Growth Rates for PJM Mid-Atlantic and PJM RTO [36]



The Utilities' also provide peak demand forecasts for the winter season as part of the Ten-Year Plan. While it does not outpace the projected PJM RTO summer peak demand growth, winter peak demand growth for the PJM service territory is projected to rapidly increase through 2015. Figure 7 depicts an average of the Utilities' forecasted winter peak demands for their Maryland service territories, contrasted with winter forecasts for the PJM Mid-Atlantic region and for the PJM RTO.

[36] The Utilities' average summer peak demand growth rates were calculated using the Utilities' data responses to the Commission's 2012 data request for the Ten-Year Plan. *See* Appendix 4(a)(i).

Figure 7: 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 [37]



As seen in Figure 7 above, the Maryland Utilities' 2012 – 2013 winter peak demand growth rate is much higher than the corresponding projections for the PJM RTO or the PJM Mid-Atlantic region. This difference is primarily attributable to the 2012 winter peak load reported by SMECO,[38] which corresponded to the actual winter peak load observed by SMECO in 2012. SMECO asserts that the 2012 winter peak load was lower than previously expected due to a mild winter;[39] however, SMECO chose to project the 2013 through 2021 winter peak loads using a normal winter forecast typical for their service territory, resulting in a 12.06% growth between years 2012 and 2013.[40]

Overall, the ten-year forecasted Maryland growth rates of summer and winter peak demand, gross of DSM, are 1.20% and 1.07%, respectively.[41] This translates into expected summer peak demand, gross of DSM, for the Maryland service territory of 16,267 MW in the year 2021; expected winter peak demand, gross of DSM, for the Maryland service territory is projected to equal 13,656 MW in the year 2021.[42]

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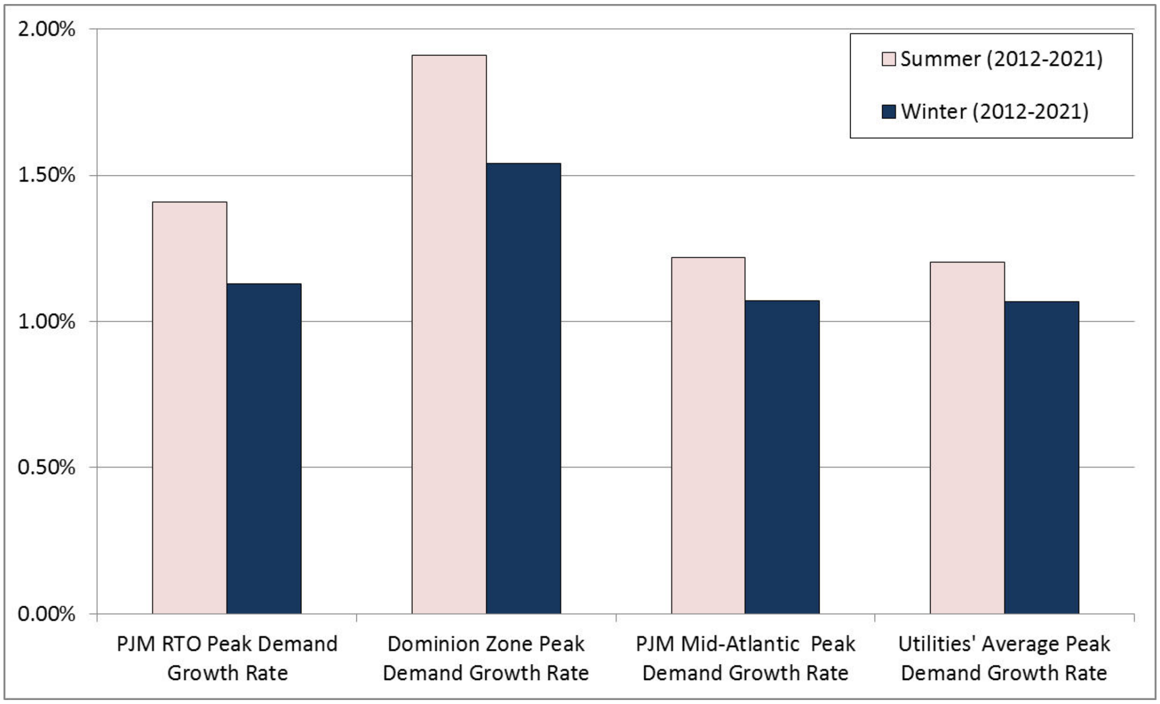
[37] The Utilities' average winter peak demand growth rates were calculated using the Utilities' data responses to the Commission's 2012 data request for the Ten-Year Plan. *See* Appendix 4(a)(iii).
[38] *See* Appendix 4(a)(iii).
[39] Email from Eugene Bradford, Rates, Economic Services, Energy Procurement Manager, SMECO, to Commission Staff (Feb. 25, 2013, 11:42 EST) (on file with Commission Staff).
[40] *Id.* SMECO reported an actual winter peak load of 743MW in 2012, and forecasted a 833MW winter peak load for 2013.
[41] *See* Appendix 4(a).
[42] *See* Appendix 4(a)(i) and 4(a)(iii).

Figure 8 contrasts the Utilities' projected ten-year annual peak load growth rates with those of the PJM RTO and the PJM Mid-Atlantic Region. As discussed previously, and again illustrated by Figure 8, peak demand for the RTO as a whole is expected to grow at a faster rate than Maryland, stemming from projected strong economic growth in the Dominion Virginia Power zone.[43]

Figure 8: Annual Peak Load Growth Rates (gross of DSM), 2012 - 2021 [44]



Although PJM is projecting strong economic growth particularly in the Dominion Virginia Power Zone,[45] overall the 2012 PJM Load Forecast projects RTO peak demand to grow at a slower pace than previously expected when compared to the PJM load forecasts of the two previous years. This slower growth is likely a result of both delayed expectations of economic recovery[46] and an increased reliance on Demand Response in

43 *PJM Load Forecast Report,* PJM 8 (Jan. 2012), https://pjm.com/~/media/documents/reports/2012-pjm-load-report.ashx.

44 The Utilities' average peak demand growth rates were calculated using the Utilities' data responses to the Commission's 2012 data request for the Ten-Year Plan. *See* Appendix 4(a)(i) and 4(a)(iii). The PJM RTO Dominion Virginia Power Zone, and PJM Mid-Atlantic 2012-2021 annual growth rates were calculated using the 2012 PJM Load Forecast Report data in Tables B-1 and B-2, *available at* https://pjm.com/~/media/documents/reports/2012-pjm-load-report.ashx.

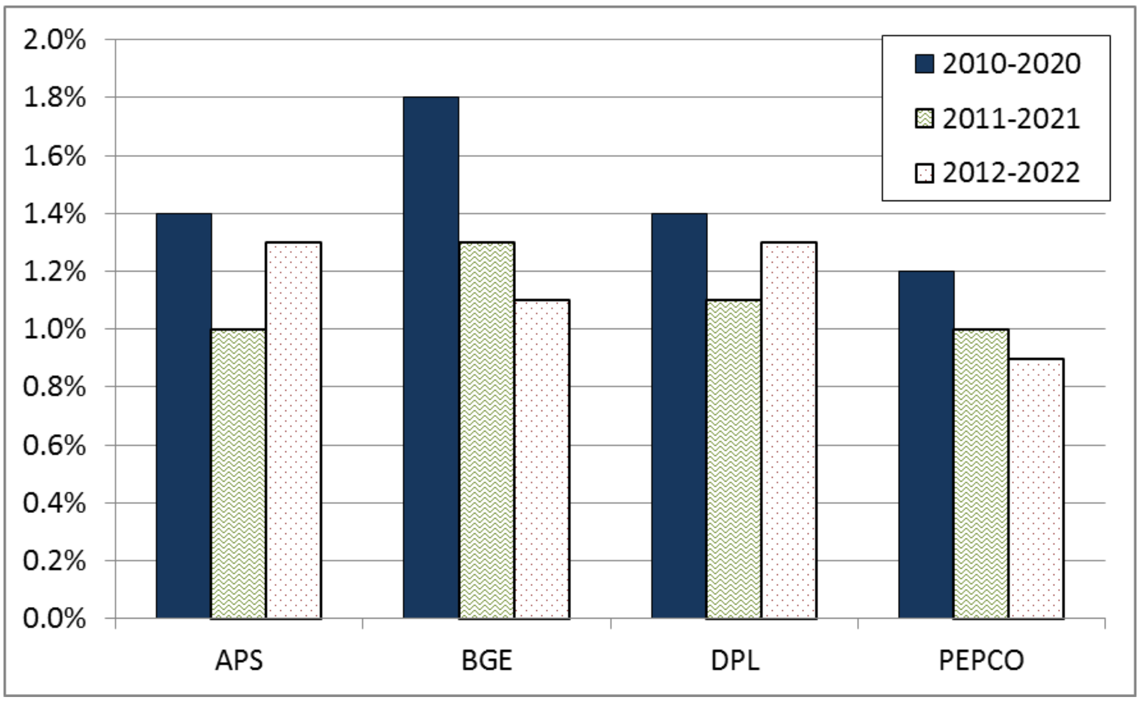
45 *Id.* at 8.

46 *See PJM Load Forecast Report,* PJM 4 (Jan. 2012), https://pjm.com/~/media/documents/reports/2012-pjm-load-report.ashx (citing a summary of the December 2011 U.S. Macro Forecast completed by Moody's Analytics).

the PJM service territory.[47] In the last two Base Residual Auctions ("BRA"), the amount of cleared Demand Response has increased by 52% and 5% in the 2014/2015[48] and 2015/2016[49] auctions, respectively.

However, when making this same comparison specific to the Maryland PJM zones, this downward trend of lowered peak demand growth only holds true for two Maryland PJM Zones: the BGE and PEPCO zones. As illustrated by Figures 9 and 10 below, both summer and winter ten-year peak demand growth is expected to be higher in the Allegheny Power Zone ("APS")[50] and DPL zones than previously projected by the 2010 and 2011 PJM Load Forecast reports.

Figure 9: Comparison of Maryland PJM Zone Ten-Year Summer Peak Load Growth Rates as Reported in PJM Load Forecast Reports of 2010, 2011, and 2012 [51]



[47] *See* Section II.D for a more detailed discussion of the impact of DSM programs on both energy sales forecasts and peak load forecasts.

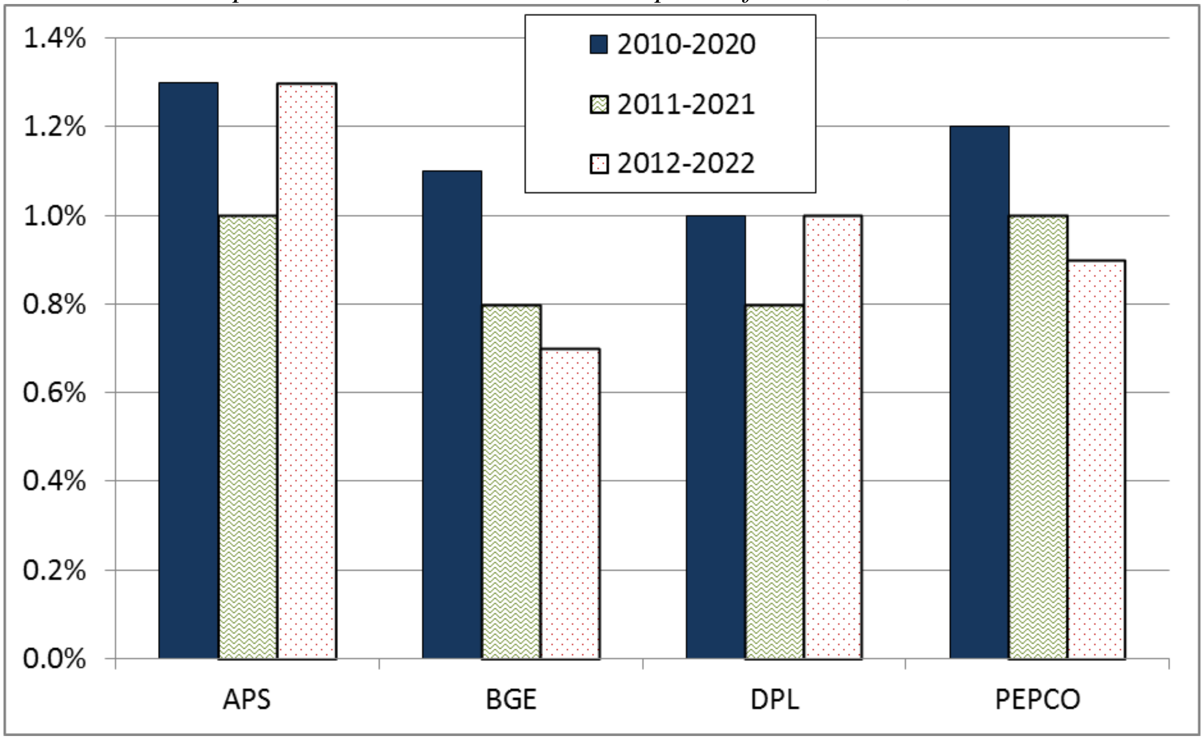
[48] *2014/2015 RPM Base Residual Auction Results*, PJM 4 (May 13, 2011), http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/20110513-2014-15-base-residual-auction-report.ashx.

[49] *2015/2016 RPM Base Residual Auction Results*, PJM 7 (May 18, 2012), http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/20120518-2015-16-base-residual-auction-report.ashx.

[50] "APS" represents the Allegheny Power Zone, of which the Potomac Edison Company is a sub-zone.

[51] *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.

Figure 10: Comparison of Maryland PJM Zone Ten-Year Winter Peak Load Growth Rates as Reported in PJM Load Forecast Reports of 2010, 2011, and 2012 [52]



D. Impact of Demand Side Management

Demand Side Management ("DSM") programs result in lower growth of both energy sales and peak load. To evaluate the impact of DSM programs, the Utilities provide forecasts for energy sales and peak load in terms of "gross of DSM" and "net of DSM."[53] 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. Alternatively, this section contrasts the gross of DSM forecasts with the net of DSM forecasts, which reflect the forecasts *after* the benefits of DSM programs are included. For purposes of this section, only the five utilities participating in EmPOWER Maryland are evaluated: BGE, DPL, PE, PEPCO, and SMECO ("the Participating Utilities").[54]

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[52] *See PJM Load Forecast Report,* PJM Table B-2 (Jan. 2012), https://pjm.com/~/media/documents/reports/2012-pjm-load-report.ashx; *PJM Load Forecast Report,* PJM Table B-2 (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-2 (Jan. 2010), http://www.pjm.com/sitecore%20modules/web/~/media/documents/reports/2010-load-forecast-report.ashx.

[53] *See* Appendix 2(a)(ii) for the Maryland Energy Sales forecast, Net of DSM programs; Appendix 4(a)(ii) for the Maryland Summer Peak Demand Forecast, Net of DSM programs; and Appendix 4(a)(iv) for the Maryland Winter Peak Demand Forecast, Net of DSM programs.

[54] *See* Section V for more information on the energy efficiency and demand response programs associated with EmPOWER Maryland.

As expected, the Participating Utilities project that DSM programs will reduce the growth rate of their energy sales for the ten-year planning period. The five Participating Utilities project a variance in the ten-year growth rate between 0.25% and 0.53% when the benefits of DSM programs are included in the energy sales forecasts.

Figure 11: Impact of DSM Programs on Ten-Year Energy Sales Growth Rates, 2012 - 2021 [55]

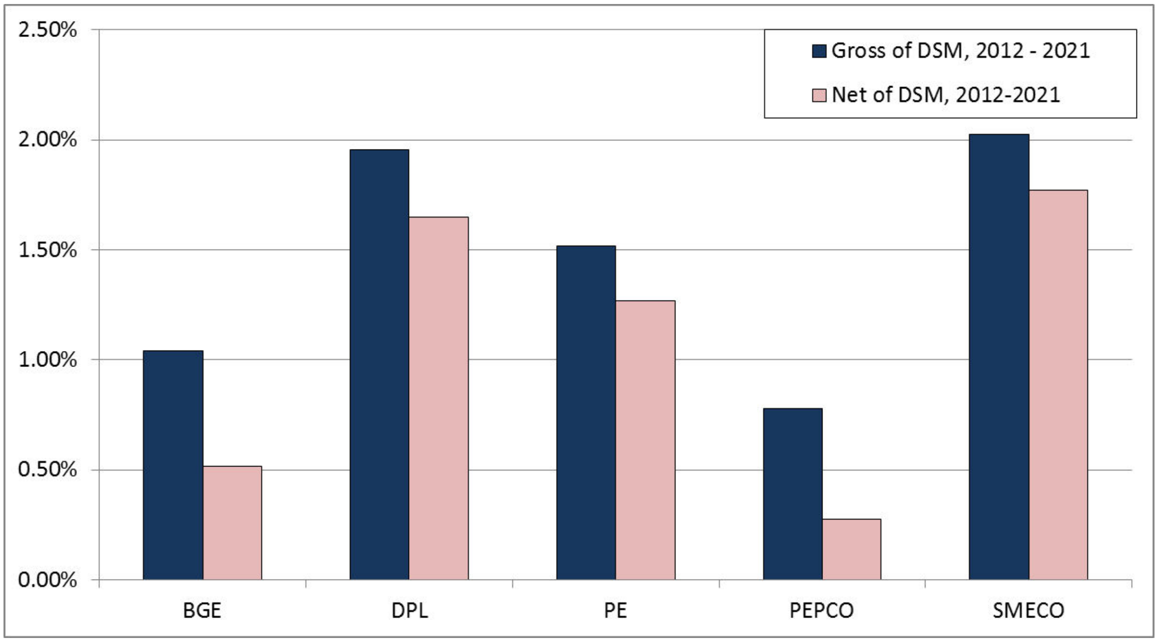

Table 4: Impact of DSM on Energy Sales (GWh)[56,57]

	BGE		DPL		PE		PEPCO		SMECO	
Year	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
2012	31,326	31,142	4,251	4,184	7,550	7,416	15,207	14,858	3,627	3,561
2021	34,391	32,618	5,060	4,848	8,645	8,306	16,310	15,233	4,344	4,170
10-Yr Growth	1.04%	0.52%	1.95%	1.65%	1.52%	1.27%	0.78%	0.28%	2.03%	1.77%
Variance in Growth Rates	-0.53%		-0.30%		-0.25%		-0.50%		-0.25%	

The Participating Utilities also project that DSM programs will have an even greater impact on peak load forecasts for the ten-year planning period. In fact, DPL and PEPCO provided ten-year forecasts that project negative growth, resulting in a summer peak load (net of DSM programs) that is lower in 2021 than the projected 2012 summer peak load.

