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PUBLIC SERVICE COMMISSION OF MARYLAND

TEN-YEAR PLAN (2010 – 2019) 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
August 2011

State of Maryland
Public Service Commission

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LIST OF ACRONYMS AND DEFINITIONS USED

ACEEE	American Council for an Energy Efficient Economy
ACP	Alternative Compliance Penalty
AMI	Advanced Metering Infrastructure
AP	Allegheny Power (Prior to merger with First Energy)
ARR	Auction Revenue Right
ARRA	American Recovery and Reinvestment Act of 2009
AVL	Automatic Vehicle Locationing
BERAP	Bowie Electric Reliability Action Plan
BGE	Baltimore Gas and Electric Company
BRA	Base Residual Auction
C&I	Commercial and Industrial
CETL	Capacity Emergency Transfer Limit
CETO	Capacity Emergency Transfer Objective
CFL	Compact Fluorescent Light bulb
CHP	Combined Heat and Power
CIS	Customer Information System
CO_2	Carbon Dioxide
CPCN	Certificate of Public Convenience and Necessity
CSP	Curtailment Service Provider
DG	Distributed Generation
DG WG	Distributed Generation Work Group
DLC	Direct Load Control
DOE	United States Department of Energy
DPL	Delmarva Power and Light Company
DR	Demand Response or Demand Resource
DSM	Demand-Side Management
DY	Delivery Year
EDC	Electric Distribution Company
EE&C	Energy Efficiency and Conservation
EIA	Energy Information Administration
EIPC	Eastern Interconnection Planning Collaborative
EIS	Environmental Impact Statement
EISA	Energy Independence and Security Act of 2007
EISPC	Eastern Interconnection State Planning Council
ELRP	Economic Load Response Program
EMAAC	Eastern Mid-Atlantic Area Council
EMS	Energy Management System
EM&V	Evaluation, Measurement, and Verification
EPA	United States Environmental Protection Agency
ETR	Estimated Time of Restoration
FERC	Federal Energy Regulatory Commission
FRR	Fixed Resource Requirement
FTR	Financial Transmission Right
GATS	Generation Attributes Tracking System

GIS	Geographic Information System
GW/GWh	Gigawatt/Gigawatt-hours
GWD	Graphical Work Design
HVAC	Heating, Ventilation, and Air Conditioning
HVCS	High Volume Call Service
HVDC	High Voltage Direct Current
IOU	Investor-Owned Utility
IRM	Installed Reserve Margin
ISO	Independent System Operator
IVR	Interactive Voice Response
kV	Kilovolt
kW/kWh	Kilowatt/Kilowatt-hours
LDA	Load Deliverability Area
LMP	Locational Marginal Price
LSE	Load Serving Entity
MAAC	Mid-Atlantic Area Council
MADRI	Mid-Atlantic Distributed Resources Initiative
MAPP	Mid-Atlantic Power Pathway
MDE	Maryland Department of the Environment
MDS	Mobile Dispatch System
MEA	Maryland Energy Administration
MW/MWh	Megawatt/Megawatt-hours
NERC	North American Electric Reliability Council
NGO	Non-government Organization
NIETC	National Interest Electric Transmission Corridor (DOE)
NOPR	Notice of Proposed Rulemaking
NRC	United States Nuclear Regulatory Commission
O&M	Operation and Maintenance
OATT	Open Access Transmission Tariff (PJM)
OMS	Outage Management System
OPC	Office of People's Counsel (Maryland)
OPSI	Organization of PJM States, Inc.
PATH	Potomac-Appalachian Transmission Highline
PE	The Potomac Edison Company
Pepco	Potomac Electric Power Company
PJM	PJM Interconnection, LLC (Pennsylvania-Jersey-Maryland)
PJM-EIS	PJM – Environmental Information Services, Inc
PSC/ MD PSC	Maryland Public Service Commission
PTR	Peak-Time Rebate
PURPA	Public Utility Regulatory Policies Act of 1978
QF	Qualifying Facility
REC	Renewable Energy Credit
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RPM	Reliability Pricing Model (PJM)

RPS	Renewable Energy Portfolio Standard
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
SCADA	Supervisory Control and Data Acquisition
SEIF	Maryland Strategic Energy Investment Fund
SGIG	Smart Grid Investment Grant
SMECO	Southern Maryland Electric Cooperative, Inc.
SOS	Standard Offer Service
SSC	Stakeholder Steering Committee
SWMAAC	Southwest Mid-Atlantic Area Council
TDU	Transmission-dependent Utility
TEAC	Transmission Expansion Advisory Committee (PJM)
TOU	Time of Use
TrAIL	Trans-Allegheny Interstate Line
WMIS	Work Management Information System
WMS	Work Management System

I. INTRODUCTION

Section 7-201 of the Public Utilities Article, *Annotated Code of Maryland,* requires the Maryland Public Service Commission ("Commission" or "PSC" or "MD PSC") to forward a Ten-Year Plan of Electric Companies in Maryland ("Ten-Year Plan") to the Secretary of Natural Resources on an annual basis. This report constitutes that effort for the 2010-2019 timeframe and, with exceptions as noted in the text, the referenced data and information is as it existed as of December 31, 2009. It is a compilation of information on long-range plans of Maryland electric utilities. This report also includes summaries of events that have affected or may affect the electric utility industry in Maryland in the near future.

A principal focus of the Commission is the reliability of Maryland's electricity supply. Achieving reliability is a complex undertaking requiring a consideration of factors which affect both supply and demand. To address the elements affecting reliability the Commission, as detailed in this report, is taking action on several fronts: challenging wholesale power policies at the Federal Energy Regulatory Commission ("FERC"); working with the wholesale market monitor to effectuate positive market results; evaluating the need for procuring new generation in the State; directing new utility investment in demand response programs to reduce peak electricity demand; evaluating conservation and energy efficiency programs to meet EmPower Maryland peak and overall energy reductions;[1] and encouraging better use of emergency generation within the State to promote adequate, economical, and efficient delivery of electricity services.

Section II of this plan addresses the peak demand load forecast for Maryland and establishes the baseline load requirements for the next ten years. **Section III** provides information on generation, including certificates of public convenience and necessity ("CPCNs"), and forecasts the availability of generation to meet load requirements. **Section IV** reviews transmission issues impacting Maryland including the Department of Energy's National Interest Electric Transmission Corridors. **Section V** addresses the options of energy efficiency, conservation, and demand response as part of Maryland's supply resources and discusses the effort required to meet EmPower Maryland goals. Proposals to deploy advanced metering infrastructure are also discussed in this section. Because the environment continues to play an increasingly important role in energy decisions, **Section VI** discusses Maryland's involvement in the Regional Greenhouse Gas Initiative, and issues involving the growth of renewable generation. **Section VII** provides information on distribution reliability, the manner in which utilities have managed outages, and how utilities plan to meet load requirements.

Beginning with **Section VIII**, we broaden our perspective and review Maryland's Electricity Market in general terms and its relation to Commission efforts that are currently underway or anticipated. **Section IX** discusses PJM Interconnection, LLC ("PJM") and the impact that market rule changes have had both regionally and in

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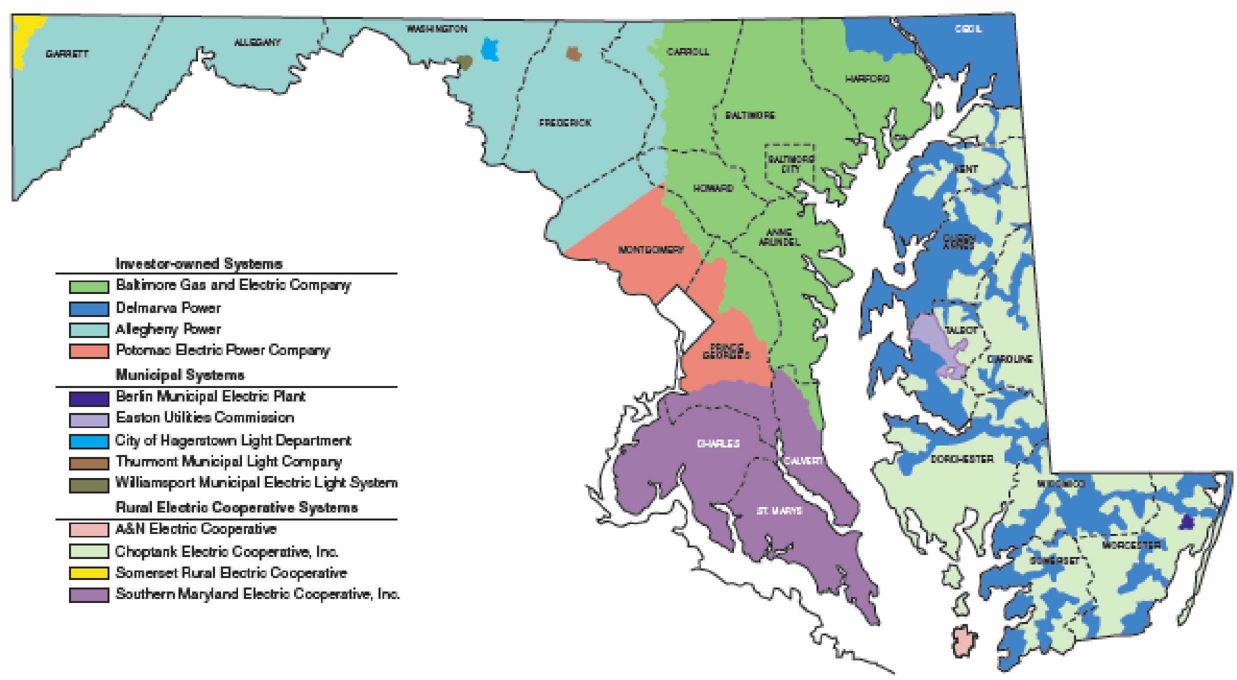
[1] EmPower Maryland Energy Efficiency Act of 2008, codified within § 7-211 of the Public Utilities Article, *Annotated Code of Maryland*.

Maryland. **Section X** reviews national issues and the impact generated by FERC rulings and Department of Energy actions. Also included in the Ten-Year Plan is an Appendix that contains a compilation of data provided by Maryland's utilities summarizing, among other things, demand and sales anticipated over the next 15 years.

Maryland is geographically divided into thirteen electric utility service territories. Four of the largest are investor-owned utilities ("IOUs"), four are electric cooperatives (two of which serve only small areas of Maryland), and five are electric municipal operations.[2] Table A-1 in the Appendix lists the utilities providing retail electric service in Maryland and Map I.1 below provides a geographic picture of the utilities' service territories.

Map I.1: Maryland Utilities and their Service Territories in Maryland



Source: Maryland Dept. of Natural Resources, CEIR 15 (January 2010).

II. MARYLAND UTILITY AND PJM ZONAL LOAD FORECASTS

A. Introduction

The foundation of an analysis for meeting Maryland's electricity needs starts with a forecast of the anticipated demand over a relevant planning horizon. The Commission routinely evaluates forecasts from individual utilities, and the PJM forecast which provides separate estimates for the transmission zones shown in Figure II.A.1.

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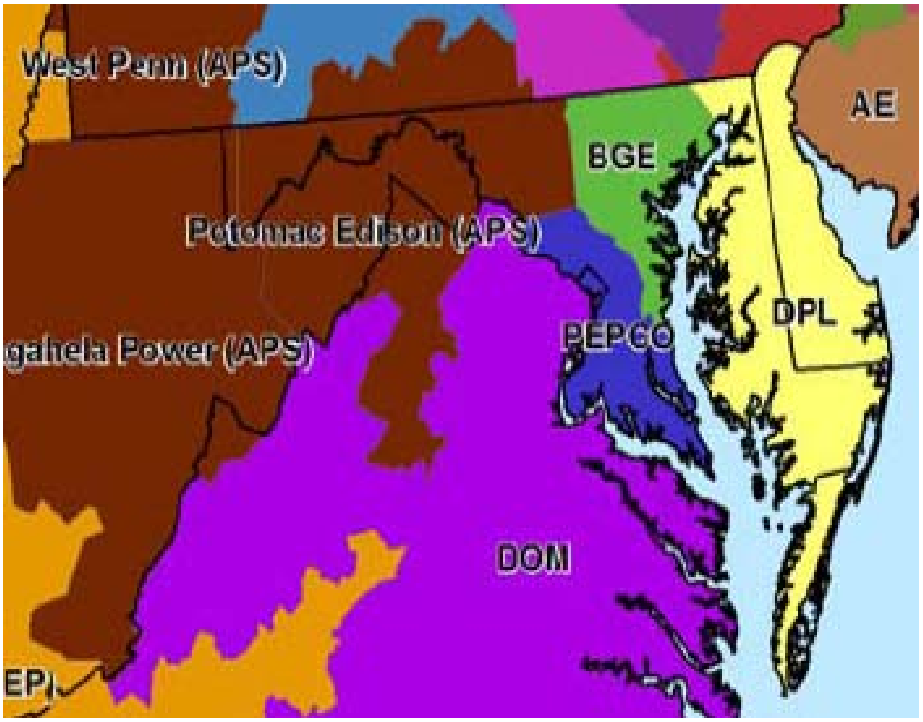
2 The St. Michaels Utilities Commission service territory was transferred to Choptank Electric Cooperative, Inc. in October 2006.

Figure II. A.1: PJM Maryland Forecast Zones



Source: PJM Interconnection

PJM sub-regions, known as zones, generally correspond with the IOU service territories. The PJM zones include adjacent municipal and rural electric cooperatives.[3] The four IOUs operating in Maryland are Baltimore Gas and Electric Company ("BGE"), Potomac Electric Power Company ("Pepco"), Delmarva Power and Light Company ("DPL"), and The Potomac Edison Company ("PE"). PJM zones for three of the four IOUs traverse state bounds and extend into other jurisdictions. Pepco, DPL, and PE company data are a subset of the PJM zonal data, since PJM's zonal forecasts are not limited to Maryland. The BGE zone, alone, resides solely within the State of Maryland.

PJM operates the wholesale power market that includes the entire mid-Atlantic region and dispatches power plants to serve load on an economic bid basis, subject to transmission capacity availability. PJM's load forecasts drive the need for generation, which impacts electric consumer prices at the retail level. The Commission closely monitors the development of PJM regional forecasts.

While forecasts can rely on similar economic data, projections of peak demand and energy usage can vary based upon the underlying assumptions used to generate the forecasts. In general, the expected growth in peak demand and electricity usage is due primarily to expected increases in population and economic activity, which have a direct impact on electricity consumption levels. Key forecast variables include economic and non-economic variables. Economic variables used in forecast models can include gross

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[3] PJM is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia.

domestic product, employment, energy prices, and population. Non-economic variables can include weather normalized variables, monthly seasonal variables, ownership of appliances, and building codes.

B. PJM Zonal Forecast

PJM's 2010 Load Forecast Report includes long-term forecasts of peak loads and net energy for the entire wholesale market region and each PJM sub-region (*i.e.*, zone) – including the four sub-regions in which Maryland resides.[4] The 2010 Load Forecast Report concludes that the PJM region will, in aggregate, experience higher peak usage in the summer throughout the forecast period ending 2025.[5] PJM expects average annual summer peak PJM growth of 1.7% for the next ten-year period and 1.5% for the 15-year forecast horizon. Tables II. B. 1 and 2 present comparisons in expected growth for the four PJM zones containing Maryland.[6] The 2010 Load Forecast is compared to the 2009 Load Forecast on a very broad macro level for the four PJM regions roughly corresponding with the four IOU service territories that serve Maryland. When compared, the 2010 and 2009 PJM Load Forecasts are consistent for three zones – PE, BGE, and Pepco – while there is a significant downward revision to the forecast for DPL, which serves Maryland and Delaware. The PJM zones containing BGE, DPL, and Pepco experience their peak demands during the summer while the PJM region containing PE experiences peak demands in the winter.

Table II.B.1. Summer Peak Load (MW) Growth Rates

PJM Zone	2009-2019*	2010-2020**
PE	1.5%	1.4%
BGE	1.8%	1.8%
DPL	2.1%	1.4%
Pepco	1.2%	1.2%

Table II.B.2. Winter Peak Load (MW) Growth Rates

PJM Zone	2009-2019*	2010-2020**
PE	1.3%	1.3%
BGE	1.0%	1.1%
DPL	1.5%	1.0%
Pepco	1.1%	1.2%

Sources: * PJM Load Forecast Report, January 2009, Tables B-1 and B-2.
** PJM Load Forecast Report, January 2010, Tables B-1 and B-2.

4 PJM, PJM Load Analysis Subcommittee, available at: http://www.pjm.com/committees-and-groups/subcommittees/las.aspx.

5 The current forecast reflects an increase over the prior forecast of 244 MW (0.2%) for 2013 and 709 MW (0.5%) for 2015, respectively.

6 For Maryland, the four PJM regions contain all four of the State's investor-owned utilities, the five municipal systems, and Maryland's four rural electric cooperatives.

C. Maryland Company Forecasts

Maryland's electric utilities annually submit responses to Commission data requests that include forecasts of peak and annual energy demand. The information provided by each company is summarized in the Appendices as Tables A-5(a)-(d). Data requests for the current Ten-Year Plan include responses that expand beyond a ten-year period – from 2010 through 2024. The prior year's submissions began and terminated one year earlier, that is, from 2009 through 2023. A comparison of the electric utility submissions for the first and last years of the forecast period is provided to indicate, on an aggregate basis, current expectations for reduced peak usage in the State for electricity, as well as a reduction in overall State consumption levels. The utility forecasts reflect short-term recessionary impacts, the utilities' current expectations with regard to nascent demand-side management ("DSM") and energy efficiency programs, and the expected reductions in energy usage attributable to these programs. Precision and certainty diminish the longer the time period over which a forecast is generated. Comparisons are first presented for the State in aggregate for four common future years: 2010, 2015, 2020, and 2023.[7] Additional analysis pertaining to 2010 and the period 2010 to 2020 are also explored.

Table II.C.1 compares Maryland peak demand forecasts on an aggregate basis and includes utility provided estimates of currently approved DSM and energy efficiency measures. Actual peak demand in 2010 net of DSM programs compared to the 2009 forecasted peak demand net of DSM programs indicates that peak demand increased by 0.65%. Peak demand forecasts for this report compared to 2009 forecasted peak demand indicate that peak demands are estimated to increase by .4% in 2015, .2% in 2020, and .09% in 2023.[8]

Table II.C.1 Comparison of Maryland Peak Demand Forecasts (Net of DSM Programs; MW)

Year	2009 - 2018 Ten-Year Plan	2010 - 2019 Ten-Year Plan	Change	%
2010	13,913	14,004	91	0.65
2015	13,162	13,646	484	0.36
2020	14,181	14,437	256	0.18
2023	14,855	14,988	133	0.09

Sources: PSC, Ten-Year Plan (2009-2018) of Electric Companies in Maryland, and PSC Ten-Year Plan (2010-2019) of Electric Companies in Maryland, Table A-5(b).

Table II.C.2 compares utility forecasted energy sales within the State of Maryland. When compared to utility estimates provided last year, the electric utility forecasts, in aggregate, project additional reductions in overall annual electricity sales in

7 Additional data for the 2010 to 2024 period can be located in the Appendix. Corresponding data considering the 2009 to 2023 time period can be located in last year's Ten-Year Plan.

8 Reductions are a comparison strictly to last year's submissions and not considered on a per capita basis in keeping with the goals of EmPower Maryland.

the State. During the timeframe examined, reductions in energy usage trend downward between 1.4% and 3.2% when compared to last year's electric utility submissions.

Table II.C.2 Comparison of Maryland Energy Sales Forecast (Net of DSM Programs; GWh)

Year	2009 - 2018 Ten-Year Plan	2010 - 2019 Ten-Year Plan	Change	%
2010	64,246	63,361	-885	-1.4
2015	67,457	66,002	-1,455	-2.2
2020	72,178	70,306	-1,872	-2.6
2023	75,214	72,791	-2,423	-3.2

Sources: PSC, Ten-Year Plan (2009-2018) of Electric Companies in Maryland, and PSC Ten-Year Plan (2010-2019) of Electric Companies in Maryland, Table A-6(b).

As reflected in Table II.C.1 and Table II.C.2, utility projections of peak demand and of annual energy sales are currently moving in opposite directions: peak demand is increasing while annual energy sales are decreasing. Historically, however, peak demand and annual energy sales have moved in tandem.

Numerous changes have recently occurred or have been proposed to PJM demand response (DR) programs. These changes include implementing a more accurate method of measuring and verifying the quantity of demand reductions provided and proposals to significantly expand both the time period and the seasons during which DR participants must reduce load. Some of the proposals have created uncertainty as to whether and to what extent certain direct load control ("DLC") programs would continue to qualify under PJM's DR programs. The uncertainty associated with such changes tends to moderate projections of future DSM impacts. Therefore, it is impossible to conclude, based solely upon the utility-only projections summarized in Tables II.C.1 and II.C.2, that peak loads and annual energy sales are beginning to move divergently.

III. REGIONAL GENERATION AND SUPPLY ADEQUACY IN MARYLAND

A. Introduction

The Commission recognizes that in order to maintain electric system reliability and an adequate supply of electricity for customers in the future, access to adequate electric capacity must be available to meet customer demand.

A critical requirement for reliable electric service is an appropriate level of generation and transmission capacity to meet Maryland consumers' energy needs. While reliability needs may be partially met through local demand side management programs and the import of electricity using high-voltage transmission lines, local generation must be maintained and is essential to keep the lights on and the power grid operating effectively and economically. All load serving entities in the PJM region are required to ensure they have sufficient capacity contracts to provide reliable electric service during periods of peak demand. As of 2008, Maryland's net summer generating capacity was 12,583 MW. Maryland's peak demand forecast for 2010 with utility demand-side management and energy conservation measures is approximately 13,061 MW. Providing an estimate for an appropriate reserve margin of an additional 2,024 MW,[9] would result in an estimated reliability requirement of 15,085 MW. Therefore, approximately 2,500 MWs (2,502 MW) of estimated capacity in the transmission system serves to meet Maryland's requirements during periods of peak usage in the system.

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. 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 this task in order to coordinate the movement of wholesale electricity and provide 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 installed capacity required by balancing retail load and generation capacity over a regional, diversified system.

Within eastern PJM, the District of Columbia and the states of Maryland, Delaware, New Jersey, and Virginia continue to be net importers of electricity. Maryland imported about 35% of its electricity in 2008. On a percentage basis, Maryland was the seventh largest electric energy importer in the United States – surpassed by the District of Columbia, Virginia, and Delaware in the immediate PJM area (Table III.A.1). Much of the East Coast is dependent on generation exported from states to the west of the region – many with low-cost, largely depreciated, coal-fired generation assets. Prominent states within the PJM region currently exporting more electricity in aggregate than consumed within each state are Illinois, Indiana, Michigan, Pennsylvania, and West Virginia.

9 The example uses an installed reserve margin ("IRM") of 1.155 for 2010/2011, which is applicable for planning reserves on a regional basis for the entire pool of PJM resources. IRM establishes a level of installed capacity resources that will provide acceptable reliability levels for the PJM region – and not on an individual state basis – considering demand forecasts, available unforced capacity from existing generation, and the probability that a generating unit will not be available (i.e., Equivalent Demand Forced Outage Rate ("EFORd")). *See* PJM, Resource Adequacy Planning, 2009 PJM Reserve Requirements Study, Table I-1: Historical RRS Parameters, p. 3, available at: http://www.pjm.com/planning/resource-adequacy-planning/~/media/documents/reports/2009-pjm-reserve-requirement-study.ashx.

Table III.A.1: State Electricity Imports (Year 2008 in GWh)

State	Retail Sales	Losses & Direct Use	Generation	Net Imports	Percent Retail Sales Imported
D.C.	11,851	810	72	12,589	106.2%
Idaho	23,901	2,806	12,025	14,682	61.4%
Delaware	11,749	1,501	7,524	5,726	48.7%
South Dakota	10,974	930	7,083	4,821	43.9%
Virginia	110,106	7,698	72,679	45,125	41.0%
California	268,155	42,157	213,355	96,957	36.2%
Maryland	63,326	6,189	47,361	22,154	35.0%
New Jersey	80,520	9,303	63,675	26,148	32.5%
Massachusetts	55,884	7,080	46,683	16,281	29.1%
Wisconsin	70,122	7,870	63,480	14,512	20.7%

Source: U.S. Energy Information Administration ("EIA"), State Electricity Profiles 2008, Table 10, available at: http://www.eia.doe.gov/cneaf/electricity/st_profiles/sep2008.pdf.

B. Maryland Generation Profile: Age and Fuel Characteristics

Most electric generating capacity in Maryland is provided by coal-fired power plants, which contribute approximately 40% of the summer peak capacity available in-State. The vast majority of the State's coal-fired generation capacity (70%) is provided by power plants 30 or more years old. Approximately 41% of all capacity in Maryland burns oil or gas as a fuel source, and the majority of these facilities are aging. Overall, approximately 67% of Maryland generating capacity has been in operation for over thirty years. As indicated in Table III.B.1, only 22% of the State's summer generating capacity has been constructed in the past twenty years, and only 7% has been constructed in the last ten years.

Table III.B.1: Maryland Generating Capacity Profile (Year 2008)

	Capacity		Age of Plants, by % of Fuel Type			
Primary Fuel Type	**Summer (MW)**	**Pct. of Total**	**1-10 Years**	**11-20 years**	**21-30 years**	**31+ years**
Coal	4,944	39.3%	3.6	13.0	13.6	69.8
Oil & Gas	5,179	41.2%	13.8	22.5	12.1	51.6
Nuclear	1,735	13.8%	0.0	0.0	0.0	100.0
Hydroelectric	590	4.7%	0.0	0.0	0.0	100.0
Other & Renewables	135	1.0%	13.3	40.0	46.7	0.0
TOTAL	**12,583**	**100.0%**	**7.3%**	**14.8%**	**10.8%**	**67.1%**

Source: U.S. Energy Information Administration, Report EIA-860, Calendar 2008 Excel Workbook, "GenY08" Excel, available at: http://www.eia.doe.gov/cneaf/electricity/page/eia860.html.

While no generating facilities in Maryland are scheduled for deactivation (retirement), a few of the older generating units in the eastern PJM region have requested deactivation. These older generating units are located in Delaware, Pennsylvania, New Jersey, and the District of Columbia. These older generation units typically have operated only a limited number of hours each year and generate electricity at relatively high marginal costs. However, the units may also be helpful in ensuring reliable electric service in the region. PJM undertakes an analysis to determine the parameters under which units may deactivate or continue to operate.[10]

In 2007, owners of power plants requested deactivation of units at three locations in Delaware or D.C.: two Indian River units (Delaware) with a combined capacity of 179 MW; two Buzzard Point plants (D.C.), 240 MW; and two Benning site power plants (D.C.), 550 MW. The reliability issues have been identified and are expected to be resolved to meet the requested deactivation dates for all of the above units.[11] Depending on the unit, deactivation has been requested between May of 2010 through May of 2012.

In 2009, owners of power plants requested deactivation of units at three locations in New Jersey and Pennsylvania: two Cromby units (Pennsylvania) with a combined capacity of 345 MW; two Eddystone units (Pennsylvania), 588 MW, and two units at the Kearny (New Jersey) site, 250 MW. These units have requested deactivation dates between May of 2011 and June of 2012. The reliability issues have been identified and are expected to be resolved to meet the requested deactivation dates for all of the above units, except one of the Eddystone units having a capacity of 309 MW. The requested deactivation date for this unit has been delayed from May 31, 2011 to June of 2012, and it will continue to operate during this period.

