PUBLIC SERVICE COMMISSION
OF MARYLAND

TEN-YEAR PLAN
(2007 – 2016)
OF ELECTRIC COMPANIES
IN MARYLAND

(as of December 31, 2007)

Prepared for the
Maryland Department of Natural Resources
In compliance with Section 7-201
of the Maryland Public Utility Companies Article

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LIST OF ACRONYMS AND DEFINITIONS USED

A&N	A&N Electric Cooperative
ACEEE	American Council for an Energy Efficient Economy
AMI	Advanced Metering Infrastructure
AP / PE	The Potomac Edison Company d/b/a Allegheny Power
Berlin	Town of Berlin
Blueprint Plan	Blueprint for the Future Plan
BGE	Baltimore Gas and Electric Company
BRAC	Base Realignment and Closing Commission
BTU	British thermal unit
C&I	Commercial and Industrial
CAISO	California Independent System Operator
CEG / Constellation	Constellation Energy Group
CETL	Capacity Emergency Transfer Limit
CETO	Capacity Emergency Transfer Objective
CFL	Compact Fluorescent Light bulbs
Choptank	Choptank Electric Cooperative
CIS	Customer Information System
CO_2	Carbon Dioxide
COMAR	Code of Maryland Regulations
Commission / MDPSC	Public Service Commission of Maryland
CONE	Cost of New Entry
CPCN	Certificate of Public Convenience and Necessity
CSA	Construction Service Agreement
D.C.	District of Columbia
DG	Distributed Generation
DNR	Department of Natural Resources (Maryland)
DOE	Department of Energy
DPL / Delmarva	Delmarva Power and Light Company
DR	Demand Response (or Resource)
DRI	Demand Response Initiative
DSM	Demand Side Management
DSRWG	Demand Side Response Working Group
Easton	Easton Utilities Commission
EDC	Electric Distribution Company
EIA	Energy Information Administration
Electric Act	Electric Customer Choice and Competition Act of 1999
EMAAC	Eastern Mid-Atlantic Area Council
EMS	Energy Management System
EPA	Environmental Protection Agency
EPAct	Energy Policy Act
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
ESA 2007	Energy and Security Act of 2007
ESP	Electro-Static Precipitator

EVA	Economic Value Added
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization (System)
FTR	Financial Transmission Right
GATS	Generation Attributes Tracking System
GIS	Geographic Information System
GW/GWh	Gigawatt/Gigawatt-hours
HAA	Healthy Air Act
Hagerstown	Hagerstown Municipal Electric Light Plant
Hg	Mercury
HVAC	Heating, Ventilation, and Air Conditioning
IEEE	Institute of Electrical and Electronics Engineers
IOU	Investor-Owned Utility
IRM	Installed Reserve Margin
ISA	Interconnection Service Agreement
ISO	Independent System Operator
ISO-NE	ISO-New England
kV	Kilovolt
kW/kWh	Kilowatt/Kilowatt-hours
LDA	Load Deliverability Area
LMP	Locational Marginal Price
LNG	Liquefied Natural Gas
LSE	Load Serving Entity
MAAC	Mid-Atlantic Area Council
MACRUC	Mid-Atlantic Conference of Regulatory Utilities Commissions
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
MERTT	Maryland Electric Reliability Tree Trimming (Council)
MISO	Midwest Independent (Transmission) System Operator
MMU	Market Monitoring Unit (PJM)
MOU	Memorandum of Understanding
MW/MWh	Megawatt/Megawatt-hours
NERC	North American Electric Reliability Council
NIETC	National Interest Electric Transmission Corridors (DOE)
NIST	National Institute of Standards and Technology
NOx	Nitrous Oxides
NYISO	New York Independent System Operator
O&M	Operation and Maintenance
OA	Operating Agreement (PJM)
OATT	Open Access Transmission Tariff (PJM)
ODEC	Old Dominion Electric Cooperative
OFA	Over Fire Air
OMS	Outage Management System

OPC	Office of People's Counsel (Maryland)
OPSI	Organization of PJM States, Inc.
PATH	Potomac-Appalachian Transmission Highline
PE / AP	The Potomac Edison Company d/b/a Allegheny Power
Pepco	Potomac Electric Power Company
PHI	Pepco Holding, Inc.
PJM	PJM Interconnection, LLC (Pennsylvania-Jersey-Maryland)
PJM-EIS	PJM – Environmental Information Systems, Inc
PPRP	Power Plant Research Program
PSC	Public Service Commission
PUC	Public Utility Commission
PURPA	Public Utility Regulatory Policies Act (of 1978)
PV	Photo-voltaic
QF	Qualifying Facility
REC	Renewable Energy Credit
RFC	Reliability First Corporation
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RIM	Rate Impact Measure
ROW	Right-of-Way
RPM	Reliability Pricing Model (PJM)
RPPWG	Regional Planning Process Working Group
RPS	Renewable Energy Portfolio Standard
RPS Legislation	PUC Article § 7-701 et seq.
RTEP	Regional Transmission Expansion Plan
RTEPP	Regional Transmission Expansion Planning Protocol
RTO	Regional Transmission Organization
SACR	Selective Auto-Catalytic Reduction
SCADA	Supervisory Control and Data Acquisition
SCR	Selective Catalytic Reduction
SERC	Southeast Reliability Council
SMECO	Southern Maryland Electric Cooperative, Inc.
SO_2	Sulfur Dioxide
Somerset	Somerset Rural Electric Cooperative
SOS	Standard Offer Service
SPP	Southwest Power Pool
Staff	Technical Staff of the Maryland PSC
SWMAAC	Southwest Mid-Atlantic Area Council
TEAC	Transmission Expansion Advisory Committee (PJM)
Ten-Year Plan	Ten-Year Plan of Electric Companies in Maryland
Thurmont	Thurmont Municipal Light Company
TrAIL	Trans-Allegheny Interstate Line
TRC	Total Resource Cost
TWG	Technical Working Group
Williamsport	Town of Williamsport
WMS	Work Management System

I. INTRODUCTION

Section 7-201 of the Public Utility Companies Article, *Annotated Code of Maryland*, requires the Maryland Public Service Commission to forward a Ten-Year Plan to the Secretary of Natural Resources on an annual basis. This report constitutes that effort for the 2007-2016 timeframe, and the referenced data and information is as it existed as of December 31, 2007. It is a compilation of information on long-range plans of Maryland electric utilities. This report also includes summaries of events that have or may affect the electric utility industry in Maryland in the near future.

Historically, the Ten-Year Plan documented how the State would meet its short and long-term energy needs. However, in the past few years, it has become more of a descriptive document discussing the status of retail customer choice, Standard Offer Service, electricity procurement and information on generation plants and related Certificates of Public Convenience and Necessity.