[55] *See* Appendix 2(a)(i) and 2(a)(ii) for data used to derive this graph.
[56] *Id.*
[57] 1 gigawatt hour ("GWh") is equivalent to 1,000 megawatt hours ("MWh").

Figure 12: Impact of DSM Programs on Ten-Year Summer Peak Load Growth Rates, 2012 - 2021 [58]

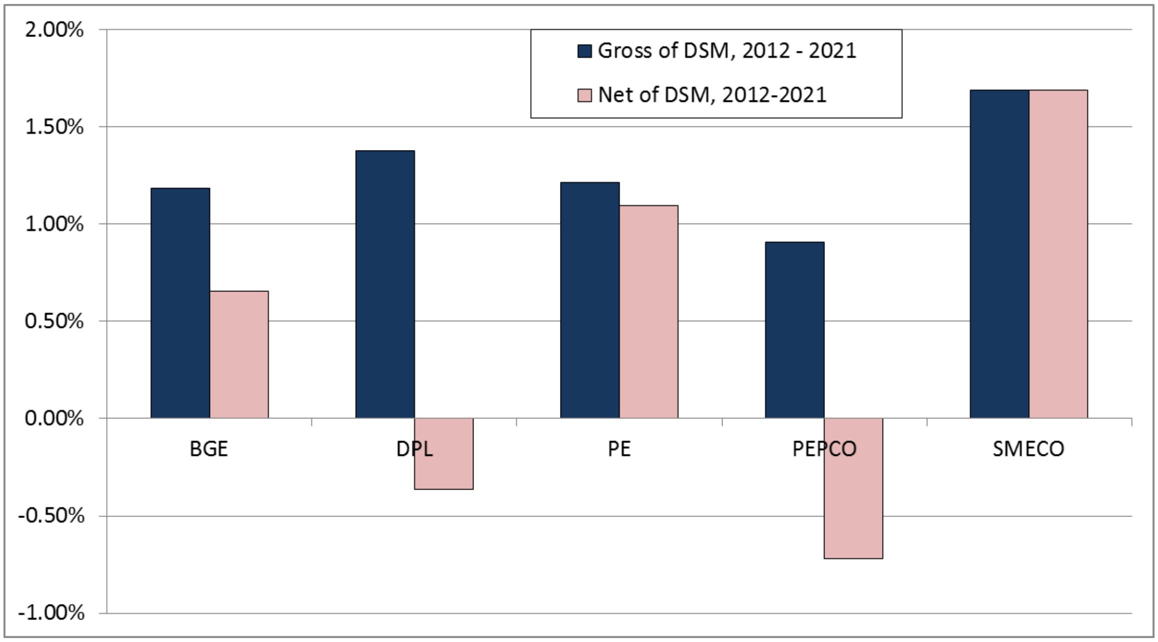

Table 5: Impact of DSM on Summer Peak Load (MW)[59]

	BGE		DPL		PE		PEPCO		SMECO	
Year	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
2012	7,221	7,179	986	938	1,468	1,462	3,668	3,477	881	836
2021	8,028	7,614	1,115	907	1,636	1,612	3,979	3,259	1,025	972
10-Yr Growth	1.18%	0.66%	1.38%	-0.36%	1.21%	1.09%	0.91%	-0.72%	1.69%	1.69%
Variance in Growth Rates	-0.53%		-1.74%		-0.12%		-1.63%		0.00%	

As seen in Figure 12 and Table 5 above, SMECO is not projecting a reduction in the ten-year growth rate associated with the utility's summer peak demand; however, SMECO *is* forecasting the net of DSM programs to lower the overall summer peak demand projected for each year of the ten-year planning period.[60] Therefore, while the impact of DSM programs is not projected to lower the ten-year growth rate of SMECO's summer peak demand, the SMECO service territory will benefit from an overall lower summer peak demand as a result of the DSM program implementation.

Unlike the summer peak load ten-year forecasts, all five of the Participating Utilities do not offer DSM programs that affect the winter peak load; only BGE and PE

[58] *See* Appendix 4(a)(i) and 4(a)(ii) for data used to derive this graph.
[59] *Id.*
[60] *Id.*

provided ten-year forecasts that reflect an impact of DSM programs on winter peak load. As to be expected, Figure 13 and Table 6 illustrate that the DSM programs offered by BGE and PE result in lower winter peak loads and growth rates.

Figure 13: Impact of DSM Programs on Ten-Year Winter Peak Load Growth Rates, 2012 - 2021 [61]

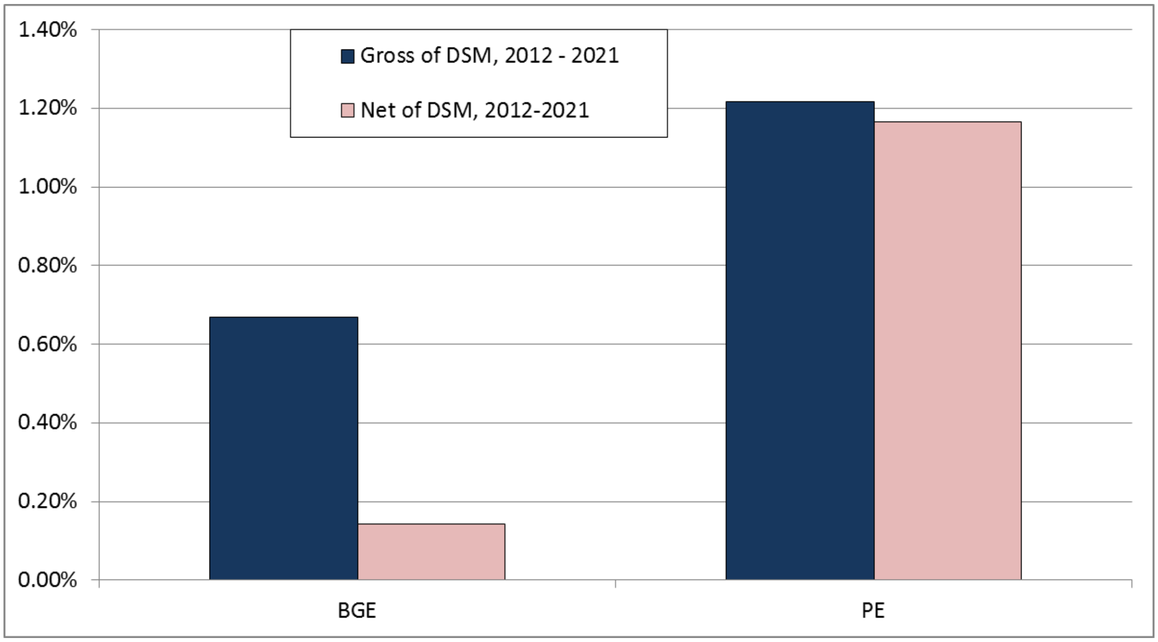

Table 6: Impact of DSM on Winter Peak Load (MW)[62]

	BGE		DPL		PE		PEPCO		SMECO	
Year	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
2012	5,983	5,948	930	930	1,566	1,555	2,851	2,851	743	743
2021	6,353	6,025	1,019	1,019	1,746	1,726	3,101	3,101	972	972
10-Yr Growth	0.67%	0.14%	1.03%	1.03%	1.22%	1.16%	0.94%	0.94%	3.02%	3.02%
Variance in Growth Rates	-0.53%		0.00%		-0.05%		0.00%		0.00%	

As discussed throughout this section, Demand Side Management programs are expected to reduce energy sales and peak load by the end of the ten-year planning period. The source of these savings will be further discussed in Section V, which covers energy efficiency, conservation, and demand response programs in Maryland.

[61] *See* Appendix 4(a)(iii) and 4(a)(iv) for data used to derive this graph.
[62] *Id.*

III. Transmission, Supply, and Generation

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

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."[63] 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 SWMAAC sub-region of PJM, with an in-service date of June 1, 2015.[64] In deciding to order new generation, the Commission made several important findings: the long-term demand for electricity in Maryland, specifically in the SWMAAC zone, compels the order of new generation;[65] Maryland's status as a net importer renders the State very dependent on transmission projects; the uncertain impact of future EPA regulations could greatly impact our State's and the region's aging coal fleet; and the PJM Reliability Pricing Model ("RPM") has been unsuccessful in attracting appreciable new generation.[66]

For purposes of the Ten-Year Plan, the congestion costs and role of transmission infrastructure in planning processes is discussed in Section III.A; Section III.B focuses on the 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[67] is discussed in Section III.C. Lastly, section III.D discusses the role of PJM's RPM in establishing the amount of generation and transmission 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 2011, Maryland's net summer generating capacity was approximately 12,583 MW.[68] Maryland's peak demand forecast for 2012, net of utility demand-side management and energy conservation measures, is approximately 14,262 MW.[69]

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[63] *In the Matter of Whether New Generating Facilities are Needed to Meet Long-Term Demand for Standard Offer Service*, Case No. 9214, Maillog No. 134480, pp. 2 (Sept. 29, 2011).
[64] *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.
[65] *Id.* at 29.
[66] *Id.* at 18 – 23.
[67] *Id.* at 19.
[68] *See infra* Table 9.
[69] *See* Appendix 4(a)(ii).

A. Regional Transmission[70]

A major regional development in 2012 was the termination of both the Potomac-Appalachian Transmission Highline ("PATH") and the Mid-Atlantic Power Pathway ("MAPP") and removal of both projects from the Regional Transmission Expansion Plan ("RTEP"), effective immediately.[71] PJM staff determined that analyses indicate reliability drivers no longer exist for the proposed projects within the 15-year planning cycle.[72] In its 2011 RTEP, PJM expanded upon this point and stated, "[g]iven that load is a primary driver of reliability criteria violations, lower load forecasts are deferring the need for some RTEP upgrades."[73]

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.[74] The PJM energy market provides a pricing system that accounts for congestion. 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.

In recent years, congestion costs have decreased within PJM; Table 7 compares the congestion costs for 2010 and 2011. As shown below, total PJM congestion costs decreased by 29.8% ($424.6 million) between calendar years 2010 and 2011.[75]

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[70] *See* Appendix 5 for a full list of transmission enhancements proposed by Maryland utilities.
[71] Letter from Steven R. Herling, Vice President of Planning, to Transmission Expansion Advisory Committee, PJM (August 28, 2012), *available at* http://www.pjm.com/~/media/committees-groups/committees/teac/20120913/20120913-srh-letter-to-teac-re-mapp-and-path.ashx.
[72] *Id.*
[73] *Book 1: PJM 2011 RTEP in Review*, PJM 13 (Feb. 28, 2012), http://www.pjm.com/~/media/documents/reports/2011-rtep/2011-rtep-book-1.ashx.
[74] Monitoring Analytics, *Quarterly State of the Market Report for PJM: January through September 2012*, PJM 203 (Nov. 15, 2012), http://www.pjm.com/~/media/documents/reports/state-of-market/2012/2012q3-som-pjm.ashx.
[75] Monitoring Analytics, *State of the Market Report for PJM - 2011*, PJM 394, Tables G-6 & G-7 (March 15, 2012), http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2011/2011-som-pjm-volume2.pdf.

Table 7: PJM Total Annual Zonal Congestion Costs, 2010 – 2011 [76]

PJM Control Zone	2010 Total Annual Zonal Congestion Costs ($ million)	2011 Total Annual Zonal Congestion Costs ($ million)
Allegheny Power (Potomac Edison)	$282.70	$143.90
Baltimore Gas and Electric	$91.10	$50.50
Delmarva Power	$47.10	$38.80
Potomac Electric Power	$97.70	$71.10
Maryland Zones Total	**$518.60**	**$304.30**
PJM RTO Total Annual Zonal Congestion Costs ($ Million)	**$1,423.60**	**$999.00**
Percent Attributed to MD Zones	**36.4%**	**30.5%**
Decrease in Costs for PJM RTO (2010 -2011)		**-29.8%**
Decrease in Costs for MD Zones (2010 - 2011)		**-41.3%**

The downward trend reflected in Table 7 continued during the first three quarters of 2012, with total PJM congestion costs for the months of January through September 2012 accounting for only 48.6% of PJM total congestion costs for the same timeframe in 2011.[77] Although both the PJM total congestion costs and Maryland zonal congestion costs are on track to decline for calendar year 2012, congestion remains a cost issue for zones located on the constrained side of affected facilities—especially in the specific zones located to the east and south of the AP South interface.[78] The AP South interface was the largest contributor to congestion costs in the first nine months of 2012, contributing $50.9 million in congestion costs, or 12% of total PJM congestion costs during that timeframe.[79] Figure 14 shows the top 10 locations affecting PJM congestion costs for January through September 2012.[80]

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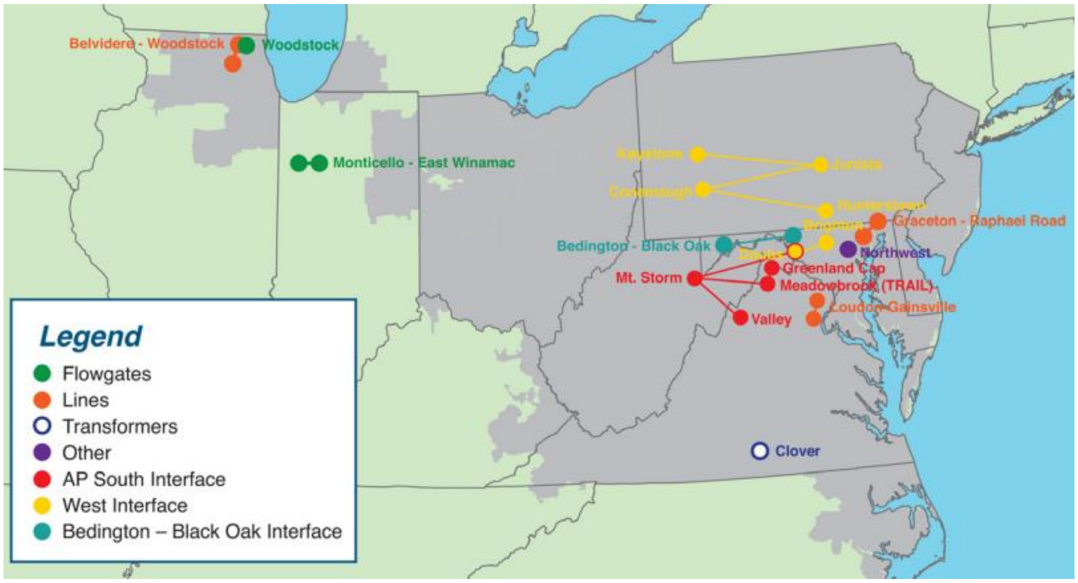
[76] *Id.*
[77] PJM congestion costs for Jan.-Sept. 2011 totaled $874.9 million, while PJM congestion costs for Jan.-Sept. 2012 totaled $425.2 million. Data for the final quarter of 2012 is not yet available. Monitoring Analytics, *Quarterly State of the Market Report for PJM: January through September 2012*, PJM 212-213, Tables 10-17 – 10-18 (Nov. 15, 2012), http://www.pjm.com/~/media/documents/reports/state-of-market/2012/2012q3-som-pjm.ashx.
[78] *Id.* at 158.
[79] *Id.* at 219, Table 10-27.
[80] *See supra* Figure 2 for a map of the PJM Maryland zones.

Figure 14: Top 10 Locations Affecting PJM Congestion Costs [81]



As previously discussed, the two most recent transmission plans proposed through PJM were halted in 2012. While load forecasts have decreased[82]—thereby lessening the need for the PATH and MAPP transmission upgrades—portions of Maryland continue to experience heavy congestion relative to other areas within PJM. Specifically, as was observed by the Commission in Case No. 9214, the Southwestern Mid-Atlantic Area Council ("SWMAAC") load deliverability area ("LDA") is a persistently constrained zone; the SWMAAC LDA covers areas of central Maryland, generally corresponding to BGE's service territory.[83] The impact of congestion costs experienced in the SWMAAC LDA is reflected in the PJM BRA resource clearing prices for the upcoming delivery years. As shown by Table 8, SWMAAC resource clearing prices for upcoming delivery years are significantly higher than prices for the PJM RTO, and are expected to remain constrained in future delivery years.

Table 8: PJM RPM BRA Resource Clearing Price Results [84]

Delivery Year	SWMAAC ($/MW-day)	RTO Price ($/MW-day)
2012/2013	$133.37	$16.46
2013/2014	$226.15	$27.73
2014/2015	$136.50	$125.99
2015/2016	$167.46	$136.00

[81] *Id.* at 221.
[82] *See supra* Section II.
[83] In the PJM market design, an LDA is a Control Zone or part of a Control Zone within PJM with defined internal generation and defined transmission capability to import capacity in the RPM design. *Id.* at 346.
[84] *PJM RPM Auction User Information: Delivery Year*, PJM Markets & Operations (Delivery Years 2012-2016), *available at* http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx.

2. Regional Transmission Upgrades

In addition to lower system load or more localized generation assets, congestion in Maryland could be further offset through transmission upgrades. On a jurisdictional basis, Maryland experienced higher real-time, average LMP[85] than any other jurisdiction in PJM for both calendar years 2010 and 2011.[86] Transmission expansions and improvements can reduce the LMP differences from zone to zone, and can support reliability requirements and mitigate economic concerns.

The Commission recognizes the need to maintain and improve the transmission system within Maryland in order to ensure safe, reliable electricity service to its ratepayers. In 2011, to ensure the smooth operation of the transmission system within the PJM service territory, the PJM Board and PJM's 2011 RTEP approved over 400 individual bulk electric system upgrades.[87] Determined via PJM's RTEP process,[88] the upgrades are required to support reliable electricity flows and ensure the power supply system meets national reliability standards through year 2026.