The Maryland generating profile differs considerably from its capacity profile. Coal and nuclear facilities generate almost 90% of all electricity produced in Maryland, even though they represent little more than half of in-state capacity. In contrast, oil and gas facilities, which tend to operate as mid-merit or peaking units, coming on line only when needed, generate less than 6% of the electricity produced by in-State resources, while representing approximately 41% of in-State capacity. Table III.B.2 summarizes Maryland's in-State fuel-mix in MWh by generating sources for 2008. In 2008, Maryland plants produced 47,360,953 MWh of electricity.

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10 PJM, Manual M-14D: Generator Operational Requirements, Revision: 17, effective date January 1, 2010, available at: http://www.pjm.com/~/media/documents/manuals/m14d.ashx.

11 PJM, Planning, Generation Retirements, Generation Retirement Summaries, Pending Deactivation Requests, available at: http://www.pjm.com/planning/generation-retirements/gr-summaries.aspx.

Table III.B.2: Maryland Electric Power Generation Profile (2008)

Source	MWh	Share (%)
Coal	27,218,239	57.5
Oil & Gas	2,591,811	5.5
Nuclear	14,678,695	31.0
Hydroelectric	1,974,078	4.1
Other & Renewables	898,130	1.9
Total	**47,360,953**	**100.0**

Source: EIA, Maryland Electricity Profile, Table 5, available at: http://www.eia.doe.gov/cneaf/electricity/st_profiles/maryland.html.

The total summer capacity of Maryland generators is 12,583 MW, and over 80% of the in-State generation capacity is owned by two companies: Constellation Energy Group and Mirant. Constellation Energy Group owns 43% of this capacity, and Mirant owns 38%. Nearly two-thirds (65%) of the State's power plant capacity resides in one of four counties: Anne Arundel, 18%; Calvert, 14%; Charles, 12%; and Prince George's, 21%. Table III.B.3 lists Maryland generating units by owner, county, and capacity.

Table III.B.3: Generation by Owner, County, and Capacity (Year 2008)

Operator/Owner	Plant Name	County	Capacity Statistics (MWs)		
			Nameplate	Summer	Pct. Summer
A & N Electric	Smith Island	Somerset	2	2	0.02
AES Warrior Run	AES Warrior Run	Allegany	229	180	1.43
Allegheny Energy	R Paul Smith	Washington	109	115	0.91
American Sugar	Domino Sugar	Baltimore City	18	18	0.14
Town of Berlin	Berlin	Worcester	7	7	0.06
BP Piney & Deep Creek LLC	Deep Creek	Garrett	20	18	0.14
Covanta	Montgomery County Recovery	Montgomery	68	54	0.43
Constellation	Calvert Cliffs	Calvert	1829	1735	
Constellation	Brandon Shores	Anne Arundel	1370	1286	
Constellation	C P Crane	Baltimore	416	399	
Constellation	Gould Street	Baltimore City	103	97	
Constellation	Herbert A Wagner	Anne Arundel	1058	996	42.91
Constellation	Notch Cliff	Baltimore	144	120	
Constellation	Perryman	Harford	404	355	
Constellation	Philadelphia	Baltimore City	83	64	
Constellation	Riverside	Baltimore	257	228	
Constellation	Westport	Baltimore City	122	121	
Easton Utilities	Easton	Talbot	72	69	0.55
Energy Recovery Operations, Inc	Harford Waste to Energy Facility	Harford	1	1	0.01
Exelon Power	Conowingo	Harford	507	572	4.55
INGENCO	Wicomico	Wicomico	5	5	0.04
MD Environment Service	Eastern Correctional Inst.	Somerset	6	5	0.04
Mirant	Chalk Point LLC	Prince George's	2647	2413	
Mirant	Dickerson	Montgomery	930	849	37.73
Mirant	Morgantown	Charles	1548	1486	
NAEA	Rock Springs	Cecil	773	632	5.02
NewPage Corp.	Luke Mill	Allegany	65	60	0.48
NRG Vienna	Vienna	Dorchester	183	170	1.35
Panda Energy	Brandywine	Prince George's	289	230	1.83
PEPCO Holdings	Crisfield	Somerset	12	10	
PEPCO Holdings	Eastern Landfill	Baltimore	3	3	0.27
PEPCO Holdings	NIH Cogen. Facility	Bethesda	22	21	
Prince George's County	Brown Station Road	Prince George's	7	6	0.05
Severstal	Sparrows Point	Baltimore	120	152	1.21
Solo Cup Co	Solo Cup Co	Baltimore	11	11	0.09
Trigen	Hawkins Point	Baltimore	10	7	
Trigen	Inner Harbor East	Baltimore City	2	2	0.24
Trigen	UMCP CHP Plant	Prince George's	27	21	
Wheelabrator Environmental	Wheelabrator Baltimore Refuse	Baltimore City	65	61	0.48
Worcester County Renewable	Worcester County Renewable	Worcester	2	2	0.02
Total			**13546**	**12583**	**100.00**

Source: U.S. Energy Information Administration, Report EIA-860, Calendar 2008 Excel Workbook, "GenY08" and "PlantY08" Excel spreadsheets, available at: http://www.eia.doe.gov/cneaf/electricity/page/eia860.html.

C. Potential Generation Additions in Maryland

Siting for central station generation in Maryland continues to be an important concern. There are reliability, environmental, and competitive issues that must be resolved when finding an appropriate location for a new generator. With generation largely deregulated and currently the responsibility of independent power producers, siting has tended to be limited to the expansion of existing sites. Generation companies have proposed various projects, but they are typically either expansions of existing sites or conjoined locations with other industrial or government facilities. Without the financial assurances that were typically available through utility ownership, it has become increasingly difficult for generation companies to secure potential new sites, long-term sales contracts, and the funding necessary to build new generation.

Other sources of generation have benefited from the Commission's small generation interconnection rules. Distributed generation from solar facilities and combined heat and power installations are examples of small scale generation. Co-locating smaller generation facilities with other industrial process facilities provides an alternative to increasing central station generation capacity.

However, regardless of the growth in distributed generation, there will still be a need for central power stations that can be acceptably developed. Areas in or near the State that may be considered for new generation include projects in the Atlantic Ocean, 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. Upgrades and additions to existing sites (*i.e.*, brownfield deployment) offer advantages over new, undeveloped greenfield sites with respect to licensing, transmission facilities, and environmental concerns.

Although no significant generation has been constructed in Maryland within the past few years, the Commission has granted both CPCNs and approvals for construction for those who quality for CPCN exemptions for new generation, and no units have been retired. The Commission currently has before it several applications for construction of new generation and transmission. When and if constructed, these projects will make available additional electricity for use in Maryland and the PJM region, and should ease congestion substantially.

During 2009, the Commission initiated a new proceeding (Case No. 9214) to consider proposals for new electric generation facilities in Maryland, received five CPCN applications (Case Nos. 9199, 9206, 9218, 9223, and 9227) and approved one CPCN application (Case No. 9127). The Commission also received and approved multiple applications for permission to construct new generation units having a capacity of less than 70 MW each from entities that were exempt from CPCN requirements. These approvals are discussed further in Section III.E.

The status of Commission proceedings covering proposed new electric generator facilities in Maryland, with a capacity greater than 70 MW, that were active cases in late 2009 and 2010, is as follows :

- Case No. 9127: Approved June 26, 2009. Request for Reconsideration denied November 30, 2009. UniStar Nuclear Energy, LLC and UniStar Nuclear Operating Services, LLC filed a joint CPCN application on November 13, 2007, to construct a third unit at the existing Calvert Cliffs Nuclear site. With a nameplate capacity of approximately 1,710 MWs, the proposed nuclear unit is designed to provide base load generation in Maryland and would equal the capacity of the two existing Calvert Cliffs units. The Combined Operating License application is under review by the Nuclear Regulatory Commission ("NRC") which has initiated preparation of the Environmental Impact Statement ("EIS").
- Case No. 9199: Completed. Energy Answers International, Inc. filed an application on May 22, 2009, for a CPCN to construct a 120 MW renewable-fuel-fired power plant located at the former site of the FMC Corporation facility in Baltimore City. On August 6, 2010, the Commission granted the requested CPCN with conditions.
- Case No. 9206: Completed. Constellation Power Source Generation, Inc. filed an application on July 16, 2009, for a CPCN to enlarge the rail coal handling facilities and certain other modifications, if necessary, at the Charles P. Crane generating facility in Baltimore County. The application was approved on June 2, 2010.
- Case No. 9214: In Progress. The Commission, by Order 82936 issued on September 29, 2009, initiated this case to receive proposals for new Maryland-located electric generation facilities. This case examines issues regarding new generation identified in Case No. 9117 concerning the best method to procure Standard Offer Service to serve residential and small commercial customers. On December 29, 2010, the Commission issued for comment a draft Request for Proposal ("RFP") to seek offers for new generating facilities in and around Maryland. The fact the Commission issued that notice or has prepared a draft RFP should not be construed as a finding by the Commission that new generation is required, or that the Commission has decided to order any party to construct, acquire, lease or operate new capacity resources in or around Maryland.
- Case No. 9218: Completed. Calvert Cliffs 3 Nuclear Project, LLC and UniStar Nuclear Operating Services, LLC filed a CPCN application on November 20, 2009, for certain minor modifications to an existing CPCN approved by the Commission in Case No. 9127. A modified CPCN was granted on August 24, 2010.
- Case No. 9227: Withdrawn. Constellation Power Source Generation, Inc. filed on November 9, 2009 a CPCN application requesting Commission reauthorization of the air quality portion of the CPCN issued in Case No. 9132

for the Riverside Unit 5 generation project in Baltimore County. On April 29, 2010, CPSG filed a letter withdrawing its request which was accepted by the Commission.

The number of projects for which a transmission interconnection request (capacity or energy) has been filed with PJM provides an indication of potential generation capacity additions in Maryland. Table III.C.1 lists the new generation projects located in Maryland for which a transmission interconnection request has been made to PJM and that are categorized as under study, under construction, providing partial service, or currently suspended. The table demonstrates the diversity of projects being pursued throughout the State. The vast majority (over 95%) of proposed new generation capacity would be located within the Southern Maryland Electric Cooperative, Inc. ("SMECO") and Pepco service territories, and would use natural gas or nuclear fuel. Additional generation capacity, especially from renewable sources, has been proposed for the BGE, DPL, and PE service territories.

Table III.C.1: PJM Transmission Queue Active New Generating Capacity

Plant Capacity (MW) By Fuel					
Service Territory Location	Natural Gas	Nuclear	Other & Renewable	Total	In-service Dates
BGE	-	-	133	133	2011-13
DPL	-	-	15.68	15.68	2009-12
PE	-	-	91.7	91.7	2009-11
PEPCO	3,234	-	-	3,234	2010-14
SMECO	645	1,640	-	2,285	2012-17
TOTAL	3,879	1,640	240.38	5,759.38	2009-17

Source: Appendix Table A-10.

D. CPCN Exemptions for Generation

Pursuant to PUA § 7-207.1, certain power generating stations are exempted from the requirement to obtain a CPCN but are required to obtain Commission approval. These approvals are available to generating stations that are designed to provide on-site generated electricity and that meet the following qualifications:[12]

1. The capacity of the generating station does not exceed 70 MW; and

2. The electricity that may be exported for sale from the generating station to the electric system is sold only on the wholesale market pursuant to an

[12] PUA § 1-101(s) defines "On-site generated electricity" as electricity that: (1) is not transmitted or distributed over an electric company's transmission or distribution system; or (2) is generated at a facility owned or operated by an electric customer or operated by a designee of the owner who, with the other tenants of the facility, consumes at least 80% of the power generated by the facility each year.

interconnection, operation, and maintenance agreement with the local electric company.[13]

For wind-powered generating stations with a capacity up to 70 MW, there are two additional qualifications that must be met in order to be granted approval without obtaining a CPCN. The first is that the generating station must be land-based; so any off-shore facility within State waters will be required to obtain a CPCN. The second qualification is that the Commission must provide an opportunity for public comment at a public hearing.

The Commission's PUA § 7-207.1 application requires the applicant to select one of four specific types of generating stations: Type I, Type II, Type III, or Type IV. With the exception of Type I, all generators are required to obtain an Interconnection, Operation, and Maintenance Agreement ("Interconnection Agreement") with the local Electric Distribution Company ("EDC"). Type I generators must obtain a letter from the local EDC that states an Interconnection Agreement is not necessary.

A Type I generator is not synchronized with the local electric company's transmission and distribution system and will not export electricity to the electric system.[14] An emergency or back-up generator is the most common Type I generator. A Type II generator is synchronized with the electric system; however, it will not export electricity to the electric system. Generators used for peak-load shaving or generators participating in a demand response program are the most common form of Type II generators. Type III generators are synchronized with the electric system and export electricity for sale on the wholesale market. A Type IV generator is a generator that is synchronized with the electric system, but utilizes the disconnect feature of an inverter to prevent export of power in the event of a power failure on the utility's grid. Type IV generators are capable of "net-metering," but cannot sell electricity on the wholesale markets.

Table III.D.1. provides an overview of the type, number, and capacity of generators that have applied for PUA § 7-207.1 approvals on an annual basis. The number of applications has been increasing over time, and these generators have a cumulative generation capacity of over 1,100 MWs.

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13 The statute also provides for an exemption from the CPCN process for a generating station that does not exceed 25 MWs if electricity that may be exported for sale from the generating station to the electric system is sold only on the wholesale market pursuant to an interconnection, operation, and maintenance agreement with the local electric company, and at least 10% of the electricity generated at the generating station each year must be consumed on-site.

14 PUA § 1-101(h) defines "Electric company," with certain exclusions, as a person who physically transmits or distributes electricity in the State to a retail electric customer.

Table III.D.1: Construction Approvals for CPCN Exempt Generation Since October 2001

Period Approved	Applications	No. of Units	Total MWs
Calendar Year 2002	14	33	103.7
Calendar Year 2003	20	28	42.5
Calendar Year 2004	38	59	78.0
Calendar Year 2005	37	70	94.4
Calendar Year 2006	31	55	91.4
Calendar Year 2007	40	62	67.3
Calendar Year 2008	78	130	212.1
Calendar Year 2009	108	153	269.2
Calendar Year 2010	86	119	135.1
Total	**452**	**709**	**1,093.7**
Pending	11	13	10.4
Total (Including Pending)	**463**	**722**	**1,104.1**

Source: PSC database.
Note: 2010 data is as of November 30, 2010.

In Table III.D.2, fossil fuel generators were 98.2% of the 541 units reported in September 2009. Since then, of the 135 approvals, 133 (98.5%) have been fossil fueled. These fossil fuel generators provided 682.3 MW (80.5 %) of the total 847.7 MW of generating capacity approved by the end of September 2009. At that time, generators using renewable resources were 165.4 MW (19.5%) of generating capacity in September 2009. Wind-powered generating units were 139.6 MW (16.5%) of the total capacity.

The approvals granted during the Reporting Period added 203.3 MW to the installed base of generation, raising the total capacity to 1051.0 MW. Oil remained the dominant fuel source for new DG generators. Oil-fired generators were 130.5 MW (64.2%) of the total 203.3 MW of generation added during the Reporting Period. As of September 30, 2010, total fossil-fueled CPCN exempt capacity reached 834.1 MW (79.5%) of the total CPCN exempt capacity.

Table III.D.2: Number and Capacity in MW of CPCN Exempt Generation by Energy Resource as of September 30, 2010

	Energy Resource	Total Approved as of 9/30/2009 (a)	Percent of Total Approved as of 9/30/2009 (b)	Approved 10/01/2009 - 09/30/2010 (c)	Percent of Approvals 10/01/2009 - 09/30/2010 (d)	Total Approved as of 09/30/2010 (e)	Percent of Total 09/30/2010 (f)	Percentage Change 09/30/2009 - 09/30/2010 (g)
UNITS								
Fossil	**Oil**[15]	503	93.0	127	94.1%	630	93.2%	25.2%
Fossil	**Natural Gas**	26	4.8%	6	4.5%	32	4.7%	23.1%
Fossil	**Propane**	2	0.4%	-	0.0%	2	0.3%	0.0%
	Fossil Total	***531***	***98.2%***	***133***	***98.5%***	***664***	***98.2%***	***98.2%***
Renewable	**Biomass**	1	0.2%	-	0.0%	1	0.1%	0.0%
Renewable	**Digester Gas**	3	0.6%	-	0.0%	3	0.4%	0.0%
Renewable	**Landfill Gas**	2	0.4%	-	0.0%	2	0.3%	0.0%
Renewable	**Solar**	2	0.4%	1	0.7%	3	0.4%	50.0%
Renewable	**Wind**	2	0.4%	1	0.7%	3	0.4%	50.0%
	Renewable Total	***10***	***1.9%***	***2***	***1.5%***	***12***	***1.8%***	***20.0%***
	Grand Total	**541**	**100.0%**	**135**	**100.0%**	**676**	**100.0%**	**25.0%**
CAPACITY IN MW								
Fossil	**Oil**	590.4	69.6%	130.5	64.2%	719.9	0.0%	22.1%
Fossil	**Natural Gas**	91.7	10.8%	22.3	11.0%	114.0	25.0%	24.3%
Fossil	**Propane**	0.2	0.0%	0.0	0.0%	0.2	0.0%	0.0%
Fossil Total		***682.3***	***80.5%***	***152.8***	***75.2%***	***834.1***	***79.5%***	*25.0%*
Renewable	**Biomass**	19.8	2.3%	0.0	0.0%	19.8	0.0%	0.0%
Renewable	**Digester Gas**	3.2	0.4%	0.0	0.0%	3.2	50.0%	0.0%
Renewable	**Landfill Gas**	2.0	0.2%	0.0	0.0%	2.0	50.0%	0.0%
Renewable	**Solar**	0.9	0.1%	0.5	0.2%	1.4	20.0%	57.1%
Renewable	**Wind**	139.6	16.5%	50.0	24.6%	189.6	25.0%	35.8%
Renewable Total		***165.4***	***19.5%***	***50.5***	***24.8%***	***215.9***	***20.5%***	***30.5%***
Grand Total		**847.7**	**100.0%**	**203.3**	**100.0%**	**1,051.0**	**100.0%**	**24.0%**

Source: PSC database.
Note: For each line in the table:
(b) =[Column (a) divided by Grand Total column (a)]*100
(d) =[Column (c) divided by Grand Total Column (c)]*100
(e) = Column (a) + Column (c)
(f) = [Column (e) divided by Grand Total Column (e)]*100
(g) =[[Column (e) – (a) divided by Grand Total Column (a)]]*100

During the Reporting Period, wind-powered units added 50 MW (a 35.8% increase in wind-powered generators) to reach a total of 189.6 MW (18.0 %) of total

15 "Oil" includes any of the petroleum fractions produced in conventional distillation operations including diesel fuels and fuel oils, primarily products known as No. 1, No. 2, and No. 4 diesel, heating or fuel oils that commonly are used for space heating and electric power generation. *See* U.S. Energy Information Administration website, glossary, available at: http://www.eia.gov/glossary/index.cfm.

CPCN exempt capacity. The 57.1% increase in solar units results from the small number of these Type IV units. Similarly, as of September 30, 2010, approval and development of the seven pending applications for solar-powered units with a total of 2.4 MW of capacity would increase the total capacity from solar energy by 171%. The high rate of growth may suggest a positive response by developers to tax and other economic incentives offered to stimulate development of solar units.

In order to obtain approval to construct a generator under PUA § 7-207.1, an applicant must submit a completed application. In addition, the generator will need a wholesale sales agreement with PJM if the generator is selling electricity on the wholesale market. It is important to note that the approval does not exempt an applicant from complying with other regulations or from obtaining all other necessary state and local permits, such as those required by the Air and Radiation Management Administration at Maryland Department of the Environment ("MDE").

IV. TRANSMISSION INFRASTRUCTURE: PJM, MARYLAND, AND NATIONAL

A. Introduction

Transmission facilities in PJM and Maryland have continued to play a key role in energy supply. With Maryland's dependence on energy imports, it is necessary that adequate transmission facilities be available to reliably provide electricity supplies. While all network systems can experience congestion at times, portions of the Mid-Atlantic States -- including central Maryland and the Delmarva Peninsula -- have continued to experience significantly higher levels of congestion than the rest of PJM. This, in turn, has led to higher energy and capacity costs in portions of Maryland and the surrounding States since local, but more expensive, generation resources had to be deployed to meet load. Adequate capacity and reliable supplies of electricity are continually monitored, managed, and, when necessary, supplemented with additional infrastructure.

B. Eastern Interconnection Planning Collaborative

Pursuant to a Department of Energy grant, the Eastern Interconnection Planning Collaborative ("EIPC") represents a first-of-its-kind effort to involve Planning Authorities in the Eastern Interconnection in modeling the impact on the grid of various policy options determined to be of interest by state, provincial, and federal policymakers and other stakeholders. EIPC is to prepare analyses of transmission requirements under a broad range of alternative futures and develop long-term interconnection-wide transmission expansion plans in response to the alternative resource scenarios selected through a stakeholder process.

Stakeholder input to EIPC comes from the Stakeholder Steering Committee ("SSC"). The SSC is composed of stakeholder representatives from eight sectors, whose purpose is to provide strategic guidance to EIPC Analysts on the scenarios to be modeled, the modeling tools to be used, key assumptions from the scenarios, and other essential activities. Representation on the SSC, which has 29 members, is as follows:

SSC Sectors and Seats

- 3 Transmission Owners and Developers
- 3 Generation Owners & Developers (minimum 1 renewable, minimum 1 non-renewable)
- 3 Other Suppliers (e.g. Power Marketers, Energy Storage, Distributed Generation, minimum 1 Demand-side Resources representative)
- 3 Transmission-dependent Utilities ("TDUs"), Public Power, & Coops (e.g. Municipal utilities, Rural Co-ops, Power Authorities, minimum 1 public power or coop TDU)
- 3 End Users (e.g. Small consumer advocates, large consumers – minimum 1 state consumer advocate agency)
- 3 Non-government Organizations ("NGOs") (e.g. climate change & energy, land and habitat conservation)
- 10 State Representatives
- 1 Canadian Provincial representative
- Ex Officio Members: U.S. Department of Energy ("DOE") and U.S. Environmental Protection Agency ("EPA")

Chairman Nazarian is one of the state representatives on the SSC.

In addition to having 10 seats on the SSC, states are represented by The Eastern Interconnection State Planning Council ("EISPC"). It represents the 39 states and 8 Canadian Provinces located within the Eastern Interconnection electric transmission grid.

EIPC's schedule calls for it to complete its initial analysis in 2012.

C. The Regional Transmission Expansion Planning Protocol

Planning the enhancement and expansion of transmission capability on a regional basis is one of the primary functions of the wholesale market operator, PJM. PJM implements this function pursuant to the Regional Transmission Expansion Planning Protocol set forth in Schedule 6 of the PJM Operating Agreement.

PJM annually develops the Regional Transmission Expansion Plan ("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.

PJM's RTEP looks at a 15-year projection of the grid to predict reliability problems. The system is planned for the probability of loss of load to be one day in ten years. Single contingency analysis allows for the grid to function with the loss of any one line. In some cases double contingency analysis is used. PJM's 15-year planning horizon process has predicted that the congestion on the eastern and western interfaces may cause both load deliverability and generator deliverability issues in central Maryland.[16] Deliverability issues can be a result of significant load growth and the retirement of existing generation.[17] Ideally, these problems can be solved with a combination of new generation, transmission projects, and demand response.

The RTEP process applies reliability criteria over a 15-year horizon to identify transmission constraints and reliability concerns. PJM uses CETO/CETL[18] analysis to determine the import capabilities of the transmission system to supply the peak load requirements for sub-regions within PJM. There are currently 23 sub-regions or load deliverability areas ("LDAs") in PJM. The Transmission Expansion Advisory Committee ("TEAC") is the primary forum for stakeholders to discuss the RTEP results. The Maryland Public Service Commission is an active participant in the RTEP and regularly attends the TEAC meetings.

1. Baseline Reliability Assessment

PJM establishes a baseline from which the need and responsibility for transmission system enhancements can be determined. PJM performs a comprehensive load flow analysis of the ability of the grid to meet reliability standards, taking into account forecasted loads, imports and exports to neighboring systems, existing generation and transmission assets, and anticipated new generation and generation retirements. The baseline reliability assessment identifies areas where the planned system is not in compliance with standards required by the North American Electric Reliability

16 The central Maryland region of the Mid-Atlantic area generally includes northern Virginia and the Baltimore/Washington region.

17 Generation slated for retirement includes Benning Road, Buzzard Point, and Gude Landfill in Washington, DC; Gould Street in Baltimore; and Indian River on the Eastern Shore.

18 Capacity Emergency Transfer Objective/ Capacity Emergency Transfer Limit.

Corporation ("NERC")[19] and the regional reliability councils. The baseline assessment develops and recommends enhancement plans to achieve compliance.

2. Inter-regional Planning

PJM is engaged in planning processes that address issues of mutual concern to PJM and neighboring transmission grid systems: the Midwest Independent System Operator ("ISO"); ISO New England; the New York ISO; the Tennessee Valley Authority; and the North Carolina Planning Collaborative (added in 2009). The Inter-regional Planning Stakeholder Advisory Committee facilitates stakeholder review and input into the Coordinated System Plan. Coordinated regional transmission expansion planning across seams is expected to reduce congestion on an inter-Regional Transmission Organization ("RTO") basis, and enhance the physical and economic efficiencies of congestion management. Inter-regional ties are a benefit for reliability, especially when load centers peak at different times (referred to as "load diversity"). This kind of forum has been important for addressing problems such as loop flows around Lake Erie.

3. Obligation to Build RTEP Projects

PJM's Transmission Owners' Agreement obligates transmission owners to proceed with building transmission projects that are needed to maintain reliability standards as approved by the PJM Board of Directors. Transmission owners can voluntarily build these projects or PJM can file with FERC to request FERC to order the project to be built. In Maryland, CPCNs are required for transmission lines above 69,000 volts or modifications to existing facilities.

4. PJM's Authority

FERC approved PJM as an Independent System Operator in 1997. Since that time, PJM has administered its RTEP as described in Schedule 6 of the Operating Agreement. PJM has subsequently received authority from FERC for procedures and rules for transmission expansions needed to enable the interconnection of new and expanded generation and merchant transmission facilities (1999). PJM has amended the RTEP to include the development of transmission projects to support competition in

[19] Since 1968, NERC has been committed to ensuring the reliability of the bulk power system in North America. To achieve that goal, NERC develops and enforces reliability standards; assesses adequacy annually via a 10-year forecast and winter and summer forecasts; monitors the bulk power system; audits owners, operators, and users for preparedness; and educates, trains, and certifies industry personnel. NERC is a self-regulatory organization, subject to oversight by FERC. As of June 18, 2007, FERC granted NERC the legal authority to enforce reliability standards with all U.S users, owners, and operators of the bulk power system, and made compliance with those standards mandatory and enforceable. NERC's status as a self-regulatory organization means that it is a non-government organization which has statutory responsibility to regulate bulk power system users, owners, and operators through the adoption and enforcement of standards for fair, ethical, and efficient practices.

wholesale electric markets, allowing it to justify projects for economic reasons as well as reliability.

PJM received final FERC approval as an RTO in 2002. As an RTO, PJM is the administrator of the Open Access Transmission Tariff ("OATT") as approved by FERC. The OATT is the basis for PJM to collect charges to recover the costs of projects owned, constructed, or financed by the transmission owners. Transmission owners file rate schedules with FERC to recover transmission investments made pursuant to the RTEPs approved by the PJM Board. The OATT enables generation to be sold anywhere in the system.