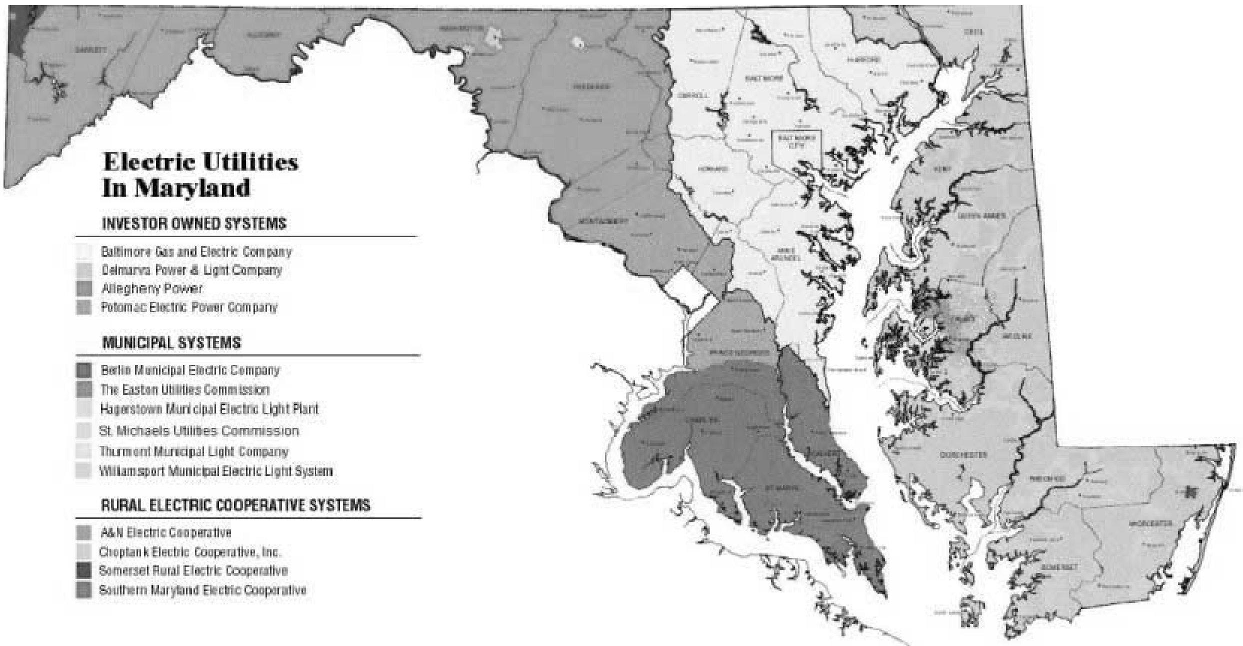
Section II of this plan addresses the peak demand load forecast for Maryland and establishes the baseline load requirements for the next ten years. **Section III** provides information on generation, including CPCNs, and forecasts the availability of generation to meet load requirements. **Section IV** reviews transmission issues impacting Maryland including the Department of Energy's National Interest Electric Transmission Corridors. **Section V** addresses the need for energy efficiency, conservation, and demand response as part of Maryland's supply resources and discusses the effort required to meet the Governor's "EmPower Maryland" goals. As the environment continues to play an increasingly important role in energy decisions, **Section VI** discusses the Maryland Climate Change initiative, 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 they 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 the PJM Regional Transmission Organization and the impact that market rule changes have had both regionally and in Maryland. **Section X** reviews national issues and the impact generated by Federal Energy Regulatory Commission rulings and the 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.

The Maryland energy service territory is geographically divided among thirteen electric utilities. Four of the largest are investor-owned utilities, four are electric cooperatives (two of which serve only small areas of Maryland) and five are electric municipal operations.[1] 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 their service territories.

[1] The St. Michaels Utilities Commission service territory was transferred to Choptank Electric Cooperative, Inc.

<u>Map I.1: Maryland Utilities and their Service Territories in Maryland</u>



While the distribution of retail electricity is regulated at the state level, transmission lines at voltages of 69 kV and above are regulated by FERC and deregulated generation continues to operate under market rules established by the RTO, PJM Interconnection, LLC, as approved by FERC. Neither transmission nor generation stop at state boundaries nor are they regulated at the state level in restructured states such as Maryland. As such, there are regional concerns that can have significant impact well beyond any one state's boundaries. East-West transmission congestion in Pennsylvania or other neighboring states, for example, can cause increased energy prices in many eastern states. Similarly, reduced levels of generation in Maryland requiring significant imports can also impact pricing in nearby jurisdictions. The generation and transmission of energy is no longer simply a single state's concern.

II. MARYLAND AND PJM ZONAL LOAD FORECAST

The foundation of an analysis for meeting Maryland's electricity needs starts with a forecast of the anticipated demand over the planning horizon, in this case the years 2007 through 2015. The Commission evaluated forecasts from three sources - individual utility forecasts, a PJM regional forecast by electric company zones, and a load forecast prepared by the Maryland Department of Natural Resources' Power Plant Research Program. While each forecast relies on similar economic data, there are significant differences in the forecasts of peak demand and energy usage created to a large degree by assumptions used to produce the forecasts. At an energy planning conference held by the Commission in August 2007, the proponents of the three forecasts presented a detailed review of their forecast methodology and the parameters used in creating the forecast. The load forecasts and growth rates, as most recently submitted by PJM[2], are used as the baseline for the planning analysis in this report. These PJM estimates for load growth and peak demand fell in the middle of the PPRP and individual utility results.

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 typically include per-capita income, gross domestic product, employment, energy prices, and population. Non-economic variables include weather normalized variables, monthly seasonal variables, ownership of appliances, building codes, and BRAC data.

The PJM forecast is based primarily on historical load growth, modified for weather and other key variables. It offers the result of a rigorous and autonomous review. External variables such as the load impact of the Base Realignment and Closing Commission and the Governor's "EmPower Maryland," will have a definite, if unknown, impact on future electricity usage. The most recent PPRP forecast estimated load growth at slightly over one-half of one percent per year. While considerably less than PJM's historical growth rates, it assumed higher demand elasticity (by virtue of higher energy prices, consumers would use less energy). The utilities' independent forecasts tended to follow historical patterns with continued higher load growth rates. While not discounting these various forecasts, the PJM version seems more conservative and consistent with this Commission's obligations to preserve reliability in the State.