In its RTEP process, PJM identified several trends in its baseline study which have emerged in Maryland and throughout the Mid-Atlantic region:

- Growing native load;
- Deactivation of existing generation resources;
- Sluggish development of new generation resources; and
- Continued reliance on transmission to meet deliverability needs.[89]

Collectively, the four trends identified above are considered to have a negative impact on reliability in Mid-Atlantic PJM.[90] As discussed in the following section, Maryland continues to rely heavily upon imports of electricity, which in turn puts a strain on Maryland's transmission system. In response, during 2011 PJM approved 18 transmission upgrades in Maryland and the District of Columbia ranging from $5.8

[85] 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.
[86] Monitoring Analytics, *State of the Market Report for PJM - 2011*, PJM 356, Table C-17 (March 15, 2012), http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2011/2011-som-pjm-volume2.pdf.
[87] *Book 1: PJM 2011 RTEP in Review*, PJM 7 (Feb. 28, 2012), http://www.pjm.com/~/media/documents/reports/2011-rtep/2011-rtep-book-1.ashx. Data for 2012 is not currently available.
[88] PJM annually develops the RTEP to meet system enhancement requirements for new backbone transmission lines and interconnection requests for new generation. To establish a starting point for development, PJM performs a baseline analysis of system adequacy and security. The baseline is used for conducting feasibility studies on behalf of all proposed generation and transmission projects. Subsequent System Impact Studies for those potentially viable projects provide recommendations that become part of the RTEP Report.
[89] *Book 5: PJM 2011 RTEP State Summaries*, PJM 119 (Feb. 28, 2012), http://www.pjm.com/~/media/documents/reports/2011-rtep/2011-rtep-book-5.ashx.
[90] *Id.*

million to $32.4 million.[91] In total, the upgrades are expected to cost over $317 million. Some of the upgrades of interest to the Commission include:

- A new 500/230 kV substation at Emory Grove in the BGE zone. The project will cost $64 million, with an expected completion date of June 2017;
- Rebuilding the existing Erdman 115 kV substation to a dual ring-bus configuration to enable termination of new circuits. The project will cost $32.4 million, with an expected completion date of June 2015; and
- Reconductoring the Oak Grove—Aquasco 230 kV circuit and upgrading the terminal equipment at the Oak Grove and Aquasco substations. The project will cost $27 million, with an expected completion date of June 2016.[92]

Appendix Table 5 lists all transmission enhancements identified by the Maryland Utilities in response to data requests for the Ten-Year Plan. Together, the 73 identified transmission enhancements in Appendix 5 account for over 560 miles of upgrades.

B. Electricity Imports

Maryland's heavy reliance upon imported electricity puts a strain on the transmission systems serving the State. Within eastern PJM,[93] the District of Columbia, Delaware, Maryland, New Jersey, and Virginia continue to be net importers of electricity. Maryland imported about 42% of its retail electricity sales in 2010,[94] up 2% from 2009 levels.[95] On a percentage basis, Maryland was the fifth largest electricity importer in the United States – surpassed by the District of Columbia, Delaware, and Virginia in the immediate PJM area.[96] Much of the East Coast is dependent on generation exported from states to the west of the region[97] – many with low cost, largely depreciated, coal-fired generation assets. For calendar year 2010, the states within the PJM region that exported more electricity in aggregate than consumed within each state are Illinois, Indiana,

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[91] *Id.* at 120-121.
[92] *Id.*
[93] 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.
[94] *State Electricity Profiles 2010*, U.S. ENERGY INFORMATION ADMINISTRATION, Table 10 (Jan. 27, 2012), http://www.eia.gov/electricity/state/pdf/sep2010.pdf. The 2010 data reflects the most current data available. According to the EIA's website, 2011 data is scheduled for release in April 2013.
[95] *State Electricity Profiles 2009*, U.S. ENERGY INFORMATION ADMINISTRATION, Table 10 (April 15, 2011), http://www.eia.gov/cneaf/electricity/st_profiles/sep2009.pdf.
[96] *Id. See also* Table 9.
[97] All major utility systems in the eastern half of the United States and Canada are interconnected and operate synchronously as part of the Eastern Interconnection.

Michigan, Pennsylvania, and West Virginia.[98] Table 9 shows the percent of retail sales that was imported by Maryland in 2010, along with other net-importing states in the PJM RTO and the adjacent Northeast region.

Table 9: State Electricity Imports (Year 2010) (GWh) [99]

State	Retail Sales	Estimated Losses & Direct Use	Generation	Net Imports	Percent Retail Sales Imported
D.C.	11,877	681	200	-12,358	104%
Delaware	11,606	952	5,628	-6,931	60%
Virginia	113,806	9,907	72,966	-50,746	45%
Maryland	65,335	5,814	43,607	-27,432	42%
Tennessee	103,522	9,336	82,349	-30,509	29%
New Jersey	79,179	8,060	65,682	-21,423	27%
Massachusetts	57,123	928	42,805	-14,030	25%
North Carolina	136,415	12,019	128,678	-19,756	14%
Ohio	154,145	9,187	143,598	-19,733	13%
New York	144,624	10,114	136,962	-10,746	7%
Kentucky	93,569	6,831	98,218	-2,183	2%

Maryland currently imports 42% of its retail electricity needs from surrounding states. The State imports a significant and growing percentage[100] of electricity primarily because there has not been a significant increase in Maryland's generation capacity over the last several years.[101] Recently Maryland has made effective use of programs such as EmPOWER Maryland to keep peak demand from increasing,[102] delaying the need to fulfill the gap created by inadequate in-State generation and capacity. Although demand side management programs may be successful in alleviating short-term reliability concerns, the Commission recognized the need to address Maryland's long-term reliability issues in Case No. 9214, approving a bid by CPV Maryland, LLC to construct a 661 MW natural gas-fired combined cycle facility in Charles County, with an in-service date of June 1, 2015.[103]

[98] *State Electricity Profiles 2010*, U.S. ENERGY INFORMATION ADMINISTRATION, Table 10 (Jan. 27, 2012), http://www.eia.gov/electricity/state/pdf/sep2010.pdf.

[99] *Id.*

[100] Maryland imported 29 % of its electricity needs in 2007; 35 % in 2008; 40 % in 2009; and 42 % in 2010. *See generally*, *State Electricity Profiles*, U.S. ENERGY INFORMATION ADMINISTRATION, Table 10, http://www.eia.gov/electricity/state/.

[101] In 2007 Maryland generators were capable of producing 12,520 MW of summer capacity. In 2011 generation capability was 12,583 MW, an increase of only 63 MW.

[102] Peak demand this year is 14,262 compared to 14,667 in 2007.

[103] *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.

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.[104] 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[105] coal-fired generation.[106]

1. Conventional Capacity and Generation Profiles, 2011

Much of the electric generation capacity in Maryland is provided by coal-fired power plants aged 31 or more years. Together, oil and natural gas account for the other significant portion of Maryland's summer peak capacity profile.[107]

Table 10: Maryland Summer Peak Capacity Profile, 2011 [108]

Primary Fuel Type	Capacity	
	Summer (MW)	Percent Of Total
Coal	4,886.0	38.8%
Oil and Gas	5,127.7	40.8%
Nuclear	1,705.0	13.6%
Hydroelectric	590.0	4.7%
Other and Renewables	273.9	2.2%
Total	**12,582.6**	**100.0%**

Table 11: Age of Maryland Generation by Fuel Type, 2011 [109]

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	13%	15%	10%	62%
Nuclear	0%	0%	0%	100%
Hydroelectric	0%	0%	0%	100%
Other and Renewables	77%	4%	15%	4%

[104] The uncertainty stems from both pending regulations of the United States Environmental Protection Agency, and from the economic pressure on coal as a result of decreasing shale

[105] PJM categorizes coal generation more than 40 years old and less than 400 MW as at "high-risk" of retirement. *Id.* at PJM Comments, 11-12.

[106] *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.19.

[107] *See* Appendix 6 for a complete list of Maryland generation capacity in 2011.

[108] *Report EIA-860: "GenY11" Excel*, U.S. ENERGY INFORMATION ADMINISTRATION (Jan. 3, 2013), http://www.eia.gov/cneaf/electricity/page/eia860.html.

[109] *Id.*

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 little more than half of in-State capacity.[110] Conversely, oil and natural gas facilities, which operate as mid-merit or peaking units that come on-line when needed, generate less than 8% of the electric energy produced by in-State resources while representing approximately 41 % of in-State capacity.[111] Table 12 summarizes Maryland's in-State fuel-mix in MWh by generation fuel source for 2010.[112]

Table 12: Maryland Generation Profile, 2010 [113]

Primary Fuel Type	Generation	
	Annual (MWh)	Percent Of Total
Coal	23,668,205	54.3%
Nuclear	13,993,948	32.1%
Oil & Gas	3,431,312	7.9%
Hydroelectric	1,667,396	3.8%
Other & Renewables	843,407	1.9%
Total	**43,604,268**	**100.0%**

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 half of the in-State generation in 2010. If operational extensions for Maryland coal generation units are not made, the need for additional in-State resources—like the CPV plant ordered by the Commission in Case No. 9214—will be further necessitated to avoid potential reliability concerns.

However, at the time of this report Maryland's generating capacity portfolio is relatively unchanged for the immediate future. PJM currently registers 12,634 MW of capacity requesting deactivation, but within Maryland there is only one pending request: a 118 MW plant in BGE's transmission zone with a deactivation date of June 1, 2014.[114]

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[110] *See supra* Table 10. Coal facilities represented 38.8% of the in-State capacity in 2011, while nuclear facilities represented 13.6% of capacity. Therefore, coal and nuclear facilities combined for 52.4% of Maryland's generating capacity profile in 2011.
[111] *Id.*
[112] At the time of this report, data for 2011 was not available. According to the United States Energy Information Administration website, the next data update is scheduled for April 2013. *See* http://www.eia.gov/electricity/state/.
[113] *State Electricity Profiles 2010*, U.S. ENERGY INFORMATION ADMINISTRATION, Table 5 (Jan. 27, 2012), http://www.eia.gov/electricity/state/pdf/sep2010.pdf.
[114] *Future Deactivations,* PJM (Feb. 27, 2013), http://www.pjm.com/planning/generation-retirements/~/media/planning/gen-retire/pending-deactivation-requests.ashx.

Outside of the State, but within the four transmission zones that include Maryland, there are two plants which account for 651.7 MW of capacity requesting deactivation or are recently retired: (1) Potomac River, 482 MW; and (2) Indian River 3, 169.7 MW.[115] PJM completed a reliability analysis of each location; PJM identified no reliability impacts prior to the October 1, 2012 retirement of Potomac River. PJM expects that the reliability impacts associated with Indian River 3 will be resolved before the unit is deactivated in December 2013.[116]

2. Proposed Conventional Generation Additions[117]

Small generation, such as distributed generation and combined heat and power, has played an increasing role in Maryland as a source of total generation. However, centralized generation will continue to be necessary in the future. Site considerations for new generation include the Nanticoke River area around Vienna on the Lower Eastern Shore, the Calvert Cliffs area in southern Maryland, various brownfield sites in the central Maryland area, and wind power sites in the mountains of western Maryland and the Atlantic Ocean. Currently, some of these greenfield projects have been delayed, but may be revived in the future as economic, political, and financial conditions change. In the interim, upgrades and additions to existing sites (*i.e.* brownfield deployment) may now offer advantages due to licensing, transmission facilities, and environmental concerns.

Table 13 shows the proposed new conventional generation additions within Maryland for the next ten years. Notably, all of the proposed conventional generation is natural gas; 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 in Pepco's service territory. The sites are located in Charles and Prince George's counties.

Table 13: Proposed New Conventional Generation in Maryland (MW) [118]

Transmission Owner	Fuel Type	In-Service Date Range	Total Capacity (MW)
APS	Natural Gas	2014	4
BGE	Natural Gas	2015	256
DPL	Oil	2013	12
ODEC	Natural Gas	2017	852
PEPCO	Natural Gas	2015 - 2016	5,428
		Total (MW):	**6,552**

[115] *Id.*
[116] *Id.*
[117] *See* Appendix 7 for a complete list of new conventional generation proposed in Maryland.
[118] *Generation Queues: Active (Maryland)*, PJM (last visited Feb. 28, 2013), http://www.pjm.com/planning/generation-interconnection/generation-queue-active.aspx.

3. Renewable Portfolio and Proposed Additions

The Commission recognizes the importance renewable generation plays in meeting Maryland's energy needs while also addressing environmental concerns. Maryland renewable energy provided 177 MW of capacity in 2011. Table 14 shows the 2011 net generation from Maryland renewable sources. Due to its relatively large size compared to other renewable sources and its high capacity factor, over 88% of the energy generation came from refuse resources at the Baltimore Refuse Energy Company.

Table 14: Maryland Net Generation (MWh) from Renewable Sources, 2011 [119]

Category	2011 Net Generation (MWh)	Percent of Total Renewable Generation
Biomass & Refuse	311,340	88.56%
Hydro	1,601	0.46%
Methane / Landfill Gas	38,407	10.93%
Solar	34	0.01%
Wind	160	0.05%
Total	**351,542**	**100.00%**

Over the ten-year planning period, Maryland's renewable generation capacity is planned to increase by an additional 767 MW,[120] more than four times what is installed to date. The proposed renewable generation projects are mainly wind, solar and biomass plants ranging from 1 MW to 150 MW each. The largest proposed renewable energy projects are a pair of 150 MW wind projects in DPL's service territory, with projected in-service dates of late 2014 and mid-2015.

Table 15: Proposed New Renewable Generation in Maryland [121]

Transmission Owner	Fuel Type	In-Service Date Range	Total Capacity (MW)
APS	Biomass	2013-2016	101
	Hydro	2013	14
	Methane	2013	2
	Solar	2013	1
	Wind	2013	168
BGE	Methane	2013	4
	Solar	2013-2014	22
DPL	Biomass	2013	20
	Methane	2013	2
	Solar	2011-2017	133
	Wind	2014-2015	300
		Total (MW):	**767**

[119] *See* Appendix 8.
[120] *Generation Queues: Active (Maryland)*, PJM (last visited Feb. 28, 2013), http://www.pjm.com/planning/generation-interconnection/generation-queue-active.aspx. *See also* Appendix 9.
[121] *See* Appendix 9.

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; subsequently, 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 attempt to ensure reliability in the PJM region for future years.

Using this information, PJM evaluates offers three years in advance from generators and other resources 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").[122] 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."[123] Furthermore, the Mid-Atlantic Council ("MAAC") LDA, which includes SWMAAC, has experienced significant volatility in Net Load[124] prices as a result of the past nine BRAs. The historical pattern suggests that future BRA results could vary significantly from year to year and must be closely monitored.

Table 16: PJM BRA Capacity Prices by Zone [125]

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

[122] Reliability Pricing Model, PJM MARKETS & OPERATIONS (last visited Feb. 28, 2013), http://www.pjm.org/markets-and-operations/rpm.aspx.
[123] *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.
[124] The Zonal Net Load capacity price reflects the BRA resource clearing price and credits from any transmission capacity transfer rights.
[125] *PJM RPM Auction User Information: Delivery Year*, PJM Markets & Operations (Delivery Years 2012-2016), http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx.

PJM noted that the 2015/2016 capacity prices are higher than the previous delivery year mainly due to the impact of environmental regulations; an unprecedented amount of over 14,000 MW of generation retirements have been announced for the next three years.[126] These retirements are primarily driven by environmental regulations such as EPA's Mercury and Air Toxics Standards and New Jersey's High Electricity Demand Day Rule. These two environmental regulations have compliance deadlines of April 16, 2015 and May 1, 2015, respectively.[127] The retirement of existing generation increases the need for new capacity and energy resources.

IV. Reliability in Maryland

Beginning in 2011, the Commission undertook a rulemaking to revise the existing reliability standards by which some Maryland electric utilities are judged.[128] The new regulations, established as part of Rulemaking 43 ("RM43"), seek to improve performance in a host of areas, including service interruptions and vegetation management—two areas which have drawn significant scrutiny recently.[129] The new regulations, promulgated under COMAR Title 20, Subtitle 50, became effective in May 2012; the standards will renew on a four-year cycle thereafter. Since the regulations became effective in May 2012, no annual reports have been filed yet and so there is no available data or basis on which to forecast improvements to utility reliability. As of December 2012, the Utilities have only filed their vegetation and outage management plans; therefore, this section will provide a brief summary of the regulations that have resulted from RM43.

A. Reliability and Operations Standards

Under the new reliability and operations standards codified in COMAR 20.50.12, each qualifying utility will be required to report on system performance measured against objective standards for reliability, poorest performing feeders, device activation, downed wires, and customer communication as each of these relate to outages. Each qualifying utility is required to report to the Commission annually and can be assessed penalties for not meeting the new standards. The first annual report is due to the Commission by April 1, 2013.

Under COMAR 20.50.12, each qualifying utility must track two distinct scores for measuring system-wide reliability. The first is the System Average Interruption

[126] *2015/2016 RPM Base Residual Auction Results,* PJM 2 (May 18, 2012), http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20120518-2015-16-base-residual-auction-report.ashx.
[127] *Id*.
[128] The regulations that resulted from RM43 only apply to electric utilities with more than 40,000 customers. *See* COMAR 20.50.12.01.
[129] *See e.g., In the Matter of the Electric Service Interruptions in the State of Maryland Due to the June 29, 2012 Derecho Storm,* Case No. 9298.

Frequency Index ("SAIFI"), which tracks the average number of outages the utility's customers have experienced during the past reporting period. The second score is the System Average Interruption Duration Index ("SAIDI"), which tracks the average length of outage time a utility's customers have experienced during the past reporting period. Each utility has a baseline against which improvements in scoring must be made in order to track improvements in frequency and duration of outages.[130]

Major contributors to the utility's SAIFI and SAIDI scores are feeder reliability and performance of protective devices. In order to improve the reliability of feeders, COMAR requires that the utilities list the poorest performing three percent of system feeders.[131] These poorest performing feeders are identified by each utility using a formula outlined in its annual plan, which is approved by the Commission. Once the poorest performing feeders have been identified, the respective utility is allotted time to make necessary corrections. Identification and remediation of the poorest performing feeders is an annual process; however, once a feeder has been identified for this list, it cannot be relisted in future years. If a protective device is activated more than five times and causes loss of service to more than ten customers, it must be reported in the annual report to the Commission. Furthermore, the cause of these activations must be explained as part of the report.

In order to improve customer safety and reliability, the new regulations require that utilities respond to at least 90 % of all downed wire calls within four hours of notice. If a utility cannot meet this standard, it is required to file with the Commission a corrective action plan to resolve the issue in the following year.

Finally, in order to improve communication between the utilities and their customers, calls are required to be answered within 30 seconds at least 75 % of the time and, similar to downed wires, failure to achieve this rate will require the filing of a corrective action plan for the subsequent year. To provide granularity on customer communication, the Commission has required, as part of the annual reports, that the following metrics be clearly explained:

- percentage of calls answered within 30 seconds;
- percentage of abandoned calls; and
- average speed of answers.

B. Vegetation Management

Another important part of COMAR 20.50.12 defines how the utilities will maintain their systems during regular operations. These new standards are intended to improve reliability performance related to downed trees and other hazards that cause service

[130] Lower SAIFI and SAIDI indices reflect improvements in reliability.
[131] COMAR 20.50.12.03(A)(1) raised the number of poorest performing feeders that require remedial corrective action from 2 % to 3 %.

interruptions or impede the response to service interruptions. Each utility was required to file a vegetation management plan outlining how it will meet the standards set for each of these categories going forward. For example, the Utilities can adopt a four or five year schedule for pruning or, alternatively, can adopt a minimum distance vegetation management plan. Each utility has a minimum standard for the following issues:

- tree pruning and removal;
- cultural control practices;
- vegetation management around energized electric plants;
- vegetation management along rights-of-way;
- public education; and
- debris management.