D. Congestion in Maryland

1. <u>PJM's Definition of Congestion</u>

PJM's Locational Marginal Pricing ("LMP") system takes account of congestion in determining electricity prices. It reflects the value of the energy at the specific location and time it is delivered. Theoretically, if the lowest-priced electricity could simultaneously be distributed across the entire 13 states and the District of Columbia, which encompass the PJM wholesale market, prices would be the same across the entire PJM grid. However, the capital investments that would be required for such an expansive transmission system would be extremely expensive. Therefore, more expensive but advantageously located power plants that generate electricity are required to meet the demand. As a result, LMPs are higher in the congested areas and lower at the source of cheaper power. Congestion costs vary significantly during the course of a day, seasonally, and from year to year. Persistent patterns of high LMPs can indicate future reliability problems and the need for new generation, new transmission, and/or demand response.

2. <u>Location of Congestion</u>

One constraint accounted for over a quarter of total congestion costs in 2009 and the top five constraints accounted for half of total congestion costs. In 2009, the PE South interface continued to be the largest contributor to congestion costs for the second consecutive year. The PE South interface is now the primary west-to-east transfer constraint.

3. <u>Costs of Congestion</u>

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities and the cost and geographical distribution of generation facilities. Total congestion costs decreased by $1,397 billion or 66%, from $2,117 billion in calendar year 2008 to $719 million in calendar year 2009.

Zone	2009	Total Annual Zonal Congestion Costs ($ million) [20]
Allegheny Power (Potomac Edison)		$95.3
Baltimore Gas & Electric		$33.5
Delmarva Power		$31.1
Potomac Electric Power		$58.4

Wholesale prices for electricity are determined in PJM's Reliability Pricing Model ("RPM") Base Residual Auctions ("BRAs"). Blocks of capacity are sold regionally for future delivery. The data below summarizes the capacity price for Maryland in 2013/2014.[21]

Zone	$/MW-day
Western Maryland (PE)	$27.73
Central Maryland (BGE)	$226.15
Central Maryland (Pepco)	$247.14
Delmarva (DPL)	$245.00
Delmarva South	$245.00

Transmission expansion for the bulk electric system can act to reduce the differences from zone to zone and support reliability requirements and economic concerns.

Financial Transmission Rights ("FTRs") and Auction Revenue Rights ("ARRs") give transmission service customers and PJM members an offset against congestion costs in the Day-Ahead Energy Market. An FTR provides the holder with revenues, or charges, equal to the difference in congestion prices in the Day-Ahead Energy market across the specific FTR transmission path. An ARR provides the holder with revenues, or charges, based on the price differences across the specific ARR transmission path that results from the annual FTR auction. In PJM, FTRs have been available to network service and long-term, firm, point-to-point transmission service customers as a hedge against congestion costs since the inception of locational marginal pricing on April 1, 1998. FTRs became available to all transmission service customers and other PJM members with the introduction of the annual FTR auction effective June 1, 2003.

The total of ARR and FTR revenues hedged over 100% of the congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2008 to 2009 planning period and 93.5% of the congestion costs in PJM in the first seven

20 Data for 2009. The zones for Allegheny, DPL, and Pepco include territory outside of Maryland (Delaware, District of Columbia, Pennsylvania, New Jersey, West Virginia, Virginia). Monitoring Analytics, LLC, 2009 State of the Market Report for PJM, Table 7-17 (March 11, 2010), available at: http://monitoringanalytics.com/reports/PJM_State_of_the_Market/2009.shtml.

21 PJM, 2013-2014 RPM Pricing Points (May 14, 2010), available at: http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item07.

months of the 2009 and 2010 planning period.[22] For the planning period 2008 to 2009, Potomac Edison was hedged at greater than 100%, BGE at 89.0%, DPL at 44.6%, and Pepco at 1.9%.

Congestion of the electricity transmission grid continues to affect the Baltimore/Washington area and to warrant attention. During the summers of 2008 and 2009, however, overall congestion was not as pronounced as in prior years. This has resulted primarily from reduced demand and the absence of significant generation or transmission outages. The PJM metered peaks for 2008 and 2009 were lower than the peaks in 2007 and 2006. This was due to the relatively mild weather, the slowing economy, and increased diversity (non-coincident regional peaks).

For the 2013/2014 capacity auction, PJM announced an increase in Demand Resources ("DR") of 3,105.1 MWs (32%) from the prior auction. A total of 63% of the DR cleared in constrained regions, reflecting its value in helping to reduce congestion.

E. High Voltage Transmission Lines in PJM

PJM's 2010 Regional Transmission Expansion Plan ("RTEP") was not published until February 2011. However, the PJM Board approved over 400 individual bulk electric system upgrades in 2010. Determined via PJM's RTEP process, the upgrades are required to support reliable electricity flows and ensure the power supply system meets national standards through 2024. The PJM Board has approved more then $19.022 billion of bulk electric system upgrades since the inception of the RTEP process in 1997, ensuring that PJM is compliant with NERC reliability criteria.

The deep recession experienced by the country, which began in 2008, continues to have a substantial impact on PJM's RTEP. Load growth is a fundamental driver of resource adequacy and transmission expansion plans. As the economy slowly recovers from the recession, PJM has had to dramatically adjust its backbone transmission line project plans. In particular, the 2011 load forecast issued in January 2011 forecasts significantly lower load growth in the near term. Projects of interest to Maryland which have been affected include:

- PATH is a 765-kV transmission line that will extend 300 miles from the Amos Substation (Charleston, WV) to the Kemptown Substation in Frederick County, Maryland. This project is docketed as Case No. 9233. Although included in the 2010 RTEP as a baseline transmission project, in an RTEP update for events since December 2010 the PJM stated, "Preliminary 2011 PJM RTEP process analysis suggests that the need for the PATH line has moved several years into the future beyond 2015. This has led the PJM Board to direct owners to suspend efforts on

[22] The ARR and FTR revenue adequacy results are aggregate results and all those paying congestion charges were not necessarily hedged. Aggregate numbers do not reveal the underlying distribution of FTR holders, their revenues, or those paying congestion premiums. The FTR markets can be risky and have resulted in defaults for some participants. Financial entities own about 77% of all Monthly Balance of Planning Period FTRs.

the PATH line pending a more complete analysis in the 2011 RTEP." PJM 2010 RTEP 2/28/2010, p. 1.

- Mid-Atlantic Power Pathway ("MAPP") is a 500-kV line that will connect the Possum Point Substation in Virginia and the generation plants in southern Maryland to Vienna and then to Indian River on the Delmarva Peninsula. The portion under the Chesapeake Bay will be a submarine high-voltage DC line ("HVDC"). This project is docketed as Case No. 9179 at the MD PSC. Although not formally suspended, the 2010 RTEP indicates that the 2011 RTEP will address the impact of the lower load forecast and other factors on MAPP.

- TrAIL, 502 Junction to Loudon. Construction continues on TrAIL, and its in-service date remains 2011. This 500 kV transmission line will run from near the border of Pennsylvania and West Virginia to northern Virginia. The expected in-service date of this project is June 2011.

- Susquehanna to Roseland is a 500-kV line, approximately 130 miles from northern Pennsylvania to northern New Jersey. Its in-service date remains 2012.

The PJM RTEP requires that cost responsibility for transmission enhancements be established. The cost of transmission facilities in PJM that operate at a voltage of 500 kV and above are currently socialized across all PJM load. The backbone projects listed above have secured incentive rate adders from FERC. [23] To make this determination, FERC requires the applicant to satisfy its nexus test (non-routine project with advanced technology) and address the rebuttable presumption standard (a project required by PJM).

Transmission projects not highlighted above but identified by the transmission owners are listed in Table A-8 of the Ten-Year Plan for Maryland. For instance, the Southern Maryland Electric Cooperative is continuing with plans for its 230 kV loop in Southern Maryland.

V. DEMAND RESPONSE AND CONSERVATION AND ENERGY EFFICIENCY

Demand-side management, including various methods of energy efficiency, conservation, demand reduction, and distributed generation, is expected to become an important source of meeting the State's needed supply. DSM supports system reliability, energy security, energy and capacity price mitigation (*i.e.*, reducing overall energy costs), and enhanced energy market competitiveness, and limits environmental impacts. The Commission encourages energy service providers to offer DSM programs to customers where appropriate. Distribution companies have been tasked with providing cost-

[23] For the MAPP project, FERC granted Pepco a 12.8% return on equity (including incentives), and no rehearing was sought; as well, FERC granted BGE a 12.8% return on equity (including incentives), and denied rehearing. The TrAIL project settled for a 12.7% return on equity (including incentives). FERC granted PATH a 14.3% return on equity (including incentives); however, rehearing remains pending.

effective DSM programs, particularly for mass market residential and small commercial customers. As part of the EmPower Maryland Energy Efficiency Act of 2008 ("EmPower Maryland"),[24] the Commission has required the utilities to implement aggressive and cost-effective demand management and energy conservation programs.

A. Statutory Requirements

Recognizing energy efficiency as one of the least expensive ways to meet growing electricity demands in the State, the EmPower Maryland Energy Efficiency Act was enacted on April 24, 2008. By statute, each utility 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. EmPower Maryland also establishes long-term reduction goals for electric consumption and demand, based on a per capita and 2007 energy consumption baseline. The Act specifically states at §§ 7-211(g)(1) and (2):

> (1) To the extent that the Commission determines that cost-effective energy efficiency and conservation programs and services are available, for each affected class, require each electric company to procure or provide for its electricity customers cost-effective energy efficiency and conservation measures programs and services with projected and verifiable energy electricity savings that are designed to achieve a targeted reduction of at least 5% by the end of 2011 and 10% by the end of 2015 of per capita electricity consumed in the electric company's service territory during 2007; and
>
> (2) require each electric company to implement a cost-effective demand response program in the electric company's service territory that is designed to achieve a targeted reduction of at least 5% by the end of 2011, 10% by the end of 2013, and 15% by the end of 2015, in per capita peak demand of electricity consumed in the electric company's service territory during 2007.

The Act also states at § 7-211(i)(1):

> (1) In determining whether a program or service encourages and promotes the efficient use and conservation of energy, the Commission shall consider the: (i) cost–effectiveness; (ii) impact on rates of each ratepayer class; (iii) impact on jobs; and (iv) impact on the environment.

Prior to July 1, 2008, the Act required each utility to consult with the Maryland Energy Administration ("MEA") regarding the design and adequacy of the programs it was proposing. Each utility is also required to provide an annual update to the PSC and MEA on plan implementation and progress towards meeting the goals. The PSC, in consultation with MEA, must provide an annual report to the General Assembly

24 *See* PUA § 7-211.

regarding the status of the programs, a recommendation for the appropriate funding level to adequately fund the programs and services, and the per capita electricity consumption and peak demand for the previous year.

Utilities are required to submit these plans by September 1, for the next three subsequent years,[25] with the Commission directed to make its determination by December 31 of each year whether each utility's initial plans are adequate and cost-effective in reaching the EmPower Maryland goals. The Commission is also required to report its findings to the General Assembly regarding the implementation and success of these programs beginning on or before March 1, 2009 and every year thereafter.

In order for the Commission to monitor the progress and cost-effectiveness of the programs that are offered, the utilities are required to file quarterly and annual reports that detail: the current savings generated by each program; the status of the program; and the budget for each program by quarter and annually. The quarterly reports are to include program participation levels and expenditures which are to be filed by the end of the month following the calendar quarter end. The annual reports are due to the Commission by January 31 of each year and provide a comprehensive year-end report of the previous year's results. The annual reports are to include a summation of the quarterly reports, as well as year-to-year comparisons, total energy savings, and other information identified by the Commission Staff.

In the spring of 2009, Commission Staff also filed and presented a Consensus Report on an Evaluation, Measurement, and Verification ("EM&V") plan of the EmPower Maryland programs. This plan included a PSC-directed Independent Evaluator whose role will be to assist in the oversight, quality control, and due-diligence of the Utilities' EM&V activities as well as to conduct additional State-wide analysis as deemed necessary by the Commission. An Independent Evaluator was hired in April 2010.

B. Demand Response Initiatives

Demand Response is defined as changes in electric usage by end-use customers from their normal consumption patterns either in response to changes in the price of electricity over time or to incentive payments designed to induce lower electricity use at times of high wholesale market prices and when system reliability is jeopardized. The increase in electricity prices and changes in technology have spurred interest in finding cost-effective means of reducing electricity consumption. Additionally, the price of electricity in the wholesale markets serving the central and eastern portions of Maryland is determined, in part, by the relative scarcity of generation and transmission capacities serving those areas.

Demand Response initiatives comprise utility-run direct load control programs, inclusive of their legacy demand response programs – the precursor of these DLC programs. These programs, although approved separately by the Commission and, in many cases prior to the EmPower Maryland Energy Efficiency and Conservation

[25] This process began September 1, 2008.

("EE&C") plans, are a critical component in meeting the EmPower Maryland goals and as such are considered part of the EmPower Maryland umbrella package.

DLC Programs

In 2008, the Commission approved BGE, DPL, Pepco, and SMECO's DLC programs.[26] Detailed information for the four Commission-approved programs is provided in Section V of the Appendix of the Commission's Ten-Year Plan (2008-2017) of Electric Companies in Maryland. Additionally, that Report's Table A-11 provides a side by side comparison of the four DLC programs.

Each DLC program includes these common components: (1) all DLC programs are voluntary; (2) upon receiving a customer request, the utility installs either a programmable thermostat or a direct load control switch for a central air conditioning system or an electric heat pump on a customer's premise; (3) the utilities provide one-time installation incentive and bill credits to the participants in the summer peak months; and (4) with the exception of SMECO, customers can choose one of three cycling choices: 50%, 75%, and 100%.[27] Utilities will invoke the cycling process when PJM calls for an emergency event or a utility-determined event during summer peak season. SMECO uses an initial 2 degree offset followed by 30% cycling for the thermostats, and a 50% cycling option followed by 30% cycling for the switches during specified time periods. The incentives vary among utilities. The one-time installation incentive is credited to the customer's bill after installation is complete and an annual bill credit is awarded for each participation year. Table V.B.1 summarizes the utilities' incentives to the program participants.

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26 The Commission approved BGE's PeakRewards Program on November 30, 2007; Pepco and DPL's Energy Wise Programs on April 18, 2008; and SMECO's CoolSentry Program on April 15, 2008. The utilities' filings were documented in Case Number 9111. Potomac Edison/Allegheny Power also filed its direct load control program, but it was not found to be cost-effective at the time.

27 The cycling choices of 50%, 75%, and 100% represent the air conditioner compressor working cycle reduced by 50%, 75%, and 100% under PJM- or utility- invoked emergency events during summer peak season.

Table V.B.1: Utilities' Incentives to DLC Program Participants

Utility	50% Cycling		75% Cycling		100% Cycling		Bill Credit Month
	Installation Incentive	Annual Bill Credit	Installation Incentive	Annual Bill Credit	Installation Incentive	Annual Bill Credit	
BGE	$50	$50	$75	$75	$100	$100	Jun. – Sept.
DPL	$40	$40	$60	$60	$80	$80	Jun.– Oct.
Pepco	$40	$40	$60	$60	$80	$80	Jun.– Oct.
	Installation incentive		Annual Bill Credit				Bill Credit Month
	Thermostat	Digital Switch		Thermostat	Digital Switch		
SMECO	***	None $50			$50		Jun.– Oct.

*** A participant in SMECO's CoolSentry program can keep the installed thermostat for free after 12 months of the installation; otherwise, the thermostat will be removed if the participant terminates the participation less than 12 months.
Source: Utilities' EmPower Maryland Energy Efficiency Program Websites.

Table V.B.2 summarizes the progress in installing these devices for each utility DLC program as of September 30, 2010 since each program's inception. Installed devices (programmable thermostats and digital switches) number 399,258 units.

Table V.B.2: Utilities' Direct Load Program Installations; Program-to-Date as of December 31, 2010

Utility	Air Conditioning	
	Installation Numbers	Enrollment
BGE	326,000	299,500
DPL	13,807	16,673
PEPCO	39,987	52,444
SMECO	19,464	25,090
Total	399,258	393,707

Source: Utilities 2010 Quarter 3 Report of EmPower Maryland Program.

The DLC program resulted in 803 MW being bid for Delivery Year ("DY") 2013-2014 in the May 2010 PJM RPM auction, a 16% decrease from the 2009 bid of 952 MW for DY 2012-2013. To date, these programs have accounted for 3,050 MW of the total capacity bid into PJM's capacity market. Table V.B.3 summarizes the capacity bid into PJM's capacity market from the DLC program by utility and delivery year.

Table V.B.3: Direct Load Control Program Bids into PJM BRA (MW)

Utility	DY 2013-2014	DY 2012-2013	DY 2011-2012	DY 2010-2011	DY 2009-2010	Total
BGE[1]	615	740	512.6 415.4	217.0		2,500
DPL	32.1	38.8	24.7	N/A N/A		95
Pepco	124.1	148.7	99.2	N/A N/A		372
SMECO	31.9	25.0	25.0	N/A N/A		82
Total	803	952.5	661.5 415.4		217	3049.5

Source: Various data requests in Case Nos. 9111, 9154, 9155, 9156, and 9157.
Notes: BGE's bid includes both its current DLC and its legacy demand response program. N/A means data are not available because there was no program launched for these utilities.

The following section provides an update of each of the four programs.

1. BGE

BGE launched its DLC program, PeakRewards, in June 2008. Popular to date, PeakRewards installed a total of 326,000 air conditioning cycling devices from January 1, 2010 through December 2010. BGE is aggressively marketing this program to meet a 50% participation goal, or approximately 450,000 customers, by the end of 2011. A total of 274,000 participants enrolled in the program since its inception, with 300,750 installed devices (thermostats or switches). BGE also has its legacy demand response programs, which include air conditioner and water heater switches installed in the customer premises, and is in the process of transferring these customers to the PeakRewards program, if the customer decides to continue to participate. BGE plans to phase out the legacy programs in 2011. Therefore, BGE's bid currently includes both the PeakRewards and legacy demand response programs.

Since the inception of PeakRewards, BGE has bid into PJM's BRA for five consecutive delivery years (*see* Table V.B.3), totaling approximately 2,500 MW of demand reduction.

2. Pepco

Pepco launched its Energy Wise program (similar in program design to PeakRewards) in January 2009.[28] Pepco had installed 34,527 devices as of December 2010.

Pepco has bid into the last three of PJM's RPM BRAs, with a total bid of 372 MW to date. The Company bid 124 MW for DY 2013/2014 and 149 MW for DY 2012/2013 into PJM's BRA.

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[28] Pepco and DPL entered into a contract with Comverge on January 20, 2009, and started the testing phase with their own employee volunteers. .

3. DPL

Concurrently with Pepco, DPL launched its Energy Wise program in January 2009. The Company had installed 11,706 devices by the end of December 2010.

DPL has bid into the last three of PJM's RPM BRA, with a total bid of 96 MW. The Company bid 32.1 MW for DY 2013/2014, 38.8 MW for DY 2012/2013, and 24.7 MW for DY 2011/2012 into the PJM BRA.

4. SMECO

SMECO launched its CoolSentry Program in November 2008. A customer may elect to have installed either a thermostat or a digital switch on his/her air conditioner or electric heat pump. SMECO offers a $50 annual bill credit to each participant, but if a participant chooses to install a thermostat, the participant can also keep the thermostat for free after 12 months of participation. No installation incentive is offered to a participant to choose a digital switch. SMECO has installed 19,464 devices since the program's inception.

SMECO bid a total of 81.9 MW into PJM's RPM BRA over the last three years, 31.9 MW for DY 2013/2014, and 25 MW for each DY 2011/2012 and 2012/2013.

Suspension of White Rogers Programmable Thermostat Installation

The Commission temporarily suspended the installation of thermostats due to a potential safety hazard with the devices. On September 23, 2010, Pepco Holdings, Inc. ("PHI") notified the Commission of a potential fire hazard associated with the model of programmable thermostats that Pepco and DPL were installing as part of their EnergyWise program.[29] The Commission issued Order No. 83588 on September 23, 2010 that directed Pepco, DPL, and SMECO[30] ("the Companies") to cease the installation of the affected thermostats immediately and appear before the Commission at a hearing on September 24, 2010. On September 24, 2010, the Commission issued Order No. 83592 reinforcing the decision to cease thermostat installation in Order No. 83588 and directed the Companies to notify the Commission when the Consumer Protection Safety Commission ("CPSC") issued a decision on corrective actions for the safety issue with the thermostats. On March 7, 2011, by Order No. 83899, the Commission authorized the Companies to resume installing programmable thermostats as a part of their respective Demand Response programs.

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[29] The safety issue for Model 1F88 of programmable thermostat was reported to the Consumer Protection Safety Commission by the manufacturer of the thermostat, White Rogers. The manufacturer notified the PHI's contractor, Comverge. Comverge informed PHI.

[30] SMECO also was installing the same White Rogers programmable thermostats in its CoolSentry program

Peak Load Reduction Forecast

Table V.B.4 lists the peak load reduction forecasting data from utilities reporting their load reductions from demand side programs. Table V.B.4 demonstrates a steady increase in peak load reductions resulting from such programs for all utilities, except Choptank and SMECO, during the 2009-2023 forecast period. These utilities' total peak load reductions totaled 416 MW for 2009 and, based on the combined forecast of 3,116 MW for 2023, would result in an estimated annual growth rate of 15.5%.

Table V.B.4: Peak Load Reduction Forecast (MW)

Year	BGE	Choptank	DPL	PE*	Pepco	SMECO	Total
2010	646	10	21	6 67		41	416
2011	793	10	44	17	179	59 844	
2012	805	10	137	31 511		70	1578
2013	1,124	10	174	43 634		77	2207
2014	1,249	11	206	56 676		85	2608
2015	1,457	10	225	68 716		94	2795
2016	1,458	10	237	78 757		94	2985
2017	1,458	11	237	76 757		94	3019
2018	1,458	10	237	74 757		94	3045
2019	1,457	10	237	72 757		94	3069
2020	1,458	10	237	69 757		94	3090
2021	1,458	10	237	66 757		94	3106
2022	1,458	10	237	60 757		94	3114
2023	1,458	10	237	51 757		94	3117
2024	1,458	10	237	41 757		94	3116
Change	**812**	**0**	**216**	**35 690**		**53**	**2,700**
Percentage Change	**126**	**0.0**	**1,028.6**	**583.3 1,029.9**		**128**	**649.0**
Annual Growth Rate (%)	**6**	**0.0**	**18.9**	**14.7 18.9**		**6**	**15.5**

Source: Tables 4A (Gross Peak Load Forecast) and 4B (Net Peak Load Forecast) in Company data responses to the Commission's 2010 data request for the Ten-Year Plan. Data were obtained by subtracting the net of DSM peak load forecast from the gross of DSM peak load forecast.
Note: Hagerstown, Easton, Thurmont, and Williamsport did not report any demand response or load control program.

The major contributors to the peak load reduction are: (1) the current direct load control program (BGE, DPL, Pepco, and SMECO); (2) legacy load reduction program (BGE, SMECO, and Choptank); (3) BGE's Smart Grid Initiative,[31] and (4) energy efficiency & conservation programs (BGE, DPL, Pepco, PE, and SMECO).[32] The peak load forecast for the utilities listed in Table V.B.4 is 14,488 MW for 2009 and 17,793 MW for 2023 without DSM programs. These utilities' peak load forecast is 14,072 MW for 2009 and 14,677 MW for 2023 with DSM programs. Therefore, holding all other factors constant, it is forecast that the DSM programs will reduce the peak demand by over 17% (3,116 MW) by 2023.

[31] Pepco did not include demand reductions from its Commission-approved AMI initiative.
[32] The contribution information is obtained through Staff communication with the utilities.

C. Energy Efficiency and Conservation Programs

On December 31, 2008, the Commission preliminarily approved the utilities' EmPower Maryland EE&C portfolios, contingent upon varying Commission-prescribed alterations to their programs, budgets, and projected savings. Although BGE's programs were approved in whole, the Commission directed the other utilities to file their revised portfolios, along with information confirming their final estimated costs and budgets through completed RFPs or finalized contracts by March 31, 2009. Comments by the interveners, as well as a response by the utility, were filed in each proceeding. As with the original series of proceedings, the Commission conducted hearings for each utility's proposal. The remaining four utilities' - PE, DPL, Pepco and SMECO - programs were approved in August 2009.

Two points on the plans warrant comment. First, four of the five utilities' plans (Potomac Edison is the exception) projected that the utilities' customers will meet the Act's goal of a 5% peak demand reduction by 2011. Only BGE, Pepco, and DPL project that their customers will meet the goal of 15% reduction in peak demand by 2015. None of the utilities' plans projected meeting the 2011 or the 2015 energy consumption targets. Second, there is no current baseline study of Maryland customers that allows the utilities or the regulators to assess the reasonableness of the utilities' assumptions regarding participation rates, necessary rebates, and the like. Pursuant to Commission direction, a new baseline study should be completed by May 2011.

Although CYs 2008 and 2009 served as planning and approval years for the EmPower Maryland programs, the task remained to monitor the EmPower target goals. Economic conditions contributed to two out of the five participating utilities succeeding in meeting or exceeding 2011 target energy reduction goals and contributed to four utilities meeting their 2011 target demand reduction goal. Obviously, few conclusions can be drawn about the 2015 goals, given that few programs were running in CY 2009, but the utilities remain well below the possibility of achieving the goals even with a sluggish economy and the mild summer weather of 2008 and 2009. It is likely that utilities will be fighting an uphill battle in meeting their 2015 target goals as more typical weather patterns return and the economy rebounds.

Table V.C.1: Five Percent Reduction in Maryland Energy Sales 2011

EmPower Maryland - 5 Percent Reduction in Maryland Energy Sales 2011						
2010 Utility Company Data Request Information						
Maryland Utility	2007 per Capita Energy Use MWh	2011 per Capita Energy Use Goal MWh	2011 per Capita Energy Reduction Target MWh (1)	2010 per Capita Energy Use MWh	Percentage Reduced from 2007 Baseline (3)	Percentage of Per Capita Energy Savings Achieved Towards 2011 Reduction Target (4)
B	13.39	12.72	0.67	13.17	1.7%	34.0%
Pepc	9.39	8.92	0.47	8.97	4.5%	90.0%
PE	17.54	16.66	0.88	19.39	-10.5%	-210.9%
GE Delmarva	13.61	12.93	0.68	13.14	3.4%	68.5%
SMECO	11.15	10.59	0.56	10.83	2.9%	57.8%

Source: 2010 Utility Company Data Request Information of wholesale electricity sales.

Table V.C.2: Five Percent Reduction in Maryland Peak Demand 2011

EmPower Maryland - 5 Percent Reduction in Maryland Peak Demand 2011						
2010 Utility Company Data Request Information						
Maryland Utility	2007 per Capita Peak Demand MW	2011 per Capita Peak Demand Goal MW	2011 per Capita Demand Reduction Target MW (1)	2010 per Capita Peak Demand MW	Percentage Reduced from 2007 Baseline (4)	Percentage of Per Capita Peak Demand Savings Achieved Towards 2011 Reduction Target (5)
BGE	0.0028	0.0026	0.0001	0.0025	8.0%	159.3%
Pepco	0.0020	0.0019	0.0001	0.0020	-0.6%	-12.2%
PE	0.0033	0.0032	0.0002	0.0029	12.3%	245.0%
Delmarva	0.0031	0.0030	0.0002	0.0028	11.7%	233.2%
SMECO	0.0023	0.0022	0.0001	0.0024	-6.1%	-122.0%

Source: 2010 Utility Company Data Request Information of Wholesale Electricity Sales.