This section of the report details the energy sales forecasts provided by PJM for each transmission zone serving Maryland, and provided by each company serving each service territory in Maryland. The PJM zones in Maryland that are being tracked in this study are Baltimore Gas and Electric Company, Potomac Electric Power Company, Delmarva Power and Light Company, and The Potomac Edison Company d/b/a Allegheny Power. Pepco, DPL and AP company data are a subset of the PJM zonal data, since PJM's zonal forecasts are not limited to Maryland, but include other jurisdictions served by the respective utility.[3]

After the review of PJM data is completed, a forecast is generated for BGE, Pepco, DPL and AP based on each company's forecast for its Maryland service territory in 2007. The respective

[2] Jan. 2008 PJM Load Forecast, http://www.pjm.com/planning/res-adequacy/downloads/2008-load-report.pdf.
[3] BGE serves only Maryland customers.

2007 values provided by the companies are projected out for fifteen years by applying the respective PJM fifteen-year annual growth rates. Even though this method used the same values for the start year (2007), this method resulted in projections for the companies' Maryland peak demand and energy sales that are lower than those projected by each company for its own Maryland service territory.

Table II.1: Maryland Electricity Load Forecasts

Year	PPRP Forecast (GWh)	PJM Forecast (GWh)	Utility Forecast (GWh)
2007	69,397	69,397	69,397
2008	69,800	70,112	70,661
2009	70,203	70,835	71,948
2010	70,606	71,566	73,258
2011	71,009	72,303	74,592
2012	71,411	73,049	75,950
2013	71,814	73,802	77,333
2014	72,217	74,563	78,742
2015	72,620	75,332	80,176

III. GENERATION AND SUPPLY ADEQUACY IN MARYLAND

Pursuant to the Maryland Electric Choice and Competition Act of 1999, the Commission must maintain electric system reliability in the State. The Commission recognizes that in order to maintain electric system reliability and an adequate supply of electricity for customers in the future, there must be adequate electric generating capacity to meet customer demand.

A critical requirement for reliable electric service is an appropriate level of capacity to meet Maryland consumers' energy needs. While those needs may be met with transmission imports and demand side management, there is a certain level of in-state generation that is essential to keeping the lights on and the power grid operating effectively and economically. As of December 2006, Maryland's net summer generating capacity was approximately 12,500 MW. This compares to a peak load requirement of approximately 16,100 MW of demand plus 1,400 MW of reserve margin for a total requirement of 17,500 MW. To satisfy this demand, approximately 5,000 MW of capacity had to be imported from outside the State to meet Maryland's peak loads. Similarly, with respect to energy needs, Maryland retail sales were approximately 63,173 GWh.[4] The total energy need including transmission and distribution line losses was 68,227 GWh. Since approximately 48,957 GWh was actually generated in Maryland, the remaining 19,270 GWh had to be imported from neighboring states.

Maryland continues to be a net importer of energy, importing nearly 30% of its needs in 2006. On an absolute basis, Maryland is now the fourth largest electric energy importer in the United States. Only California, Virginia and New Jersey exceed Maryland's use of imported energy. Nearby, the District of Columbia and Delaware are also large importers, ranking 6th and 12th respectively, out of the top importing states.[5] Given this situation, it becomes readily apparent that much of the East Coast is dependent on generation from the west, particularly in Pennsylvania, West Virginia and Kentucky, which are the predominant energy exporting states.

A. Current Maryland Generation Profile and At-Risk Generation Units

Maryland generators are capable of producing 12,520 MW of summer capacity. Constellation Energy Group owns the largest amount of Maryland summer capacity with 42.8%. Mirant also owns a large portion of Maryland summer capacity: 38.1%. No other company owns more than 5.0% of Maryland capacity. Only four counties contain more than 10.0% of Maryland's summer capacity: Anne Arundel 18.3%; Calvert 13.9%; Charles 11.9%; and Prince Georges 21.6%. Table III.A.1 lists Maryland generating units by owner, county, and capacity.

There has been little change to the amount (in MW) and fuel-mix of generation in Maryland during the last decade. No significant generation has been constructed in Maryland within the past few years, and no units have retired since the Gould Street plant (101 MW) was deactivated. The Gould Street plant was located in the BGE zone and ceased operations in November 2003. While no generating facilities in Maryland are planning to retire, several generating units near Maryland, and in PJM, are requesting to be deactivated within the next five years.

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[4] See Tables IX.E.1 and IX.E.2 in Section IX.

[5] Source: Energy Information Administration website.

Table III.A.1: Generation by Owner, County, and Capacity

		Capacity Statistics (MWs)		
Owner Name/Plant Name	**County**	**Nameplate**	**Summer**	**Pct.**
A & N Electric Coop/Smith Island	Somerset	1.7	1.6	0.01%
AES Warrior Run Inc/AES/Warrior Run Cogen F	Allegheny	229.0	180.0	1.44%
Allegheny Energy Supply Co LLC/R. Paul Smith	Washington	109.5	115.0	0.92%
Alternative Energy Associates/Brighton Dam	Montgomery	0.5	0.5	0.00%
Berlin MD (Town of)/Berlin	Worcester	7.2	7.0	0.06%
Brookfield Asset Management Inc/Deep Creek	Garrett	20.0	18.0	0.14%
ConEd Inc./Rock Springs Generating Facility	Cecil	397.8	299.0	2.39%
CEG/Calvert Cliffs Nuclear Power Plant	Calvert	1,960.7	1,735.0	42.75%
CEG/Brandon Shores	Anne Arundel	1,370.0	1,289.0	
CEG/C P Crane	Baltimore	415.8	399.0	
CEG/Herbert A Wagner	Anne Arundel	1,058.5	1,007.0	
CEG/Notch Cliff	Baltimore	144.0	128.0	
CEG/Perryman	Harford	404.4	360.0	
CEG/Philadelphia Road	Baltimore City	82.8	64.0	
CEG/Riverside (MD)	Baltimore	257.2	249.0	
CEG/Westport	Baltimore City	121.5	121.0	
Easton Utilities/Easton; Easton 2	Talbot	72.4	68.9	0.55%
Exelon Corp./Conowingo	Harford	510.4	548.0	4.38%
First Reserve Corp/Newland Park Landfill	Wicomico	4.0	4.0	0.03%
Florida Crystals Corp./Domino Sugar Baltimore	Baltimore City	17.5	17.5	0.14%
MD Dept of Pub Safety & Corr Svc/Eastern Corr Inst	Somerset	5.8	3.8	0.03%
MeadWestvaco Corp (The)/Luke Mill	Allegany	65.0	65.0	0.52%
Mirant Corp/Chalk Point	Prince Georges	2,647.0	2,428.0	38.12%
Mirant Corp./Dickerson	Montgomery	930.0	853.0	
Mirant Corp/Morgantown Generating Station	Charles	1,548.0	1,492.0	
Mittal Steel Co. N V/Sparrows Point	Baltimore	120.0	152.0	1.21%
Northeast MD Waste Disp Auth/Montgomery Co.	Montgomery	67.8	54.0	0.43%
NRG Energy Inc./Vienna	Dorchester	183.0	170.0	1.36%
ODEC/Rock Springs Generating Facility	Cecil	374.8	312.9	2.50%
Panda Energy Intl Inc/Panda Brandywine LP	Prince Georges	288.8	248.4	1.98%
Pepco Holdings Inc/Crisfield	Somerset	11.6	10.0	0.10%
Pepco Holding Inc/Eastern Sanitary Landfill	Baltimore	3.0	3.0	
Prince Georges County/Brown Station Road I and II	Prince Georges	6.7	6.1	0.05%
TriGen Cinergy Sol. Balto/Inner Harbor East Heat	Baltimore City	2.1	2.1	0.08%
Millennium Hawkins Point	Baltimore	10.5	7.1	
Trigen Cinergy Sol. College Park/UMCP CHP Plant	Prince Georges	27.4	27.4	0.22%
Trigen Cinergy Sol. Sweetheart Cup/Owings Mills	Baltimore	11.2	11.2	0.09%
Waste Energy Partners LP/Waste Energy Partners LP	Harford	1.2	1.1	0.01%
Waste Management/Wheelabrator Baltimore Refuse	Baltimore City	64.5	61.3	0.49%
		13,553.3	**12,519.9**	**100.00%**