V. Energy Efficiency and Demand Response Programs

The Commission recognizes the potential of demand-side management ("DSM") as a powerful tool to bolster energy efficiency and conservation efforts in our State. Furthermore, DSM supports system reliability, energy security, energy and capacity price mitigation (*i.e.*, reducing overall energy costs), enhanced energy market competitiveness, and reduced environmental impacts. As set out by policy and statute, the Commission encourages energy service providers to offer DSM programs to customers where appropriate. Distribution companies have been tasked with providing cost-effective DSM programs, particularly for mass market residential and small commercial customers. As part of EmPOWER Maryland,[132] the Commission has required the Utilities to implement aggressive and cost-effective demand management and energy conservation programs.

Recognizing energy efficiency as one of the least expensive ways to meet growing electricity demands in the State, the EmPOWER Maryland Energy Efficiency Act ("Act") was enacted on April 24, 2008. By statute, each participating Utility[133] is required to develop and implement cost-effective programs and services that encourage and promote the efficient use and conservation of energy by consumers and utilities alike.

In 2010 the EmPOWER Maryland Utilities[134] began the planning process for the next three-year program cycle, which will run from 2012 through 2014. This two-year planning process established by Commission Order No. 84569 provided direction to the Utilities on how to proceed with their 2012-2014 programs. Specifically, Commission Order No. 84569 included the transfer of control of the EmPOWER Limited Income programs from the EmPOWER Utilities to the Maryland Department of Housing and Community Development. Furthermore, it provided for the approval or denial of specific programs and measures as part of each Utility's plan.

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[132] *See* MD. CODE ANN., PUB. UTIL. § 7-211 (2011).
[133] The term "Utilities" used in this Section refers to: BGE; DPL; Pepco; PE; and SMECO.
[134] For more information about the forecasted energy and demand savings discussed in this Section, *see* the Utilities' 2012-2014 plans filed in Case Nos. 9153-9157.

A. EE&C Forecasted Energy and Demand Savings

This section provides forecasted energy savings and demand reductions from the Utilities Energy Efficiency & Conservation ("EE&C") programs for the portion of the ten-year planning period covered by the Utilities' currently-approved plans.[135] The programs span the primary EmPOWER portfolios: residential, commercial and industrial, and other programs.[136] Table 17 shows a breakdown of forecasted energy savings and demand reductions by utility for 2012 – 2015. In total, the 2012—2015 EE&C forecasts for the EmPOWER Maryland programs are projected to reduce peak demand by 21% against the revised 2015 statewide goal, and to achieve energy savings of approximately 41% against the revised 2015 statewide goal.[137] Forecasted energy savings are reported incrementally, meaning that these forecasted achievements and percentages are *in addition to* the energy savings already realized by the Utilities in the previous program cycles.[138] For a cumulative review of both 2012-2015 forecasted savings, and the Utilities' verified 2009-2011 EmPOWER savings, see Appendix 10.

Table 17: Forecasted Energy Savings and Demand Reductions for EE&C programs by Utility, 2012—2015 [139]

		BGE	DPL	PEPCO	PE	SMECO	Total
Energy Savings (MWh)	**2012 - 2015 Forecasted Energy Savings (MWh)**	987,220	192,051	687,298	245,319	113,533	**2,225,421**
	2015 Energy Savings Goal (MWh)	3,593,750	143,453	1,239,108	415,228	83,870	**5,475,409**
	Percentage of Goal Forecasted to Achieve (2012 - 2015)	27.47%	133.88%	55.47%	59.08%	135.37%	**40.64%**
Demand Reduction (MW)	**2012 - 2015 Forecasted Demand Reduction (MW)**	185	42	153	36	21	**437**
	2015 Demand Reduction Target (MW)	1,267	18	672	21	139	**2,117**
	Percentage of Goal Forecasted to Achieve (2012 - 2015)	14.60%	233.33%	22.77%	171.43%	15.11%	**20.64%**

[135] The Utilities' plans currently approved by the Commission cover the 2012 – 2014 program cycle. The Utilities' forecasted savings include through year 2015, but do not include forecasted savings from programs that have not yet received Commission approval.
[136] "Other" programs include programs where savings are reported through the EmPOWER Maryland programs but costs are not recovered through the EmPOWER Maryland surcharges. Examples include Advanced Metering Infrastructure, Street Lighting, and Conservation Voltage Reduction.
[137] For more information about the formulation of the revised 2015 EmPOWER Maryland goals, *see Comments of the Maryland Public Service Commission Technical Staff,* Case Nos. 9153 – 9157, Maillog No. 134615 (Oct. 5, 2011).
[138] For information pertaining to energy savings and demand reductions achieved by the Utilities in previous program cycles, *see* The EmPOWER Maryland Energy Efficiency Act Standard Report, submitted annually by the Commission to the General Assembly.
[139] Forecasted savings from programs that have not received Commission approval have not been included in these figures.

According to the plans filed by the five participating EmPOWER Maryland Utilities,[140] forecasted energy reductions from 2012—2014 will amount to 1,660,000 MWh. These EE&C reductions from EmPOWER Maryland programs represent a 2.53% reduction to forecasted Statewide gross energy sales in 2014.[141] If additional savings forecasted through 2015 are included,[142] total energy reductions amount to 2,225,421 MWh, or a 3.33% savings of 2015 gross energy sales[143] and 41% of the EmPOWER Maryland 2015 goal.[144]

As part of the EE&C programs, the EmPOWER Utilities also forecast peak demand savings. While these savings are, in total, less than the demand savings achieved by traditional load control programs (which are discussed in the next section), they nonetheless do add a significant level of peak demand savings for Maryland. Through the EE&C programs, the EmPOWER Utilities have forecasted 320 MW of peak demand reductions in 2014. These EE&C program reductions represent a 2% reduction in 2014 peak demand.[145] In 2015, this percent reduction in peak demand increases to nearly 3% of gross peak demand.[146] As a percentage of the EmPOWER Maryland 2015 goal, the EE&C program reductions forecasted for 2012 – 2015 amount to 21% of the 2015 statewide goal. Like energy savings, if future legislation is enacted, peak demand reductions from EE&C programs will likely continue into the future.

B. Demand Response Forecasted Energy and Demand Savings

Demand response, or direct load control programs ("DLC"), are a separate part of the EmPOWER Maryland programs. These programs are classified as Residential and Commercial/Industrial in most territories and add the majority of demand reduction to utility portfolios. On the following page, Table 18 shows a breakdown of energy savings and demand reduction by utility through 2015. Again, forecasted energy savings are reported on an incremental basis and are *in addition to* both the energy savings discussed in Section V.A, and those energy savings already realized by the Utilities in the previous

[140] The five participating utilities are Baltimore Gas and Electric (Case No. 9154), Potomac Electric Power Company (Case No. 9155), Delmarva Power and Light Company (Case No. 9156), The Potomac Edison Company (Case No. 9153), and Southern Maryland Electric Cooperative Inc. (Case No. 9157).

[141] *See* Appendix 2(a)(i). The statewide energy sales forecast for 2014 is 65,593 GWh. Energy savings of 1,660 GWh would lower the 2014 statewide energy sales forecast by 2.53 %.

[142] This is the final year of reductions forecasted by all EmPOWER utilities. Forecasts going forward are not reviewed because they are not inclusive of all utilities.

[143] *See* Appendix 2(a)(i). The statewide energy sales forecast for 2015 is 66,875 GWh. Energy savings of 2,225 GWh would lower the 2015 statewide energy sales forecast by 3.33 %.

[144] As currently forecasted, the 2015 EmPOWER Maryland goal is 5,475,409 MWh. This number has been calculated using the updated methodology. Previous methodologies resulted in a 2015 goal of 7,268,540 MWh. For more information, *see* The EmPOWER Maryland Energy Efficiency Act Standard Report of 2012, submitted to the General Assembly.

[145] *See* Appendix 4(a)(i). The statewide summer peak demand forecast for 2014 is 15,060 MW. Forecasted demand reductions of 320 MW would lower the 2014 summer peak demand by 2.12 %.

[146] *Id.* The statewide summer peak demand forecast for 2015 is 15,325 MW. Forecasted demand reductions of 437 MW would lower the 2015 summer peak demand by 2.85 %.

program cycles. For a cumulative review of both 2012-2015 forecasted savings, and the Utilities' verified 2009-2011 EmPOWER savings, see Appendix 10.

Table 18: Forecasted Energy Savings and Demand Reductions for DLC programs by Utility, 2012 – 2015 [147]

		BGE	DPL	PEPCO	PE	SMECO	Total
Energy Savings (MWh)	2012 - 2015 Forecasted Energy Savings (MWh)	19,776	4,476	18,526	--	--	**42,778**
	2015 Energy Savings Goal (MWh)	3,593,750	143,453	1,239,108	--	--	**4,976,311**
	Percentage of Goal Forecasted to Achieve (2012 - 2015)	0.55%	3.12%	1.50%	--	--	**0.86%**
Demand Reduction (MW)	2012 - 2015 Forecasted Demand Reduction (MW)	509	48	132	--	16	**705**
	2015 Demand Reduction Target (MW)	1,267	18	672	--	139	**2,096**
	Percentage of Goal Forecasted to Achieve (2012 - 2015)	40.17%	266.67%	19.64%	--	11.51%	**33.64%**

As a result of the Utilities' DLC programs, total peak demand reduction[148] is forecast to be 705 MW at the end of 2015—a decrease of approximately 5% of the projected 2015 statewide peak demand.[149] As a percentage of the EmPOWER Maryland 2015 goal, this demand reduction accounts for 34% of the statewide goal. Despite this significant projected progress, growth in demand reduction from DLC will begin to slow significantly in 2015 as residential saturation is achieved.

In addition to the reductions in peak demand, DLC programs also offer the ancillary benefit of energy savings from the use of DLC programmable thermostats.[150] Total energy savings from DLC programs through 2015 are forecast to be 42,778 MWh—too small to provide a quantifiable reduction in statewide energy sales for the EmPOWER Maryland goals. Incremental savings from 2015 are forecast to add 12,000 MWh in 2015 and will likely add similar amounts in years after. However, because of saturation in DLC programs and the shift from DLC to other demand response programs (such as dynamic pricing) it is unlikely that significant increases in either energy savings or demand reductions will continue after 2015.

[147] PE is not included in this table because it does not offer a demand response program as part of its EmPOWER Maryland portfolio. No energy savings are forecasted for SMECO's demand response programs as they are not tracked by the Cooperative.

[148] This includes the residual reductions from previous years. Unlike energy savings, demand reductions are not reported incrementally here but instead reflect total potential reductions.

[149] *See* Appendix 4(a)(i). The statewide summer peak demand forecast for 2015 is 15,325 MW. Forecasted demand reductions of 705 MW would lower the 2015 summer peak demand by 4.60 %.

[150] SMECO does not record these savings as part of their projections. If they had included these savings it is likely that a modest increase in total savings would have been seen.

C. Other EE&C and Demand Side Programs

In addition to the core EmPOWER Maryland programs discussed above in Sections V.A and V.B, many of the State's utilities are operating other energy saving programs such as Advanced Metering Infrastructure ("AMI") or Conservation Voltage Reduction ("CVR").[151] BGE, Pepco, and DPL have received Commission approval to begin the implementation of their respective AMI programs, while SMECO has filed for approval of its AMI proposal.[152] To date, only PE has received approval to implement a CVR program as part of its EmPOWER portfolio,[153] although the Commission directed the other utilities to investigate the feasibility of implementing CVR in their respective service territories.[154]

AMI programs can achieve potential savings directly through improvements to customer meters and the electric grid infrastructure, as well as from pricing programs designed to encourage customers to reduce energy usage at critical times.[155] Table 19 delineates the forecasted demand reductions through 2017 for each utility currently approved for AMI deployment.

Table 19: Annual Demand Reductions from AMI Programs (MW) [156]

Utility	2012	2013	2014	2015	2016	2017
BGE	0	0	125	240	240	240
PEPCO	2	157	176	176	175	174
DPL	0	0	0	1	48	55
Total	**2**	**157**	**301**	**417**	**463**	**469**

[151] Savings estimates from CVR are included in Table 19.
[152] *See In the Matter of the Request of Southern Maryland Electric Cooperative, Inc. for Authorization to Proceed with Implementation of Advanced Metering Infrastructure System*, Case No. 9294. SMECO has not reported any savings from AMI or pricing programs as part of its Ten-Year Plan data responses. As such, Staff does not include any projected savings in the Ten-Year Plan document.
[153] The Commission has allowed PE to record its savings for the CVR program under its EmPOWER portfolio; however, the costs of this program will be recovered in base rates.
[154] *See* Order No. 84569. Because the CVR programs are in their infancy and have not gone through a rigorous review, Staff has elected not to discuss these programs at length in this document. As the programs mature and further studies are completed regarding the implementation and savings of these programs, individual CVR forecasts will be included in future iterations of this Plan.
[155] For purposes of the Ten-Year Plan, BGE, DPL, and Pepco forecast all energy and demand savings coming from dynamic pricing programs and no savings coming directly from metering implementation.
[156] As reported in the 2012 Ten-Year Plan data responses, these reductions may or may not reflect reductions reported as part of the AMI programs or as forecasted as part of AMI plans.

Total statewide demand reductions in 2017 are projected to be 469 MW.[157] This is an increase of 467 MW from 2012 forecasts, primarily due to the respective deployment schedules for each utility's AMI program.[158] Only Pepco forecasted demand reductions in 2012, during which time it began operating a short-term AMI pilot. Ramp-up in demand reductions from AMI primarily begins in 2014 when all three utilities begin forecasting savings. In 2014, total demand savings are forecast to be 301 MW, which represents 64% of the total demand reductions achieved through 2017. In the following year, 2015, both BGE and DPL continue to project increased savings, while Pepco's savings remain constant. Current forecasts for 2016 only show growth in savings from DPL while both Pepco and BGE forecast constant savings. Over time, these rates of constant savings are set because of the assumption that full saturation and adoption rates will have been achieved.

As a percentage of statewide peak demand, these programs account for a 2.71% reduction in 2015 peak demand[159] and 19.65% of the EmPOWER Maryland 2015 goal.[160]

D. Future Forecasting

Recently, the Maryland Energy Administration ("MEA"), in consultation with the Commission, undertook a study as required under the EmPOWER Maryland legislation to determine whether electricity savings goals for the EmPOWER Maryland programs should be revised for future years. In addition, this study will seek to determine whether the EmPOWER Maryland programs should expand to include goals for natural gas energy savings.[161] This report is required under the original EmPOWER Maryland Energy Efficiency Act of 2008 and was filed on December 31, 2012.

VI. Energy, the Environment, and Renewables[162]

Maryland participates in two important efforts to reduce the impact of emissions on the environment: (1) the Regional Greenhouse Gas Initiative ("RGGI"); and (2) the State's mandatory Renewable Portfolio Standard ("RPS"). The first of its kind in the United States, RGGI is a market-based program designed to stabilize and then reduce greenhouse gas emissions. The RPS is a statewide program designed to encourage the

[157] Staff has used a cut-off date of 2017 because DPL and Pepco did not forecast energy and demand savings beyond this date. BGE did forecast savings; however, reporting only BGE's savings forecasts would skew the results.
[158] For more information, *see* Case Nos. 9207 and 9208.
[159] *See* Appendix 4(a)(i). The statewide summer peak demand forecast for 2015 is 15,325 MW. Forecasted demand reductions of 416 MW by 2015 would lower the 2015 summer peak demand by 2.71 %.
[160] The statewide 2015 EmPOWER Maryland goal for all utilities is 2,117 MW. Forecasted demand reductions of 416 MW by 2015 would achieve 19.65 % of the 2015 statewide goal.
[161] *See* sections 4 and 5 of EmPOWER Maryland Energy Efficiency Act of 2008, 2008 Md. Laws Ch. 131.
[162] *See* Appendix 8 for a list of current renewable energy generating facilities in Maryland as of December 31, 2011. *See* Appendix 9 for a list of proposed new renewable energy generation projects in Maryland.

consumption of energy from renewable energy sources throughout the State by mandating specific levels of energy use come from these sources.

A. Regional Greenhouse Gas Initiative

After a comprehensive two-year program review, the nine Northeastern and Mid-Atlantic states participating in the Regional Greenhouse Gas Initiative released an updated RGGI Model Rule and Program Review Recommendations Summary on February 7, 2013.[163] The updated Model Rule will guide the RGGI states as they follow state-specific statutory and regulatory processes to propose updates to their CO_2 Budget Trading Programs.

The major development resulting from the two-year program review was a recommendation from the nine participating states to lower the regional CO_2 cap by 45% to align with current emissions levels.[164] The new regional emissions cap in 2014 will equal 91 million short tons. The regional emissions cap and each participating state's individual emissions budget will decline 2.5% each year 2015 through 2020. As a reference, Maryland's forecasted emissions for 2012 are projected at 25 million short tons; as a result of the revised RGGI 91 million cap, Maryland's forecasted emissions for 2020 are projected at 17 million short tons.[165]

Table 20: RGGI Participating States CO_2 Emissions Caps, 2009—2020

State	Existing Budget (165M Cap), 2009 - 2013	Revised Budget (91M Cap), 2014 - 2020
CT	10,695,036	5,891,895
DE	7,559,787	4,164,687
ME	5,948,902	3,277,250
MD	**37,503,983**	**20,660,944**
MA	26,660,204	14,687,106
NH	8,620,460	4,749,011
NY	64,310,805	35,428,822
RI	2,659,239	1,464,975
VT	1,225,830	675,310
RGGI	**165,184,246**	**91,000,000**

163 *See Program Review*, RGGI (2013), http://rggi.org/design/program_review.
164 For a complete description of recommended RGGI programmatic changes, *see RGGI 2012 Program Review: Summary of Recommendations to Accompany Model Rule Amendments*, RGGI (Feb. 7, 2013), http://rggi.org/docs/ProgramReview/_FinalProgramReviewMaterials/Recommendations_Summary.pdf.
165 *See IPM Modeling: 2012 Modeling Materials*, RGGI (Dec. 7, 2012), http://rggi.org/design/program_review/materials_by_topic/ipm_modeling.

B. Renewable Portfolio Standard

The Maryland RPS sets a requirement that a minimum of 20% of electricity use come from renewable resources by 2022, of which 2% must be from solar generation. This program has helped to encourage the development of alternative electricity generation such as wind, solar, and biomass resources. According to information from MEA, in-State capacity in 2011 was 910 MW, which is 25% of the 2022 goal of 3,721 MW.[166] As reported in the Utilities' Ten-Year Plan responses, approximately 767 MW of Maryland-based renewable generation projects are expected to come online by 2017. For a complete list of proposed renewable generation projects in Maryland, see Appendix Table 9.