EmPower Maryland EE&C Programs

On December 31, 2008, by Order Nos. 82383, 82384, 82385, 82386, and 82387,[33] the Commission partially approved the Energy Efficiency, Conservation, and Demand Response Programs pursuant to the EmPower Maryland Energy Efficiency Act of 2008. With the exception of BGE's portfolio, which was approved as a whole, Delmarva Power, Pepco, Potomac Edison and SMECO were all requested to make alterations to some program designs as well as revise the total estimated cost and savings with the finalized RFPs. The Commission approved these revised plans in Order Nos. 82825 on August 6, 2009, and 82835, 82836 and 82837 on August 13, 2009. The approved

[33] The Commission subsequently approved certain program revisions for BGE in Order No. 82674.

programs are designed for residential customers,[34] as well as small and large commercial businesses.[35] Generally, most programs are designed to provide a rebate to consumers to encourage the purchase of energy-efficient products, equipment, or services.

1. BGE

For 2009-2011, these EE&C programs are estimated to cost a total of $149,207,339. The Commission approved BGE's 2010 Residential EE&C EmPower Maryland Surcharge at $0.000730 per kWh by Letter Order dated January 14, 2010. The Company's EmPower Maryland EE&C Programs are projected to achieve 52% of its 2011 energy savings goal (2,052,948 MWh) and 232% of the 2011 peak reduction goal (513 MW). At the conclusion of 2010, the programs had resulted in a reported annualized energy savings of 371,440 MWh and 66 MW of peak demand reduction.[36]

2. Pepco

For 2009-2011, the total cost of the programs is expected to be $49.8 million. The Commission approved Pepco's Residential EE&C EmPower Maryland surcharge at $0.000780 per kWh on January 22, 2010. The Company's EE&C Programs are projected to achieve 65% of its 2011 energy savings goal (685,378 MWh) and 150% of the 2011 peak reduction goal (230 MW). At the conclusion of 2010, its EE&C programs had resulted in a reported annualized energy savings of 134,179 MWh and 13 MW of peak demand reduction.[37]

3. DPL

Total program costs for 2009 through 2011 are estimated to be $19.6 million. The Commission approved DPL's Residential EE&C EmPower Maryland surcharge at $0.000922 per kWh on January 22, 2010. These programs should result in DPL obtaining an estimated 54% of its 2011 goal (205,846 MWh) for energy savings and 124% of the 2011 demand reduction goal (73 MW). At the conclusion of 2010, the programs had resulted in a reported annualized energy savings of 22,925 MWh and 2 MW of peak demand reduction.[38]

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[34] Residential programs include Lighting and Appliances; Home Performance with Energy Star, Quick Home Energy Check-up, and Comprehensive Home Audits; Energy Star for New Homes; Limited Income Energy Efficiency Program; Heating, Ventilation, and Air Conditioning ("HVAC") and Domestic Hot Water Heaters. Program availability varies slightly across service territories.

[35] Non-residential programs include the Lighting; C&I Prescriptive and Custom; Commissioning; Variable Frequency Drive ("VFD") for Motors and Drives. Program availability varies slightly across service territories.

[36] These are preliminary figures based upon EmPower Maryland quarterly reports and are subject to Evaluation, Measurement, & Verification.

[37] These are preliminary figures based upon quarterly reports and are subject to Evaluation, Measurement, & Verification.

[38] *Id.*

4. SMECO

The total cost for the 2009-2011 programs is estimated at $14.3 million. The Commission approved SMECO's Residential EE&C EmPower Maryland surcharge at $0.00079 per kWh on January 14, 2010. The programs are expected to yield 88% of the 2011 energy reduction goal (94,229 MWh) and 206% of the 2011 peak reduction goal (29 MW). At the conclusion of 2010, the programs had resulted in a reported annualized energy savings of 18,494 MWh and 3 MW of peak demand reduction.[39]

5. PE

The total cost for these programs from 2009 through 2011 is estimated to be approximately $33 million. PE expects to reach 90% of its energy savings goal (122,664 MWh) and 72% of its demand reduction goal (49.4 MW) for 2011. By Letter Order dated Janaury 21, 2010, the Commission approved PE's Residential EE&C EmPower Maryland Surcharge at $0.00063. At the conclusion of 2010, the programs had resulted in a reported annualized energy savings of 15,057 MWh and 5 MW of reported peak demand reduction.[40]

D. Advanced Metering Infrastructure / Smart Grid

1. Background

"Smart grid" technology is generally defined as a two-way communication system and associated equipment and software, including equipment installed on an electric customer's premise that uses the electric company's distribution network to provide real-time monitoring, diagnostic, and control information and services that can improve the efficiency and reliability of the distribution and use of electricity. Advanced Metering Infrastructure ("AMI") is a component of smart grid and refers to the installation of meters on a customer's premises capable of being addressed by the utility and read by the customer. The technology can enable customers to see and respond to market-based pricing as well as be more self-aware of their energy usage, assisting in grid reliability and reducing environmental impacts. Reliability and power quality benefits can also accrue when AMI is employed to reduce blackout probabilities and forced outage rates while restoring power in shorter time periods.

On September 28, 2007, the Commission issued Order No. 81637, which established the following minimum technical standards for AMI:

- A minimum of hourly meter reads delivered one time per day;

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[39] These are preliminary figures based upon quarterly reports and are subject to Evaluation, Measurement, & Verification.

[40] These are preliminary figures based upon quarterly reports and are subject to Evaluation, Measurement, & Verification.

- Non-discriminatory access for retail electric suppliers and curtailment service providers to meter data and demand response functions that is equivalent to the electric company's own access to those functions;
- AMI shall be implemented for all customers of the electric company;
- Metering and meter data management and AMI/DSM implementation should generally continue to be an electric company function;[41]
- All AMI meters shall have the ability to monitor voltage at each meter and report the data in a manner that allows the utility to react to the information;
- All meters shall have remote programming capability;
- All meters shall be capable of two-way communications;
- Remote disconnect / reconnect for all meters rated at below 200 amps;
- Time-stamp capability for all AMI meters;
- All meters shall have a minimum of 14 days of data storage capability on the meter;
- All meters shall communicate outages and restorations; and
- All meters shall be net metering and bi-directional metering capable.

BGE, Pepco, DPL, and SMECO filed for matching funds under the Smart Grid Investment Grant ("SGIG") program[42] administered by the United States Department of Energy ("DOE"). BGE and Pepco were successful in obtaining grants. BGE was awarded $200 million in funds from DOE, $136 million for AMI and $34 million for demand response. The remaining $30 million is for an upgrade to the Customer Information System. Pepco was awarded $104 million in funds from DOE, $69 million for AMI and $26 million for demand response. The remaining $9 million is for Distribution Automation and Communication Infrastructure upgrades.

2. Approved AMI Initiatives

BGE

On August 13, 2010, the Commission issued Order No. 83531 in Case No. 9208,[43] which authorized BGE to deploy its AMI Initiative. Some highlights of the approved AMI Initiative are:

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41 Metering and data management options may be considered for larger non-residential customers (this does not exclude any customer from a requirement that their AMI shall at a minimum be fully consistent with all AMI standards). For example, if an industrial or commercial customer (and its retail supplier or CSP) requires more frequent meter reads or downloads, the utility shall work in good faith to accommodate such requirements.

42 On February 19, 2009, President Barack Obama signed into law the American Recovery and Reinvestment Act ("ARRA"). The ARRA provides targeted support for the development of a Smart Grid, with $4.5 billion appropriated to the DOE for spending on grid modernization; demand responsive equipment; energy storage research, development, demonstration and deployment; and, most significantly for smart grid businesses, implementation of smart grid programs created under the Energy Independence and Security Act of 2007 ("EISA").

43 *In the Matter of Baltimore Gas and Electric Company for Authorization to Deploy a Smart Grid Initiative and to Establish a Surcharge Mechanism for the Recovery of Cost.*

- Install over 2 million electric meters and gas modules;
- Deployment cost of $440 million in capital cost and $57 million in operational costs;
- Total cost over the life of the program of $641 million capital cost and $194 million in operational costs offset by $136 million[44] in federal grants from the Department of Energy;
- Total benefits over the life of the project are estimated at $2.7 billion; and
- 80 percent of all meters to be installed by 2014.

Order No. 83531 directs BGE to do the following:

1) Establish a regulatory asset for the AMI Initiative. Once the Company has delivered a cost-effective AMI system, it may seek cost recovery in its base rates, including incremental costs and net depreciation and amortization costs relating to the meters;
2) Allow cost recovery for the replacement of legacy meters by smart meters to be considered in a future depreciation proceeding;
3) Submit for Commission approval, an updated customer education plan;
4) Develop "a comprehensive set of installation, performance, benefits and budgetary metrics" that will allow the Commission to assess the progress and performance of the Initiative;[45] and
5) Notify the Commission of whether it will proceed with the initiative. BGE confirmed its intent to proceed with the initiative in a letter sent to the Commission on August 16, 2010.

Since authorization, BGE, in conjunction with PHI, Staff and other stakeholders, established a Smart Grid Collaborative Work Group per Commission direction. The Work Group offers a venue to discuss issues such as the consumer education plan and the comprehensive set of performance metrics. The Company provided an update on deployment efforts at a status conference on December 15, 2010. The Company proposed that deployment take place from 2011-2014, with installation of smart meters beginning in October 2011.

Pepco

On September 2, 2010, the Commission issued Order No. 83571 in Case No. 9207,[46] authorizing Pepco to deploy its AMI Initiative contingent upon the Company submitting an amended business case and a comprehensive consumer education plan. Some highlights of the approved Smart Grid Initiative are:

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44 BGE was awarded $200 million in American Recovery and Reinvestment Act funding. Of this, $136 million funds AMI deployment and $64 million for Peak Rewards and Customer Care & Billing.

45 Order No. 83531at 48.

46 *In the Matter of Potomac Electric Power Company and Delmarva Power and Light Company Request for the Deployment of Advanced Meter Infrastructure.*

- Install 570,000 electric meters;
- Deployment cost of $69.4 million in capital cost;
- Total cost over the life of the program of $127 million in capital cost and $1.038 million in annual incremental operational costs;
- Total benefits over the life of the project are estimated at $311.6 million; and
- Pepco awarded $104.8 million in Smart Grid Investment Grant funds.

Order No. 83571 directs and allows Pepco to do the following:

1) Submit an amended business case and associated benefits-to-costs analysis that demonstrates the cost-effectiveness of the AMI proposal;
2) Submit a plan detailing how it intends to fund its proposed Critical Peak Rebate dynamic pricing structure, including the manner in which it intends to monetize peak demand and energy use reductions attributable to AMI;
3) Develop "a detailed and comprehensive customer education and communications plan," along with a corresponding customer education and communications budget;[47]
4) Develop a comprehensive set of metrics of the Company's AMI proposal, including: (a) installation and performance of the technology; (b) incremental costs incurred; (c) incremental benefits realized; (d) effectiveness of customer education and communications efforts to include customer satisfaction and participation levels; and (e) customer privacy and cyber security;
5) Establish a regulatory asset for the incremental costs associated with the AMI deployment, including start-up costs, which the Company may seek to recover in a base rate proceeding;
6) Seek cost recovery for the replacement of legacy meters by smart meters to be considered in a future depreciation proceeding. The Order also prohibits the Company from implementing a Critical Peak Pricing rate structure. A dynamic rate schedule will go in effect once AMI has been installed. Further, the Commission ordered Commission Staff as well as Pepco to convene an AMI working group, which is to include representatives from Pepco, BGE, and the Office of People's Counsel to submit a proposal for "uniformity of critical peak period seasons, times, frequency, and duration, and other aspects of dynamic pricing implementation."[48]

Pepco filed with the Commission its Customer Education Plan on October 15, 2010 and an amended business case on December 13, 2010, in accordance with Order No. 83571. Pepco provided cost-benefit analyses under three different post-deployment scenarios, all of which yielded cost-effectiveness scenarios greater than 1.0. The filing also included depreciation timetables for advanced metering infrastructure and estimated costs for regulatory assets. The consumer education plan and amended business case's final budget - as well as the performance metrics required to be reported - will be subject

[47] *Id*. at 4.
[48] *Id*. at 51.

to the review of the Smart Grid Collaborative Work Group and to the approval of the Commission. In its amended business case filed December 13, 2010, Pepco proposed a time period of 15 months for AMI installation, and the starting month is expected to be June 2011, with completion in August 2012.

3. Deferred AMI Initiatives

DPL

In Order No. 83571, the Commission deferred the decision on DPL's request to proceed with deployment of its AMI Initiative. DPL's request to establish a regulatory asset for the incremental costs associated with its proposed AMI deployment was deferred as well.

Order No. 83571:

1) Deferred DPL's request to proceed with deployment of its AMI Initiative, and directed the Company to submit an amended business case and associated cost-benefit analysis demonstrating the cost-effectiveness of the proposal;
2) Required the Company to submit a plan detailing how it intends to fund its proposed Critical Peak Rebate dynamic pricing structure, including the manner in which it intends to monetize peak demand and energy use reductions attributable to AMI;
3) Denied DPL's request to establish a regulatory asset for the incremental costs associated with AMI deployment, pending submission of a revised business case of AMI system deployment that is agreeable to the Commission; and
4) Prohibited the Company from implementing a Critical Peak Pricing rate structure.

DPL filed a revised business case for its AMI Initiative on December 14, 2010, which includes forecast scenarios for all of the adjustments specified by Order No. 83571.

4. AMI Pilots

SMECO

SMECO proposed a two-phase AMI Pilot Program to test the operational benefits of AMI deployment, such as savings from eliminating meter readings and improved outage restoration. Phase I of the pilot, approved by the Commission in December of 2009, includes the installation of 1,000 meters in one section of the service territory and went into effect in 2010. The Cooperative will attempt to quantify the level of operational benefits attainable through deployment of AMI, and the Cooperative will report the results of Phase I to the Commission prior to implementing Phase II, which will be a 10,000 meter deployment across the entire service territory. At the time of this report, SMECO had not yet submitted the report on Phase I of the project. SMECO notified Commission Staff that Phase I would commence in mid-March 2011.

E. Mid-Atlantic Distributed Resources Initiative ("MADRI")

MADRI was established in 2004, and currently consists of seven PJM State Commissions, DOE and PJM.[49] Its goal is "to develop regional policies and market-enabling activities to support distributed generation and demand response in the Mid-Atlantic region." Facilitation support is provided by the Regulatory Assistance Project funded by DOE. There has been much participation by a large number of stakeholders, including utilities, Commission Staff, FERC, service providers, and consumers. During 2010, MADRI was active in the following areas:

- Review of PJM work on price responsive demand;
- Support for the federally funded Smart Grid Clearinghouse; and
- Updates and discussion of Smart Grid and other demand side initiatives and developments in the MADRI states.

VI. ENERGY, THE ENVIRONMENT, AND RENEWABLES

A. The Regional Greenhouse Gas Initiative

The Regional Greenhouse Gas Initiative ("RGGI") is the first mandatory cap-and-trade program in the United States for carbon dioxide ("CO_2"). Under RGGI, ten northeastern and Mid-Atlantic states have jointly designed a cap-and-trade program that limits permitted carbon dioxide emissions from fossil fuel power plants, and then incrementally lowers that level or "cap" 10% by 2018.

RGGI, Inc. is a nonprofit Delaware corporation formed to provide technical and scientific advisory services to participating states in the development and implementation of the carbon dioxide budget trading programs. The RGGI, Inc. offices are located in New York City in space co-located with the New York Public Service Commission. The RGGI Board of Directors is composed of two representatives from each member state (20 total), with equal representation from the states' environmental and energy regulatory agencies. Agency Heads (two from each state), who also serve as RGGI Board members, constitute a steering committee that provides direction to the Staff Working Group and allows coordination of in-process projects for Board review.

Under RGGI, the participating states have agreed to use an auction of allowances as the means to distribute CO_2 emissions allowances to electric power plants regulated under coordinated state CO_2 cap-and-trade programs. All fossil fuel electric power plants 25 megawatts or greater must obtain allowances and adhere to RGGI guidelines. The effective date for RGGI was January 1, 2009. From 2009 through 2014, the cap

[49] The Commissions are Delaware, D.C., Illinois, Maryland, New Jersey, Ohio and Pennsylvania.

stabilizes emissions at 2009 levels of approximately 188 tons annually. These initial base annual emissions budgets for the 2009-2014 period are summarized in Table VI.B.1.

Table VI.B.1: State CO_2 Allowances (2009 – 2014)

State	Carbon Dioxide Allowances (in Short Tons)
Connecticut	10,695,036
Delaware	7,559,787
Maine	5,948,902
Maryland	**37,505,984**
Massachusetts	26,660,204
New Hampshire	8,620,460
New Jersey	22,892,730
Rhode Island	2,659,239
Vermont	1,225,830
Total	1,888,078,977

Source: The Regional Greenhouse Gas Initiative, Memorandum of Understanding, available at: http://www.rggi.org.

Beginning in 2015, the cap is reduced by 2.5% each year until 2018. This phased approach, with initially modest emissions reductions, is intended to provide market signals and regulatory certainty so that electricity generators may begin planning for, and investing in, lower-carbon alternatives throughout the region while avoiding volatile wholesale electricity price impacts and attendant retail electricity rate impacts. The RGGI memorandum of understanding apportions carbon dioxide allowances among signatory states through a process that was based on historical emissions and negotiation among the signatory states. Together, the emissions budgets of each signatory state comprise the regional emissions budget or RGGI "cap."

In 2010, RGGI held four successful auctions for carbon dioxide allowances (an allowance is a limited permission to emit one ton of carbon dioxide). Maryland's Strategic Energy Investment Fund has received a cumulative total of $147,530,362 dollars through December 2010, with $34 million being received in 2010.

During 2010, auction clearing prices continued a downward trend that started in mid-2009. The auction clearing prices for allowances decreased from $2.07 per allowance at the first auction held in March 2010 to $1.86 at the auction held in December 2010. The price for 2013 allowances sold in 2010 auctions remained at $1.86 per allowance, unchanged from the auctions in September and December 2009.

B. The Renewable Energy Portfolio Standard Program

The Renewable Energy Portfolio Standard ("RPS") Program imposes an annual requirement upon Maryland load serving entities ("LSEs"), which include electricity suppliers and the utilities that provide Standard Offer Service ("SOS"), to meet a renewable energy portfolio standard.[50] LSEs file compliance reports with the Commission verifying that the renewable requirement for each entity is satisfied. The RPS obligation applies to anyone who has completed an electricity sale at retail to customers in the State of Maryland. Additional information regarding the annual status of the Maryland RPS is available in the annual Renewable Energy Portfolio Standard Reports submitted to the General Assembly.[51]

Each supplier must present, on an annual basis, renewable energy credits ("RECs") equal to the percentage specified by the RPS Statute,[52] or pay compliance fees equal to any shortfalls. A REC is equal to one MWh of electricity generated using specified renewable sources. As such, a REC is a tradable commodity equal to one MWh of electricity generated or obtained from a renewable energy generation resource. Generators and suppliers are allowed to trade RECs using a system known as the Generation Attributes Tracking System ("GATS"). GATS is a system designed and operated by PJM Environmental Information Services, Inc. ("PJM-EIS") that tracks the ownership and trading of the generation attributes.[53] A REC has a three-year life during which it may be transferred, sold, or redeemed. Suppliers that do not meet the annual RPS requirement are required to pay compliance fees.

Compliance fees are deposited into the Maryland Strategic Energy Investment Fund ("SEIF" or "Energy Fund") as dedicated funds to provide for loans and grants that can indirectly spur the creation of new renewable energy sources in the State.[54] The Commission is responsible for creating and administering the RPS Program; responsibility for developing renewable energy resources through loans and grants has been vested with the Maryland Energy Administration.

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50 Standard Offer Service is electricity supply purchased from an electric company by the company's retail customers who choose not to transact with a competitive supplier operating in the retail market. *See* PUA §§ 7-501(n) and 7-510(c).

51 PSC Reports, available at: http://webapp.psc.state.md.us/Intranet/psc/Reports_new.cfm.

52 Using the Tier 2 RPS requirement as an example, assume a hypothetical LSE operating in the State had 100,000 MWh in retail electricity sales for 2008. In 2008, the Tier 2 requirement was 2.5 %. Thus, the LSE would have to verify the purchase of 2,500 Tier 2 RECs in satisfaction of the Tier 2 RPS obligation, or pay compliance fees for deficits. Similar requirements apply to Tier 1 and Tier 1 solar, the additional RPS tiers provided for in Maryland's RPS Statute.

53 An attribute is "a characteristic of a generator, such as location, vintage, emissions output, fuel, state RPS program eligibility, etc." PJM Environmental Information Services, Generation Attribute Tracking System Operating Rules, Revision 5, at 3 (December 8, 2008).

54 Chapters 127 and 128 of the Laws of 2008 repealed the Maryland Renewable Energy Fund and redirected compliance fees paid into that fund into the Maryland Strategic Energy Investment Fund.

Eligible fuel sources for Tier 1 RECs and Tier 2 RECs are listed in Table VI.B.1. In order to verify that each LSE has met its RPS obligation, the Commission requires that all licensed electricity suppliers and electric companies file a Supplier Annual Report no later than April 1st each year.[55] The April 1st deadline provides time for LSEs to calculate electricity sales for the compliance year that ends on December 31st, based on settlement data. The April 1st deadline also allows LSEs time to purchase any RECs needed to fulfill their respective RPS obligations.

Table VI.B.1. Eligible Tier 1 and Tier 2 Resources

Tier 1 Renewable Technologies	Tier 2 Renewable Technologies
• Solar (set-aside with separate standard) • Wind • Qualifying Biomass • Methane (landfill or wastewater treatment plant) • Geothermal • Ocean Energy (waves, tides, currents, and thermal differences) • Fuel Cells (which produce electricity from biomass or methane under Tier 1) • Hydroelectric Power Plant (less than 30 MW capacity) • Poultry Litter-to-Energy	• Hydroelectric Power (other than pump storage generation) at or above 30 MW • Waste-to-Energy

Source: PUA § 7-701.
Note: Tier 1 RECs may be used to satisfy Tier 2 obligations; Tier 2 RECs, however, may not be used to satisfy Tier 1 obligations.

LSEs are required to purchase specified minimum percentages of their electricity resources via RECs from Maryland-certified Tier 1 and Tier 2 renewable resources. As presented in Table VI.C.2, Tier 1 and the Tier 1 solar set-aside requirements gradually increase until they peak in 2022 at 18% and 2%, respectively, and are subsequently maintained at those levels.[56] SB 277, passed during the 2010 Session of the Maryland General Assembly, changed the allocation between the solar set-aside and other Tier 1 resources. The total Tier 1 RPS remained the same; however, from 2011 through 2016 there is an increase in the rate at which the Tier 1 solar requirements change.[57] Maryland's Tier 2 requirement remains constant at 2.5% through 2018, after which it sunsets.

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55 These reports have been filed pursuant to PUA § 7-705 and COMAR 20.61.01.04.

56 "Tier 1 solar set-aside" refers to the set-aside (or carve-out) of Tier 1 for energy derived from qualified solar energy facilities. The Tier 1 solar set-aside requirement applies to retail electricity sales in the State by LSEs and is a sub-set of the Tier 1 standard.

57 Chapter 494, 2010 Laws of Maryland, which amended PUA § 7-703.

Table VI.B.2: RPS Percentage Requirements

Compliance Year	Original Tier 1 Solar Set Aside	SB 277 Reallocation to Solar Tier 1	Solar Tier 1 as of 1/1/2011	Other Tier 1 as of 1/1/2011	Total Tier 1	Tier 2	Total RPS
2010	0.025%	0.000%	0.025%	3.00%	3.025%	2.50%	5.53%
2011	0.040%	0.010%	0.050%	4.95%	5.000%	2.50%	7.50%
2012	0.040%	0.040%	0.100%	6.40%	6.500%	2.50%	9.00%
2013	0.100%	0.100%	0.200%	8.00%	8.200%	2.50%	10.70%
2014	0.150%	0.150%	0.300%	10.00%	10.300%	2.50%	12.80%
2015	0.250%	0.150%	0.400%	10.10%	10.500%	2.50%	13.00%
2016	0.350%	0.150%	0.500%	12.20%	12.700%	2.50%	15.20%
2017	0.550%	0.000%	0.550%	12.55%	13.100%	2.50%	15.60%
2018	0.900%	0.000%	0.900%	14.90%	15.800%	2.50%	18.30%
2019	1.200%	0.000%	1.200%	16.20%	17.400%		17.40%
2020	1.500%	0.000%	1.500%	16.50%	18.000%		18.00%
2021	1.850%	0.000%	1.850%	16.85%	18.700%		18.70%
2022	2.000%	0.000%	2.000%	18.00%	20.000%		20.00%

Source: PUA § 7-703 and SB 277.

Suppliers of electricity not meeting the RPS standard pay an Alternative Compliance Penalty ("ACP") for shortfalls, as seen in Table VI.C.3. Table VI.C.3 presents the ACP schedule separated by tiers for each year of the RPS from 2008 to 2023 and beyond. Compliance fees, as previously mentioned, are deposited into the SEIF and dedicated to supporting the development of new Tier 1 renewable resources in Maryland.

Calendar year 2009 marked the fourth compliance year for the Maryland RPS, and the second year for LSEs to comply with the solar Tier 1 set-aside. GATS and the RPS compliance reports submitted to the Commission by LSEs provide information regarding the RECs retired and the underlying renewable energy facilities (*e.g.*, type and location) utilized by electricity suppliers to comport with Maryland RPS obligations.[58] RPS compliance reports were filed by 52 electricity LSEs: 24 competitive suppliers, 18 brokers or wholesale electricity suppliers with zero retail electricity sales, and 10 electric distribution companies, which included four investor-owned utilities. There were approximately 63.2 million MWh of total retail electricity sales in Maryland for 2009, of which 61.4 million MWh (97.2%) were subject to RPS compliance, and 1.8 million MWh (2.8%) were exempt.[59]

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58 According to PUA § 7-709, a REC can be diminished or extinguished before the expiration of three years by: the LSE that received the credit; a nonaffiliated entity of the LSE that purchased or otherwise received the transferred credit; or demonstrated noncompliance by the generating facility with the requirements of PUA § 7-704(f). In the PJM region, the regional term of art is "retirement," and describes the process of removing a REC from circulation by the REC owner, *i.e.,* the owner "diminishes or extinguishes the REC." PJM Environmental Information Services, Generation Attribute Tracking System Operating Rules, at 52-54 (December 8, 2008).

59 According to PUA § 7-703(a)(2), exceptions for the RPS requirement may include: industrial process load that exceed 300,000,000 kWh to a single customer in a year; regions where

Table VI.B.3: RPS Alternative Compliance Fee Schedule

Compliance Year	Tier 1 (non-solar)	Solar Tier 1	Tier 2	IPL[60] Tier 1
2008	$20	$450	$15	$8
2009	$20	$400	$15	$5
2010	$20	$400	$15	$5
2011	$40	$400	$15	$4
2012	$40	$400	$15	$4
2013	$40	$400	$15	$3
2014	$40	$400	$15	$3
2015	$40	$350	$15	$2.50
2016	$40	$350	$15	$2.50
2017	$40	$200	$15	$2
2018	$40	$200	$15	$2
2019	$40	$150		$2
2020	$40	$150		$2
2021	$40	$100		$2
2022	$40	$100		$2
2023 and beyond	$40	$50		$2

Source: PUA § 7-705(b).

Note: According to PUA § 7-705(b)(2) and COMAR 20.61.01.06(E)(5), a supplier sale from Industrial Process Load is required to meet the entire Tier 1 obligation for electricity sales, including solar. However, the ACP for an IPL Tier 1 non-solar shortfall and a Tier 1 solar shortfall is the same. For IPL, there is no compliance fee for Tier 2 shortfalls.