Most electric generating capacity in Maryland is produced from coal plants, which represent about 40% of summer peak capacity. However, the only units built within the last thirty-five years were the two Brandon Shores plants (646 and 643 MW, 1984 and 1991) and the AES Warrior Run plant (180 MW, 1999). The other major coal facilities in Maryland include Morgantown (1,244 MW); Chalk Point (683 MW); Dickerson (546 MW); H.A. Wagner (459

MW); and C.P. Crane (385 MW). About 24% of all capacity burns oil either as the primary or the sole fuel source, and the majority of these facilities are aging. Overall, only 22% of the State's summer generating capacity has been constructed in the past twenty years.

Table III.A.2: Maryland Generating Capacity Profile (as of January 1, 2006)

	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	4,966	39.6%	3.6%	12.9%	13.6%	69.8%
Dual-fired*	3,138	25.1%	6.3%	32.3%	19.5%	41.9%
Nuclear	1,735	13.9%	0.0%	0.0%	0.0%	100.0%
Gas	1,113	8.9%	56.8%	0.0%	0.2%	43.0%
Petroleum	879	7.0%	1.4%	2.7%	1.4%	94.4%
Hydroelectric	567	4.5%	0.0%	0.0%	0.1%	99.9%
Other Renewables	122	1.0%	6.8%	44.2%	49.0%	0.0%
TOTAL	**12,520**	**100.0%**	**8.2%**	**13.9%**	**10.9%**	**67.0%**

*Dual-fired plants primary fuel types: 65.57% Oil; 34.43% Gas.

The Maryland generating profile differs considerably from its capacity profile. In 2006, Maryland plants produced 48,956,880 MWh of electricity, generated 60.1% by coal and 28.3% by nuclear plants. Thus, Maryland coal and nuclear facilities generate 88.4% of all electricity, although they represent only 53.5% of capacity. In contrast, oil and gas facilities generate 5.5% of all electricity, despite representing 41.0% of in-State capacity. The State remains a net importer of electricity. In 2006, Maryland retail sales were 68,226,994 MWh (including an 8% T&D loss factor), meaning that 19,270,114 MWh (28.2%) of electricity were imported from neighboring states over the transmission grid.

Many older generating units within PJM can no longer compete with newer, more efficient plants. In 2007, the Martins Creek (New Jersey) facility was deactivated, representing a PJM capacity loss of 285 MW. The Buzzard Point (D.C.) plant deactivated one unit in 2007 and plans to gradually deactivate the remaining units through 2012. The Buzzard Point plant retirement will reduce total PJM capacity by 256 MW. During 2010 and 2011, a portion of the Indian River (Delaware) plant—representing 179 MW—is expected to be deactivated. Benning (D.C.) plant generating capacity of 550 MW is projected to retire in 2012. The total capacity loss for the four facilities mentioned equals 1,270 MW.

Electricity generated in Maryland comes primarily from solid fuels, coal and nuclear, a condition that has changed little over the last eight years. In 1999, coal supplied 57.4% of the electricity generated in the State, while nuclear provided 25.8%. In 2006, the most recent year for which complete information is available, coal generated 60.1% of the electricity generated in the state while nuclear provided 28.3%. Natural gas, petroleum, hydroelectricity, other gases, and other renewable sources combined for 11.1% of all in-State generation during 2006. Table III.A.3 summarizes Maryland's in-State fuel-mix in MWh by generating sources for the years 1999, 2004, and 2006.

Table III.A.3: Maryland Electric Power Generation Profile

	1999		2004		2006	
Source	**MWh**	**%Share**	**MWh**	**%Share**	**MWh**	**%Share**
Coal	29,687,655	57.44%	29,215,529	56.13%	29,404,947	60.06%
Petroleum	4,290,788	8.30%	3,295,913	6.33%	581,732	1.19%
Natural Gas	2,125,193	4.11%	1,183,005	2.27%	1,768,346	3.61%
Other Gases	59,891	0.12%	412,690	0.79%	333,298	0.68%
Nuclear	13,312,335	25.76%	14,580,260	28.01%	13,830,411	28.25%
Hydroelectric	1,424,197	2.76%	2,507,521	4.82%	2,104,275	4.30%
Oth Renewables	785,562	1.52%	569,265	1.09%	629,242	1.29%
Other	0	0.00%	288,586	0.55%	304,628	0.62%
Total	**51,685,621**	**100%**	**52,052,770**	**100%**	**48,956,880**	**100%**

In seven years, Maryland electricity imports have increased 58.9% from 12,127,502 MWh in 1999 to 19,270,114 MWh in 2006. Imports in 2006 represent almost 30% of all electricity consumed in Maryland. The large increase in imported electricity is not surprising: Consumption increased 6.9% from 1999 to 2006, while generation decreased 5.3% during the same period. The 6.9% consumption increase over the past seven years translates to a Maryland annualized compound growth rate of 1.0%.

B. Potential Generation Additions in Maryland in the PJM Queues

During the last five years, the Commission has granted several CPCNs for generating projects in Maryland. When and if constructed, the electricity generated by these projects will be available for Maryland and the PJM region. On the next page, Table III.B.1 identifies all proposed generating projects for which the Commission has recently granted or received an application to grant a CPCN.