VII. FERC and Other Federal Energy Issues

As transmission, wholesale electricity, and bulk power system standards have 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 consumers. The Federal Energy Regulatory Commission ("FERC") is the principle governing body at the federal level for electricity matters. FERC activities include:

• regulation of wholesale sales of electricity and transmission of electricity in interstate commerce;
• oversight of mandatory reliability standards for the bulk power system (which are administered by the North American Electric Reliability Corporation);
• promotion of strong national energy infrastructure, including adequate transmission facilities; and
• regulation of jurisdictional issuances of stock and debt securities, assumptions of obligations and liabilities, and mergers.[167]

As a regional transmission operator ("RTO"), PJM administers the Open Access Transmission Tariff ("OATT") as approved by FERC. FERC is ultimately responsible for approving tariff changes proposed by PJM that wholesale market entities operating in Maryland must follow.

The Commission, through its Office of General Counsel, Commission Advisors, and Technical Staff, regularly participates in PJM's stakeholder process, including engaging in policy development at PJM. These policies are later approved by FERC and may be litigated by dissenting parties. Therefore, the Commission regularly monitors

[166] *See Increase Maryland's In-State Renewable Generation to 20% by 2022*, GOVERNOR O'MALLEY'S STATESTAT (last visited Feb. 28, 2013), http://www.statestat.maryland.gov/GDUenergy.asp.
[167] *Strategic Plan - FY 2009–FY 2014,* FEDERAL ENERGY REGULATORY COMMISSION (Feb. 13, 2012), http://www.ferc.gov/about/strat-docs/strat-plan.asp.

FERC actions and orders. Examples of the issues tracked by the Commission are listed below:

• PJM's Minimum Offer Price Rule ("MOPR"). In 2012, the Commission filed a major protest against PJM's proposal to *again* revise its Minimum Offer Price Rule to: (1) eliminate the current unit-specific review process; (2) implement a highly restrictive competitive entry exemption; and (3) raise the mitigation threshold for new entrants. PJM's new proposal would rewrite the RTO's capacity procurement rules to severely constrain states such as Maryland from exercising their traditional authority to engage in the development of reliable and least cost electricity within their borders. FERC's decision in this matter could affect the State's ability to order new generation to mitigate the risk of PJM capacity (reliability) shortfalls in the future.

• Transmission Planning and Transmission Cost Allocation. The Commission continues to monitor PJM's transmission planning process and has filed comments in FERC's Order 1000 proceedings – *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities* (Docket Nos. ER13-198 and ER13-90). FERC Order 1000 requires that RTO such as PJM amend their tariffs to describe procedures that provide for consideration of driven by federal, state, and local public policy. The Commission has participated in numerous PJM, Organization of PJM States, Inc. ("OPSI") and the PJM Independent State Agencies Committee ("ISAC") addressing approaches for incorporating public policy and multi-driver considerations in PJM's transmission planning process. The Commission also continues to support FERC's decision on remand from the United States Court of Appeals for the Seventh Circuit in *Illinois Commerce Commission v. FERC*, 576 F.3d 470 (7th Cir. 2009), reaffirming its conclusion in Opinion No. 494 providing that the cost of extra high voltage ("EHV") transmission facilities (500 kV and above) should be socialized on a load-ratio-share basis. FERC's decision in these matters could affect the State's ability to ensure the development of EHV transmission facilities needed to integrate renewable and other generation resources needed to meet Maryland's public policy goals and objectives.

• The 1-Day in 10-Years Load Loss Standard. This year FERC is engaged in a review of its Load Loss standard, which forms the basis of PJM's own reliability standard. Each year at the base residual auction, PJM procures enough capacity to meet all but the highest peak day in a ten-year period. Any changes or direction from FERC as a result of its study could impact how PJM determines its reliability standard.

• Compliance Filings. PJM routinely submits filings in active FERC dockets seeking clarification, proposing tariff changes, or notifying FERC of its progress in implementing changes. As noted above, the Commission monitors numerous PJM and other FERC filings in order to follow important wholesale market-related generation and transmission policy activities.

A. FERC's Strategic Plan, FY 2009 – 2014

The FERC strategic plan encompasses FERC's goals and objectives for the planning period fiscal years 2009 to 2014. In its strategic plan, FERC has outlined two main goals: (1) to ensure that rates, terms, and conditions are just, reasonable and not unduly discriminatory or preferential; and (2) to promote the development of safe, reliable, and efficient infrastructure that serves the public interest.[168]

To fulfill these goals, FERC outlined a series of objectives that it hopes to achieve during its current planning period. FERC's objectives include, among others: market reforms and improved Demand Response implementation; enhanced enforcement of rules that deter market manipulation; enhanced development of efficient wholesale utility infrastructure; and enhanced reliable operation of the bulk power system. In the Fiscal Year 2012 (October 2011 to September 2012) Performance and Accountability Report,[169] FERC reviewed the progress made towards meeting the Strategic Plan goals. Of the 17 performance measures for Fiscal Year 2012, FERC states that all but two have been met. In the area of Demand Response, FERC issued Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*.[170] Since the Order, PJM has filed a series of compliance filings during fiscal year 2012 revising its tariffs to comply with the Order.

The Commission monitors FERC and PJM for all important filings which may have an impact on Maryland. Below are some of the objectives FERC has laid out in its Strategic Plan, which the Commission expects to monitor closely or intervene:

• <u>Ensure implementation of appropriate regulatory and market means for establishing rates.</u> FERC in large part relies on the organized wholesale electric markets to ensure that rates are just and reasonable. In order to improve the wholesale market, FERC strives to eliminate market barriers, for instance, by requiring that demand response be compensated on par with generation in the wholesale electricity market. FERC found the potential for peak demand reductions across the nation is between 38,000 MW and 188,000 MW depending on how extensively demand response is applied.[171] 188,000 MW is approximately 20 % of national peak demand.

Additionally, as part of its ongoing effort to improve the wholesale market, FERC issued Order No. 719 in October 2008 directing all RTOs to improve the operation of organized wholesale electric power markets, including improving RTO board responsiveness to consumers.

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[168] *Id.*
[169] *Performance and Accountability Report: Fiscal Year 2012*, FEDERAL ENERGY REGULATORY COMMISSION (2012), http://www.ferc.gov/about/strat-docs/2012-audit.pdf.
[170] Docket No. RM10-17-000.
[171] *Strategic Plan - FY 2009–FY 2014,* FEDERAL ENERGY REGULATORY COMMISSION (Feb. 13, 2012), http://www.ferc.gov/about/strat-docs/strat-plan.asp.

• Increase efficient infrastructure consistent with demand. Through the use of incentives applicable to regional transmission projects and smart grid initiatives, FERC aims to increase the number of transmission projects that incorporate advanced technologies. By the end of FERC's planning period, FERC predicts that 50 % of all new transmission projects will incorporate advanced technologies.[172] More recently, FERC has adopted reforms that tie transmission incentives more closely to risk.

• Cyber Security. FERC also has an important role in maintaining the reliability of the electric transmission grid. Pursuant to the Energy Policy Act of 2005, FERC oversees and approves the mandatory reliability and cyber security standards developed by the North American Electric Reliability Corporation. FERC also monitors system disturbances to identify near and long-term issues affecting generation and transmission.

The Commission continues to monitor these and other FERC initiatives to response to the impacts they may have on Maryland ratepayers.

VIII. Conclusion

A number of open and continuing issues will effect planning for electric regulatory policy in the near and medium term. Changes such as new standards for reliability intended to improve the service quality of many of Maryland's electric utilities; potential revisions to energy efficiency, conservation, and demand response; greenhouse gas programs; and the need for potential future generation will all influence the electric planning and composition of Maryland utilities. In response to these, and other developments, the 2013 Ten-Year Plan can be expected to review the changes and directions that the issues described above will have on long-term electricity resource planning.

[172] *Id.*

Appendices to the 2012-2021 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 July 12, 2012 and returned by September 1, 2012.

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	Total
2012	2,396	1,244,585	52,504	200,631	10,993	17,548	255,095	534,416	154,963	**2,473,131**
2013	2,396	1,252,824	52,840	202,543	11,202	17,629	258,019	537,633	157,573	**2,492,659**
2014	2,408	1,263,163	53,401	204,511	11,411	17,710	260,763	542,037	160,203	**2,515,607**
2015	2,420	1,275,698	54,096	206,511	11,620	17,792	263,374	546,086	162,843	**2,540,440**
2016	2,444	1,289,211	54,832	208,472	11,829	17,875	265,650	549,417	165,483	**2,565,214**
2017	2,469	1,300,616	55,480	210,398	12,038	17,957	267,599	551,902	168,223	**2,586,682**
2018	2,493	1,312,121	56,020	212,324	12,247	18,040	269,331	554,403	170,963	**2,607,942**
2019	2,531	1,323,728	56,477	214,236	12,456	18,124	270,951	556,562	173,803	**2,628,868**
2020	2,569	1,335,438	56,894	216,143	12,665	18,208	272,450	558,411	176,653	**2,649,431**
2021	2,607	1,347,252	57,299	218,043	12,874	18,292	273,853	559,911	179,293	**2,669,424**
Change (2012-2021)	**211**	**102,667**	**4,795**	**17,412**	**1,881**	**744**	**18,758**	**25,495**	**24,330**	**196,293**
Percent Change (2012-2021)	**8.82%**	**8.25%**	**9.13%**	**8.68%**	**17.11%**	**4.24%**	**7.35%**	**4.77%**	**15.70%**	**7.94%**
Compound Annual Growth Rate	**0.94%**	**0.88%**	**0.98%**	**0.93%**	**1.77%**	**0.46%**	**0.79%**	**0.52%**	**1.63%**	**0.85%**

Note: A&N, Somerset, Thurmont, and Williamsport 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	Total
2012	1,971	1,119,082	47,389	174,261	8,538	14,898	223,826	486,773	140,300	**2,217,037**
2013	1,971	1,126,467	47,416	175,828	8,676	14,973	226,387	489,867	142,700	**2,234,285**
2014	1,981	1,135,772	47,605	177,443	8,814	15,047	228,774	494,006	145,100	**2,254,541**
2015	1,991	1,147,079	48,029	179,091	8,952	15,123	231,041	497,794	147,500	**2,276,599**
2016	2,011	1,159,281	48,535	180,702	9,089	15,198	233,021	500,907	149,900	**2,298,643**
2017	2,031	1,169,554	48,994	182,282	9,227	15,274	234,726	503,244	152,400	**2,317,732**
2018	2,051	1,179,918	49,356	183,862	9,365	15,351	236,235	505,574	154,900	**2,336,612**
2019	2,082	1,190,375	49,629	185,431	9,503	15,427	237,638	507,583	157,500	**2,355,168**
2020	2,113	1,200,924	49,850	186,999	9,641	15,505	238,934	509,317	160,100	**2,373,383**
2021	2,145	1,211,566	50,041	188,560	9,779	15,582	240,140	510,720	162,500	**2,391,033**
Change (2012-2021)	**174**	**92,485**	**2,652**	**14,298**	**1,242**	**684**	**16,314**	**23,947**	**22,200**	**173,996**
Percent Change (2012-2021)	**8.82%**	**8.26%**	**5.60%**	**8.21%**	**14.54%**	**4.59%**	**7.29%**	**4.92%**	**15.82%**	**7.85%**
Compound Annual Growth Rate	**0.94%**	**0.89%**	**0.61%**	**0.88%**	**1.52%**	**0.50%**	**0.78%**	**0.54%**	**1.65%**	**0.84%**

Note: A&N, Somerset, Thurmont, and Williamsport 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	Total
2012	294	119,957	4,840	25,857	2,456	2,603	28,017	47,544	14,660	**246,228**
2013	294	120,772	5,149	26,203	2,527	2,610	28,371	47,663	14,870	**248,458**
2014	295	121,757	5,520	26,555	2,598	2,617	28,718	47,928	15,100	**251,089**
2015	297	122,926	5,790	26,908	2,669	2,623	29,052	48,189	15,340	**253,794**
2016	300	124,176	6,020	27,259	2,740	2,630	29,340	48,407	15,580	**256,451**
2017	303	125,254	6,209	27,605	2,811	2,636	29,577	48,555	15,820	**258,770**
2018	306	126,341	6,387	27,951	2,882	2,643	29,794	48,726	16,060	**261,090**
2019	311	127,437	6,571	28,294	2,953	2,649	30,004	48,876	16,300	**263,395**
2020	315	128,543	6,767	28,634	3,024	2,656	30,201	48,991	16,550	**265,682**
2021	320	129,659	6,981	28,974	3,095	2,663	30,391	49,089	16,790	**267,961**
Change (2012-2021)	**26**	**9,702**	**2,141**	**3,116**	**639**	**60**	**2,374**	**1,545**	**2,130**	**21,733**
Percent Change (2012-2021)	**8.82%**	**8.09%**	**44.24%**	**12.05%**	**26.02%**	**2.31%**	**8.47%**	**3.25%**	**14.53%**	**8.83%**
Compound Annual Growth Rate	**0.94%**	**0.87%**	**4.15%**	**1.27%**	**2.60%**	**0.25%**	**0.91%**	**0.36%**	**1.52%**	**0.94%**

Note: A&N, Somerset, Thurmont, and Williamsport 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	Total
2012	112	5,546	23	237	0	46	2,904	0	3	**8,871**
2013	112	5,585	23	237	0	46	2,912	0	3	**8,919**
2014	113	5,634	23	238	0	46	2,921	0	3	**8,977**
2015	113	5,692	23	238	0	46	2,930	0	3	**9,045**
2016	114	5,755	23	237	0	47	2,937	0	3	**9,116**
2017	115	5,808	23	237	0	47	2,942	0	3	**9,175**
2018	117	5,862	23	236	0	47	2,947	0	3	**9,235**
2019	118	5,916	23	236	0	47	2,953	0	3	**9,296**
2020	120	5,971	23	235	0	47	2,958	0	3	**9,357**
2021	122	6,027	23	235	0	47	2,964	0	3	**9,420**
Change (2012-2021)	**10**	**481**	**-**	**(2)**	**-**	**1**	**60**	**-**	**-**	**549**
Percent Change (2012-2021)	**8.82%**	**8.67%**	**0.00%**	**-1.01%**	**N/A**	**2.17%**	**2.07%**	**N/A**	**0.00%**	**6.19%**
Compound Annual Growth Rate	**0.94%**	**0.93%**	**0.00%**	**-0.11%**	**N/A**	**0.24%**	**0.23%**	**N/A**	**0.00%**	**0.67%**

Note: A&N, Somerset, Thurmont, and Williamsport 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	Total
2012	19	0	252	275	0	0	345	100	0	**991**
2013	19	0	252	275	0	0	346	102	0	**994**
2014	19	0	253	275	0	0	347	103	0	**996**
2015	19	0	254	275	0	0	348	103	0	**999**
2016	19	0	254	275	0	0	349	103	0	**1,000**
2017	20	0	254	275	0	0	351	103	0	**1,002**
2018	20	0	254	275	0	0	352	103	0	**1,004**
2019	20	0	254	275	0	0	353	103	0	**1,005**
2020	20	0	254	275	0	0	354	103	0	**1,006**
2021	21	0	254	275	0	0	355	103	0	**1,008**
Change (2012-2021)	**2**	**-**	**2**	**0**	**-**	**-**	**10**	**3**	**-**	**17**
Percent Change (2012-2021)	**8.82%**	**-**	**0.79%**	**0.03%**	**-**	**-**	**2.90%**	**3.10%**	**-**	**1.70%**
Compound Annual Growth Rate	**0.94%**	**-**	**0.09%**	**0.00%**	**-**	**-**	**0.32%**	**0.34%**	**-**	**0.19%**

<u>Note:</u> A&N, Somerset, Thurmont, and Williamsport did not report applicable information for this table.
<u>Note:</u> 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	Total
2012	0	0	0	0	0	0	3	0	0	**3**
2013	0	0	0	0	0	0	3	0	0	**3**
2014	0	0	0	0	0	0	3	0	0	**3**
2015	0	0	0	0	0	0	3	0	0	**3**
2016	0	0	0	0	0	0	3	0	0	**3**
2017	0	0	0	0	0	0	3	0	0	**3**
2018	0	0	0	0	0	0	3	0	0	**3**
2019	0	0	0	0	0	0	3	0	0	**3**
2020	0	0	0	0	0	0	3	0	0	**3**
2021	0	0	0	0	0	0	3	0	0	**3**
Change (2012-2021)	**-**	**-**	**-**	**-**	**-**	**-**	**0**	**-**	**-**	**-**
Percent Change (2012-2021)	**-**	**-**	**-**	**-**	**-**	**-**	**0.00%**	**-**	**-**	**0.00%**
Compound Annual Growth Rate	**-**	**-**	**-**	**-**	**-**	**-**	**0.00%**	**-**	**-**	**0.00%**

<u>Note:</u> A&N, Somerset, Thurmont, and Williamsport did not report applicable information for this table.
<u>Note:</u> 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. Potomac Edison 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): 2011 Customer Numbers and Energy Sales

Appendix Table 1(b)(i): Customer Class Breakdown as of December 31, 2011 (# of customers)

	System Wide						Maryland					
Utility	Residential	Commercial	Industrial	Other	Sales for Resale	Total	Residential	Commercial	Industrial	Other	Sales for Resale	Total
Berlin	1,960	291	110	19	0	**2,380**	1,960	291	110	19	0	**2,380**
BGE	1,116,401	118,894	5,824	0	0	**1,241,119**	1,116,401	118,894	5,824	0	0	**1,241,119**
Choptank	47,255	4,735	23	251	0	**52,264**	47,255	4,735	23	251	0	**52,264**
DPL	440,980	58,892	478	647	0	**500,997**	173,481	25,659	240	274	0	**199,654**
Easton	8,225	2,321	0	0	0	**10,546**	8,225	2,321	0	0	0	**10,546**
Hagerstown	14,824	2,597	46	0	0	**17,467**	14,824	2,597	46	0	0	**17,467**
PE	338,935	43,585	4,882	668	5	**388,075**	221,748	27,357	2,885	343	3	**252,336**
PEPCO	713,020	73,971	14	117	0	**787,122**	483,569	47,508	13	90	0	**531,180**
SMECO	137,963	14,461	2	304	0	**152,730**	137,963	14,461	2	304	0	**152,730**
Thurmont	2,452	336	10	44	0	**2,842**	2,452	336	10	44	0	**2,842**
Williamsport	854	110	29	9	0	**1,002**	854	110	29	9	0	**1,002**
Total	**2,822,869**	**320,193**	**11,418**	**2,059**	**5**	**3,156,544**	**2,208,732**	**244,269**	**9,182**	**1,334**	**3**	**2,463,520**