For the 2009 compliance year, electricity LSEs retired 2,793,479 RECs, which was greater than the obligation for the year by approximately 23,000 RECs. According to the compliance reports filed with the Commission, the cost of RECs retired totaled $3,052,300 for the 2009 compliance year. For the four compliance years, Table VI.B.4 displays the breakdown of RECs submitted for each tier in MWh, the number of RECs retired in the year by tier in MWh, as well as the payments for the shortfalls in terms of the ACP amount required in dollars per MWh.[61]

residential customer rates are subject to a freeze or cap (under PUA § 7-505); or electric cooperatives under a purchase agreement that existed prior to October 1, 2004, until the expiration of the agreement.

60 Industrial Process Load ("IPL").

61 The RPS obligation is the total obligation for electricity sales in MWh, which is equal to the number of RECs required for compliance. The number of retired RECs is the actual number of RECs retired for RPS compliance in each corresponding compliance year. The ACP required is calculated by multiplying the difference between the RPS obligation and the actual retired RECs (*i.e.*, the shortfalls) by the applicable ACP and is denominated in U.S. dollars.

Table VI.B.4: RPS Supplier Annual Report Results as of December 31, 2009

	RPS Obligation			RPS Compliance Method			
Compliance Year	Tier 1 (MWh)	Tier I Solar (MWh)	Tier 2 (MWh)	Tier 1 RECs (MWh)	Tier I SRECs (MWh)	Tier 2 RECs (MWh)	ACP Required ($/MWh)
2006	520,073	N/A	1,300,201	552,874	N/A	1,322,069	$38,209
2007	553,612	N/A	1,384,029	553,374	N/A	1,382,874	$36,374
2008	1,183,439	2,934	1,479,305	1,184,174	227	1,500,414	$1,235,965
2009	1,228,521	6,125	1,535,655	1,280,946	3,260	1,509,270	**$1,148,265**
Total	3,485,645	9,059	5,699,190	3,571,368	3,487	$5,714,627	**$3,485,645**

Sources: Annual Utility RPS Filings with the Commission 2007, 2008, 2009, and 2010, available at: http://webapp.psc.state.md.us/Intranet/psc/Reports_new.cfm.

Notably, in 2008 there was a shortfall of 2,707 MWh (92.2%) in SRECs for the initial year of the Solar Tier 1 requirement of 2,934 MWh. This shortfall occurred because there had been fewer than 300 Maryland eligible SRECs created by the end of 2008. For residential and small commercial SOS, three of the four Maryland investor-owned utilities purchased two-year supply contracts via competitive bids conducted twice each year.[62] The statute governing the RPS was amended during the Maryland General Assembly's 2007 session to include a specific Tier 1 solar RPS requirement starting January 1, 2008,[63] which occurred during the effective period of a number of then-existing two-year SOS procurement contracts.[64] Over 98% of the total ACPs for the 2008 compliance year were from Solar Tier 1 shortfalls.[65] Acquisition of RECs also depends upon the availability of solar technologies to provide generation capacity and

62 The Potomac Edison Company d/b/a Allegheny Power has been in a transition mode purchasing 5-month to 29-month contracts for its residential and small commercial SOS via competitive bids conducted up to four times a year.

63 *See* PUA § 7-703.

64 Normally, renewable electricity (*i.e.*, the RECs) is provided to the utilities as a product component within the wholesale power purchase agreements. However, an SOS service year runs for a 24-month contract term and straddles two RPS compliance years (in this case, calendar years 2008 and 2009). In the event the RPS requirement is increased, the contracts supporting SOS require the utilities and suppliers to meet via a stakeholder process to consider terms under which the wholesale suppliers could supply the incremental RPS requirement, but ultimately leave it up to the Commission to determine how this requirement will be met. Stakeholders proposed to have the utilities pay the statutory penalty for noncompliance (*i.e.*, the alternative compliance payment or ACP) with the RPS Tier 1 solar requirement for the period from June 1, 2008 through December 31, 2008. The Commission approved the stakeholder proposal. For the period covering January 1, 2009 through May 31, 2009, the stakeholders proposed to develop and conduct a competitive bid to purchase the needed SRECs.

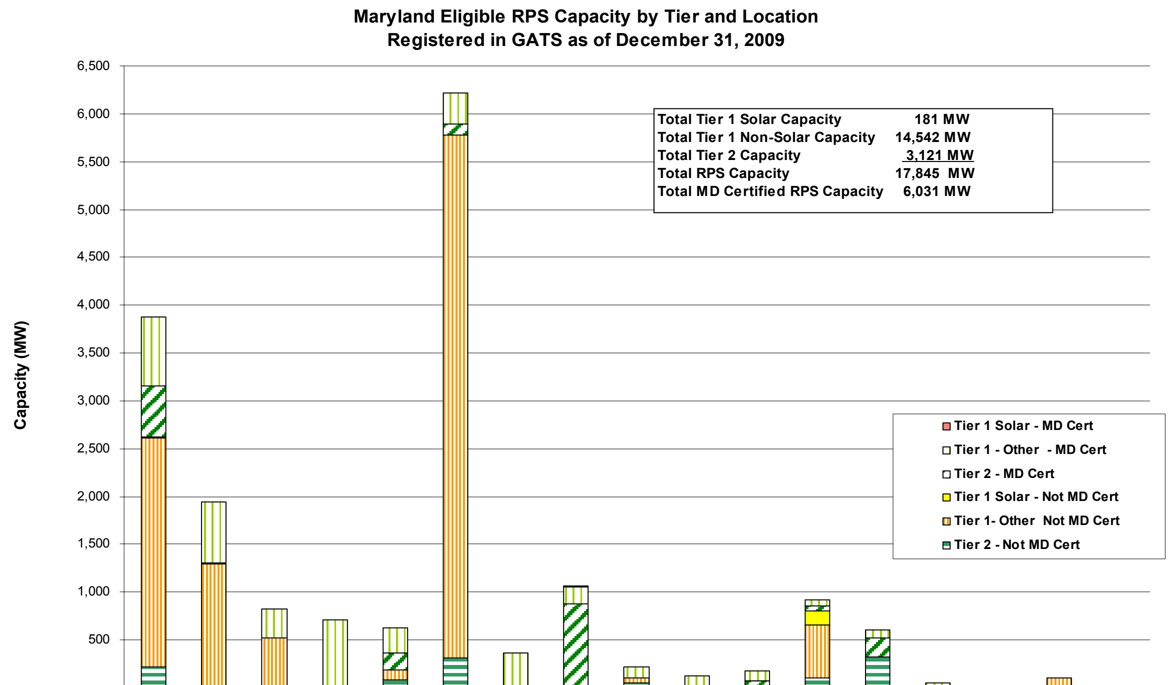
65 Of the remaining portion of ACPs (non-solar) paid, 94% was provided by one LSE.

efficiencies for the Tier 1 Solar compliance options selected.[66] In 2009, only 53% of the solar REC obligation was met by the retirement of SRECs. Of the total ACP payments received in 2009, over 99% were related to meeting the solar REC requirement.

Chart VI.B.5 presents the geographical location and the total generating capacity (6,031 MW) for all Maryland RPS-certified facilities by tiers. RPS requirements also exist in the surrounding states, which generally support out-of-state and regional market participation. Of the renewable facilities that are eligible to participate and potentially provide renewable energy to Maryland, 73% are located in the Mid-Atlantic states; Illinois and North Carolina account for 11.0% and 5.9%, respectively, of the remaining 27%. Similarly, only 54% of the RPS facilities that have Maryland certifications are located in the Mid-Atlantic region. Consequently, the decisions made in surrounding states on RPS requirements, ACP levels, and the availability of state grants or subsidized loans can affect the amount of new solar capacity built in Maryland and prices that Maryland LSEs will need to offer to obtain RECs in the spot market and under longer term arrangements.

[66] As noted above, LSEs can meet RPS obligations by either purchasing available RECs or paying the ACP. For SOS procurement auctions that had occurred before the solar requirement was enacted, it was too late to buy solar RECs for those SOS contracts. Therefore, only the default ACP option was available. However, currently, parties are working to implement a supplemental procurement method for solar RECs for SOS contracts still operative that were procured before the enactment of the current solar REC requirement.

Chart VI.B.5: MD RPS Eligible Capacity by State as of December 31, 2009



	PA	IL	IN	MD	WV	VA	DE	NC	NJ	IA	OH	NY	MI	WI	TN	KY	DC
Tier 1 Solar - MD Cert	0.02			0.06		0.04		6.69			0.09		0.04				0.01
Tier 1 - Other - MD Cert	714	635	300	705	270	324	370	172	109	95	104	63	79	54	3		
Tier 2 - MD Cert	534				169	120		870			76	59	198				
Tier 1 Solar - Not MD Cert	10.6	10.2	0.1	5.1	0.03	0.4		0.2	1.1	0.0	0.0	145.6	0.0			0.1	0.6
Tier 1- Other Not MD Cert	2,394	1,298	526	0	108	5,462		12	59	26		553				106	
Tier 2 - Not MD Cert	221				84	314			47			103	325				

States

Source: Renewable Generators Registered in GATS, available at: https://gats.pjm-eis.com/mymodule/rpt/myrpt.asp?r=228.
Notes: Only resources eligible in Maryland that are used to generate electricity are included; solar thermal facilities are not included. *See* PUA § 7-701. Facilities are classified as "MD Certified" if they have applied to the Commission and received an approval number that is recorded in GATS.

C. Solar Power Requirements in Maryland

In 2008, the Commission laid the foundation for an active solar market in Maryland. Regulations were enacted which established a small generator interconnection standard with an expedited process for interconnection of solar facilities. Regulations were adopted establishing the mechanism for creating renewable energy credits and tracking sites. An on-line Solar Renewable Energy Facility application form was introduced to the Commission's website. In 2009, the Commission approved modifications to the solar regulations to reduce the filing requirements for small solar facilities.

The RPS standard requires an LSE to purchase SRECs for 0.01% of the State's electricity in 2009. This amount increases incrementally each year until reaching the required 2% by 2022.[67] If an LSE fails to offset the applicable percentage of retail electricity sales with electricity derived from solar resources or from SRECs, then the LSE is responsible for making an alternative compliance payment as set forth in PUA § 7-705(b). Table VI.B.2 summarizes percentage requirements of the Maryland RPS through 2022.

The Maryland Solar RPS grants customers rights to the SRECs each system earns, and requires contract terms to be a minimum of 15 years when the renewable energy credits are purchased by an electricity supplier directly from the solar electricity generator. For facilities that are greater than 10 kW in rated capacity, the stipulation associated with an LSE purchasing SRECs directly from a renewable on-site generator to meet the solar component of the Maryland RPS is that the contract terms for the SRECs must be for no less than 15 years.[68]

An LSE that purchases SRECs directly from a solar renewable on-site facility that is less than 10 kW in rated capacity must do so through a contract that provides for an up-front lump sum payment for at least 15- years' worth of SRECs at a price that is determined by the Commission. The up-front purchase of SRECs is intended to aid in financing the construction of this type of solar installation. The current proposed level of payment for the SRECs is the net present value of the 15-years' worth of RECs using 80% of the compliance fee schedule, with a discount rate that is equal to the Federal Secondary Credit Interest Rate.[69]

PUA Title 7, Subtitle 7 calls for electricity generated from a Tier 1 solar renewable source to be connected with the electric distribution grid serving Maryland as of January 1, 2012 in order for the generation to be eligible to create Maryland SRECs after that date. Until January 1, 2012, SRECS from non-Maryland Tier 1 solar renewable energy facilities located in PJM are eligible for the Maryland RPS only to the extent that there is a shortage of SRECs derived from facilities interconnected with the Maryland grid. All Maryland-based Tier 1 solar renewable energy facilities must be certified by the Commission as a Maryland renewable energy facility, prior to the facility being eligible to create Maryland-eligible SRECs. As of December 31, 2009, GATS had registrations for 582 solar facilities in Maryland with total capacity of 6.69 MW.

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67 *See* Table VI.B.2 and accompanying text for a discussion of changes to SREC requirements enacted during the 2010 session of the Maryland General Assembly.

68 PUA § 7-709.

69 *See* COMAR 20.61.

VII. ELECTRIC DISTRIBUTION RELIABILITY IN MARYLAND

The Commission supervises and regulates public service companies to promote the economical and efficient delivery of utility services in the State. Economical and efficient delivery of electricity depends on a well-planned, maintained, and operated distribution system.

A. Electric Distribution Reliability Reporting, Operation and Maintenance

Electric utilities serving 40,000 or more Maryland customers are required to file an Annual Reliability Report with the Commission. For each utility, the reports contain measurements of reliability for the preceding calendar year of the System Average Interruption Duration Index (SAIDI), the System Average Interruption Frequency Index (SAIFI) and the Customer Average Interruption Duration Index (CAIDI).[70] Each investor-owned utility also reports the reliability measurements for a group of the least reliable electric feeders in its system for the year, together with the remedial actions it has taken to improve the reliability of those feeders. The same feeders are not permitted to appear on a utility's least reliable list in any two successive years under a COMAR provision designed to gradually increase over time the reliability of all feeders in the least performing range. The large electric cooperatives report the operating district with the least reliability for the year, together with the remedial actions taken to improve reliability within those districts.

Routine inspection and maintenance of existing distribution system equipment must be performed periodically to help maintain a baseline level of reliability. All electric companies serving Maryland have developed written O&M procedures pursuant to COMAR 20.50.02.04. The O&M procedures must list the specific inspection and maintenance tasks to be performed and the frequency with which the tasks are to be performed. The six largest electric utilities operating in Maryland are required to maintain their written O&M procedures with the Commission and to file annual updates of any changes that are made to those procedures. While the procedures vary somewhat from utility to utility, there are many common practices, since the procedures are based on utility experience and accepted good practice within the industry.

With respect to substations, periodic attention is typically given to power transformers, various electrical relays and circuit breakers used primarily for equipment protection, and devices used for controlling voltage such as capacitors and voltage regulators.

For distribution feeder lines, inspection and maintenance attention is typically focused on the electrical conductors in general, capacitors and other voltage regulators, automatic re-closers, electronic monitoring/control devices, vegetation management, and support poles for overhead equipment. Utilities have ongoing, proactive programs for

70 CAIDI is calculated by dividing SAIDI by SAIFI

replacement of aged underground electrical conductors, in addition to such activity in reaction to service interruptions. Some utilities inject conditioners in to existing underground cable to increase its life expectancy.

The electric distribution system is a large-scale array of electric power circuits and, increasingly, electronic sensing and control circuits. Excessive heat, whether generated internally or by a hot day, is one of the greatest threats to the proper operation of electric and electronic circuits. Electric utilities use infrared imaging technology in performing periodic inspections to identify substation equipment that is operating at a temperature higher than the normal range for proper operation. Some utilities include distribution feeder equipment in such inspections. The value in this procedure is that abnormally hot spots in electric conductors or equipment can often be detected and corrected long before they fail due to overheating.

Each utility is required by COMAR to keep sufficient records to demonstrate compliance with its O&M procedures. The Commission's Engineering Division conducts yearly inspection visits to the electric utilities to examine these records, in a continuing effort to assure basic distribution system reliability.

In recent years, electric distribution utilities have been attempting to raise the baseline level of service reliability by increasing the automation of distribution feeders, with the potential to reduce both frequency and duration of sustained electric service interruptions. For example, some feeders can be connected with other feeders by switches that are normally off (open), but can be closed so that one of the feeders may temporarily supply part or all of a feeder experiencing an outage. Currently, many of these switches are manually operated, and require a utility crew to operate the switches to restore power. If the operation of such a switch is automated, either with local electronic intelligence or through remote operation from the distribution system control or operations center, service outage time to customers can be reduced.

Although electric service interruptions cannot be totally avoided, new utility operating methods that could serve to improve reliability include more aggressive attempts to reduce the threat of large privately- and publicly- owned trees or large branches falling on overhead power lines. Utilities work to gain tree owner cooperation to allow the removal of large trees near the lines or large branches overhanging the lines, which would help reduce the frequency of service outages, particularly during storms. Other efforts involve limiting the number of customers exposed to any given outage that does occur.

As members of Mutual Assistance Groups, the utilities share restoration crew manpower and other resources when outages increase beyond levels thought to be manageable using the utility's normal resources. Such assistance serves to reduce outage duration, one common measure of reliability. In addition to crew sharing, the groups hold conference calls for storm preparation for storm damage assessment, and to discuss overall restoration resource availability.

The four large investor-owned electric utilities operating in Maryland are members of the Mid-Atlantic Mutual Assistance group and the Southeastern Electrical Exchange. Another similar group, Maryland Utilities, includes municipal and cooperative electric utilities. These groups and others will continue to be important alliances in the years to come, as effective distribution outage management and storm restoration requires not only a community-wide effort, but sometimes also a regional or national effort.

B. Distribution Reliability Issues

1. BGE and Electric Service Reliability in Bowie

Background

The City of Bowie and the nearby surrounding area are supplied with electric service by 21 BGE distribution feeder lines. Like many other distribution feeders across Maryland, each feeder serves about 1,000 customers, on average. Some of the Bowie feeders have been among the least reliable during the years since 2000, when Annual Reliability Report data for least reliable feeders became available.

Of the 21 BGE feeders serving Bowie, nine feeders were placed on the Company's least reliable list between 2000 and 2008, with one of those feeders appearing three times. Some of the other Bowie feeders, while not among the least reliable in the last nine years, experienced below-average reliability relative to all BGE feeders. BGE has stated that in 2006 and 2007, customers on the 21 Bowie feeders experienced, on average, twice the number of service interruptions as compared to the BGE system average.

The BGE Electric Service Reliability Improvement Initiative in Bowie

During the 2004 to 2007 period, a number of organized Bowie electric customers began complaining about the lack of electric reliable service in the area.

In early 2008, BGE developed the Bowie Electric Reliability Action Plan ("BERAP"), in cooperation with the Bowie Citizens Task Force. The three-year plan was designed to improve electric service reliability in the Bowie area. In addition to extensive and enhanced tree trimming, the plan involved construction work such as relocation of poles and power lines, including relocation of some overhead lines to underground, installation of stronger poles and tree wire, and the installation or rearrangement of distribution automation equipment.

Success in Bowie

BGE reported that nearly all the planned work in Bowie had been completed by the end of 2009.[71] BGE also presented data showing that BERAP was successful in raising the achievable level of electric service reliability in Bowie. Where there had been a per-month average of 5,600 customer outages in the Bowie area due to all causes for the period before BERAP, the average afterward was 2,200. The average per-month lost hours of service due to all causes for the area dropped from greater than 34,000 for the time before the project to about 3,600 since project completion. BGE further reported that during major snowstorms in February 2010, customers in the Bowie area experienced fewer outages than customers throughout the rest of its distribution system.

BERAP should be considered a communication and cooperation success. BGE cited communications activities and site visits with customers as "critical to the success of the program."[72] BGE's interaction with Bowie customers included five open houses, newsletters distributed to all residents, personal letters, and door hangers. Utility representatives attended Bowie Council sessions and collaborated with the Bowie Citizens Task Force. BGE reported that its construction and vegetation management work in the city affected approximately 7,700 private landowners, and there were minimal customer complaints. The successes achieved by BERAP could not have been accomplished without good cooperation from tree owners and the citizens of Bowie.

2. Pepco Service Quality and Reliability

In 2010, the Commission initiated Case No. 9240[73] to investigate the distribution system reliability and service quality of Pepco in Maryland due to the large number of customer complaints that service outages have been too frequent and have lasted too long, both in stormy and clear weather. The case is ongoing. However, early in the proceeding, Pepco filed a Reliability Enhancement Plan[74] for its distribution system in the State. The plan describes a renewed Pepco focus on tree trimming on a timely basis, inspection and maintenance of equipment, replacing deteriorated or damaged equipment, and addressing electrical load growth in a timely manner. The Pepco plan also includes the deployment of distribution system automation equipment and an enhanced vegetation management program, which will seek to remove more large trees and tree branches that threaten to cause service outages on overhead distribution lines.

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71 *See* Completion of Bowie Electric Reliability Action Plan (ML#123241), filed with the Commission by BGE on May 21, 2010.

72 *See* Completion of Bowie Electric Reliability Action Plan (ML#123241), filed with the Commission by BGE on May 21, 2010.

73 *See* Case No. 9240, *In the Matter of an Investigation into the Reliability and Quality of the Electric Distribution Service of Potomac Electric Power Company.*

74 Two Reliability Enhancement Plans were filed in Case No. 9240. On August 27, 2010, Pepco filed a Reliability Enhancement Plan covering its service area in Montgomery County and on September 7, 2010, the Company filed a Reliability Enhancement Plan for its service area in Prince George's County.

3. Winter 2009-2010 Storms

From February 5 through February 11, 2010, a series of storms brought record levels of snowfall to Maryland, resulting in large numbers of service interruptions to electricity customers. Pursuant to Commission Order No. 83173, Major Storm Reports were filed by the six largest electric distribution utilities in the State.[75]

The February 2010 snowstorms resulted in a total of about 5.9 million hours of lost service among the customers of the reporting utilities. Fallen trees or tree limbs caused about 3.2 million of those hours of lost service, or about 54% of the total.[76]

Although the February 2010 snowstorms were particularly severe, the percentage of lost service hours attributable to fallen trees or branches was very similar to the historical trend in the State in recent years. Major Storm Reports filed from the beginning of 2006 to the end of 2009 indicate that the Major Storms during that period resulted in a total of about 15.6 million hours of lost electric service in Maryland. Of that total, about 8.7 million hours of lost service, or about 56%, were caused by fallen trees or tree limbs. More aggressive tree management techniques, such as those employed in Bowie, might further reduce tree-related outages during severe storms. During the February 2010 snowstorms, customers in the Bowie area experienced fewer outages than customers throughout the rest of BGE's distribution system. About 9% of the customers in the Bowie area experienced an interruption due to the storms, compared to 12% of the customers in the entire BGE service area.

C. Managing Distribution Outages

An important tool developed in recent years for managing electric distribution system outages is the computerized Outage Management System ("OMS"). When an outage occurs, a fully developed OMS accepts information input from several sources, including customers and systems internal to the utility, and uses that information to help develop output information as to the location and type of equipment that needs attention in order to end the outage. This output information can then be used to generate work orders for repairs or dispatch repair crews by way of a Mobile Dispatch System ("MDS") using two-way radio communication. After repairs are made or other actions taken to end the outage, related outage information is entered as additional input into the OMS. The OMS then can identify what customers were affected by the outage, usually what caused the outage, and when it started and ended.

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75 *See* Case No. 9220, *In the Matter of an Investigation into the Performance of Utilities during the Snowstorms between the Period February 5 through February 12, 2010.* The Commission ordered BGE, Pepco, DPL, PE, SMECO, and Choptank to file a Major Storm Report without regard to whether the filing thresholds contained in COMAR 20.50.07.07 had been exceeded in each company's service area.

76 The totals given are based on the data provided in Major Storm Reports filed by BGE, Pepco, DPL, PE, SMECO, and Choptank as related to the February 2010 snowstorms. Major Storm Reports must list the number of service interruption hours due to several common power outage causes, including "fallen tree or tree limb."

Typical information inputs to the OMS are:

- <u>Customer Information System ("CIS"):</u> When a customer calls in an outage, the customer interacts with elements within the utility that have access to the CIS, such as a Customer Service Representative, an automated Interactive Voice Response ("IVR") unit, or a High Volume Call Service ("HVCS"). The CIS contains the customer's address, can identify the distribution system transformer that serves the customer, and passes this information on to the OMS. The OMS then can be used, with assistance from the next two listed inputs, to identify the location of the customer, both in terms of electrical position in the system diagram and geographic position.

  The traditional CIS function will be transformed as some utilities begin to implement elements of Advanced Metering Infrastructure. Advanced electric service meters and associated two-way communications systems between the customer and utility provide an information channel with the potential for use by both parties to make important decisions related to the efficient supply and use of electricity. AMI also promises faster detection of and more accurate utility response to electric service outages, and may largely replace the role of outage detection provided by customer calls within the traditional CIS.

- <u>Energy Management System ("EMS"):</u> The EMS includes an electronic diagram of the electric system showing how elements are connected electrically. The EMS also uses remote monitoring devices such as those of the Supervisory Control and Data Acquisition ("SCADA") system, so that information related to the operational condition of important, major pieces of electric system equipment can be passed on to the OMS.

- <u>Geographic Information System ("GIS"):</u> The GIS includes a map of key landmarks such as streets, and it shows the location of important elements of the electric system relative to those landmarks. This relationship is clearly important in the effort to get repair crews to the heart of the matter. In addition to providing information to the OMS, both the EMS electric system diagram and the GIS map can be displayed on computer monitors and are used by dispatchers to direct the efforts of repair crews.

- <u>Mobile Dispatch System and Work Management System ("WMS"):</u> After an outage is cleared, a work order is closed out within the WMS, and in some cases the repair crew can directly close the outage with, and enter related information directly into, the OMS using the MDS. The WMS or MDS information usually includes the time of restoration and the cause of the outage. After this information input is made, the OMS then contains an archive of important information about the entire history of the outage.

Typical information outputs from the OMS include the following:

- Information about the type of equipment involved in the outage and its location is passed to the WMS or MDS so that crews can be effectively dispatched to clear the outage.

- Prior to the clearing of an outage, an Estimated Time of Restoration ("ETR") and other information can be fed back to the CIS, so customers calling in who are affected by a particular ongoing outage may be kept informed.

- Information concerning outages can be extracted from the OMS in near real-time to feed Internet websites containing outage reports or outage maps.

- The OMS can be queried for outage information to be used to generate reports concerned with reliability statistics for the entire distribution system or any part thereof.

The four large investor-owned electric utilities operating in Maryland and the large electric cooperatives, Choptank and SMECO, have implemented OMS, each with functionality developed generally to the extent described above.

Improvements and efforts to increase the functionality of the OMS elements are ongoing. As with most computer and software-based systems, the OMS evolves with each new software upgrade, and as utilities learn how to best utilize the systems. The following are summaries of recent or planned activity by the largest electric utilities operating in Maryland to increase the utility of OMS.

1. <u>Energy Management System</u>

PE

PE is currently upgrading its EMS, implementing both the latest software version release and new hardware from its EMS vendor. The upgraded EMS is currently scheduled to go on line during the first half of 2011.

BGE

During 2010, BGE implemented a SCADA expansion, including deploying two new computer servers, in order to provide increased ability to electronically monitor and control those parts of its distribution system under SCADA surveillance and active control. BGE plans to begin upgrading its Energy Control System in 2011 to incorporate the latest software version releases, with completion expected in 2013.

Choptank

Choptank currently uses power line carrier signals and cellular telephone technology to communicate with its energy management devices in the field from its Denton headquarters, but indicates that communication coverage is incomplete throughout its distribution system. The Cooperative is continuing a gradual migration toward implementing a fiber optic network communications scheme for energy management and other communications functions, to include some remote control of certain system assets.

Pepco and DPL

Pepco and DPL have undertaken establishment of a common EMS platform, with expected productivity and operations improvements due to use of a common system. The new system would interface with the separate electrical connectivity models of the two utilities. Pepco completed implementation in April 2010. DPL plans to complete installation by December 2010.

SMECO

SMECO expects to begin to gather requirements for SCADA expansion and develop a Request for Proposals in 2011, and to implement the expansion by the end of 2011.

2. Geographic Information System

PE

PE plans to transition to a GIS system used by First Energy, upon approval of the merger of the two companies.