Late in 2007, the Commission received four CPCN applications totaling nearly 2,300 MW in new generation and another 186 MW of reactivated generation. All of these CPCNs (Case Nos. 9124, 9127, 9129, and 9132) have expedited procedural schedules such that the Commission may reach a decision during 2008. These projects are described in more detail below:

- A CPCN application has been received from UniStar, a division of Constellation Energy, and docketed as Case No. 9127. It will generate approximately 1,710 MWs from nuclear energy at the existing Calvert Cliffs Nuclear site and provide approximately 1,600 MWs of base load generation to the grid. It is scheduled for commercial operation in 2016. Feasibility and Impact studies have been completed as project #Q48 in the PJM queues. These studies require many network upgrades in the BGE and Pepco service territories. However, the proposed 500 kV MAPP transmission project extends both to the east and to the west through the Calvert Cliffs substation. This project will greatly assist in making the power available to the grid and will reduce the number of upgrades required by the studies.

- Constellation has also decided to re-activate the Gould Street generating station which was retired in 2003 due to equipment failure. The gas fired generator will be rebuilt to provide 101 MWs of capacity to the grid. The CPCN application has been docketed as Case No. 9124. It is listed in the PJM queues as project #S67.

- Competitive Power Ventures announced plans for a 600 MW gas-fired plant in Charles County on July 24, 2007. A CPCN application was received by the Commission on December 14, 2007 and docketed as Case No. 9129. It is listed in the PJM queues as project #R17 Morgantown-Oak Grove 230 kV. A CPCN was previously granted to Free State Electric, LLC for a project on this site known as Kelson Ridge in 2001 (See Case No. 8843). The project was originally permitted for 1,200 MW, but the CPCN was subsequently relinquished on December 6, 2002, and the plant was not constructed.

- Constellation has also filed with the Commission on December 27, 2007, a CPCN application to reactivate Unit 5 of the existing Riverside Generating Station to operate exclusively as a natural gas-fired unit. The unit will offer up to 85 MW for sale to the PJM grid. The current generating capacity of the plant is 261 MW and first went into operation in 1951. Unit 5 was taken out of service in 1993. The new project has been listed by PJM as project #S33. The feasibility study calls for a long list of network upgrades for a 300 MW injection with optional delivery points – one for 115 kV and one for 230 kV. The PJM Impact Study will probably limit the scope of this project and require fewer upgrades.

Table III.B.1: New Generating Resources Planned for Construction in Maryland

Resource Developer And Location	Capacity & Fuel	Expected In-Service Date	To be Interconnected w/PJM?	CPCN Status
Clipper Windpower, Inc., Garrett Co.	101 MW Wind	4th Qtr. 2006 (Suspended)	Yes	Granted 3/26/2003
Savage Mountain US Wind Force LLC, Allegany and Garrett Cos.	40 MW Wind	4th Qtr. 2007	Yes, PJM ISA Issued	Granted 3/20/2003
Sempra Energy, Catoctin Power LLC / EastAlco, Frederick Co.	640 MW Gas	2009 (Suspended)	Yes	Granted 4/25/2005
Synergics Wind Energy, Roth Rock Windpower Project, Garrett Co.	40 MW Wind	2008 (Suspended)	Yes	H.E. Order 10/31/2006
Gould Street, Constellation Energy, Baltimore City (reactivation)	101 MW Gas	2nd Qtr. 2008	Yes	CN 9124 In Progress
UniStar (Constellation Energy), Calvert Co.	1,640 MW Nuclear	4th Qtr. 2015	Yes	CN 9127 In Progress
Competitive Power Ventures, Charles Co.	645 MW Gas	4th Qtr. 2010	Yes	CN 9129 In Progress
Riverside, Constellation Energy, Baltimore Co. (reactivation)	85 MW Gas	2nd Qtr. 2010	Yes	CN 9132 In Progress

Additional projects are listed for Maryland in the PJM queues in various stages of the study process. This includes some projects powered by wind, natural gas, and landfill gas. Some projects below 70 MWs do not require CPCNs. Other projects less than 20 MWs represent additions to existing plants or commitment of behind the meter generation to sell power to the grid. PJM is re-evaluating the generator interconnection process for three reasons:

- The large number of last minute requests throughout the PJM territory;
- The high attrition rate (75%); and,
- Developers asking that analysis be performed for too many options.

A fundamental obligation of the PJM planning process is the examination of the generation interconnection requests. The generation queues are open for each sequential six-month period during which time a generation company may submit proposals. The process for a generator to make its way through the generation queue is one that involves several steps. These steps include the Interconnection Request, the Feasibility, Impact and Facilities Studies, the Interconnection Service Agreement/Construction Service Agreement Execution, and the ISA/CSA Implementation. PJM Manual 14A[6] outlines the Generation and Transmission Interconnection Process. Within each queue, specific rights are based upon queue position and the satisfaction of milestone requirements. Required transmission upgrades are also based on reliability criteria.

The Interconnection Planning Process is initiated by the developer that contacts PJM via the hotline or PJM's website[7]. A PJM Generation Interconnection Request is required of a party that wishes to connect a new electricity generation resource to the PJM System. This is specified in the PJM Open Access Transmission Tariff.

The Generation Interconnection Feasibility Study gauges new generation that is seeking to connect with the PJM system and examines the potential reliability impacts. The study defines the projected resources and time needed to complete work associated with any identified system upgrade projects. This stage can take as long as eight months.

The transmission provider performs the System Impact Study biannually. This stage can take as long as five months after the issuance of the results of the first stage's Generation Interconnection Feasibility Study. An evaluation of the reliability impacts of new generation that will be interconnected as a capacity resource with PJM is provided in this study. Results of the study include cost estimates, project descriptions, and cost allocation for network upgrade work.

The Generation Interconnection Facilities Study provides comprehensive details associated with the requirements for interconnecting the PJM system with a new generation project. Included in this report are any revisions to the System Impact Study Report, cost estimates for work, descriptions of the given facility's design, and a general description of the new generation interconnection project.

The Interconnection Service Agreement follows the Generation Interconnection Facilities Study and establishes the responsibilities and rights of the generation or transmission developer. The Construction Service Agreement establishes the Standard Terms and Conditions that interconnected generators or transmission projects must abide by through the construction

[6] http://www.pjm.com/contributions/pjm-manuals/pdf/m14a.pdf.
[7] http://www.pjm.com.