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 1(b)(ii): Utilities' 2011 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	24	3	12	0	0	**40**	24	3	12	0	0	**40**
BGE	12,652	16,479	2,678	0	0	**31,809**	12,652	16,479	2,678	0	0	**31,809**
Choptank	693	217	92	1	0	**1,002**	693	217	92	1	0	**1,002**
DPL	5,256	5,276	2,215	49	0	**12,796**	2,190	1,754	402	12	0	**4,358**
Easton	112	151	0	0	0	**263**	112	151	0	0	0	**263**
Hagerstown	156	102	70	0	0	**328**	156	102	70	0	0	**328**
PE	5,075	2,876	2,279	21	1,413	**11,664**	3,293	2,057	1,483	16	1,411	**8,260**
PEPCO	8,106	17,470	685	76	0	**26,337**	6,030	8,567	468	74	0	**15,139**
SMECO	2,114	1,194	123	6	0	**3,438**	2,114	1,194	123	6	0	**3,438**
Thurmont	38	17	27	1	0	**82**	38	17	27	1	0	**82**
Williamsport	10	2	7	0	0	**20**	9	2	7	0	0	**18**
Total	**34,235**	**43,788**	**8,189**	**154**	**1,413**	**87,778**	**27,310**	**30,543**	**5,362**	**110**	**1,411**	**64,737**

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

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

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Total
2012	38	31,326	1,014	4,251	275	317	7,550	15,207	3,627	**63,605**
2013	39	31,673	1,054	4,342	277	301	7,629	15,324	3,723	**64,361**
2014	40	32,282	1,117	4,457	279	302	7,805	15,494	3,817	**65,593**
2015	40	32,947	1,173	4,556	282	304	7,979	15,687	3,906	**66,875**
2016	40	33,563	1,221	4,655	284	305	8,126	15,844	3,997	**68,036**
2017	41	33,727	1,262	4,764	287	307	8,222	15,962	4,068	**68,640**
2018	41	33,892	1,301	4,835	289	308	8,319	16,066	4,139	**69,189**
2019	42	34,057	1,342	4,913	291	310	8,426	16,164	4,211	**69,757**
2020	42	34,224	1,387	4,987	294	311	8,533	16,250	4,276	**70,305**
2021	43	34,391	1,435	5,060	296	313	8,645	16,310	4,344	**70,837**
Change (2012-2021)	5	3,066	421	809	21	(4)	1,095	1,103	717	**7,232**
Percent Change (2012-2021)	11.79%	9.79%	41.50%	19.03%	7.72%	-1.26%	14.50%	7.25%	19.78%	**11.37%**
Compound Annual Growth Rate	1.25%	1.04%	3.93%	1.95%	0.83%	-0.14%	1.52%	0.78%	2.03%	**1.20%**

Note: A&N, Somerset, Thurmont, and Williamsport 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
2012	38	31,142	1,013	4,184	275	317	7,416	14,858	3,561	**62,804**
2013	39	30,930	1,052	4,270	277	301	7,429	14,829	3,628	**62,755**
2014	40	31,185	1,116	4,350	279	302	7,539	14,854	3,695	**63,360**
2015	40	31,512	1,172	4,415	282	304	7,652	14,902	3,758	**64,037**
2016	40	31,790	1,219	4,479	284	305	7,783	14,913	3,824	**64,637**
2017	41	31,954	1,260	4,553	287	307	7,883	14,886	3,895	**65,065**
2018	41	32,119	1,300	4,623	289	308	7,980	14,990	3,965	**65,614**
2019	42	32,284	1,341	4,701	291	310	8,088	15,088	4,037	**66,182**
2020	42	32,451	1,385	4,776	294	311	8,190	15,174	4,103	**66,726**
2021	43	32,618	1,434	4,848	296	313	8,306	15,233	4,170	**67,261**
Change (2012-2021)	**5**	**1,476**	**421**	**664**	**21**	**(4)**	**890**	**376**	**609**	**4,458**
Percent Change (2012-2021)	**11.79%**	**4.74%**	**41.56%**	**15.88%**	**7.72%**	**-1.26%**	**12.00%**	**2.53%**	**17.12%**	**7.10%**
Compound Annual Growth Rate	**1.25%**	**0.52%**	**3.94%**	**1.65%**	**0.83%**	**-0.14%**	**1.27%**	**0.28%**	**1.77%**	**0.76%**

Note: A&N, Somerset, Thurmont, and Williamsport 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
2012	38	31,326	1,014	12,738	275	317	14,343	26,827	3,627	**90,505**
2013	39	31,673	1,054	13,102	277	301	14,502	27,170	3,723	**91,841**
2014	40	32,282	1,117	13,430	279	302	14,797	27,607	3,817	**93,672**
2015	40	32,947	1,173	13,696	282	304	15,084	28,014	3,906	**95,446**
2016	40	33,563	1,221	13,963	284	305	15,337	28,355	3,997	**97,067**
2017	41	33,727	1,262	14,235	287	307	15,518	28,631	4,068	**98,075**
2018	41	33,892	1,301	14,439	289	308	15,703	28,862	4,139	**98,973**
2019	42	34,057	1,342	14,661	291	310	15,904	29,097	4,211	**99,915**
2020	42	34,224	1,387	14,894	294	311	16,105	29,323	4,276	**100,856**
2021	43	34,391	1,435	15,152	296	313	16,312	29,533	4,344	**101,819**
Change (2012-2021)	**5**	**3,066**	**421**	**2,414**	**21**	**(4)**	**1,968**	**2,706**	**717**	**11,314**
Percent Change (2012-2021)	**11.79%**	**9.79%**	**41.50%**	**18.95%**	**7.72%**	**-1.26%**	**13.72%**	**10.09%**	**19.78%**	**12.50%**
Compound Annual Growth Rate	**1.25%**	**1.04%**	**3.93%**	**1.95%**	**0.83%**	**-0.14%**	**1.44%**	**1.07%**	**2.03%**	**1.32%**

Note: A&N, Somerset, Thurmont, and Williamsport 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
2012	38	31,142	1,013	12,647	275	317	14,208	26,436	3,561	**89,637**
2013	39	30,930	1,052	13,006	277	301	14,297	26,633	3,628	**90,164**
2014	40	31,185	1,116	13,298	279	302	14,524	26,925	3,695	**91,364**
2015	40	31,512	1,172	13,529	282	304	14,748	27,186	3,758	**92,530**
2016	40	31,790	1,219	13,760	284	305	14,982	27,382	3,824	**93,586**
2017	41	31,954	1,260	13,997	287	307	15,164	27,512	3,895	**94,416**
2018	41	32,119	1,300	14,201	289	308	15,349	27,743	3,965	**95,314**
2019	42	32,284	1,341	14,423	291	310	15,550	27,978	4,037	**96,255**
2020	42	32,451	1,385	14,655	294	311	15,747	28,204	4,103	**97,192**
2021	43	32,618	1,434	14,914	296	313	15,958	28,414	4,170	**98,159**
Change (2012-2021)	**5**	**1,476**	**421**	**2,267**	**21**	**(4)**	**1,749**	**1,978**	**609**	**8,522**
Percent Change (2012-2021)	**11.79%**	**4.74%**	**41.56%**	**17.92%**	**7.72%**	**-1.26%**	**12.31%**	**7.48%**	**17.12%**	**9.51%**
Compound Annual Growth Rate	**1.25%**	**0.52%**	**3.94%**	**1.85%**	**0.83%**	**-0.14%**	**1.30%**	**0.80%**	**1.77%**	**1.01%**

Note: A&N, Somerset, Thurmont, and Williamsport 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): Typical Monthly Electric Bills of Maryland Customers Utility Sales Only

Appendix Table 3(a)(i): Average Winter Month, 2011

	Energy Use (kWh)				Typical Bill ($)				Revenue ($/kWh)			
Utility	Residential	Commercial	Industrial	Other	Residential	Commercial	Industrial	Other	Residential	Commercial	Industrial	Other
Berlin	1,280	1,035	8,798	1,636	$185.49	$193.93	$1,417.70	$369.78	$0.1449	$0.1874	$0.1611	$0.2260
BGE	1,230	4,474	6,678	N/A	$168.76	$546.11	$721.07	N/A	$0.1372	$0.1221	$0.1080	N/A
Choptank	1,458	3,537	314,773	275	$116.85	$258.64	$22,321.66	$16.60	$0.0801	$0.0731	$0.0709	$0.0604
DPL	1,306	5,492	132,957	3,806	$159.32	$280.52	$1,935.90	$830.72	$0.1220	$0.0511	$0.0146	$0.2183
Easton	1,225	4,901	N/A	N/A	$115.33	$473.63	N/A	N/A	$0.0942	$0.0966	N/A	N/A
PE	1,237	6,264	42,844	N/A	$138.28	$769.69	$3,782.19	N/A	$0.1118	$0.1229	$0.0883	N/A
PEPCO	1,178	14,747	3,013,976	81,517	$141.88	$678.57	$66,708.30	$3,159.00	$0.1204	$0.0460	$0.0221	$0.0388
SMECO	1,695	7,037	N/A	N/A	$223.25	$886.66	N/A	N/A	$0.1317	$0.1260	N/A	N/A
Total	**10,609**	**47,487**	**3,520,026**	**87,234**	**$1,249.16**	**$4,087.74**	**$96,886.82**	**$4,376.10**	**$0.1177**	**$0.0861**	**$0.0275**	**$0.0502**

Note: A&N, Hagerstown, Somerset, Thurmont, and Williamsport did not report applicable information for this table.
Note: For those utilities that have retail competition available, bills and revenues reflect SOS, distribution service and any non-bypassable charges.

Appendix Table 3(a)(ii): Average Summer Month, 2011

	Energy Use (kWh)				Typical Bill ($)				Revenue ($/kWh)			
Utility	Residential	Commercial	Industrial	Other	Residential	Commercial	Industrial	Other	Residential	Commercial	Industrial	Other
Berlin	1,031	933	10,811	1,663	$152.44	$179.31	$1,707.37	$379.62	$0.1479	$0.1922	$0.1579	$0.2283
BGE	1,341	4,280	5,917	N/A	$176.24	$502.47	$640.63	N/A	$0.1314	$0.1174	$0.1083	N/A
Choptank	1,277	4,585	344,824	276	$102.39	$341.77	$25,079.31	$16.62	$0.0802	$0.0745	$0.0727	$0.0602
DPL	1,121	6,530	150,420	3,802	$141.54	$321.06	$2,028.73	$824.38	$0.1263	$0.0492	$0.0135	$0.2168
Easton	1,265	5,875	N/A	N/A	$143.50	$642.37	N/A	N/A	$0.1135	$0.1093	N/A	N/A
PE	1,237	6,264	42,844	N/A	$125.38	$791.55	$3,620.46	N/A	$0.1014	$0.1264	$0.0845	N/A
PEPCO	1,203	16,811	3,281,728	57,228	$153.15	$870.56	$73,914.84	$2,054.05	$0.1273	$0.0518	$0.0225	$0.0359
SMECO	1,414	8,028	N/A	N/A	$205.59	$1,093.05	N/A	N/A	$0.1454	$0.1362	N/A	N/A
Total	**9,889**	**53,305**	**3,836,544**	**62,969**	**$1,200.23**	**$4,742.14**	**$106,991.33**	**$3,274.67**	**$0.1214**	**$0.0890**	**$0.0279**	**$0.0520**

Note: A&N, Hagerstown, Somerset, Thurmont, and Williamsport did not report applicable information for this table.
Note: For those utilities that have retail competition available, bills and revenues reflect SOS, distribution service and any non-bypassable charges.

Appendix Table 3(a)(iii): Average Month on Annual Basis, 2011

	Energy Use (kWh)				Typical Bill ($)				Revenue ($/kWh)			
Utility	Residential	Commercial	Industrial	Other	Residential	Commercial	Industrial	Other	Residential	Commercial	Industrial	Other
Berlin	1,002	893	9,207	1,636	$147.97	$169.95	$1,470.89	$370.79	$0.1476	$0.1904	$0.1598	$0.2267
BGE	957	3,990	5,479	N/A	$131.24	$474.34	$571.65	N/A	$0.1372	$0.1189	$0.1043	N/A
Choptank	1,222	3,805	332,214	276	$97.94	$282.41	$23,730.33	$16.62	$0.0801	$0.0742	$0.0714	$0.0602
DPL	1,052	5,697	139,650	3,798	$131.12	$281.15	$1,912.45	$825.84	$0.1246	$0.0494	$0.0137	$0.2174
Easton	1,184	5,239	N/A	N/A	$128.55	$569.05	N/A	N/A	$0.1086	$0.1086	N/A	N/A
PE	1,237	6,264	42,844	N/A	$130.52	$771.06	$3,672.33	N/A	$0.1055	$0.1231	$0.0857	N/A
PEPCO	1,039	15,028	3,017,359	68,070	$128.70	$728.11	$70,886.55	$2,547.07	$0.1239	$0.0485	$0.0235	$0.0374
SMECO	1,309	7,164	N/A	N/A	$182.56	$932.10	N/A	N/A	$0.1395	$0.1301	N/A	N/A
Total	**9,002**	**48,081**	**3,546,753**	**73,780**	**$1,078.60**	**$4,208.18**	**$102,244.20**	**$3,760.32**	**$0.1198**	**$0.0875**	**$0.0288**	**$0.0510**

Note: "Average Month on Annual Basis" reflects a monthly average between January 1 and December 31.
Note: A&N, Hagerstown, Somerset, Thurmont, and Williamsport did not report applicable information for this table.
Note: For those utilities that have retail competition available, bills and revenues reflect SOS, distribution service and any non-bypassable charges.

Appendix Table 3(b): Typical Monthly Electric Bills of Maryland Customers Utility and Distribution Sales

Appendix Table 3(b)(i): Average Winter Month, 2011

	Energy Use (kWh)				Typical Bill ($)				Revenue ($/kWh)			
Utility	**Residential**	**Commercial**	**Industrial**	**Other**	**Residential**	**Commercial**	**Industrial**	**Other**	**Residential**	**Commercial**	**Industrial**	**Other**
Berlin	1,280	1,035	8,798	1,636	$185.49	$193.93	$1,417.70	$369.78	$0.1449	$0.1874	$0.1611	$0.2260
BGE	1,256	12,132	38,214	N/A	$148.16	$526.62	$830.05	N/A	$0.1180	$0.0434	$0.0217	N/A
Choptank	1,458	3,537	314,773	275	$187.99	$421.77	$29,529.04	$71.95	$0.1289	$0.1192	$0.0938	$0.2616
DPL	1,306	5,492	132,957	3,806	$159.32	$280.52	$1,935.90	$830.72	$0.1220	$0.0511	$0.0146	$0.2183
Easton	1,225	4,901	N/A	N/A	$115.33	$473.63	N/A	N/A	$0.0942	$0.0966	N/A	N/A
Hagerstown	1,161	3,565	119,804	N/A	$118.97	$372.71	$11,025.07	N/A	$0.1025	$0.1045	$0.0920	N/A
PE	1,237	6,264	42,844	N/A	$36.90	$218.24	$694.66	N/A	$0.0298	$0.0348	$0.0162	N/A
PEPCO	1,178	14,747	3,013,976	81,517	$141.88	$678.57	$66,708.30	$3,159.00	$0.1204	$0.0460	$0.0221	$0.0388
SMECO	1,695	7,037	N/A	N/A	$223.25	$886.66	N/A	N/A	$0.1317	$0.1260	N/A	N/A
Thurmont	1,785	4,669	249,193	1,547	$168.86	$444.86	$21,469.81	$168.79	$0.0946	$0.0953	$0.0862	$0.1091
Williamsport	1,319	2,368	26,043	1,943	$119.17	$221.61	$2,445.59	$212.09	$0.0903	$0.0936	$0.0939	$0.1091
Total	**14,900**	**65,748**	**3,946,601**	**90,724**	**$1,605.32**	**$4,719.12**	**$136,056.12**	**$4,812.33**	**$0.1077**	**$0.0718**	**$0.0345**	**$0.0530**

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

Note: For those utilities that have retail competition available, bills and revenues reflect SOS, distribution service and any non-bypassable charges.

Appendix Table 3(b)(ii): Average Summer Month, 2011

	Energy Use (kWh)				Typical Bill ($)				Revenue ($/kWh)			
Utility	**Residential**	**Commercial**	**Industrial**	**Other**	**Residential**	**Commercial**	**Industrial**	**Other**	**Residential**	**Commercial**	**Industrial**	**Other**
Berlin	1,031	933	10,811	1,663	$152.44	$179.31	$1,707.37	$379.62	$0.1479	$0.1922	$0.1579	$0.2283
BGE	1,368	13,617	45,158	N/A	$147.80	$535.37	$927.17	N/A	$0.1080	$0.0393	$0.0205	N/A
Choptank	1,277	4,585	344,824	276	$165.94	$547.01	$32,815.41	$72.16	$0.1299	$0.1193	$0.0952	$0.2614
DPL	1,121	6,530	150,420	3,802	$141.54	$321.06	$2,028.73	$824.38	$0.1263	$0.0492	$0.0135	$0.2168
Easton	1,265	5,875	N/A	N/A	$143.50	$642.37	N/A	N/A	$0.1135	$0.1093	N/A	N/A
Hagerstown	878	3,471	139,951	N/A	$81.18	$329.04	$11,228.16	N/A	$0.0925	$0.0948	$0.0802	N/A
PE	1,237	6,264	42,844	N/A	$36.83	$222.08	$727.93	N/A	$0.0298	$0.0355	$0.0170	N/A
PEPCO	1,203	16,811	3,281,728	57,228	$153.15	$870.56	$73,914.84	$2,054.05	$0.1273	$0.0518	$0.0225	$0.0359
SMECO	1,414	8,028	N/A	N/A	$205.59	$1,093.05	N/A	N/A	$0.1454	$0.1362	N/A	N/A
Thurmont	1,196	4,189	220,417	1,527	$113.02	$363.87	$17,281.82	$155.55	$0.0945	$0.0869	$0.0784	$0.1018
Williamsport	882	1,547	19,869	1,943	$79.16	$135.12	$1,754.81	$202.73	$0.0898	$0.0874	$0.0883	$0.1043
Total	**12,871**	**71,850**	**4,256,021**	**66,439**	**$1,420.15**	**$5,238.84**	**$142,386.23**	**$3,688.49**	**$0.1103**	**$0.0729**	**$0.0335**	**$0.0555**

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

Note: For those utilities that have retail competition available, bills and revenues reflect SOS, distribution service and any non-bypassable charges.