BGE

BGE refers to its existing system as the Geospatial Information System, and currently has plans to enhance the system over the next several years. The utility hopes to expand the use and functionality of the system to improve process standardization, increase integrity and currency of data about its system, reduce the potential for public safety incidents, and improve operational efficiency. BGE expects this enhancement initiative to continue for several years, with a goal of achieving better integration of the GIS with the OMS, CIS, work management system, mobile operations, and its electric distribution system design operations.

Choptank

Choptank upgraded its GIS in June 2009 to the ArcFM product made by Telvent Miner & Miner. It has completed making data additions to the system and has interfaced it with the utility's engineering analysis system, OMS, and construction operations.

Pepco and DPL

Pepco and DPL use a GIS platform from ESRI, a GIS and mapping company originally founded as Environmental Systems Research Institute, Inc. Pepco expects to complete its 2010 plan to upgrade to ESRI version 9.2 before the end of 2011. Pepco uses Graphical Work Design ("GWD") software that allows electric system designers to integrate work with location information from the GIS, and is currently upgrading the software. Current plans are for DPL to migrate to the latest version of GWD by mid-2011.

SMECO

In 2010, SMECO completed a software upgrade of its GIS to ArcGIS/ArcFM version 9.3.

3. Mobile Dispatch System

PE

PE does not utilize an MDS and currently does not have plans to implement a system within the next few years. Upon approval of its merger with First Energy, however, PE intends to transition to using First Energy's MDS by 2012. PE currently uses a related technology, Automated Vehicle Locating ("AVL") Devices in each of the vehicles used by linemen, meter-reading personnel, supply chain personnel, and meter technicians. Use of the devices allows the utility's crew dispatchers and management to track the location of company personnel during the work day. The utility expects to realize efficiency gains within the operations and management of each of those operational areas. PE expects full implementation of AVL for its Maryland operations by the time this report is issued.

BGE

The utility is consolidating its two separate MDS platforms into one, and is planning to deploy the integrated system in 2011. Efforts in future years will involve extending the system for use by all field crews and to integrate it with other business systems, such as the CIS, WMS, and asset management systems.

Choptank

Choptank does not utilize an MDS and currently does not plan to implement such a system.

Pepco and DPL

Pepco, over the past few years, has been implementing an MDS software platform called Ventyx Advantex/Service Suite for mobile applications, which it adopted from DPL. The system already is in place for field service personnel responsible for service restoration and meter service work, and Pepco is currently introducing the system to its Customer Care workforce. Both DPL and Pepco intend to upgrade to a newer software version in 2011 to 2012.

SMECO

SMECO launched the first phase of its MDS in July 2007, with initial training of service crews and supervisors designated as the utility's first response task force. Since then, the MDS has been introduced to Meter Operations and Credit & Collections personnel, Construction Operations personnel, and cable locators and storm assessment personnel. In 2010, the Cooperative added enhancements to the package that included travel mileage and timesheet tracking/accounting functionality.

4. Work Management System

PE

PE's previous plans to upgrade or enhance its WMS in 2010 or 2011 were suspended pending the outcome of the merger with First Energy. Upon approval of the merger, PE intends to adopt the WMS of First Energy.

BGE

In 2008 and 2009, BGE implemented the first two phases of a new, computerized WMS that consolidates asset tracking and data for its electric distribution system, as well as for its gas and electric transmission networks. Future phases of the program are planned to include standardized, company-wide processes for construction, maintenance and service meter work. BGE expects the overall implementation to extend through the next several years.

Choptank

Choptank implemented a new WMS with Itron, Inc., called the Interneer Intellect work management system, during 2008 and 2009. The system includes the Itron Distribution Staker package (for design and layout of new electric distribution construction). The system coordinates with the utility's GIS mapping system and the iVue customer information system. Choptank currently has no changes planned for the system.

Pepco and DPL

Both Pepco and DPL use Logica Work Management Information System ("WMIS") version 2.9. Both Companies expect to complete a version upgrade in 2011. The utilities expect that the upgrade will take advantage of improved processes and functionality to standardize work efforts across utilities within Pepco Holdings, Inc.

SMECO

The Cooperative recently implemented a major update of its WMS software to WMIS version 2.10, to obtain new functionality. The utility conducted study and analysis workshops to modify business processes and information flows to take advantage of the added functionality.

5. <u>Outage Management Communications</u>

PE

In 2010, PE added a Communications position to its service restoration Incident Management Team to ensure that information is provided to EMAs and large commercial and industrial customers during larger service outage events. PE provides service outage information through its IVR unit, providing calling customers concerned about an outage with the probable cause of the outage. Other capabilities of the IVR include providing estimated times of restoration and call-backs to customers to confirm power restoration. The utility also communicates service outage information by way of a public website at <u>http:www.alleghenypower.com</u>. The number of service outages can be viewed by state, county, or city, and an estimated time of restoration is also given on the website. PE maintains a separate website with more detailed outage information for State Regulatory, State Emergency Management, and County 911/EMA personnel.

BGE

In 2009, BGE completed an upgrade of its Predictive Dialer System, providing increased capacity and two-way communications with customers. One use of the system is to help predict the location of electric distribution facilities that are involved in service outages. The upgrade has enabled communication with customers concerning estimated time for service restoration and the scheduling of planned service outages. BGE is planning to implement a smart energy manager web service accessible through BGE.com. The website service is intended to provide energy management information and other communications, such as customer notifications.

Choptank

Choptank replaced its old low band radio system with an UHF trucking radio system in 2009, to be used for communications with outage restoration crews.

Pepco and DPL

In early 2009, Pepco and DPL replaced the separate internet outage and work location maps with one system incorporating both functions, with the expectation that the update would make improved and timely outage-related information available to customers and emergency management personnel. The availability and functionality of this system is under review in Case No. 9240.

SMECO

SMECO's web-based service outage map is updated automatically from its OMS at ten-minute intervals and can be accessed from http://www.smeco.coop. Press releases issued by the Cooperative are included on the site. SMECO has the capability to send emails concerning expected major weather storm events to approximately 30,000 of its members who have registered to receive the notifications. During 2010, SMECO tested and implemented a process to notify customers of their estimated time of restoration during outage events.

D. Distribution Planning Process

The role of an electric distribution system planner begins with identification of customer needs, both for the near term and the longer term. Once identified, those needs are translated into a flexible plan involving the engineering and operations functions necessary to meet those needs. Short term planning typically focuses on system expansion to keep pace with electric load growth and maintenance or improvements related to reliability or safety of the system, with a forecast horizon of a few years. Longer term planning, with a forecast horizon of 10 to 20 years, may include expectations of new technologies and altered business climate, in addition to considerations of expanded load growth, reliability, and safety of the system.

A sampling of the largest electric distribution system projects and programs, ongoing, planned, or in development by Maryland's large electric companies, follows.

1. PE

- In 2012, PE expects to complete construction of two substations, to serve the town of Keedysville and surrounding area, and to serve the area of Lappans Crossroads.

- PE plans to complete a major upgrade of facilities at its Urbana substation in 2012 to provide additional capacity to serve the town of Urbana and the surrounding area.

- PE plans to complete construction in 2013 of a substation to serve the town of Walkersville and the surrounding area.

- In 2014, PE plans to upgrade three substations. The substations supply an area west of Frederick, an area south of Frederick, and the Taneytown area.

- PE plans to complete the construction of a new substation to serve an area around Deep Creek Lake by 2014.

- PE expects to complete a capacity upgrade of a substation serving an area south of Mt. Airy in 2017.

- PE plans to construct a new substation to serve the area southwest of Frederick in 2019.

2. <u>BGE</u>

- By the end of 2011, BGE plans to rebuild three substations and build one new substation. The substations serve areas in Anne Arundel County, including an area near Annapolis, and southwestern Harford County.

- BGE plans to construct three additional new substations by the end of 2012. The substations are to serve the Fallston area of Harford County, the Laurel area of Howard County, and the Sykesville area of Carroll County.

- BGE expects to finish the rebuilding of a substation serving northern Baltimore City/Baltimore County in 2012. The utility also expects to complete work to transfer load between feeders and substations to benefit the Westport area of Baltimore City in 2012. The work will retire aging facilities and increase reliability of the network distribution system in the area.

- In 2013, BGE plans to build a new substation to serve load growth in the Konterra Town Center and to relieve other existing substations in the Laurel area. Plans for 2013 also include completing a capacity upgrade in a substation serving Prince George's County.

- BGE plans to complete the construction of two new substations and the rebuilding of two others in 2014. The rebuilding efforts will retire aging facilities and increase electric capacity. These efforts will benefit the Cockeysville and Towson areas of Baltimore County, and the Carroll/Calverton area of Baltimore City.

- Between 2015 and 2016, BGE intends to build five new substations and rebuild two others. The work would provide additional electric capacity to three areas in Harford County, three areas in Baltimore City, and the Hampstead area of Carroll County.

3. <u>Choptank</u>

- Choptank expects load growth to occur along the U.S. Route 301 corridor in Kent and Queen Anne Counties, Chestertown, Cambridge, Easton, the west side of Salisbury, and the east side of Berlin.

- By the end of 2011, Choptank expects to complete construction of a substation near Hebron in Wicomico County to serve load growth on the southwest side of Salisbury.

- Construction of a new substation to serve the Cambridge area is planned for completion by the end of 2012. Currently, most of Choptank's electrical load in Dorchester County is supplied by one substation, which constitutes a single point of connection to the transmission grid. The addition of the new substation would create a backup delivery point in addition to providing increased capacity.

4. <u>DPL</u>

- DPL began a capacity upgrade of a substation serving western Kent County during 2010 and plans to complete the upgrade by the end of 2011.

- By mid-2011, DPL expects to convert a feeder serving Worcester County from 4 kV to 25 kV operation. Distribution feeders operating at 4 kV typically are aged, less efficient, and provide less capacity than modern feeders operating at 13 kV or 2 kV.

- DPL plans to complete the construction of a substation to serve southern Talbot County in 2012.

- To serve southwestern Kent County, DPL plans to construct a substation and extend two feeders in 2013. The utility also intends to complete construction of a new substation that year to serve growing electrical load in Harford County.

- DPL expects to complete the construction of a substation and the extension of three feeders in 2014 to serve Cecil County.

- During 2017, DPL intends to complete construction of a new substation to serve the Queenstown area of Queen Anne's County, and the rebuilding of a substation to serve the Salisbury area.

5. Pepco

- Pepco plans to complete a capacity upgrade for a feeder serving the Sligo area of Montgomery County by mid-2011.

- During 2012, Pepco plans to build two new feeders and to extend two others to serve the Lanham area of Prince George's County. Plans for the year also include extending and increasing the capacity of an existing feeder to serve the Greenbelt Station Project.

- By the close of 2012, Pepco plans to complete construction of a new feeder and the extension of another to meet the electricity needs of the National Harbor Development and the Gaylord National Hotel and Conference Center.

- Pepco's plans for 2013 include a capacity upgrade of a substation serving the Colesville, Rossmoor, and Fairland areas of Montgomery County.

- Pepco plans to complete the construction of a substation in 2014 to supply the Westphalia Town Center and the Melwood and Forestville areas of Prince George's County.

- To accommodate the projected demand for electricity in the Hunting Hill, Shady Grove, and Fernwood Road areas of Montgomery County, Pepco plans to complete the construction of two substations by mid-2015. By the close of that year, the utility intends to extend three feeders to serve the Woodmount area of Montgomery County.

- Pepco plans to complete the construction of a new substation in 2017 to accommodate load growth in the Beltsville area of Prince George's County.

6. SMECO

- SMECO plans to upgrade two substations and construct new feeders in Saint Mary's County in 2011 to serve load growth and provide alternate power sources during service outages. One of the stations serves an area near Route 4 along Patuxent Beach Drive, and the other new or upgraded facilities would serve the Leonardtown area.

- To serve load growth and to implement outage contingency plans in Charles County, SMECO intends to complete capacity upgrades and feeder additions to two substations in 2011. Areas that will benefit from the construction include Blossum Point Road near Route 6 and Vivian Adams Drive near Route 5.

- During 2013, SMECO plans to purchase an additional mobile substation to be used to provide backup power during outage contingency situations in areas where providing backup power through distribution feeder switching is difficult or impossible.

VIII. MARYLAND ELECTRICITY MARKETS

The Electric Customer Choice and Competition Act of 1999 ("Electric Choice Act") established the legal framework for the restructuring and revised regulation of the electric industry in Maryland. The Electric Choice Act altered the Commission's role relative to electricity generation and provided that retail electric choice would be available to all customers. Beginning on July 1, 2000, all retail electric customers of IOUs in the State were given the opportunity to choose their electricity supplier. Since July 1, 2003, customers of Maryland's electric cooperatives have had the right to choose suppliers under a separate schedule adopted by the Commission. Customers of Maryland's municipal electric utilities will be allowed to choose suppliers on a timetable established in part by the municipal utilities.

A. Status of Retail Electric Choice in Maryland

Customers shopping for electricity in Maryland may choose to buy electricity from a competitive supplier or to take standard offer service from their local electric company. This framework was established by the Electric Choice Act of 1999. This Act deregulated the pricing of electric generation and opened retail markets to competitive suppliers. Opening retail markets for competition has attracted competitive suppliers to Maryland. As of November 1, 2010, the Commission has issued 49 electricity supplier licenses and 101 electricity broker licenses. As of December 1, 2010, the following numbers of companies had registered on the Commission's website as actively soliciting new customers in any Maryland service territory: 16 serving residential load, 57 serving industrial load, 60 serving commercial load, and 17 serving other types of load (such as government).

An examination of the number of customers using a competitive supplier indicates that the transition from utility-supplied generation service to electric competition in Maryland shows that a smaller percentage of residential customers have switched to retail suppliers than non-residential customers. As of December 2010, 13.5% of residential customers, 27.9% of small commercial customers, 54.4% of mid-sized commercial and industrial customers and 88.2% of large commercial and industrial customers were served by retail electric suppliers. In terms of total electric supply, almost half of IOU load (45.8%) is now served by retail electric suppliers.

In 2010, residential switching accelerated compared with previous years as the number of Residential Choice customers increased by 125% statewide. The increase in switching may be due to the availability of savings over the Standard Offer Service rates. Certain residential electricity offers have been observed to be on the order of 10% below the cost of Standard Offer Service, saving an average customer about $150 per year. The implementation of utility purchase of retail supplier receivables in 2010 for those suppliers that use utility billing probably also played a significant role in the increase in the number of residential customers served by retail electric suppliers.

The following table illustrates the increase in residential customer switching during 2010. For many years, residential switching remained relatively unchanged. However, beginning in 2009 there was a significant increase in the total number of switched customers.

Table VIII.A.1: Residential Customers Enrolled in Retail Supply at Year End

	2009	2010	Annual % Increase
BGE	53,126	179,801	238%
Pepco	40,267	64,335	60%
DPL	2,463	12,759	418%
PE	2,743	11,763	329%
Md. Total	**98,599**	**268,658**	**172%**

Source: Electric Choice Enrollment Monthly Reports.
Note: 2010 data is as of December 31, 2010.

Between December 2005 and December 2010, the total number of customers statewide served by electricity suppliers increased from 39,527 to 350,729 customers. During the same time, the number of customers served by electricity suppliers in BGE's service territory increased from 3,347 to 226,384.

Table VIII.A.2: Electric Choice Enrollment in Maryland, December 31, 2010

Number of Customers Served by Competitive Electricity Suppliers

Utilities	Residential	Small C&I	Mid C&I	Large C&I	All C&I	Total
PE	11,763	5,147	2,898	114	8,159	19,922
BGE	179,801	31,389	14,513	681	46,583	226,384
DPL	12,759	5,083	2,604	73	7,760	20,519
Pepco	64,335	10,186	8,877	506	19,569	83,904
Total	**268,658**	**51,805**	**28,892**	**1,374**	**82,071**	**350,729**

Percentage of Peak Load Obligation Served by Competitive Electricity Suppliers, December 31, 2010

Utilities	Residential	Small C&I	Mid C&I	Large C&I	All C&I	Total
PE	5.8%	27.7%	62.2%	84.7%	68.0%	35.9%
BGE	17.4%	31.5%	70.0%	93.4%	76.2%	47.1%
DPL	8.3%	33.9%	69.3%	94.1%	69.8%	37.2%
Pepco	15.1%	33.1%	71.3%	95.1%	78.5%	49.3%
Total	**14.9%**	**31.8%**	**69.5%**	**93.0%**	**75.6%**	**45.8%**

Source: Electric Choice Enrollment Monthly Report, Month Ending October 2010.
Notes: Small commercial and industrial ("C&I") customers are commercial or industrial customers with demands less than or equal to 25 kW. These customers are eligible for "Type I" fixed-price utility SOS if they do not switch to a supplier. Mid-sized C&I customers are commercial or industrial customers with demands greater than 25 kW, the level for small C&I service (Type I SOS) but less than 600 kW. These customers are eligible for "Type II" fixed price utility SOS if they do not switch to a supplier. *See* Case Nos. 9037 and 9056 for more information on the Type II customer class. Large C&I customers are commercial or industrial customers with demands equal to or greater than 600 kW. These customers are no longer eligible for "Type III" SOS and receive hourly-priced service (based on PJM hourly LMP) if they do not switch to a supplier.

B. Standard Offer Service

Standard Offer Service ("SOS") is electricity supply service sold by electric utility companies to any customer who does not choose a competitive supplier. The statute requires that SOS should be "designed to obtain the best price for residential and small commercial customers in light of prevailing market conditions at the time of the procurement and the need to protect these customers against excessive price increases."[77]

The investor-owned electric companies provide SOS by purchasing wholesale power contracts, for residential and small commercial service of two-year terms, through sealed bid procurements. Procurements take place in the Spring and Fall for service starting the following Fall and Summer. Each procurement covers roughly 25% of the total SOS load. Consequently, the SOS price for residential and small commercial customers at any one time reflects an average of market conditions on those four bid days. SOS for mid-sized non-residential customers is not intended to stabilize prices over an extended period of time. Mid-sized non-residential SOS is procured through sealed bids for three-month contracts procured four times a year. The price of the service at any one time reflects market conditions on the most recent bid day. Since the end of residential price freeze, SOS rates have increased such that average total annual residential electricity expenses have increased significantly.[78]

SOS for SMECO is procured by the cooperative through an actively managed portfolio approach. Choptank provides SOS through procurement of full-requirements wholesale service through the Old Dominion Electric Cooperative.

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77 PUA § 7-510(c)(4)(ii).

78 Case No. 9056, Commission Staff Report on SOS (October 29, 2010), Exhibit 1.

IX. REGIONAL ENERGY ISSUES AND EVENTS

A. Overview of PJM, OPSI, and Reliability First

The flow of electricity and the electricity markets are undeniably regional concepts. Maryland is not an energy island—the transmission lines located within Maryland do not terminate at our borders, but rather are connected to the transmission lines in adjoining states.

The entire State of Maryland resides within PJM, the RTO that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. FERC is responsible for approving tariff changes proposed by PJM, which wholesale market entities operating in Maryland must abide by as a member of PJM. In addition, the Maryland Public Service Commission is a member of the Organization of PJM States, Inc. ("OPSI"), an organization of statutory regulatory agencies in the 13 states and the District of Columbia that form PJM. Finally, Maryland falls within the boundaries of ReliabilityFirst, one of eight regional entities approved by NERC as of January 1, 2006 to develop and enforce regional reliability standards.

1. PJM Interconnection, LLC

PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. PJM's members, totaling more than 500, include power generators, transmission owners, electricity distributors, power marketers and large consumers. The company is headquartered in Valley Forge, Pa. PJM keeps the electricity supply and demand in balance by telling power producers how much energy should be generated and by adjusting import and export transactions.

In managing the grid, the company dispatches about 163,500 megawatts (MW) of generating capacity over 56,350 miles of transmission lines. PJM exercises a broader reliability role than that of a local electric utility. PJM system operators conduct dispatch operations and monitor the status of the grid over a wide area, using an enormous amount of telemetered data from nearly 74,000 points on the grid. This gives PJM a big-picture view of regional conditions and reliability issues, including those in neighboring systems.

PJM manages a sophisticated regional planning process for generation and transmission expansion to ensure the continued reliability of the electric system. PJM is responsible for maintaining the integrity of the regional power grid and for managing changes and additions to the grid to accommodate new generating plants, substations and transmission lines.

The Maryland Public Service Commission is not a member of PJM (meaning it is unable to cast a vote); however, it does monitor and actively participate in stakeholder and committee processes at PJM.

2. Organization of PJM States, Inc. ("OPSI")

OPSI was established in 2005. The purpose of OPSI is to maintain an organization of statutory regulatory agencies in the 13 states and the District of Columbia within PJM. OPSI's activities include, but are not limited to, coordinating activities such as data collection, issue analyses, and policy formulation related to PJM, its operations, its market monitor, and related FERC matters.[79] OPSI provides a means for the PJM states to act in concert with one another when it is deemed to be in their common interest. Actions of OPSI, however, do not bind individual commissions or the states they represent.

Each state commission has a member on the OPSI Board of Directors. Chairman Nazarian of the Commission served as OPSI President during 2009. During 2010, OPSI was particularly active on demand response issues. The Maryland Commission continues to be a very active participant in OPSI and participates on several of its committees.

3. ReliabilityFirst Corporation

ReliabilityFirst is a not-for-profit company which began operations on January 1, 2006. ReliabilityFirst's mission is to preserve and enhance electric service reliability and security for the interconnected electric systems within the ReliabilityFirst geographic area. The Boundaries of ReliabilityFirst are defined by the service territories of Load Serving Entities (LSEs) and include all of New Jersey, Delaware, Pennsylvania, Maryland, District of Columbia, West Virginia, Ohio, Indiana, Lower Michigan and portions of Upper Michigan, Wisconsin, Illinois, Kentucky, Tennessee and Virginia. ReliabilityFirst's primary responsibilities include developing reliability standards and monitoring compliance to those reliability standards for all owners, operators and users of the bulk electric system and providing seasonal and long-term assessments of bulk electric system reliability within its Region. The Commission monitors ReliabilityFirst activities and comments if necessary.

B. PJM Summer Peak Events of 2009 and 2008

Peak load is maximum load usage during a specified period of time. Table IX.B.1 provides the coincident peaks as measured by PJM to illustrate the maximum amount of MW usage in PJM at a particular time during a 12-month period. PJM is a summer peaking region, meaning that it has historically experienced its peak loads during hot summer days when air-conditioning usage increases to meet cooling demand. PJM measures energy usage over an hour; accordingly, the data in the table below means the peak occurred sometime in the 59 minutes preceding the hour listed. The table also

[79] Organization of PJM States, Inc., available at: http://www.opsi.us.

shows the average locational marginal price ("LMP") for each Maryland utility zone and for all of PJM at the peak hours.

Table IX.B.1: Summer 2009 and 2008 Coincident Peaks and Zone LMP

Summer 2009 Coincident Peaks				LMP During the Peak				
Day	**Date Hour**		**MW**	**PE**	**BGE**	**DPL**	**PEPCO**	**PJM**
Monday	8/10/2009	17:00	126,944	$104.30	$104.90	$126.00	$138.98	$85.69
Tuesday	8/11/2009	17:00	120,708	$54.35	$55.21	$50.09	$79.95	$49.04
Monday	8/17/2009	17:00	121,933	$65.28	$70.44	$72.64	$58.55	$60.93
Tuesday	8/18/2009	16:00	122,369	$63.77	$153.48	$130.13	$155.48	$89.65
Thursday	8/20/2009	16:00	120,112	$88.99	$113.52	$111.51	$115.58	$83.14
Summer 2008 Coincident Peaks				**Zone LMP During the Peak**				
Day	**Date Hour**		**MW**	**PE**	**BGE**	**DPL**	**PEPCO**	**PJM**
Monday	6/9/2008	17:00	130,792	$348.69	$311.69	$358.30	$358.30	$265.17
Thursday	7/17/2008	17:00	129,790	$160.08	$231.82	$205.24	$239.30	$182.98
Friday	7/18/2008	17:00	129,429	$205.42	$274.84	$230.30	$251.63	$197.57
Monday	7/21/2008	17:00	128,813	$196.60	$212.53	$251.99	$211.89	$199.41
Tuesday	6/10/2008	16:00	128,598	$253.81	$544.55	$482.18	$522.57	$335.04

Source: PJM, Markets & Operations, Daily Real-Time LMP Files; PJM, Planning and Resource Adequacy Files, available at: www.pjm.com.

The 2009 summer peak events in PJM were lower than the summer peak events that occurred in 2008. Table IX.B.1 above shows the summer 2009 and 2008 coincident peaks in PJM and the average real-time LMP by zones located in Maryland during that time period. The summer 2009 peak was 126,944 MW and occurred on August 10, 2009 during the hour ending 5:00 PM Eastern Daylight Time.[80] The summer 2008 peak was 130,792 MW and occurred on June 9, 2008 during the hour ending 5:00 PM Eastern Daylight Time.[81]

C. PJM's Reliability Pricing Model ("RPM")

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 located within the RTO and the import capability of the RTO against the estimated demand of customers within the RTO and establishes 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 RPM is roughly based upon a forecast of the peak load projected by PJM for a particular year, plus a reserve margin. RPM works in conjunction with PJM's RTEP to ensure reliability in the PJM region for future years.

80 PJM, Planning., available at: http://www.pjm.com/~/media/planning/res-adeq/load-forcast/summer-2009-pjm-scps-and-w-n-zonal-peaks.ashx.

81 PJM, Planning, available at: http://www.pjm.com/planning/res-adequacy/downloads/summer-2008-peaks-and-5cps.pdf.

Using this information, PJM evaluates offers from generators and other resources three years in advance to be available for a one-year delivery period running from June through May (up to three years for new generation) through the Base Residual Auction ("BRA").[82] 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 NERC.

PJM held the BRA for the 2013/2014 delivery period in May 2010. PJM calculated the RTO reliability requirement to be 149,988.7 MW, which includes a 15.3% reserve margin. However, as a result of the administratively determined downward sloping demand curve - the Variable Resource Requirement - more resources than needed cleared the market. In 2010, 152,743.3 MW cleared the BRA, which essentially increased the reserve margin to 20.2%. This means 2,754.6 MW in excess of the reliability requirement were procured in the BRA. Approximately 8,154.8 MW of excess capacity was offered into the 2013/2014 BRA (*i.e.*, this capacity did not clear); accordingly, for the 2013/2014 delivery year, approximately 10,909.4 MW of capacity in excess of the RTO reliability requirement was offered into the BRA.[83]

For the 2013/2014 BRA, the Mid-Atlantic Area Council ("MAAC"), Eastern MAAC ("EMAAC"), and Southwest MAAC (" SWMAAC") transmission zones serving Maryland were modeled as constrained LDAs. As a result of transmission constraints, the LSEs, such as BGE, DPL, and Pepco, serving these transmission zones pay higher capacity resource prices than the rest of PJM in the same delivery year. Further, the 2013/2014 BRA caused "binding" constraints (demand in a zone exceeds the ability to import power into that zone under peak load) that resulted in a locational price adder for Pepco. This adder reflects the increment above resource clearing prices required to meet the Pepco forecast load requirement.[84]

The "Net Load" capacity prices for the IOUs in Maryland for each of the seven completed BRAs are presented in Table IX.C.1. The estimated total capacity cost to Maryland of each BRA is also presented. The Net Load capacity price reflects the BRA clearing price and credits from any transmission capacity transfer rights. Maryland has experienced significant volatility in Net Load prices from the past seven BRAs. The Net Load cost to Maryland from the first BRA for the 2007/2008 delivery year was approximately $693 million. By the 2009/2010 BRA, capacity cost had increased to approximately $1,131 million before declining to $580 million for 2011/2012 and then increasing to approximately $1,101 million for 2013/2014. The observed historical

82 PJM, Markets & Operations, Reliability Pricing Model, available at: http://www.pjm.org/markets-and-operations/rpm.aspx.
83 PJM, Markets & Operations, available at: http://pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2013-2014-base-residual-auction-report.ashx.
84 *Id.*

pattern of results suggests that future BRA results could vary significantly from year to year and must be closely monitored.