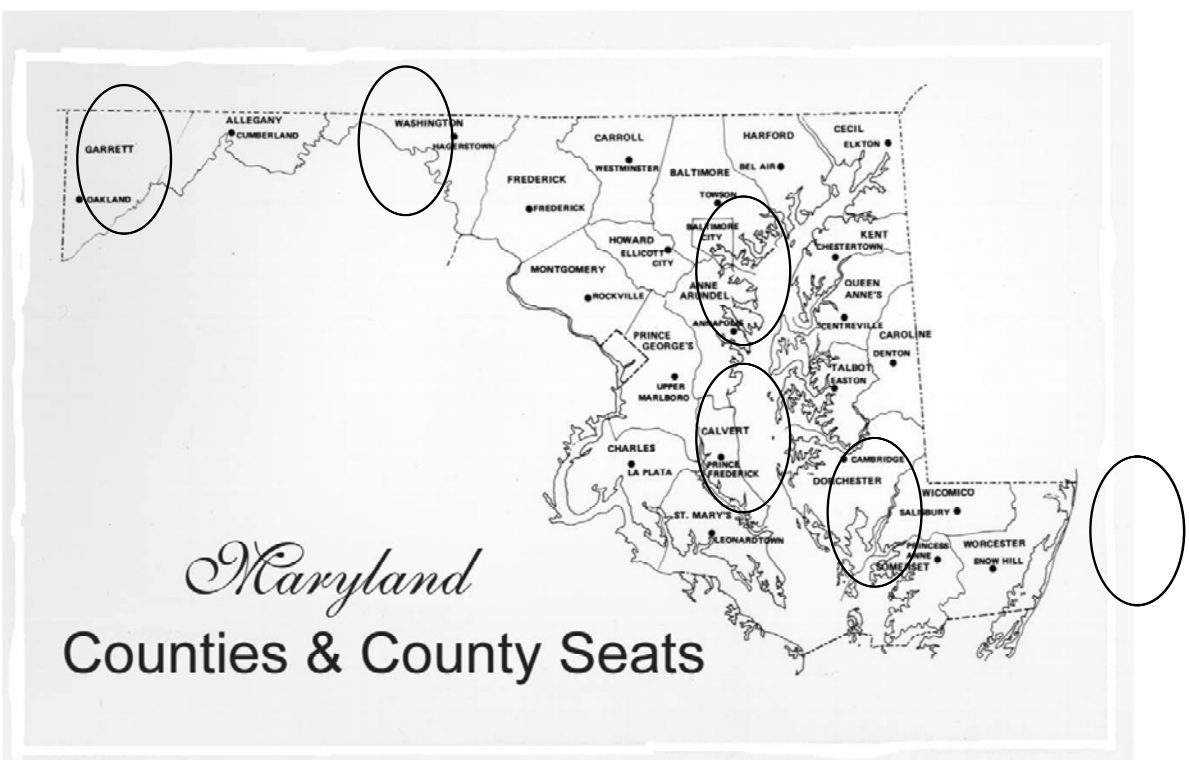
process. The ISA and CSA are executed and implemented through the queue process. Projects may drop out of the queue at any time, and completion of the aforementioned steps may result in commercial operation of the proposed facility.

Items in the active generation queue can be found in the planning section of the PJM website.[8] Typically, about 25% of the energy listed in the PJM generation queues will actually begin commercial operations. Carrying that figure forward, about 7,010 MW are currently in the PJM queue suggesting that about 1,750 MW will actually begin commercial operations.

C. Potential Generation Locations

Siting for Maryland generation continues to be an important concern. There are reliability, environmental, and competitive issues that must be resolved coincidentally with finding an appropriate location for a new generator. With generation deregulated and currently the responsibility of independent marketers and affiliates, the siting has been mostly 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 financial assurances that were typically available via regulated generation, it has become increasingly difficult for all but the major generation companies to option potential new sites and secure the permits necessary to build new generation.

Map III.C.1: Maryland Potential Generation Sites



Map Base Source: http://www.msa.md.gov/msa/mdmanual/36loc/html/02maps/seatb.html

[8] https://www.pjm.com/planning/project-queues/queue-gen-active.jsp.

As environmental and public sentiment continue to oppose new power plants, it will be critical to identify and site generation technologies that are compatible with environmental need and provide the energy necessary for Maryland consumers. In some respects, this energy need can be partially met with distributed generation that includes renewable generation and combined heat and power installations. Co-locating smaller generation facilities with other industrial process facilities provides an easier approach than 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 developed, compatible with site specific needs. Map III.C.1 above identifies general state areas that may be considered for new generation. Areas on the Eastern Shore include the off-shore Atlantic for wind projects, the Nanticoke river area around Vienna on the Lower Eastern Shore, the Calvert Cliffs area in Southern Maryland, various brownfield sites in the mid-Maryland area, and mountainous wind sites in Western Maryland.

D. Maryland's Healthy Air Act and Generation Upgrades

Pursuant to the Healthy Air Act of 2006, Constellation and Mirant investigated methods for emissions control at their Maryland coal-fired plants. Maryland's total generating capacity within the State is nearly 12,500 MW, and coal fired generation currently provides almost 60% of the power. Maryland's larger coal-fired generating units are being retrofitted with wet scrubbers for the control of sulfur dioxide and selective catalytic reduction systems for the control of nitrogen oxides. However, Constellation has determined that this was not cost-effective for the Crane and Wagner plants, so only the Brandon Shores units will have both of these controls. Constellation plans to use low-sulfur coal with reagents and sorbents for the reduction of emissions of mercury and SO_2 at both the Crane and Wagner plants. Constellation subsequently obtained permission from the Commission to conduct test burns to evaluate emissions and performance of the plants with the use of various combinations of coals, sorbents and reagents. Some plants have sought CPCNs for modifications such as barge unloading facilities to accommodate the delivery and processing of limestone and different types of coal (Morgantown, Crane, and Wagner). The evaluations will assist Constellation and the State agencies in their determination of the efficacy of the process and whether or not more testing needs to be done. A summary of plant modifications for compliance with the HAA follows.

Commercial tests have been conducted with several chemical sorbent injection systems: Chem-Mod^{TM}, Trona (Sodium Sesquicarbonate), Sodium Bicarbonate, Min Plus, and various forms of carbon. Constellation has decided to perform on-site testing with Chem-Mod^{TM}. This sorbent technology will be used in combination with various blends of bituminous and sub-bituminous coals. Various coals have different ash content, moisture content, and heating value. This can change the emissions profile and electrical output of the plant. The testing authorized by this application will provide results which Constellation can use to assess and optimize the performance of the plant.

Chem-Mod^{TM} is a dual action system: first the coal is pretreated with a liquid called MerSorb at the coal feeder for Hg control. The second chemical (S-Sorb) is injected as a dry powder into the boiler within a specific temperature window in order to reduce SO_2 emissions and complete the capture of Hg emissions. Constellation expects to reduce SO_2 emissions at Crane from current levels of 2.8-3.4 lbs/mmBTU to 0.8-1.0 lbs/mmBTU. Certified continuous emissions monitoring systems capture NOx, opacity, CO_2, SO_2, and flue gas flow data continuously and allow for subsequent report generation and analysis.