Appendix Table 3(b)(iii): Average Month on Annual Basis, 2011

	Energy Use (kWh)				Typical Bill ($)				Revenue ($/kWh)			
Utility	**Residential**	**Commercial**	**Industrial**	**Other**	**Residential**	**Commercial**	**Industrial**	**Other**	**Residential**	**Commercial**	**Industrial**	**Other**
Berlin	1,002	893	9,207	1,636	$147.97	$169.95	$1,470.89	$370.79	$0.1476	$0.1904	$0.1598	$0.2267
BGE	944	11,550	38,323	N/A	$108.64	$464.28	$737.08	N/A	$0.1150	$0.0402	$0.0192	N/A
Choptank	1,222	3,805	332,214	276	$159.17	$457.16	$31,256.31	$72.13	$0.1303	$0.1201	$0.0941	$0.2613
DPL	1,052	5,697	139,650	3,798	$131.12	$281.15	$1,912.45	$825.84	$0.1246	$0.0494	$0.0137	$0.2174
Easton	1,184	5,239	N/A	N/A	$128.55	$569.05	N/A	N/A	$0.1086	$0.1086	N/A	N/A
Hagerstown	878	3,252	126,427	N/A	$81.56	$309.65	$10,228.41	N/A	$0.0929	$0.0952	$0.0809	N/A
PE	1,237	6,264	42,844	N/A	$37.06	$221.87	$726.60	N/A	$0.0300	$0.0354	$0.0170	N/A
PEPCO	1,039	15,028	3,017,359	68,070	$128.70	$728.11	$70,886.55	$2,547.07	$0.1239	$0.0485	$0.0235	$0.0374
SMECO	1,309	7,164	N/A	N/A	$182.56	$932.10	N/A	N/A	$0.1395	$0.1301	N/A	N/A
Thurmont	1,301	4,140	222,599	1,545	$125.74	$380.76	$18,466.14	$163.17	$0.0966	$0.0920	$0.0830	$0.1056
Williamsport	942	1,876	21,279	1,943	$85.41	$170.76	$1,966.79	$208.34	$0.0907	$0.0910	$0.0924	$0.1072
Total	**12,110**	**64,909**	**3,949,903**	**77,268**	**$1,316.49**	**$4,684.84**	**$137,651.22**	**$4,187.35**	**$0.1087**	**$0.0722**	**$0.0348**	**$0.0542**

Note: "Average Month on Annual Basis" reflects a monthly average between January 1 and December 31.

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

Note: For those utilities that have retail competition available, bills and revenues reflect SOS, distribution service and any non-bypassable charges.

Appendix Table 4(a): Peak Demand Forecasts (Maryland Service Territory Only)

Appendix Table 4(a)(i): Maryland Summer, Gross of DSM Programs (MW)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Total
2012	11	7,221	239	986	69	65	1,468	3,668	881	**14,609**
2013	11	7,314	246	999	71	63	1,477	3,703	891	**14,773**
2014	11	7,457	259	1,021	72	63	1,505	3,764	909	**15,060**
2015	11	7,595	270	1,041	73	64	1,531	3,814	926	**15,325**
2016	11	7,677	280	1,054	74	64	1,555	3,834	942	**15,491**
2017	11	7,744	288	1,064	75	64	1,568	3,859	958	**15,632**
2018	11	7,802	297	1,076	77	65	1,583	3,886	975	**15,771**
2019	11	7,875	306	1,090	78	65	1,600	3,919	991	**15,935**
2020	12	7,964	315	1,104	79	65	1,620	3,958	1,009	**16,126**
2021	12	8,028	326	1,115	80	66	1,636	3,979	1,025	**16,267**
Change (2012-2021)	**1**	**807**	**87**	**129**	**11**	**1**	**168**	**311**	**144**	**1,658**
Percent Change (2012-2021)	**6.50%**	**11.18%**	**36.46%**	**13.09%**	**16.03%**	**1.54%**	**11.46%**	**8.46%**	**16.29%**	**11.35%**
Compound Annual Growth Rate	**0.70%**	**1.18%**	**3.51%**	**1.38%**	**1.67%**	**0.17%**	**1.21%**	**0.91%**	**1.69%**	**1.20%**

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

Appendix Table 4(a)(ii): Maryland Summer, Net of DSM Programs (MW)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Total
2012	7	7,179	229	938	69	65	1,462	3,477	836	**14,262**
2013	4	7,143	236	923	71	63	1,462	3,267	841	**14,009**
2014	4	7,204	249	924	72	63	1,481	3,243	857	**14,096**
2015	4	7,264	260	879	73	64	1,507	3,226	873	**14,150**
2016	4	7,271	270	865	74	64	1,531	3,180	889	**14,149**
2017	4	7,337	278	857	75	64	1,544	3,139	905	**14,204**
2018	4	7,394	287	868	77	65	1,559	3,165	922	**14,341**
2019	5	7,465	295	883	78	65	1,577	3,198	938	**14,504**
2020	5	7,551	305	897	79	65	1,596	3,238	956	**14,692**
2021	5	7,614	316	907	80	66	1,612	3,259	972	**14,831**
Change (2012-2021)	**(3)**	**435**	**87**	**(30)**	**11**	**1**	**150**	**(219)**	**136**	**569**
Percent Change (2012-2021)	**-34.19%**	**6.06%**	**38.08%**	**-3.23%**	**16.03%**	**1.54%**	**10.29%**	**-6.29%**	**16.29%**	**3.99%**
Compound Annual Growth Rate	**-4.54%**	**0.66%**	**3.65%**	**-0.36%**	**1.67%**	**0.17%**	**1.09%**	**-0.72%**	**1.69%**	**0.44%**

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

Appendix Table 4(a): Peak Demand Forecasts (Maryland Service Territory Only)

Appendix Table 4(a)(iii): Maryland Winter, Gross of DSM Programs (MW)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Total
2012	10	5,983	210	930	59	59	1,566	2,851	743	**12,412**
2013	12	6,016	229	939	60	59	1,587	2,874	833	**12,610**
2014	12	6,061	243	947	61	60	1,617	2,905	850	**12,757**
2015	13	6,129	257	963	61	60	1,646	2,946	867	**12,942**
2016	13	6,184	268	976	62	60	1,663	2,981	884	**13,091**
2017	13	6,232	280	987	63	60	1,677	3,015	901	**13,228**
2018	13	6,259	290	994	64	61	1,693	3,037	919	**13,330**
2019	13	6,295	301	1,003	64	61	1,712	3,060	937	**13,447**
2020	13	6,315	307	1,009	65	61	1,728	3,080	955	**13,533**
2021	13	6,353	324	1,019	66	62	1,746	3,101	972	**13,656**
Change (2012-2021)	**3**	**370**	**114**	**90**	**6**	**3**	**180**	**250**	**229**	**1,245**
Percent Change (2012-2021)	**31.14%**	**6.18%**	**54.10%**	**9.64%**	**10.45%**	**5.08%**	**11.50%**	**8.77%**	**30.76%**	**10.03%**
Compound Annual Growth Rate	**3.06%**	**0.67%**	**4.92%**	**1.03%**	**1.11%**	**0.55%**	**1.22%**	**0.94%**	**3.02%**	**1.07%**

Note: A&N, Somerset, Thurmont, and Williamsport did not report applicable information for this table.
Note: SMECO's 2012 value represents actual peak winter load for the SMECO service territory. All other Utilities' responses represent forecasts for the 2012 – 2021 planning period.

Appendix Table 4(a)(iv): Maryland Winter, Net of DSM Programs (MW)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Total
2012	10	5,948	200	930	59	59	1,555	2,851	743	**12,356**
2013	12	5,875	219	939	60	59	1,567	2,874	833	**12,439**
2014	12	5,855	233	947	61	60	1,597	2,905	850	**12,521**
2015	13	5,862	246	963	61	60	1,626	2,946	867	**12,645**
2016	13	5,857	258	976	62	60	1,643	2,981	884	**12,734**
2017	13	5,904	270	987	63	60	1,657	3,015	901	**12,870**
2018	13	5,932	280	994	64	61	1,673	3,037	919	**12,973**
2019	13	5,967	291	1,003	64	61	1,692	3,060	937	**13,089**
2020	13	5,988	297	1,009	65	61	1,708	3,080	955	**13,176**
2021	13	6,025	314	1,019	66	62	1,726	3,101	972	**13,299**
Change (2012-2021)	**3**	**77**	**114**	**90**	**6**	**3**	**171**	**250**	**229**	**943**
Percent Change (2012-2021)	**31.14%**	**1.30%**	**56.83%**	**9.64%**	**10.45%**	**5.08%**	**10.99%**	**8.77%**	**30.76%**	**7.63%**
Compound Annual Growth Rate	**3.06%**	**0.14%**	**5.13%**	**1.03%**	**1.11%**	**0.55%**	**1.16%**	**0.94%**	**3.02%**	**0.82%**

Note: A&N, Somerset, Thurmont, and Williamsport did not report applicable information for this table.
Note: SMECO's 2012 value represents actual peak winter load for the SMECO service territory. All other Utilities' responses represent forecasts for the 2012 – 2021 planning period.

Appendix Table 4(b): Peak Demand Forecasts (System Wide)

Appendix Table 4(b)(i): System Wide Summer, Gross of DSM (MW)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Total
2012	11	7,221	239	4,111	69	65	2,765	6,876	881	**22,238**
2013	11	7,314	246	4,166	71	63	2,787	6,940	891	**22,487**
2014	11	7,457	259	4,256	72	63	2,835	7,056	909	**22,917**
2015	11	7,595	270	4,342	73	64	2,880	7,149	926	**23,309**
2016	11	7,677	280	4,393	74	64	2,922	7,187	942	**23,550**
2017	11	7,744	288	4,438	75	64	2,948	7,234	958	**23,760**
2018	11	7,802	297	4,485	77	65	2,978	7,283	975	**23,972**
2019	11	7,875	306	4,545	78	65	3,011	7,345	991	**24,227**
2020	12	7,964	315	4,604	79	65	3,047	7,419	1,009	**24,514**
2021	12	8,028	326	4,649	80	66	3,079	7,458	1,025	**24,723**
Change (2012-2021)	**1**	**807**	**87**	**538**	**11**	**1**	**314**	**582**	**144**	**2,484**
Percent Change (2012-2021)	**6.50%**	**11.18%**	**36.46%**	**13.09%**	**16.03%**	**1.54%**	**11.34%**	**8.46%**	**16.29%**	**11.17%**
Compound Annual Growth Rate	**0.70%**	**1.18%**	**3.51%**	**1.38%**	**1.67%**	**0.17%**	**1.20%**	**0.91%**	**1.69%**	**1.18%**

Note: A&N, Somerset, Thurmont, and Williamsport 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 4(b)(ii): System Wide Summer, Net of DSM (MW)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Total
2012	7	7,221	229	4,057	69	65	2,759	6,680	836	**21,924**
2013	4	7,314	236	3,996	71	63	2,772	6,483	841	**21,779**
2014	4	7,457	249	4,009	72	63	2,811	6,505	857	**22,026**
2015	4	7,595	260	4,026	73	64	2,856	6,531	873	**22,282**
2016	4	7,677	270	4,028	74	64	2,898	6,503	889	**22,407**
2017	4	7,744	278	4,057	75	64	2,924	6,484	905	**22,536**
2018	4	7,802	287	4,104	77	65	2,954	6,533	922	**22,747**
2019	5	7,875	295	4,164	78	65	2,987	6,595	938	**23,002**
2020	5	7,964	305	4,223	79	65	3,023	6,669	956	**23,289**
2021	5	8,028	316	4,268	80	66	3,055	6,708	972	**23,498**
Change (2012-2021)	**(3)**	**807**	**87**	**211**	**11**	**1**	**296**	**28**	**136**	**1,574**
Percent Change (2012-2021)	**-34.19%**	**11.18%**	**38.08%**	**5.19%**	**16.03%**	**1.54%**	**10.72%**	**0.42%**	**16.29%**	**7.18%**
Compound Annual Growth Rate	**-4.54%**	**1.18%**	**3.65%**	**0.56%**	**1.67%**	**0.17%**	**1.14%**	**0.05%**	**1.69%**	**0.77%**

Note: A&N, Somerset, Thurmont, and Williamsport 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 4(b): Peak Demand Forecasts (System Wide)

Appendix Table 4(b)(iii): System Wide Winter, Gross of DSM (MW)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Total
2012	10	5,983	210	3,361	59	59	3,091	5,448	743	**18,965**
2013	12	6,016	229	3,394	60	59	3,134	5,492	833	**19,230**
2014	12	6,061	243	3,424	61	60	3,188	5,552	850	**19,451**
2015	13	6,129	257	3,482	61	60	3,240	5,629	867	**19,738**
2016	13	6,184	268	3,528	62	60	3,275	5,696	884	**19,970**
2017	13	6,232	280	3,567	63	60	3,306	5,762	901	**20,184**
2018	13	6,259	290	3,594	64	61	3,340	5,804	919	**20,344**
2019	13	6,295	301	3,627	64	61	3,379	5,848	937	**20,525**
2020	13	6,315	307	3,648	65	61	3,412	5,885	955	**20,662**
2021	13	6,353	324	3,685	66	62	3,448	5,926	972	**20,849**
Change (2012-2021)	**3**	**370**	**114**	**324**	**6**	**3**	**357**	**478**	**229**	**1,884**
Percent Change (2012-2021)	**31.14%**	**6.18%**	**54.10%**	**9.64%**	**10.45%**	**5.08%**	**11.56%**	**8.77%**	**30.76%**	**9.93%**
Compound Annual Growth Rate	**3.06%**	**0.67%**	**4.92%**	**1.03%**	**1.11%**	**0.55%**	**1.22%**	**0.94%**	**3.02%**	**1.06%**

Note: A&N, Somerset, Thurmont, and Williamsport 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 4(b)(iv): System Wide Winter, Net of DSM (MW)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Total
2012	10	5,983	200	3,361	59	59	3,080	5,448	743	**18,944**
2013	12	6,016	219	3,394	60	59	3,114	5,492	833	**19,200**
2014	12	6,061	233	3,424	61	60	3,168	5,552	850	**19,421**
2015	13	6,129	246	3,482	61	60	3,220	5,629	867	**19,708**
2016	13	6,184	258	3,528	62	60	3,255	5,696	884	**19,940**
2017	13	6,232	270	3,567	63	60	3,286	5,762	901	**20,154**
2018	13	6,259	280	3,594	64	61	3,320	5,804	919	**20,313**
2019	13	6,295	291	3,627	64	61	3,359	5,848	937	**20,495**
2020	13	6,315	297	3,648	65	61	3,392	5,885	955	**20,631**
2021	13	6,353	314	3,685	66	62	3,428	5,926	972	**20,819**
Change (2012-2021)	**3**	**370**	**114**	**324**	**6**	**3**	**348**	**478**	**229**	**1,875**
Percent Change (2012-2021)	**31.14%**	**6.18%**	**56.83%**	**9.64%**	**10.45%**	**5.08%**	**11.29%**	**8.77%**	**30.76%**	**9.90%**
Compound Annual Growth Rate	**3.06%**	**0.67%**	**5.13%**	**1.03%**	**1.11%**	**0.55%**	**1.20%**	**0.94%**	**3.02%**	**1.05%**

Note: A&N, Somerset, Thurmont, and Williamsport 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 5: Transmission Enhancements, by Service Territory

Transmission Owner	Voltage (kV)	Length (miles)	No. of Circuits	Start Date	Comp. Date	In-Service Date	Purpose	Start location		End Location	
								County	Terminal	County	Terminal
BGE	115	3	2	6/1/2008	6/1/2014	6/1/2014	Distribution Adequacy	Baltimore City	Westport	Baltimore City	Wilkens
BGE	115	3.3	1	4/1/2010	6/1/2014	6/1/2014	Baseline Transmission Reliability	Baltimore Co.	Deer Park	Baltimore Co.	Northwest
BGE	230	8.6	1	1/1/2011	6/1/2015	6/1/2015	Baseline Transmission Reliability	Harford	Conastone	Harford	Graceton
BGE	230	13.7	1	1/1/2009	6/1/2015	6/1/2015	Baseline Transmission Reliability	Harford	Graceton	Harford	Bagley
BGE	115	0.6	2	6/1/2012	6/1/2016	6/1/2016	Distribution Adequacy	Baltimore City	Coldspring	Baltimore City	Melvale
BGE	230	6.1	2	4/1/2007	6/1/2016	6/1/2016	Baseline Transmission Reliability	Harford	Raphael Rd	Harford	Bagley
BGE	115	1	2	9/1/2009	6/1/2017	6/1/2017	Baseline Transmission Reliability	Baltimore City	Orchard St	Baltimore City	Constitution St
BGE	230	4	2	1/1/2010	6/1/2017	6/1/2017	Baseline Transmission Reliability	Baltimore Co.	Northwest	Baltimore Co.	Hanover Pike
BGE	230	11.7	2	6/1/2007	6/1/2017	6/1/2017	Baseline Transmission Reliability	Harford	Raphael Rd	Harford	Perryman
BGE	230	8	2	6/1/2015	6/1/2017	6/1/2017	Baseline Transmission Reliability	Anne Arundel	Marley Station	Anne Arundel	Jones Station
BGE	115	5.2	2	1/1/2012	6/1/2018	6/1/2018	Distribution Adequacy	Baltimore City	Erdman	Baltimore City	Argonne
DPL	138	24	1	7/1/2014	5/31/2015	5/31/2015	Baseline Transmission Reliability	Queen Annes	Wye Mills	Queen Annes	Church
DPL	69	11.7	1	1/1/2014	5/31/2015	5/31/2015	Supplemental Transmission Reliability	Queen Annes	Wye Mills	Queen Annes	Stevensville
DPL	69	4.42	1	1/1/2015	5/31/2015	5/31/2015	Supplemental Transmission Reliability	Wicomico	Sharptown	Dorchester	Vienna
DPL	69	2.61	1	1/1/2012	12/1/2013	12/1/2013	Baseline Transmission Reliability	Worcester	Ocean Bay	Worcester	Maridel
DPL	69	18.41	1	1/1/2012	12/31/2012	12/31/2012	Baseline Transmission Reliability	Dorchester	Todd	Talbot	Trappe
DPL	138	12.33	1	7/1/2013	5/31/2014	5/31/2014	Baseline Transmission Reliability	New Castle	Townsend	Queen Annes	Church
DPL	230	28.28	1	9/1/2016	5/31/2017	5/31/2017	Baseline Transmission Reliability	Caroline	Steele	Dorchester	Vienna
DPL	230	18.7	1	1/1/2016	5/31/2018	5/31/2018	Baseline Transmission Reliability	Somerset	Loretto	Dorchester	Vienna
DPL	230	9.51	1	1/1/2016	5/31/2018	5/31/2018	Baseline Transmission Reliability	Wicomico	Piney Grove	Somerset	Loretto
DPL	69	5.99	1	1/1/2016	10/31/2018	10/31/2018	Distribution Adequacy	Queen Annes	Grasonville	Queen Annes	Queenstown
DPL	69	5.99	1	1/1/2016	10/31/2018	10/31/2018	Distribution Adequacy	Queen Annes	Wye Mills	Queen Annes	Queenstown
DPL	69	2.25	1	1/1/2015	10/31/2016	10/31/2016	Distribution Adequacy	Talbot	Trappe	Talbot	Lakeside
DPL	69	2.25	1	1/1/2015	10/1/2016	10/1/2016	Distribution Adequacy	Talbot	Talbot	Talbot	Lakeside
DPL	138	5.22	1	1/1/2015	6/1/2015	6/1/2015	Baseline Transmission Reliability	Cecil	Cecil	New Castle	Glasgow
DPL	138	N/A	N/A	4/30/2012	5/31/2013	5/31/2013	Baseline Transmission Reliability	Worcester	138th Street	Worcester	SVC site @ 138th Street
DPL	69	19.13	1	1/1/2014	5/31/2016	5/31/2016	Baseline Transmission Reliability	Accomack	Wattsville	Worcester	Kenney
DPL	69	15.04	1	1/1/2014	5/31/2015	5/31/2015	Baseline Transmission Reliability	Somerset	Crisfield	Somerset	Kings Creek
DPL	69	8.74	1	1/1/2014	12/31/2014	12/31/2014	Baseline Transmission Reliability	Worcester	Ocean City	Worcester	Worcester
DPL	138/230	-	-	6/1/2012	5/31/2013	5/31/2013	Baseline Transmission Reliability	Caroline	Steele	Caroline	Steele
DPL	138/230	-	-	10/1/2010	5/31/2013	5/31/2013	Baseline Transmission Reliability	Cecil	Cecil	Cecil	Cecil
DPL	138/230	-	-	1/1/2016	5/31/2017	5/31/2017	Baseline Transmission Reliability	Somerset	Loretto	Somerset	Loretto
DPL	138	12.33	1	1/1/2011	5/31/2012	5/31/2012	Baseline Transmission Reliability	Worcester	Bishop	Sussex	Indian River