Table IX.C.1: RPM "Net Load"[85] Price and Cost

Delivery Year	Allegheny Power ($/MW-day)	BGE ($/MW-day)	DPL ($/MW-day)	Pepco ($/MW-day)	TOTAL Maryland ($)
2007/2008	40.69	139.67	177.00	139.67	693,678,286
2008/2009	113.22	183.03	145.24	183.03	901,994,343
2009/2010	193.80	224.93	193.71	224.78	1,130,545,999
2010/2011	174.29	174.29	178.27	174.29	920,141,784
2011/2012	110.04	110.04	110.04	110.04	579,821,643
2012/2013	16.46	129.63	162.99	129.63	636,535,392
2013/2014	27.73	223.85	240.41	236.93	1,100,652,116

Source: PJM RPM Auction User Information, Delivery Year, Net Load Price, available at: http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item01.

D. Region-Wide Demand Response in PJM Markets

Demand Response continues to be actively promoted within the wholesale electricity markets. PJM provides the opportunity for DR to be bid into the Energy, Capacity, Synchronized Reserve, Day-Ahead Scheduling Reserve, and Regulation markets. 12,953 MW of demand resources were offered into the 2013/2014 BRA, which represents an increase of 32% over the amount offered into the 2012/2013 BRA.[86] Of that amount, 9,282 MW cleared and 5,872 MW was located in constrained regions, including Maryland.[87]

PJM has two basic energy and capacity market demand response programs: the Economic Load Response Program and the Emergency Load Program. The goal of these programs is to provide economic incentives for end-use customers to curtail their electricity usage in the circumstances of either peak periods or unexpected outages.

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85 The "Net Load" price for each company is the RPM auction price adjusted for any capacity transfer credits and load variations from forecast. The total Maryland cost assumes a constant demand for the periods shown based on the summer peak load contribution for each company's transmission zone. The PE zone includes PE, Hagerstown, Thurmont, Williamsport, and Somerset electric loads. The DPL zone includes DPL Maryland, Choptank, Easton, Berlin, and A&N loads. The Pepco zone includes Pepco Maryland and SMECO loads.

86 PJM, 2013/2014 RPM Base Residual Auction Results, available at: http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2013-2014-base-residual-auction-report.ashx (Nov. 19, 2010). The newly integrated ATSI transmission zone accounted for 1,384 MW of the total increase, while the other transmission zones accounted for the remaining 1,720 MW.

87 *Id.*

1. Economic Load Response Program

The PJM Economic Load Response Program ("ELRP") is a PJM-managed accounting mechanism that provides for payment of the real savings that result from load reductions to the load reducing customer. This is a voluntary program that allows customers the opportunity to reduce their load and receive payments in either the energy market or the ancillary services market, which includes reserve and regulation. Payments in the energy market generally are based upon the difference between retail rates and day-ahead or real-time LMP. Customers who elect to have their load reductions dispatched by PJM are guaranteed to receive a payment equal to their offer into the market. Payments in the ancillary services markets generally are based upon the market clearing price.

2. Emergency Load Program

The PJM Emergency Load Program is designed to provide a method by which end-use customers may be compensated by PJM for reducing load during an emergency event. The Emergency-Capacity Only program provides RPM payments for reducing capacity and reduction is mandatory. The Emergency-Full program provides both RPM payments and energy payments for reducing capacity, and reduction is mandatory. The Emergency-Energy Only program provides energy payments to end-use customers for voluntarily reducing load during an emergency event. The energy payment is the zonal LMP, but customers who elect to have their load reductions dispatched by PJM are guaranteed to receive a payment equal to their offer into the market, including shutdown costs.

X. PROCEEDINGS BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

The Commission is actively engaged in wholesale energy market policy development at PJM, which is a FERC-regulated RTO and the grid operator for 13 states, including Maryland, plus the District of Columbia. More than 600 market participants are stakeholders in PJM. Stakeholders include generation owners, transmission owners, electricity distributors (including Maryland utilities), other suppliers, and end-use customers. While the Commission is not a formal stakeholder in the stakeholder process, the Commission does actively engage on issues and voice its concerns regularly, both independently and as part of OPSI. The Commission participates in the policy development process because decisions made at PJM directly affect the price of electricity and related services to Maryland customers.

PJM holds more than 300 stakeholder meetings each year for more than two dozen committees, subcommittees, task forces, and working groups. The Commission assigns one or more Commission Advisors to represent the Commission at the major policy-setting groups. These groups include the Members Committee, the Markets & Reliability Committee, the Markets Implementation Committee, the Planning Committee, the Regional Planning Process Working Group, the Reserve Requirement Assumption

Working Group, the Shortage Pricing Working Group, the Load Analysis Special Team, and the Governance Assessment Special Team. Other Commission Staff cover technical and engineering-related meetings, such as the Transmission Expansion Advisory Committee and the Load Analysis Subcommittee.

Some of the issues in which the Commission is regularly engaged include load forecasting, demand response, price responsive demand, the capacity market, shortage pricing, governance, and planning criteria. While many of these issues are ultimately litigated at FERC, where the Office of General Counsel represents the Commission, being involved in PJM's stakeholder process gives the Commission early input into the important issues as they emerge.

APPENDIX

The Appendix contains a compilation of data provided by Maryland's electric companies, including the number of customers, sales by customer class, and typical utility bills, as well as forecasted peak demand and electricity sales over the next 15 years, by utility. It also includes a list of licensed electricity and natural gas suppliers and brokers in Maryland, renewable energy projects, planned transmission enhancements, and potential new power plants in Maryland.

Table A-1: Utilities Providing Retail Electric Service in Maryland

Utility	Service Territory
A&N Electric Cooperative	Smith Island in Somerset County
Baltimore Gas & Electric Company	Anne Arundel County, Baltimore City, Baltimore County and portions of the following counties: Calvert, Carroll, Howard, Harford, Montgomery, and Prince George's.
Town of Berlin	Town of Berlin.
Choptank Electric Cooperative	Portions of the Eastern Shore.
Delmarva Power & Light Company	Major portions of ten counties primarily on the Eastern Shore.
Easton Utilities Commission	City of Easton.
Hagerstown Municipal Electric Light Plant	City of Hagerstown.
Potomac Edison Company / Allegheny Power	Parts of Western Maryland.
Potomac Electric Power Company	Major portions of Montgomery and Prince George's Counties.
Somerset Rural Electric Cooperative	Northwestern corner of Garrett County.
Southern Maryland Electric Cooperative	Charles and St. Mary's Counties; portions of Calvert and Prince George's Counties.
Thurmont Municipal Light Company	Town of Thurmont
Town of Williamsport	Town of Williamsport

Source: Table 1 in Company data responses to the Commission's 2010 data request for the Ten-Year Plan.

Table A-2: Number of Customers by Customer Class (as of December 31, 2009)

	System-wide						Maryland					
Utility/Co.	**Residential**	**Commercial**	**Industrial**	**Other**	**Sales for Resale**	**Total**	**Residential**	**Commercial**	**Industrial**	**Other**	**Sales for Resale**	**Total**
A&N	N/A	N/A	N/A	N/A	N/A	**N/A**	N/A	N/A	N/A	N/A	N/A	**N/A**
Berlin	1,967	285	117	18	0	**2,387**	1,967	285	117	18	0	**2,387**
BGE	1,111,888	118,463	5,338	0	0	**1,235,689**	1,111,888	118,463 5,338		0	0	**1,235,689**
Choptank	47,151	4,713	21	258	0	**52,143**	47,151	4,713	21	258	0	**52,143**
DPL	438,601	58,605	498	641	0	**498,345**	173,006	25,637	248	271	0	**199,162**
Easton	8,173	2,213	0	103	0	**10,489**	8,173	2,213	0	103	0	**10,489**
Hagerstown	15,014	2,301	124	0	0	**17,439**	15,014	2,301	124	0	0	**17,439**
PE	419,885	58,157	6,410	807	6	**485,265**	219,903	27,515	2,857	345	3	**250,623**
PEPCO	704,575	73,618	12	132	0	**778,337**	478,545	47,220	11	100	0	**525,876**
SMECO	134,897	13,426	6	283	0	**148,612**	134,897	13,426	6	283	0	**148,612**
Somerset	N/A	N/A	N/A	N/A	N/A	**N/A**	N/A	N/A	N/A	N/A	N/A	**N/A**
Thurmont	2,448	339	10	42	0	**2,839**	2,448	339	10	42	0	**2,839**
Williamsport	865	69	34	44	0	**1,012**	865	69	34	44	0	**1,012**
Total	**2,885,464**	**332,189**	**12,570**	**2,328**	**6**	**3,232,557**	**2,193,857**	**242,181 8,766**		**1,464**	**3**	**2,446,271**

Source: Company data responses to Tabe 2 in the Commission's 2010 data request for the Ten-Year Plan.
Note: A&N and Somerset did not provide a response to the Commission's data request.

Table A-3: Average Monthly Sales by Customer Class (GWh) (Calendar Year 2009)

Utility/Co.	System-wide						Maryland					
	Residential	Commercial	Industrial	Other	Sales for Resale	Total	Residential	Commercial	Industrial	Other	Sales for Resale	Total
A & N	N/A	N/A	N/A	N/A	N/A	**N/A**	N/A	N/A	N/A	N/A	N/A	**N/A**
Berlin	2	0	1	0	0	**3**	2	0	1	0	0	**3**
BGE	1,071	1,308	252	0	0	**2,631**	1,071	1,308	252	0	0	**2,631**
Choptank	54	17	7	0	0	**78**	54	17	7	0	0	**78**
DPL	409	429	194	4	0	**1,036**	173	142	33	1	0	**349**
Easton	9	12	0	1	0	**22**	9	12	0	1	0	**22**
Hagerstown	12	6	10	0	0	**28**	12	6	10	0	0	**28**
PE	525	298	250	2	61	**1,136**	272	169	119	1	35	**596**
PEPCO	641	1,457	60	60	0	**2,218**	482	712	40	27	0	**1,261**
SMECO	171	93	17	0	0	**281**	171	93	17	0	0	**281**
Somerset	N/A	N/A	N/A	N/A	N/A	**N/A**	N/A	N/A	N/A	N/A	N/A	**N/A**
Thurmont	3	1	2	0	0	**6**	3	1	2	0	0	**6**
Williamsport	1	0	1	0	0	**2**	1	0	1	0	0	**2**
Total	**2,898**	**3,621**	**794**	**67**	**61**	**7,441**	**2,250**	**2,460**	**482**	**30**	**35**	**5,257**

Source: Table 3 in Company data responses to the Commission's 2010 data request for the Ten-Year Plan.
Note: Data were rounded to whole numbers. A&N and Somerset did not provide a response to the Commission's data request.
N/A: Data are not available.

Table A-4: Typical Monthly Electric Bills in Maryland (Winter 2010)

	Energy Use (kWh)			Typical Bill ($)			Revenue ($/kWh)		
Utility/Co.	Residential	Commercial	Industrial	Residential	Commercial	Industrial	Residential	Commercial	Industrial
A&N	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Berlin	1,000	1,000	80,000	156.62	188.31	10,819.32	0.1566	0.1883	0.1352
BGE	750	12,500	200,000	106.00	1,594.00	3,340.00	0.1410	0.1275	0.0167
Choptank	750	12,500	200,000	102.57	1,518.18	21,390.26	0.1368	0.1215	0.1070
DPL	750	12,500	200,00	106.25	1,649.70	18,671.91	0.1417	0.1320	0.0934
Easton	750	12,500	N/A	89.36	1,500.18	N/A	0.1192	0.1200	N/A
Hagerstown	1,315	2,989	75,875	124.65	293.05	6,559.95	0.0948	0.0981	0.0865
PE	1,689	3,273	13,074	175.23	364.11	1,090.43	0.1037	0.1112	0.0834
PEPCO	750	12,500	200,000	101.43	1,294.75	18,759.00	0.1352	0.1036	0.0938
SMECO	750	12,500	200,000	106.85	1,551.13	22,600.40	0.1425	0.1241	0.1130
Somerset	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Thurmont	1,000	10,000	150,000	106.80	1,013.09	14,083.86	0.1062	0.0985	0.0926
Williamsport	900	1,800	20,000	88.51	177.06	1,960.15	0.0972	0.0959	0.0962

Source: Table 3 in Company data responses to the Commission's 2010 data request for the Ten-Year Plan. Each utility has its own perspective on what is a "typical" customer. In some cases (PE for example), this is the arithmetic average. In most cases, it is a number similar to, but not exactly, the median. For those utilities that have retail competition available, bills and revenue reflect SOS, distribution service and any non-bypassable charges.
Note: A&N and Somerset did not provide a response to the Commission's data request.
N/A: Data are not available.

Table A-5(a): System-Wide Peak Demand Forecast (MW) (Net of DSM Programs) (as of December 31, 2009)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagers-town	PE	Pepco	SMECO	Thurmont	Williams-port	Total
2010	11	6,752	216	3,959	67	71	3,043	6,815	819	21	5	**21,779**
2011	11	6,720	221	3,834	68	68	3,094	6,544	818	21	5	**21,404**
2012	11	6,863	232	3,852	70	63	3,142	6,539	829	21	5	**21,627**
2013	11	6,666	241	3,870	71	64	3,183	6,589	840	21	5	**21,561**
2014	11	6,707	253	3,898	72	64	3,216	6,635	852	21	5	**21,734**
2015	11	6,641	262	3,944	73	64	3,256	6,675	862	21	5	**21,814**
2016	11	6,753	272	3,988	75	65	3,303	6,728	874	21	5	**22,095**
2017	12	6,867	283	4,040	76	65	3,349	6,805	886	21	5	**22,409**
2018	12	6,976	293	4,093	77	65	3,394	6,877	897	21	5	**22,710**
2019	12	7,086	304	4,144	78	65	3,443	6,959	908	21	5	**23,025**
2020	12	7,171	315	4,206	80	66	3,484	7,046	919	21	5	**23,325**
2021	12	7,257	326	4,256	81	66	3,532	7,105	930	21	5	**23,591**
2022	12	7,344	338	4,308	82	66	3,587	7,170	942	21	5	**23,875**
2023	13	7,432	351	4,374	83	67	3,644	7,245	953	21	5	**24,188**
2024	13	7,521	365	4,432	85	67	3,694	7,314	963	21	5	**24,480**
Change (2010-2024)	**2**	**769**	**149**	**473**	**18**	**-4**	**651**	**499**	**144**	**0**	**0**	**2,701**
Percentage Change	**18.2**	**11.4**	**69.0**	**11.9**	**26.9**	**-5.6**	**21.4**	**7.3**	**17.6**	**0.0**	**0.0**	**12.4**
Annual Growth Rate (%)	**1.4**	**0.8**	**3.8**	**0.8**	**1.7**	**-0.4**	**1.4**	**0.5**	**1.2**	**0.0**	**0.0**	**0.8**

Source: Table 4 in Company data responses to the Commission's 2010 data request for the Ten-Year Plan.
Note: The data were rounded to whole numbers. Percentages were rounded to one decimal place. A&N and Somerset did not provide a response to the Commission's data request. Berlin, PE, Thurmont, and Williamsport are winter-peaking service territories. BGE, Choptank, DPL, Easton, Hagerstown, Pepco, and SMECO are summer-peaking service territories. Reductions result from the following DSM programs: direct load control (BGE, Choptank, DPL, Pepco, and SMECO), AMI (BGE), and energy efficiency and conservation programs (BGE, DPL, Pepco, PE, and SMECO).

Table A-5(b): Maryland Peak Demand Forecast (MW) (Net of DSM Programs) (as of December 31, 2009)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagers-town	PE	Pepco	SMECO	Thurmont	Williams-port	Total
2010	11	6,752	216	941	67	71	1,561	3,540	819	21	5	**14,004**
2011	11	6,720	221	864	68	68	1,583	3,259	818	21	5	**13,638**
2012	11	6,863	232	843	70	63	1,598	3,204	829	21	5	**13,739**
2013	11	6,666	241	827	71	64	1,612	3,213	840	21	5	**13,571**
2014	11	6,707	253	823	72	64	1,619	3,219	852	21	5	**13,646**
2015	11	6,641	262	825	73	64	1,630	3,220	862	21	5	**13,614**
2016	11	6,753	272	836	75	65	1,652	3,248	874	21	5	**13,812**
2017	12	6,867	283	849	76	65	1,672	3,289	886	21	5	**14,025**
2018	12	6,976	293	862	77	65	1,692	3,327	897	21	5	**14,227**
2019	12	7,086	304	874	78	65	1,714	3,370	908	21	5	**14,437**
2020	12	7,171	315	889	80	66	1,731	3,416	919	21	5	**14,625**
2021	12	7,257	326	902	81	66	1,754	3,447	930	21	5	**14,801**
2022	12	7,344	338	914	82	66	1,782	3,482	942	21	5	**14,988**
2023	13	7,432	351	931	83	67	1,813	3,521	953	21	5	**15,190**
2024	13	7,521	365	945	85	67	1,838	3,558	963	21	5	**15,381**
Change (2010-2024)	**2**	**769**	**149**	**4**	**18**	**-4**	**277**	**18**	**144**	**0**	**0**	**1,377**
Percentage Change	**18.2**	**11.4**	**69.0**	**0.4**	**26.9**	**-5.5**	**17.7**	**0.5**	**17.6**	**0.0**	**0.0**	**9.8**
Annual Growth Rate (%)	**1.4**	**0.8**	**3.8**	**0.0**	**1.7**	**-0.4**	**1.2**	**0.0**	**1.2**	**0.0**	**0.0**	**0.7**

Source: Table 4 in Company data responses to the Commission's 2010 data request for the Ten-Year Plan.
Note: The data were rounded to whole numbers. Percentages were rounded to one decimal place. A&N and Somerset did not provide a response to the Commission's data request. Berlin, PE, Thurmont, and Williamsport are winter-peaking service territories. BGE, Choptank, DPL, Easton, Hagerstown, Pepco, and SMECO are summer-peaking service territories. Reductions result from the following DSM programs: direct load control (BGE, Choptank, DPL, Pepco, and SMECO), AMI (BGE), and energy efficiency and conservation programs (BGE, DPL, Pepco, PE, and SMECO).

Table A-5(c): System-Wide Peak Demand Forecast (MW) (Gross of DSM Programs) (as of December 31, 2009)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagers-town	PE	Pepco	SMECO	Thurmont	Williams-port	Total
2010	11	7,398	226	4,023	67	71	3,061	7,048	860	21	5	**22,791**
2011	11	7,513	231	4,089	68	68	3,125	7,144	877	21	5	**23,212**
2012	11	7,668	242	4,153	70	63	3,185	7,273	899	21	5	**23,590**
2013	11	7,790	251	4,219	71	64	3,239	7,371	917	21	5	**23,959**
2014	11	7,956	263	4,279	72	64	3,284	7,457	937	21	5	**24,349**
2015	11	8,098	272	4,339	73	64	3,334	7,538	956	21	5	**24,711**
2016	11	8,211	282	4,383	75	65	3,378	7,591	968	21	5	**24,990**
2017	12	8,325	293	4,435	76	65	3,423	7,668	980	21	5	**25,303**
2018	12	8,434	303	4,488	77	65	3,465	7,740	991	21	5	**25,601**
2019	12	8,543	314	4,539	78	65	3,512	7,822	1,002	21	5	**25,913**
2020	12	8,629	325	4,601	80	66	3,549	7,909	1,013	21	5	**26,210**
2021	12	8,715	336	4,651	81	66	3,593	7,968	1,024	21	5	**26,472**
2022	12	8,802	348	4,703	82	66	3,638	8,033	1,036	21	5	**26,746**
2023	13	8,890	361	4,769	83	67	3,684	8,108	1,047	21	5	**27,048**
2024	13	8,979	375	4,827	85	67	3,727	8,177	1,057	21	5	**27,333**
Change (2010-2024)	**2**	**1,581**	**149**	**804**	**18**	**-4**	**666**	**1,129**	**197**	**0**	**0**	**4,542**
Percent Change	**18.2**	**21.4**	**65.9**	**20.0**	**26.9**	**-5.6**	**21.8**	**16.0**	**22.9**	**0.0**	**0.0**	**19.9**
Annual Growth Rate (%)	**1.4**	**1.4**	**3.7**	**1.3**	**1.7**	**-0.4**	**1.4**	**1.1**	**1.5**	**0.0**	**0.0**	**1.3**

Source: Table 4 in Company data responses to the Commission's 2010 data request for the Ten-Year Plan.
Note: The data were rounded to whole numbers. Percentages were rounded to one decimal place. A&N and Somerset did not provide a response to the Commission's data request. Berlin, PE, Thurmont, and Williamsport are winter-peaking service territories. BGE, Choptank, DPL, Easton, Hagerstown, Pepco, and SMECO are summer-peaking service territories.

Table A-5(d): Maryland Peak Demand Forecast (MW) (Gross of DSM Programs) (as of December 31, 2009)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagers-town	PE	Pepco	SMECO	Thurmont	Williams-Port	Total
2010	11	7,398	226	985	67	71	1,578	3,719	860	21	5	**14,941**
2011	11	7,513	231	1,001	68	68	1,614	3,770	877	21	5	**15,179**
2012	11	7,668	242	1,017	70	63	1,642	3,838	899	21	5	**15,476**
2013	11	7,790	251	1,033	71	64	1,668	3,889	917	21	5	**15,720**
2014	11	7,956	263	1,048	72	64	1,687	3,935	937	21	5	**15,999**
2015	11	8,098	272	1,062	73	64	1,709	3,977	956	21	5	**16,248**
2016	11	8,211	282	1,073	75	65	1,727	4,005	968	21	5	**16,443**
2017	12	8,325	293	1,086	76	65	1,746	4,046	980	21	5	**16,655**
2018	12	8,434	303	1,099	77	65	1,763	4,084	991	21	5	**16,854**
2019	12	8,543	314	1,111	78	65	1,783	4,127	1,002	21	5	**17,061**
2020	12	8,629	325	1,126	80	66	1,796	4,173	1,013	21	5	**17,246**
2021	12	8,715	336	1,139	81	66	1,814	4,204	1,024	21	5	**17,417**
2022	12	8,802	348	1,151	82	66	1,833	4,239	1,036	21	5	**17,595**
2023	13	8,890	361	1,168	83	67	1,853	4,278	1,047	21	5	**17,786**
2024	13	8,979	375	1,182	85	67	1,871	4,315	1,057	21	5	**17,970**
Change (2010-2024)	**2**	**1,581**	**149**	**197**	**18**	**-4**	**293**	**596**	**197**	**0**	**0**	**3,029**
Percent Change	**18.2**	**21.4**	**65.9**	**20.0**	**26.9**	**-5.6**	**18.6**	**16.0**	**22.9**	**0.0**	**0.0**	**20.3**
Annual Growth Rate (%)	**1.4**	**1.4**	**3.7**	**1.3**	**1.7**	**-0.4**	**1.2**	**1.1**	**1.5**	**0.0**	**0.0**	**1.3**

Source: Table 4 in Company data responses to the Commission's 2010 data request for the Ten-Year Plan.
Note: The data were rounded to whole numbers. Percentages were rounded to one decimal place. A&N and Somerset did not provide a response to the Commission's data request. Berlin, PE, Thurmont, and Williamsport are winter-peaking service territories. BGE, Choptank, DPL, Easton, Hagerstown, Pepco, and SMECO are summer-peaking service territories.

Table A-6(a): System-Wide Energy Sales Forecast (GWh) (Net of DSM Programs)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williams-port	Total
2010	41	31,788	953	12,414	288	350	14,162	26,549	3,485	82	18	**90,130**
2011	41	32,211	975	12,378	293	337	14,103	26,602	3,523	82	18	**90,563**
2012	41	32,719	995	12,358	299	307	14,390	26,938	3,570	82	18	**91,717**
2013	42	33,122	1,008	12,423	304	310	14,625	27,222	3,612	82	18	**92,768**
2014	42	33,551	1,029	12,481	310	313	14,831	27,393	3,658	82	18	**93,708**
2015	43	33,889	1,047	12,402	315	316	15,016	27,386	3,700	82	18	**92,214**
2016	44	34,500	1,066	12,501	320	319	15,256	27,537	3,747	82	18	**95,390**
2017	44	35,024	1,087	12,587	326	323	15,506	27,629	3,793	82	18	**96,419**
2018	45	35,551	1,106	12,682	331	326	15,748	27,741	3,835	82	18	**97,465**
2019	46	36,078	1,126	12,774	336	329	15,992	27,844	3,882	82	18	**98,507**
2020	46	36,649	1,146	12,884	342	332	16,225	27,984	3,923	82	18	**99,631**
2021	47	37,168	1,168	12,980	347	336	16,454	28,075	3,965	82	18	**100,640**
2022	48	37,711	1,191	13,086	353	339	16,729	28,191	4,012	82	18	**101,760**
2023	48	38,253	1,215	13,194	358	342	17,002	28,308	4,054	82	18	**102,874**
2024	49	38,825	1,241	13,313	363	346	17,277	28,456	4,096	82	18	**104,066**
Change (2010-2024)	8	7,037	288	899	75	-4	3,115	1,907	611	0	0	**13,936**
Percent Change	19.5	22.1	30.2	7.2	26.0	-1.1	21.9	7.2	17.5	0	0	**15.5**
Annual Growth Rate (%)	1.3	1.5	2.0	0.5	1.7	-0.1	1.5	0.5	1.2	0	0	**1.0**

Source: Table 5 in Company data responses to the Commission's 2010 data request for the Ten-Year Plan.
Note: The data were rounded to whole numbers. Percentages were rounded to one decimal place. A&N and Somerset did not provide a response to the Commission's data request. Reductions result from the following DSM programs: direct load control (BGE, Choptank, DPL, Pepco, and SMECO), AMI (BGE), and energy efficiency and conservation programs (BGE, DPL, Pepco, PE, and SMECO).

Table A-6(b): Maryland Energy Sales Forecast (GWh) (Net of DSM Programs)

Year	Berlin	BGE	Choptank	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williams-port	Total
2010	41	31,788	953	4,048	288	350	7,382	14,926	3,485	82	18	**63,361**
2011	41	32,211	975	3,995	293	337	7,379	14,797	3,523	82	18	**63,651**
2012	41	32,719	995	3,994	299	307	7,491	14,889	3,570	82	18	**64,405**
2013	42	33,122	1,008	3,989	304	310	7,591	14,941	3,612	82	18	**65,019**
2014	42	33,551	1,029	3,978	310	313	7,671	14,961	3,658	82	18	**65,613**
2015	43	33,889	1,047	3,960	315	316	7,730	14,902	3,700	82	18	**66,002**
2016	44	34,500	1,066	3,990	320	319	7,840	15,028	3,747	82	18	**66,954**
2017	44	35,024	1,087	4,020	326	323	7,963	15,083	3,793	82	18	**67,763**
2018	45	35,551	1,106	4,052	331	326	8,078	15,160	3,835	82	18	**68,584**
2019	46	36,078	1,126	4,086	336	329	8,194	15,237	3,882	82	18	**69,414**
2020	46	36,649	1,146	4,121	342	332	8,300	15,347	3,923	82	18	**70,306**
2021	47	37,168	1,168	4,158	347	336	8,414	15,408	3,965	82	18	**71,111**
2022	48	37,711	1,191	4,198	353	339	8,549	15,498	4,012	82	18	**71,999**
2023	48	38,253	1,215	4,239	358	342	8,592	15,590	4,054	82	18	**72,791**
2024	49	38,825	1,241	4,282	363	346	8,834	15,712	4,096	82	18	**73,848**
Change (2010-2024)	8	7,037	288	234	75	-4	1,452	786	611	0	0	**10,487**
Percent Change	19.5	22.1	30.2	5.8	26.0	-1.1	19.7	5.3	17.5	0	0	**16.6**
Annual Growth Rate (%)	1.3	1.5	2.0	0.4	1.7	-0.1	1.3	0.4	1.2	0	0	**1.1**

Source: Table 5 in Company data responses to the Commission's 2010 data request for the Ten-Year Plan.
Note: The data were rounded to whole numbers. Percentages were rounded to one decimal place. A&N and Somerset did not provide a response to the Commission's data request. Reductions result from the following DSM programs: direct load control (BGE, Choptank, DPL, Pepco, and SMECO), AMI (BGE), and energy efficiency and conservation programs (BGE, DPL, Pepco, PE, and SMECO).