Table III.D.1: Emission Related Upgrades for Coal-fired Plants

Power Plant/ Owner	**Relevant Case Numbers**	**Generating Capacity**	**Existing Emissions Controls**	**Retrofits for Healthy Air Act Compliance**
Dickerson/ Mirant	CN9087	853 MW total, 3 coal units total 546 MW	Low NOx burners with OFA, ESP, fabric filters	FGD
Chalk Point/ Mirant	CN9079 CN9086	2,400 MW total, 2 coal units total 700 MW	Low NOx burners with OFA, ESP, SACR (unit 2)	FGD, SCR ($78M), sorbent (unit 1) ($1.8M)
Morgantown/ Mirant	CN9031 CN9085	1,250 MW	Low NOx burners with OFA, ESP, SCR	Delivery of coal by barge, FGD, sorbent
Brandon Shores/ Constellation	CN9075	1,370 MW	Low sulfur coal, ESP, SCR	FGD (>$500M), sorbent for Hg & SAM, fabric filter
Crane/ Constellation	CN9048	Unit 1: 190 MW Unit 2: 209 MW	Fabric filter for particulates at both units	Delivery of coal by barge, low sulfur coal, sorbents and reagents
Wagner/ Constellation	CN9083	Unit 2: 136 MW Unit 3: 359 MW	ESP, SCR (unit 3)	Low sulfur coal, sorbents and reagents (<$10M)

Constellation is expected to continue experimenting with alternate fuels and process alterations until January 1, 2009, at Crane and Wagner in order to ensure a reliable generating process that complies with the HAA. Both Mirant and Constellation are considering use of biodiesel at their oil-fired generation plants. Large quantities of sorbents and reagents may be required to reduce emissions to acceptable limits at the coal plants. Based on preliminary studies, between four and twenty tons of sorbent per hour per unit may be required. This material will be captured in the downstream particulate control equipment as fly ash. The additional accumulations of fly ash will require disposal and will be a factor in evaluating the cost of the pollution controls. The Chem-Mod™ technology warrants further study by Constellation because it uses the least amount of sorbent by mass and volume. Testing of alternate reagents and sorbents will enable Constellation to determine a cost-effective way to comply with the Healthy Air Act.

Constellation and Mirant have filed with the Commission the CPCNs necessary to implement the retrofits needed for Healthy Air Act compliance. The table below lists the relevant case numbers for each coal plant and summarizes the generating capacity, existing emissions controls, and the retrofits proposed for HAA compliance. Existing emissions controls at some of the plants include electrostatic precipitator, flue gas desulfurization systems, low NOx burners with overfire air, and selective auto-catalytic reduction.

E. CPCN Exemptions for Generation

Pursuant to PUC Article §7-207.1, the Commission can exempt certain power generation projects from the Certificate of Public Convenience and Necessity process. PUC Article §7-207.1 became effective October 1, 2001, and was modified effective October 1, 2005. More recently, a wind-generating station category was added to the section—effective July 1, 2007. Three categories of generators qualify for a CPCN exemption:

<u>On-Site Generators:</u>
- A generating station designed to provide on-site[9] generated electricity;
- The capacity of the generating station does not exceed 70 MW; and,
- 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 interconnection, operation, and maintenance agreement with the local electric company.

<u>Wind Generators:</u>
- A generating station that produces electricity from wind;
- The generating station is land-based;
- The capacity of the generating station does not exceed 70 MW;
- 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 interconnection, operation, and maintenance agreement with the local electric company; and,
- The Commission provides an opportunity for public comment at a public hearing.

<u>Other Generators:</u>
- A generating station whose capacity does not exceed 25 MW;
- 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 interconnection, operation, and maintenance agreement with the local electric company; and,
- At least 10% of the electricity generated at the generating station each year is consumed on-site.

The Commission's CPCN exemption application requires the applicant to select a specific type of generating station from the three types that are offered. A Type I generator will not be synchronized with the local electric company's[10] transmission and distribution system; will not export electricity to the electric system, and will not connect to the electric system when electricity supply is available. An emergency, or back-up, generator is the most common Type I

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9 PUC §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.

10 PUC §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.

generator. A Type II generator will be synchronized with the electric system and 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 will be synchronized with the electric system and will export electricity. Few applications for Type III generators have been filed with the Commission. Wind generators – and other more common fuel-based generators – may qualify as a Type III generator.

Table III.E.1: CPCN Exemptions Granted, Since October 2001

Period Approved	Applications	No. of Units	Total MWs
Calendar Year 2002	22	34	30.8
Calendar Year 2003	28	51	77.9
Calendar Year 2004	40	56	52.5
Calendar Year 2005	39	69	124.4
Calendar Year 2006	33	47	57.0
Calendar Year 2007	42	59	66.2
Total	**204**	**316**	**408.8**

An applicant must submit a completed application and an interconnection, operating, and maintenance agreement entered into with the local electric distribution company. If the applicant will not export any electricity from the generating station, then the applicant must obtain a letter from the local EDC that states an interconnection, operating, and maintenance agreement is not necessary. It is important to note that exemption from a CPCN does not exempt an applicant from obtaining all other necessary state permits and regulations, such as those required by the Air and Radiation Management Administration at MDE.

IV. ENERGY TRANSMISSION IN PJM AND MARYLAND

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 extremely important that adequate transmission facilities be available to provide needed supplies. While all network systems can experience congestion at times, the Maryland and D.C. areas have continued to experience significantly higher levels of congestion than the rest of PJM. This, in turn, leads to higher energy and capacity costs for Maryland consumers and potential reliability concerns. This is a concern that needs to be monitored, managed, and supplemented with additional infrastructure to ensure adequate capacity and reliability with limited levels of congestion. As this plan is implemented, it is important for the Commission to take an active role in monitoring transmission systems, setting appropriate reliability and congestion goals, and expediting infrastructure improvements where needed.

A. 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 an RTO like 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 to meet system enhancement requirements for firm transmission service, load growth, interconnection requests and other system enhancement drivers. 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 for all proposed generation and transmission projects. Subsequent System Impact Studies for those projects provide recommendations that become part of the RTEP Report.

As a regional planning effort, the RTEPP determines the best way to integrate projects to provide for the operational, economic, and reliability requirements of the grid. The RTEPP applies reliability criteria over a fifteen-year horizon to identify transmission constraints and other reliability concerns. The Reliability Planning Process Working Group has continued this year with modifications to PJM documentation for compliance with FERC Order 890.

RTEP integrates many bulk power system factors including:

- Transmission owner-identified project proposals;
- Long-term firm transmission service requests;
- Generation interconnection requests;
- Generation retirements;
- Load-serving entity capacity plans;
- Transmission enhancements to alleviate persistent congestion;
- Distributed generation and self-generation developments;
- Demand response and energy efficiency; and,
- Proposed merchant transmission projects.

The RTEPP has recently undergone significant changes to address more comprehensively the reliability and transmission congestion issues associated with PJM's growing footprint. While previously the RTEPP concentrated on generation interconnections, its focus is now on ensuring reliability throughout the expanded footprint and ensuring essential transmission infrastructure is built to support system integration and more robust wholesale power markets.