Appendix Table 5 (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	16.7	1	Canc.	-	-	Baseline Transmission Reliability	Preston, WV	Albright	Garrett	Mt. Zion
PE	138	3.2	1	Canc.	-	-	Baseline Transmission Reliability	Garrett	Mt. Zion	Mineral, WV	Beryl
PE	230	9.8	1	Canc.	--	--	Baseline Transmission Reliability	Washington	Ringgold	Frederick	Catoctin
PE	230	10.7	1	Canc.	--	--	Baseline Transmission Reliability	Frederick	Walkersville	Frederick	Catoctin
PE	138	12.7	1	2012	2013	2013	Baseline Transmission Reliability	Frederick	Catoctin	Carroll	Carroll
PE	230	5.4	1	Canc.	--	--	Baseline Transmission Reliability	Frederick	Monocacy	Frederick	Walkersville
PE	138	6.1	1	Canc.	-	-	Baseline Transmission Reliability	Mineral, WV	Beryl	Allegany	Black Oak
PE	230	0	1	2015	2016	2016	Baseline Transmission Reliability	Frederick	Doubs	Frederick	Lime Kiln (Section 207)
PE	230	0	1	2015	2016	2016	Baseline Transmission Reliability	Frederick	Doubs	Frederick	Lime Kiln (Section 231)
PE	138	4.8	1	Canc.	-	-	Baseline Transmission Reliability	Berkeley, WV	Marlowe	Washington	Halfway
PE	138	0.1	2	2016	2017	2017	Distribution Adequacy	Garrett	Altamont (new)	Garrett	Albright – Mt. Zion
PE	138	4	1	Canc.	-	-	Baseline Transmission Reliability	Washington	Ringgold	Franklin, PA	East Waynesboro
PE	765	19.6	1	Susp.	--	--	Baseline Transmission Reliability	Hardy, WV	Welton Spring (new)	Frederick	Kemptown (new)
PE	230	24.9	1	Canc.	-	-	Baseline Transmission Reliability	Doubs	Frederick	Frederick	Monocacy
PE	138	0.1	2	Canc.	-	-	Distribution Adequacy	Washington	McDade (new)	Washington	Halfway – Paramount No.
PE	230	2.1	2	2018	2019	2019	Distribution Adequacy	Frederick	Urbana	Frederick	Lime Kiln - Montgomery
PE	230	0.1	2	Canc.	-	-	Distribution Adequacy	Frederick	Jefferson No. 1 (new)	Frederick	Doubs - Monocacy
PE	230	0.1	2	2019	2019	2019	Distribution Adequacy	Frederick	South Frederick No. 1	Frederick	Monocacy – Lime Kiln
PE	138	0.1	2	Canc.	-	-	Distribution Adequacy	Washington	Fairplay (new)	Washington	Marlowe - Boonsboro
PE	230	0.6	2	Canc.	-	-	Distribution Adequacy	Frederick	Ridgeville	Frederick	Mt. Airy - Damascus
PE	138	0.1	2	2013	2013	2013	Accommodate for Generator Interconnection (Note: Only	Allegany	Dans Mountain	Allegany	Carlos Junction-Ridgeley
PE	500	2.7	1	2013	2014	2014	Baseline Transmission Reliability	Frederick	VA State Line	Frederick	Doubs
PE	138	0.1	1	2012	2013	2013	Accommodate for Generator Interconnection (Note: Only	Garrett	Frostburg	Garrett	Jennings
PE	138	0	1	2016	2016	2016	Baseline Transmission Reliability	Washington	Halfway	Washington	Paramount
PE	138	0	1	2016	2016	2016	Baseline Transmission Reliability	Berkeley, WV	Nipetown	Washington	Reid
PE	138	0	1	2016	2016	2016	Baseline Transmission Reliability	Washington	Reid	Washington	Paramount
Pepco	230	10.7	2	1/2009	7/2011	7/2011	Baseline Transmission Reliability	Montgomery	Dickerson	Montgomery	Quince Orchard
Pepco	230	7.5	1	1/2009	6/2011	6/2011	Baseline Transmission Reliability	Montgomery	Dickerson	Loudoun (VA)	Pleasant View
Pepco	230	Bus Upgrade	2	1/2009	5/2012	5/2012	Baseline Transmission Reliability	Montgomery	Quince Orchard	Montgomery	Bells Mill Rd.
Pepco	230	5.34	2	8/2009	5/2012	5/2012	Baseline Transmission Reliability	DC	Benning	Prince George's	Ritchie
Pepco	230	6.42	4	1/2009	5/2012	5/2012	Baseline Transmission Reliability	Prince George's	Burches Hill	Prince George's	Palmers Corner
Pepco	230	5.01	4	1/2011	5/2013	5/2013	Baseline Transmission Reliability	Prince George's	Oak Grove	Prince George's	Ritchie

Appendix Table 5 (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
Pepco	230	10.98	1	1/2012	5/2014	5/2014	Baseline Transmission Reliability	Prince George's	Ritchie	DC	Buzzard Point
Pepco	230	10.83	1	1/2012	5/2014	5/2014	Baseline Transmission Reliability	Prince George's	Ritchie	DC	Buzzard Point
Pepco	230	8.84	2	10/2012	6/2015	6/2015	Transmission Ower Indentified Reliability	Prince George's	Burontsville	Prince George's	Takoma
Pepco	500	33	1	Susp	5/2017	5/2017	Baseline Transmission Reliability	Prince William (VA)	Possum Point	Prince George's	Burches Hill
Pepco	500	19	1	Susp	5/2017	5/2017	Baseline Transmission Reliability	Prince George's	Burches Hill	Charles	Chalk Point
Pepco	500	20	1	Susp	5/2017	5/2017	Baseline Transmission Reliability	Charles	Chalk Point	Calvert	Calvert Cliffs
SMECO	230	20	2	2012	2013	2013	Capacity	Calvert	Holland Cliff Sw. St.	Calvert	Sollers Wharf Sw. St.
SMECO	230	10	2	2014	2015	2015	Reliability	Calvert	Sollers Wharf Sw. St.	St. Mary's	Hewitt Rd. Sw. St.

Appendix Table 6: List of Maryland Generators, as of December 31, 2011

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	1.4%
Allegheny Energy Supply Co LLC	FirstEnergy R Paul Smith Power Station	Washington	109.5	115.0	0.9%
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	1,705.0	13.6%
Exelon Generation	Notch Cliff	Baltimore	144.0	116.7	7.7%
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	
Raven Power Holdings	Brandon Shores	Anne Arundel	1,370.0	1,273.0	21.0%
Raven Power Holdings	Herbert A Wagner	Anne Arundel	1,058.5	975.9	
Raven Power Holdings	C P Crane	Baltimore	415.8	399.0	
Constellation Solar Maryland, LLC	McCormick & Co. Inc. at Belcamp	Hartford	1.4	1.4	0.0%
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	0.3%
Easton Utilities Comm	Easton 2	Talbot	38.8	37.0	0.3%
Energy Recovery Operations, Inc	Harford Waste to Energy Facility	Harford	1.2	1.1	0.0%
Exelon Power	Conowingo	Harford	530.8	572.0	4.5%
FC Landfill Energy	FC Landfill Energy	Frederick	2.2	2.2	0.0%
GenOn	Chalk Point LLC	Prince Georges	2,647.0	2,347.0	37.1%
GenOn	Morgantown Generating Plant	Charles	1,548.0	1,477.0	
GenOn	Dickerson	Montgomery	930.0	844.0	
Industrial Power Generating Company LLC	Wicomico	Wicomico	5.4	5.4	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	653.8	5.2%
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	183.0	170.0	1.4%
Panda-Brandywine LP	Panda Brandywine LP	Prince Georges	288.8	230.0	1.8%
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	0.0%
RG Steel, LLC	RG Steel Sparrows Point, LLC	Baltimore	120.0	152.3	1.2%
Roth Rock Wind Farm LLC	Roth Rock Wind Farm LLC	Garrett	40.0	40.0	0.3%
Roth Rock Wind Farm LLC	Roth Rock North Wind Farm, LLC	Garrett	10.0	10.0	0.1%
SCE Engineers	Montgomery County Oaks LFGE Plant	Montgomery	70.2	56.3	0.4%
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.	Perdue Salisbury Photovoltaic	Wicomico	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%
			13,702.8	**12,582.6**	**100.0%**

Appendix Table 7: Proposed New Conventional Generation in Maryland
PJM Queue Effective Date: February 28, 2013

Transmission Owner	Project Name	County Location	PJM Queue Status	PJM Queue #	Fuel Type	Project Capacity (MW)	Projected In-Service Date
APS	Hickory Plains	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 Study	Y1-065	natural gas	852	2017 Q2
PEPCO	White Oak	Montgomery	Under Construction	W4-010	natural gas	53	2015 Q4
PEPCO	Morgantown-Oak Grove	St. Charles	Under Study	V3-017	natural gas	725	2015 Q2
PEPCO	Burches Hill-Chalk Point 500kV	Unknown	Under Study	X4-035	natural gas	736	2016 Q2
PEPCO	Kelson Ridge 230kV	Charles	Under Study	X4-006	natural gas	785	2015 Q2
PEPCO	Kelson Ridge 230kV	Charles	Under Study	X4-007	natural gas	785	2015 Q2
PEPCO	Burches Hill-Brandywine 230kV	Prince George's	Under Study	X3-087	natural gas	894	2016 Q2
PEPCO	Kelson Ridge 230kV	Charles	Under Study	W4-044	natural gas	1450	2015 Q2

Appendix Table 8: Existing Renewable Generation in Maryland
As of December 31, 2011

Company	Project Name	Site Location	Fuel Type	Net Capacity (MW)	2011 Net Generation	In Service Date
BGE	Alternative Energy Associates	Laurel, MD	Hydro, runoff from water	N/A - energy only	1,587	Jan-86
BGE	BRESCO (Baltimore Refuse Energy Co.)	Baltimore, MD	Refuse with natural gas	57	311,288	Nov-84
DPL	INGENCO at Newland Park Sanitary Landfill	Wicomico	methane	6 MW (6 MW Energy)	715	2007 Q2
PE	Dans Mountain 138kV	Dans Mountain 138kV	Wind	14	70	2009 Q4
PE	Kelso Gap 138kV	Kelso Gap 138kV	Wind	6	30	2011 Q4
PE	Four Mile Ridge 138kV	Four Mile Ridge 138kV	Wind	7.8	60	2013 Q4
PE	Jennings Randolph Dam 138kV	Jennings Randolph Dam 138kV	Hydro	13.4	14	2013 Q3
PE	Emmitsburg 34kV	Emmitsburg 34kV	Solar	5.32	14	2012 Q2
PE	Metropolitan Court 34.5kV	Metropolitan Court 34.5kV	Bio Mass	50	52	2013 Q4
PE	Lappans 34.5kV	Lappans 34.5kV	Solar	7.6	20	2012 Q4
PE	Halfway 12.5kV	Halfway 12.5kV	Methane	0	2	2013 Q2
PEPCO	PG Landfill Gas, CVC-982	Upper Marlboro, MD	landfill gas	4-0.875 MW (landfill gas), connected to 4.16 kV units on 13.8 kV feeder	2,326	2003 Q4
PEPCO	PG Correction, CVC-946	Upper Marlboro, MD	landfill gas	3-0.875 MW (landfill gas), connected to 13.8 kV	14,514	1985 Q2
PEPCO	Gude Landfill, CVC-941	Rockville, MD	landfill gas	1-1.025 MW (landfill gas), connected to 480V unit on 13.8 kV feeder	5,621	2009 Q3
PEPCO	Oaks Landfill, CVG-991	Laytonsville, MD	landfill gas	2-1.2 MW (landfill gas), connected to 480 V units of 13.8 kV feeder	15,229	2009 Q3

Appendix Table 9: Proposed New Renewable Generation in Maryland
PJM Queue Effective Date: February 28, 2013

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	Metropolitan Court 34.5kV	Frederick	Under Study	W3-070	biomass	52	2013 Q4
APS	Jennings Randolph Dam	Garrett	Under Study	U4-007	hydro	14	2013 Q3
APS	Halfway 12.5kV	Washington	Under Construction	X2-038	methane	2	2013 Q4
APS	Solar City	Frederick	Under Study	Y2-075	solar	1	2013 Q2
APS	Deep Creek-Penn Mar 115kV	Garrett	Under Study	Y1-003	wind	8	2014 Q4
APS	Gorman-Snowy Creek 69kV	Garrett	Under Study	T16	wind	30	2011 Q4
APS	Four Mile Ridge Wind 138kV	Garrett	Under Study	U2-030	wind	60	2013 Q4
APS	Dans Mountain	Allegheny	Under Study	S14	wind	70	2009 Q4
BGE	Otter Point 34.5kV	Baltimore	Under Study	Y2-100	methane	4	2013 Q2
BGE	Friendship Manor	Howard	Under Construction	Y1-045	solar	2	2013 Q3
BGE	Perryman Solar	Harford	Under Study	Y2-117	solar	20	2014 Q4
DPL	Pocomoke	Somerset	Under Study	T144	biomass	20	2010 Q1
DPL	Cecil	Cecil	Under Construction	U3-004	methane	2	2013 Q4
DPL	Dorchester 12kV	Dorchester	Under Study	Y1-080	solar	3	2013 Q4
DPL	Costen 25kV	Worcester	Under Construction	X1-032	solar	4	2012 Q4
DPL	Church Hill 69kV	Queen Anne	Under Study	X3-066	solar	6	2012 Q3
DPL	Worcester 25kV	Worcester	Under Study	W3-160	solar	10	2011 Q1
DPL	Wye Mills 69kV	Talbot	Under Study	Y1-079	solar	10	2013 Q2
DPL	Laurel 69kV	Wicomico	Under Study	W1-070	solar	20	2011 Q2
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	Fruitland 69kV	Wicomico	Under Study	X4-017	solar	20	2017 Q2
DPL	Kingston-Westover 69kV	Somerset	Under Study	Y2-059	solar	20	2015 Q3
DPL	Loretto-Kings Creek 138kV	Somerset	Under Study	X1-096	wind	150	2014 Q4
DPL	Chestertown-Church 69kV	Kent	Under Study	Y3-033	wind	150	2015 Q3

Appendix Table 10: Cumulative EmPOWER Maryland Utility Data

Appendix Table 10(a): Cumulative Forecasted Energy Savings and Reductions (2012 – 2015) for Utility EE&C, Demand Response, and AMI Programs

		BGE	DPL	PEPCO	PE	SMECO	Total
Energy Savings (MWh)	2012 - 2015 Forecasted Energy Savings (MWh)	1,006,996	196,527	705,824	245,319	113,533	**2,268,199**
	2015 Energy Savings Goal (MWh)	3,593,750	143,453	1,239,108	415,228	83,870	**5,475,409**
	Percentage of Goal Forecasted to Achieve (2012 - 2015)	28.02%	137.00%	56.96%	59.08%	135.37%	**41.43%**
Demand Reduction (MW)	2012 - 2015 Forecasted Demand Reduction (MW)	1,059	67	796	36	37	**1,995**
	2015 Demand Reduction Target (MW)	1,267	18	672	21	139	**2,117**
	Percentage of Goal Forecasted to Achieve (2012 - 2015)	83.58%	372.22%	118.45%	171.43%	26.62%	**94.24%**

Appendix Table 10(b): Cumulative Verified Reductions (2009 – 2011) and Forecasted Energy Savings (2012 – 2015) for Utility EE&C, Demand Response, and AMI Programs

		BGE	DPL	PEPCO	PE	SMECO	Total
Energy Savings (MWh)	2009 - 2011 Verified Energy Savings (MWh)	916,879	41,394	294,099	125,581	53,417	**1,431,370**
	2012 - 2015 Forecasted Energy Savings (MWh)	1,006,996	196,527	705,824	245,319	113,533	**2,268,199**
	2015 Energy Savings Goal (MWh)	3,593,750	143,453	1,239,108	415,228	83,870	**5,475,409**
	Percentage of Goal Forecasted to Achieve (2009 - 2015)	53.53%	165.85%	80.70%	89.32%	199.06%	**67.57%**
Demand Reduction (MW)	2009 - 2011 Verified Demand Reduction (MW)	708	32	306	17	46	**1,110**
	2012 - 2015 Forecasted Demand Reduction (MW)	1,059	66	796	36	37	**1,994**
	2015 Demand Reduction Target (MW)	1,267	18	672	21	139	**2,117**
	Percentage of Goal Forecasted to Achieve (2009 - 2015)	139.48%	546.44%	164.05%	253.73%	59.62%	**146.63%**