Table A-7: Licensed Electricity Suppliers and Brokers and Natural Gas Suppliers and Brokers (as of 11/1/2010)

Company	Electricity Supplier License No.	Electricity Broker License No.	Natural Gas Supplier License No.	Natural Gas Broker License No.
A Better Choice Energy Services		IR-1697		IR-1698
Acclaim Energy, Ltd.		IR-1726		IR-1728
Affiliated Power Purchasers International, LLC.		IR-279		
Allegheny Energy Supply	IR-229		IR-229	
Ambit Northeast, LLC	IR-1992		IR-1993	
Amerex Brokers, LLC		IR-1513		IR-1512
America Approved Energy Services Direct, LLC		IR-1841		
American PowerNet Management, L.P.	IR-604			
AOBA Alliance, Inc.		IR-267		IR-375
API Ink, LLC		IR-1399		
ARS International, Inc.		IR-1181		
Avalon Energy Services, LLC		IR-1693		IR-1743
BGE Home Products and Services, Inc. also d/b/a BGE Commercial Building Systems d/b/a Constellation Electric	IR-228		IR-311	
BidURenergy, Inc.		IR-1847		IR-1846
BlueStar Energy Services	IR-757			
Bmark Energy, Inc.		IR-2018		
Bollinger Energy Corporation		IR-265	IR-322	
BP Energy Company			IR-676	
BTU Energy, LLC		IR-864		
C & D Commercial Brokerage, Inc. t/a Capital Energy Solutions		IR-1823		
Castlebridge Energy Group	IR-1735			
Chesapeake Energy Services, Inc.		IR-1638		
Choice! Energy Services		IR-682		
Clean Currents, LLC		IR-980		IR-1782
Coastal Energy Company, LLC		IR-1900		
Co-eXprise, Inc.		IR-879		IR-879
Coleman Hines, Inc.		IR-1389		
Colonial Energy, Inc.			IR-606	
Commerce Energy, Inc.	IR-639		IR-737	
Commercial and Industrial Energy Solutions, LLC		IR-2062		
Compass Energy Services			IR-652	
Competitive Energy Services-Maryland, LLC	IR-895		IR-895	
ConocoPhillips Company			IR-1359	
ConocoPhillips, Inc.			IR-378	
Consolidated Edison Solutions, Inc.	IR-603			
Constellation Energy Projects and Services Group, Inc.	IR-239			
Constellation NewEnergy, Inc.	IR-500		IR-522	
Constellation NewEnergy-Gas Division, LLC			IR-655	
Consumer Energy Solutions, Inc.		IR-1210		
Coral Energy Gas Sales, Inc.			IR-360	
CQI Associates, LLC		IR-575		IR-1753
Creativ Energy Options		IR-1528		
Cybermark Systems, Inc. d/b/a Proenergy Consultants		IR-1785		
Cypress Natural Gas, L.L.C.			IR-674	

DD&J LLC		IR-1560		
Delta Energy, LLC			IR-645	
Direct Energy Business f/k/a Strategic Energy	IR-437			
Direct Energy Services, LLC	IR-719		IR-791	
Dominion Retail, Inc.	IR-252		IR-345	
Downing Place, LLC		IR-2011		
DTE Energy Trading, Inc.	IR-686			
Early Bird Power		IR-1798		
Eastern Shore of Maryland Educational Consortium Energy Trust dba ESMEC Energy Trust		IR-342		
EDF Trading North America, LLC			IR-2019	
EGP Energy Solutions, LLC d/b/a Atlantic Energy Resources		IR-1363		IR-1430
Eisenbach Consulting, LLC		IR-1950		IR-1951
Electric Advisors, Inc.		IR-1183		IR-1523
Ellicott City Investments, LLC d/b/a Allied Power Services		IR-1890		IR-1891
Emex, LLC		IR-2065		
Eneractive Solutions, LLC		IR-1939		
Energy Advisory Service, LLC		IR-1486		IR-1485
Energy Edge Consulting, LLC		IR-2022		
Energy Options, LLC		IR-568		
Energy Plus Holdings LLC	IR-1805			
Energy Professionals, LLC		IR-1791		
Energy Services Management, LLC d/b/a Maryland Energy Consortium		IR-236		IR-312
Energy Services Provider Group, Inc.				IR-519
Energy Shopper, LLC		IR-2048		
Energy Trust, LLC		IR-1682		IR-1681
EnergyWindow, Inc.		IR-274		
Etheredge Partners, LLC		IR-2054		
Field Personnel Services d/b/a Vanguard Engineering Services		IR-1789		
FirstEnergy Solutions Corp	IR-225			
Gateway Energy Services Corporation	IR-340		IR-334	
GDF Suez Energy Resources	IR-605			
Genesis Energy International, LLC		IR-1986		
Glacial Energy of Maryland, Inc.	IR-888			
Glacial Natural Gas, Inc.			IR-1855	
Goldstar Energy Group, Inc.		IR-1370		IR-1381
Good Energy, LP		IR-1592		
Green Power Management Solutions, LLC		IR-1835		IR-1834
Hess Corporation	IR-219		IR-323	
Horizon Power & Light, LLC	IR-704			
Houston Energy Services Company, L.L.C			IR-403	
Hudson Energy Services, LLC	IR-1114		IR-1120	
I.C. Thomasson Associates, Inc.		IR-1445		IR-1446
IDT Energy, Inc.	IR-1747		IR-1745	
Integrity Energy, LTD		IR-1985		
Integrys Energy Services	IR-951			
Interstate Gas Supply, Inc. d/b/a IGS Energy d/b/a Columbia Retail Energy			IR-1836	
Knights of the Roundtable, Inc. d/b/a/ America Approved.com, LLC		IR-1664		
Liberty Power Corp, LLC	IR-607			
Liberty Power Delaware, LLC	IR-962			
Liberty Power Holdings, LLC	IR-957			
Liberty Power, MD, LLC	IR-793			
Linde Energy Services	IR-753			

Long Distance Consultants, L.L.C.		IR-1455		
MABLock Consulting d/b/a The Lock Group		IR-1683		
Major Energy Services, LLC			IR-1749	
Marathon Oil Company			IR-364	
Market Direct LLC d/b/a mdenergy		IR-614		
Maryland Energy Advisors, LLC		IR-1954		
Maryland Energy Trust, LLC		IR-1994		
Metromedia Energy, Inc.			IR-355	
Metromedia Power, Inc.		IR-867		
Mid Atlantic Renewables, LLC		IR-856		
MidAmerican Energy Company	IR-798		IR-798	
Mid-Atlantic Aggregation Group Independent Consortium, L.L.C. d/b/a MAAGIC		IR-234		
Mitchell Energy Management Services, Inc.		IR-1371		
MRDB Holdings, LP d/b/a LPB Energy Consulting		IR-930		IR-1000
MX energy			IR-327	
Mxenergy Electric Inc.	IR-1853			
Nania Energy, Inc.		IR-1857		
National Utility Service, Inc.		IR-1400		IR-1401
Natures Current, LLC		IR-1352		
NextEra Energy Services, LLC	IR-966			
North American Power and Gas LLC	IR-1983			
Northeast Energy Partners		IR-1649		
NOVEC Energy Solutions, Inc.			IR-338	
NRGing, LLC d/b/a NetGain Energy Advisors		IR-2038		IR-2037
Oasis Power, LLC d/b/a Oasis Energy			IR-1929	
Oasis Power, LLC dba Oasis Energy	IR-1848			
On-Demand Energy, Inc.		IR-1442		
Open Market Energy, LLC		IR-1981		IR-2013
Palmco Energy MD, LLC			IR-1803	
Palmco Power MD, LLC	IR-1804			
Patch Energy Services, LLC		IR-1943		
Patriot Energy, LLC		IR-1858		
Pepco Energy Services, Inc.	IR-222			
Pepco Energy Services, Inc. also d.b.a. Conectiv Energy Services			IR-316	
Platinum Advertising II, LLC		IR-1673		IR-1668
Power Brokers, LLC		IR-2066		
Power Brokers, LP		IR-1610		
Power Management		IR-1670		IR-1669
PPL EnergyPlus, LLC	IR-230		IR-335	
Premier Energy Group		IR-942		IR-943
Premier Power Solutions, LLC		IR-894		IR-894
Public Power & Utility of Maryland, LLC	IR-1781			
QVINTA Energy Services		IR-557		IR-530
Reliable Power Alternatives Corp.		IR-1719		
Reliant Energy Northeast, LLC d/b/a Reliant Energy	IR-2058			
Richards Energy Group, Inc.		IR-818		
RMI Consulting, Inc.		IR-1685		
Satori Enterprises, Inc.		IR-1499		
Select Energy Partners, LLC		IR-1864		
Sempra Energy Solutions, LLC	IR-464		IR-464	
Shell Energy, North America	IR-1357		IR-1358	
Smart Choice Energy Services		IR-1611		IR-1612

SmartEnergy.com, Inc.	IR-270			
South Jersey Energy Company	IR-740			
South River Consulting		IR-863		
Spark Energy Gas, LP			IR-613	
Spark Energy, LP	IR-979			
Sprague Energy Corp.				IR-339
Stand Energy Corporation			IR-632	
Statoil Natural Gas LLC			IR-561	
Summit Energy Services		IR-1396		
Taylor Consulting and Contracting, LLC		IR-1790		IR-1960
Technology Resources Solutions, Inc.		IR-1802		
Texas Energy Options, Inc.		IR-1542		
TFS Energy Solutions, LLC		IR-918		
TFS Energy Solutions, LLC d/b/a Tradition Energy				IR-982
The Eric Ryan Corporation		IR-1438		IR-1437
The Legacy Energy Group		IR-1692		IR-1691
The Loyalton Group, Inc.		IR-1766		IR-1765
The Royal Bank of Scotland plc	IR-1374			
Tiger Natural Gas			IR-351	
U.S. Gas & Electric d/b/a MD Gas & Electric			IR-1744	
U.S. Harvest Postal Protection Services Corp.d/b/a United States Ethane Gas Corp.				IR-1824
U.S. Harvest Postal Protection Services Corporation d/b/a U.S. Harvest Energy & Technologies Corp.		IR-1774		
U.S. Sun Energy, Inc.		IR-1952		
UEC Energy, LLC		IR-1972		
UGI Energy Services, Inc.	IR-237		IR-319	
Unified Energy Services, LLC		IR-1751		
Usource, LLC		IR-1160		
UtiliTech, Inc.		IR-915		IR-915
Virginia Power Energy Marketing, Inc. d/b/a Dominion Sales and Marketing, Inc.			IR-689	
Viridian Energy PA, LLC	IR-1840			
Volunteer Energy Services, Inc.		IR-2012	IR-2004	
Washington Gas Energy Services, Inc.	IR-227		IR-324	
World Energy Solutions, Inc.		IR-619		IR-953

The Table below lists the electricity and natural gas suppliers by license type. The license type indicates what services a supplier may offer in Maryland. The table below only indicates the license type and does not imply that all suppliers are offering services.

Electric Supplier Only	31
Electric Broker Only	64
Gas Supplier Only	27
Gas Broker Only	4
Electric Supplier & Gas Supplier	18
Electric Broker & Gas Broker	37
Total Suppliers (Incl. Brokers)	**181**

Table A-8: Transmission Enhancements by Service Area

									From Location		To Location	
Transmission Owner	#	Voltage (kV)	Length (miles)	No. of circuits	Start Date	End Date	In-Service Date	Purpose	County	Terminal	County	Terminal
PE		138	0.1	1	2010		2010	GI		Roth Rock (new)		Mettiki Tap – Mettiki
PE		138	0.1	2	2010	Suspd.	Unknown	GI		Kelso Gap (new)		Oak Park – Elk Garden
PE		230	12.7	1	2010		2013	BTR		Catoctin		Carroll
PE		230	3.2	1	2011		2012	BTR		Doubs		Eastalco (Sec. 205)
PE		230	3.7	1	2011		2012	BTR		Doubs		Eastalco (Sec. 206)
PE		138	0.1	2	2014		2014	DA		Altamont (new)		Albright – Mt Zion
PE		138	0.1	2	2016		2017	DA		McDade		Halfway – Paramount No. 1
PE		230	2.1	2	2018		2019	DA		Urbana		Lime Kiln – Montgomery
PE		138	4.8	1	2013		2014	BTR		Marlowe		Halfway
PE		230	0.6	2	2019		2020	DA		Ridgeville		Mt. Airy – Damascus
PE		230	0.1	2	2018		2019	DA		South Frederick No. 1 (new)		Monocacy Lime Kiln
PE		230	0.1	2	2019		2019	DA		Jefferson No. 1 (new)		Doubs – Monocacy
PE		765	19.6	1	2011		2015	BTR		Welton Spring (new)		Kemptown (new)
PE		138	0.1	2	2019		2020	DA		Fairplay (new)		Marlowe – Boonsboro

									From Location		To Location	
Transmission Owner	**#**	**Voltage (kV)**	**Length (miles)**	**No. of circuits**	**Start Date**	**End Date**	**In-Service Date**	**Purpose**	**County**	**Terminal**	**County**	**Terminal**
PE		230	7.8	1	2019		2020	BTR		Montgomery		Bucklodge (new)
PE		230	5.4	1	2010		2013	BTR		Monocacy		Walkersville
PE		230	0.1	2	2011		2011	DA		E. Frederick (new)		Monocacy - Eaglehead
PE		138	16.7	1	2011		2012	BTR		Albright		Mt. Zion
PE		138	3.2	1	2011		2012	BTR		Mt. Zion		Beryl
PE		230	9.8	1	2011		2012	BTR		Ringgold		Catoctin
PE		230	10.7	1	2011		2012	BTR		Walkersville		Catoctin
PE		138	6.1	1	2012		2013	BTR		Beryl		Black Oak
PE		230	6.7	1	2012		2013	BTR		Doubs		Lime Kiln (Sec. 207)
PE		230	6.7	1	2012		2013	BTR		Doubs		Lime Kiln (Sec. 231)
PE		230	24.9	1	2013		2014	BTR		Doubs		Monocacy
PE		138	4.0	1	2013		2014	BTR		Ringgold		East Waynesboro
PE		138	5.4	1	2019		2019	BTR		Albright		Garrett
PE		115	2.0	1	2019		2019	BTR		Garrett		Garrett Tap
PE		138	0.5	1	2019		2020	BTR		Black Oak		Cumberland
PE		138	6.6	1	2020		2020	BTR		Albright		Oak Park
BGE		115	3.0	2	6/08	5/13		DA	Balt City	Westport	Balt City	Wilkens (new)

									From Location		To Location	
Transmission Owner	**#**	**Voltage (kV)**	**Length (miles)**	**No. of circuits**	**Start Date**	**End Date**	**In-Service Date**	**Purpose**	**County**	**Terminal**	**County**	**Terminal**
BGE		230	8.6	1	1/11	6/14		BTR	Harford	Conastone	Harford	Graceton
BGE		230	6.1	2	4/07	6/15		BTR	Harford	Raphael Rd.	Harford	Bagley (new)
BGE		115	0.4	2	11/07	6/11		DA	Anne Arundel	Waugh Chapel	Anne Arundel	Rock Ave. (new)
BGE		115	0.4	2	8/07	5/13		BTR	Harford	Perryman	Harford	Harford
BGE		115	0.5	1	4/10	6/13		BTR	Anne Arundel	Bestgate Rd.	Anne Arundel	Jennifer Rd.
BGE		500	9.2	2	1/09	6/13		BTR	Calvert	Calvert Cliffs	Calvert	MAPP Project
BGE		115	3.3	1	4/10	6/14		BTR	Baltimore	Deer Park	Baltimore	Northwest
BGE		115	1	2	9/09	6/14		BTR	Balt. City	Orchard St.	Balt. City	Front St.
BGE		115	0.6	2	6/12	5/14		DA	Balt. City	Coldspring	Balt. City	Melvale (new)
BGE		115	22.1	2	1/13	6/14		BTR	Anne Arundel	Waugh Chapel	Anne Arundel	Bestgate Rd.
BGE		230	13.7	1	1/09	6/14		BTR	Harford	Graceton	Harford	Bagley (new)
BGE		115	5.2	2	1/12	6/15		DA	Balt. City	Erdman	Balt. City	Argon (new)
BGE		115	5	1	1/12	6/15		BTR	Balt. City	Melvale (new)	Balt. City	Argon (new)
BGE		230	4	2	1/10	6/15		BTR	Baltimore	Northwest	Baltimore	Emory Grove (new)
BGE		115	3.2	1	1/12	6/16		BTR	Baltimore	Northesat	Baltimore	Middle River
BGE		230	11.7	2	6/07	10/16		BTR	Harford	Raphael Rd.	Harford	Perryman
Choptank		25	2.9	1	2012	2012		BTR		Oil City		Hobbs

									From Location		To Location	
Transmission Owner	**#**	**Voltage (kV)**	**Length (miles)**	**No. of circuits**	**Start Date**	**End Date**	**In-Service Date**	**Purpose**	**County**	**Terminal**	**County**	**Terminal**
DPL		69	18.41	1	1/11	5/12		BTR		Trappe		Todd
DPL		138	12.98	1	1/16	5/18		BTR		Wye Mills		Easton
DPL		69	12	1	1/13	5/14		DA		McCleans (new)		Lynch
DPL		69	12	1	1/13	5/14		DA		McCleans (new)		Chestertown
DPL		69	4.42	1	1/15	5/16		STR		Vienna		Sharptown
DPL		69	2.61	1	1/11	5/12		BTR		Maridel		Ocean Bay
DPL		138	13.73	1	1/13	5/14		BTR		Vienna		Nelson
DPL		138	24	1	1/14	5/15		BTR		Church		Wye Mills
DPL		230	18.7	1	1/12	5/13		BTR		Vienna		Loretto
DPL		230	9.51	1	1/12	5/13		BTR		Loretto		Piney Grove
DPL		69	11.7	1	1/14	5/15		STR		Stevensville		Wye Mills
DPL		138	30.91	1	1/15	5/16		BTR		Wattsville		Piney Grove
DPL		138	12.33	1	1/11	5/12		BTR		Indian River		Bishop
DPL		138	12.38	1	1/14	5/15		BTR		Church		Townsend
DPL		230	28.28	1	1/13	5/14		BTR		Vienna		Steele
DPL		69	5.99	1	1/15	10/17		DA		Queenstown (new)		Grasonville
DPL		69	6.52	1	1/12	5/13		DA		Church		Massey

									From Location		To Location	
Transmission Owner	**#**	**Voltage (kV)**	**Length (miles)**	**No. of circuits**	**Start Date**	**End Date**	**In-Service Date**	**Purpose**	**County**	**Terminal**	**County**	**Terminal**
DPL		69	2.25	1	1/14	10/15		DA		Barber (new)		Trappe
DPL		138	3.96	1	1/10	12/10		BTR		Oak Hall		Wattsville
DPL		69	5.99	1	1/15	10/17		DA		Queenstown (new)		Wye Mills
DPL		69	2.25	1	1/14	10/15		DA		Barber (new)		Talbot
DPL		138	5.22	1	1/14	6/15		BTR		Glasgow		Cecil
DPL		138	1	1	1/12	5/13		BTR		SVC site		Ocean Bay
PEPCO		230	Bus Upgrade	2	1/10	5/11		BTR		Quince Orchard		Bells Mill Rd.
PEPCO		230	10.7	2	1/09	5/11		BTR		Dickerson		Quince Orchard
PEPCO		230	5.34	2	8/09	5/12		BTR		Benning		Ritchie
PEPCO		230	6.42	4	1/09	5/12		BTR		Burches Hill		Palmers Cornor
PEPCO		230	Tower & Bus Upgrade	1	1/09	5/11		BTR		Dickerson		Pleasant View
PEPCO		500	33	1	1/10	5/13		BTR		Possum Point		Burches Hill
PEPCO		500	19	1	1/10	5/13		BTR		Burches Hill		Chalk Point
PEPCO		500	20	1	1/10	5/13		BTR		Chalk Point		Calvert Cliffs
PEPCO		230	5.01	4	1/11	5/13		BTR		Oak Grove		Ritchie
PEPCO		230	10.98	1	1/12	5/14		BTR		Ritchie		Buzzard Point
PEPCO		230	10.83	1	1/12	5/14		BTR		Ritchie		Buzzard Point

									From Location		To Location	
Transmission Owner	**#**	**Voltage (kV)**	**Length (miles)**	**No. of circuits**	**Start Date**	**End Date**	**In-Service Date**	**Purpose**	**County**	**Terminal**	**County**	**Terminal**
SMECO		230	20.0	2	2012	2013		DA	Calvert	Holland Cliff	Calvert	South Calvert
SMECO		230	10.0	2	2014	2015		BTR	Calvert	South Calvert	St. Mary's	Hewitt Road

Purpose Codes:

BTR – Baseline Transmission Reliability
DA – Distribution Adequacy
OTH – Other
RLC – Relocation
STR – Supplemental Transmission Reliability
GI – Accommodate for generator interconnection
TCA – Transmission Customer Adequacy
AT – Asset Transfer from Government
COR – Contingency Overload and/or Reliability

Source: Company data responses to Question 7 in the Commission's 2010 data request for the Ten-Year Plan.

Table A-9: Renewable Projects Providing Capacity and Energy to Maryland Customers (as of December 31, 2009)

Company	Name	Site Location	QF Status (Yes or No)	Fuel	Net Capacity (MW)	2009 Net Generation (MWh)
A&N	N/A	N/A	N/A	N/A	N/A	N/A
PE	None	None	None	None	None	None
Berlin	None	None	None	None	None	None
BGE	Alternative Energy Associates ("AEA") Brighton Dam	Laurel, MD	Yes	Hydro	N/A	507
BGE	BRESCO (Baltimore Refuse Energy Systems Co.)	Baltimore, MD	Yes	Municipal solid waste	57	321,177
Choptank	Worcester County Renewable Energy LLC	Worcester County Central Landfill	N/A	Methane Gas	1	N/A
DPL	None	None	None	None	None	None
Easton	Power Plant No.1 Unit 13	Easton, MD	No	Biodiesel	5.6	0
Hagerstown	none	None	None	None	None	None
PEPCO	Prince George's County Brown Station Landfill	Upper Marlboro, MD	Yes	Landfill Gas	3.5	13,598
PEPCO	Prince George's County Detention Center	Upper Marlboro, MD	Yes	Landfill Gas	2.55	2,579
SMECO	None	None	None	None	None	None
Somerset	N/A	N/A	N/A	N/A	N/A	N/A
Thurmont	None	None	None	None	None	None
Williamsport	None	None	None	None	None	None

Source: Table 7 in Company data responses to the Commission's 2010 data request for the Ten-Year Plan.
Note: A&N and Somerset did not provide a response to the Commission's data request. QF means "Qualifying Facility" as defined in the Public Utility Regulatory Policies Act of 1978 ("PURPA").
N/A: Data are not available.

Table A-10: Power Plants in the PJM Process for New Electric Generating Stations in Maryland (as of December 31, 2009)

Electric Company Service Territory	Status within PJM Queue (Application by 12/31/09)	Plant Capacity (MW)	Fuel Type	Potential Use	Projected In-Service Date
BGE	V1-033: Pumphrey (Active-Under Study)	132	Other	Merchant Generation	2013 Q4
BGE	V4-038: Friendship Manor (Active-Under Study)	1	Methane	Merchant Generation	2011 Q1
DPL	T144: Pocomoke (Active-Under Study)	10	Biomass	Merchant Generation (20 MW Energy)	2010 Q1
DPL	U3-003 : Mt. Olive (Active- Under Construct)	0	Methane	Merchant Generation (2 MW Energy)	2012 Q2
DPL	U3-004: Cecil (Active – Under Study)	0	Methane	Merchant Generation (1 MW Energy)	2009 Q3
DPL	V2-028: Vienna (Active – Under Study)	2.28	Solar	Merchant Generation (6 MW Energy)	2010 Q4
DPL	V4-039: Church (Active – Under Study)	3.40	Solar	Merchant Generation (9 MW Energy)	2011 Q2
PE	H23_W70: Kelso Gap (Active - Partial Service)	0	Wind	Merchant Generation (100 MW Energy)	2010 Q4
PE	K28: Kelso Gap (Active - Partial Service)	20	Wind	Merchant Generation	2010 Q4
PE	R89: Conowingo (Active – Partial Service)	24	Hydro	Merchant Generation	2011 Q2
PE	S14: Dans Mountain (Active – Under Study)	14	Wind	Merchant Generation (70 MW Energy)	2009 Q4
PE	T16: Gorman-Snowy Creek (Active – Under Study)	6	Wind	Merchant Generation (30 MW Energy)	2011 Q4
PE	U2-030: Four Mile Ridge (Active – Under Study)	7.80	Wind	Merchant Generation (60 MW Energy)	2010 Q4
PE	U2-061: Garrett County (Active- Under Construct)	6.50	Wind	Merchant Generation (50 MW Energy)	2010 Q4
PE	U4-007: Jennings Dam (Active – Under Study)	13.40	Wind	Merchant Generation	2011 Q3
PEPCO	S-17: Talbert (Active – Under Study)	225	Gas	Merchant Generation	2010 Q4
PEPCO	S-32: Perryman (Active – Suspended)	230	Gas	Merchant Generation	2012 Q4
PEPCO	T-133: Chalk Pt.-Bowie (Active – Under Study)	225	Gas	Merchant Generation	2011 Q2
PEPCO	T-134: Chalk Pt.-Bowie (Active – Under Study)	325	Gas	Merchant Generation	2012 Q2
PEPCO	V2-037: White Oak (Active- Under Construct)	0	Gas	Merchant Generation (4.50 MW Energy)	2010 Q4
PEPCO	V3-017: Morgantown (Active – Under Study)	725	Gas	Merchant Generation	2012 Q2
PEPCO	V3-037: Naval Academy (Active- Under Construct)	4	Gas	Merchant Generation	2011 Q1
PEPCO	V3-001: Burches Hill 500kV (Active- Under Study)	750	Gas	Merchant Generation	2012 Q2
PEPCO	W1-034: Burches Hill (Active- Under Study)	750	Gas	Merchant Generation	2014 Q2
SMECO	R-17: Kelson Ridge CPV (Active – Under Study)	645	Gas	Merchant Generation	2012 Q4
SMECO	V2-042: Calvert Cliffs (Active – Under Study)	1,640	Nuclear	Merchant Generation	2017 Q2

Source: Table 6 in Company data responses to the Commission's 2010 data request for the Ten-Year Plan and PJM Generation Queue (available at http://pjm.com/planning/generation-interconnection/generation-queue-active.aspx).