The Transmission Expansion Advisory Committee is the primary forum for stakeholders to discuss the RTEPP results. It met three times in 2007: May 9, August 22, and December 19. The Commission is an active participant in the RTEPP and regularly attends the TEAC meetings.

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 firm loads, firm imports and exports to neighboring systems, existing generation and transmission assets, and anticipated new generation, generation retirements, and transmission assets. The baseline reliability assessment identifies areas where the planned system is not in compliance with applicable NERC and regional reliability councils' (Reliability*First*, SERC) standards, nuclear plant licensee requirements, and PJM reliability standards. The baseline assessment develops and recommends enhancement plans to achieve compliance.

Cost Allocation

The PJM RTEPP requires that cost responsibility for transmission enhancements be established. There are four categories of facility enhancements for which cost assignments are made:

1. Transmission Planning to Maintain System Reliability: Transmission system reinforcements needed to maintain national and regional reliability standards are built by transmission owners and paid for by customers in proportion to benefit. Transmission owners recover their costs through FERC-approved transmission service rates.

2. Transmission Planning for Generation Interconnection and Merchant Transmission Interconnection Projects: Generation and transmission project developers are responsible for costs associated with interconnecting their facilities to the grid. Interconnection of such facilities also may require the upgrading of additional system elements to maintain reliability. An appropriate proportion of those costs is borne by the project developer.

3. Transmission to Alleviate Persistent, Costly Congestion: Through spot market energy prices and the RTEPP, PJM market participants can identify the portions of the transmission grid prone to persistent congestion, the costs of which customers are not able to hedge through financial transmission rights. Market participants proposing solutions to resolve such constraints are responsible for direct interconnection costs and for an appropriate proportion of any network upgrade costs required to facilitate their interconnection. PJM through one of its working groups is reviewing existing transmission cost allocation methods to determine whether they should be changed.

Reviewing cost allocation tariffs is in part driven by transmission projects becoming larger, with the result that reliability and economic benefits are more regional in nature.

4. Transmission Planning to Coordinate with Neighboring Regions: PJM is engaged in planning processes that address issues of mutual concern to PJM and neighboring transmission grid systems. PJM participates in super-regional planning coordination processes with the Midwest ISO through the Joint Operating Agreement with ISO New England and the New York Independent System Operator through the Northeastern ISO/RTO Planning Coordination Protocol, and with the Tennessee Valley Authority through the Joint Coordination Agreement. 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-RTO basis, and enhance the physical and economic efficiencies of congestion management.

Obligation to Build RTEPP Projects

PJM's Transmission Owners' Agreement obligates transmission owners to build transmission projects that are needed to maintain reliability standards and that are approved by the PJM Board of Governors. Transmission owners can voluntarily build these projects or PJM can file with FERC to request FERC to order the project to be built. At the state level, CPCN permits are required for new rights-of-way or modifications to existing facilities.

PJM's Authority

FERC approved PJM as an Independent System Operator in 1997. Since that time, PJM has administered its RTEPP 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 RTEPP to include the development of transmission projects to support competition in wholesale electric markets (during 2003 and subsequently in November 2006), allowing them to justify projects for economic reasons as well as reliability.

With the addition of Allegheny Power in 2002, PJM received final approval as an RTO. PJM is the administrator of the Open Access Transmission Tariff 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.

Transmission Expansion Highlights for 2007

RTEP results are presented to the Transmission Advisory Committee. The Planning Committee then seeks approval from the Members Committee and PJM's Board of Directors. In 2007, PJM presented expansion plans to TEAC on three occasions. These presentations elaborated on changes to the baseline system as of December 31, 2006. This year's studies include the retirement of generation in Washington, DC: the Benning deactivation of 550 MW and the Buzzard deactivation of 256 MW. It also includes the addition of new nuclear generation at Calvert Cliffs, 1,640 MW estimated for 2016. Some projects are initiated by individual transmission owners for their service territory. Several large interstate lines have been approved by PJM this year. A full list of RTEP projects may be found in Appendix Table A-8.

B. Proposals for New High Voltage Transmission Lines in PJM

Demand for power on the East Coast has pushed the current grid configuration to its limits. This is evidenced by persistent congestion in central Maryland and northern Virginia. CETO/CETL analysis for 23 load deliverability areas has passed the deliverability test for 2011. However, PJM is predicting delivery problems in 2012. Consequently, several large interstate transmission projects have been proposed. They are in various stages of the approval and development process. Some projects are not physically located in Maryland; however, Maryland can be affected by these projects due to inter-regional dependence on the grid.

The Mid-Atlantic Power Pathway project is a major 500 kV loop from Virginia east across Southern Maryland and the Chesapeake Bay to Indian River and north through Delaware to New Jersey. This project postpones many future overloads along the way until 2022. It would also be expected to relieve congestion and satisfy load growth for EMAAC (Delmarva Peninsula, New Jersey, eastern Pennsylvania) and SWMAAC (BGE, Pepco). The large loop poses a possible stability risk for the grid which requires further study. The total cost is estimated at $1.05B with service date to be determined. The PJM Board has recently approved the MAPP project.

Merchant transmission project #O66 Neptune is an underwater HVDC line between Bergen (NJ) and 49th Street in ConEd (NYISO). It withdraws 670 MW of firm transmission from PJM and would require $450 million in PJM network upgrades.

The Trans-Allegheny Interstate Line is 210 miles of 500 kV (AP) and 30 miles of 500 kV (Dominion) at an estimated cost of $970M with a June 2011 in-service date. It goes from Prexy (near Pittsburgh, Pennsylvania) to Loudoun (northern Virginia). Public hearings have taken place in West Virginia and are scheduled for Virginia and Pennsylvania.

Potomac-Appalachian Transmission Highline has been officially announced as a joint venture between AEP and Allegheny. It is 250 miles of 765 kV between Amos (Charleston, WV) and Bedington (West Virginia near Washington Co., MD). It is 40 miles of twin-circuit 500 kV from Bedington to Kemptown (Frederick Co., MD). PATH was authorized by the PJM Board on June 22, 2007. It is estimated at $1.8B with a June 2012 in-service date.

C. Transmission Congestion in Maryland

In the 2006 *Ten-Year Plan*, the Commission identified that some progress had been made in reducing both the LMP and LMP differential with other states and regions in PJM, but that Maryland continued to experience significant transmission congestion and high LMPs. The average figures for the 2007 year-to-date[11] LMP figures are at, or slightly above, 2005 levels.

[11] The year-to-date LMP data for 2007 are from the dates spanning January 1, 2007 to October 31, 2007.

Chart IV.C.1: Average Locational Marginal Price by Zone

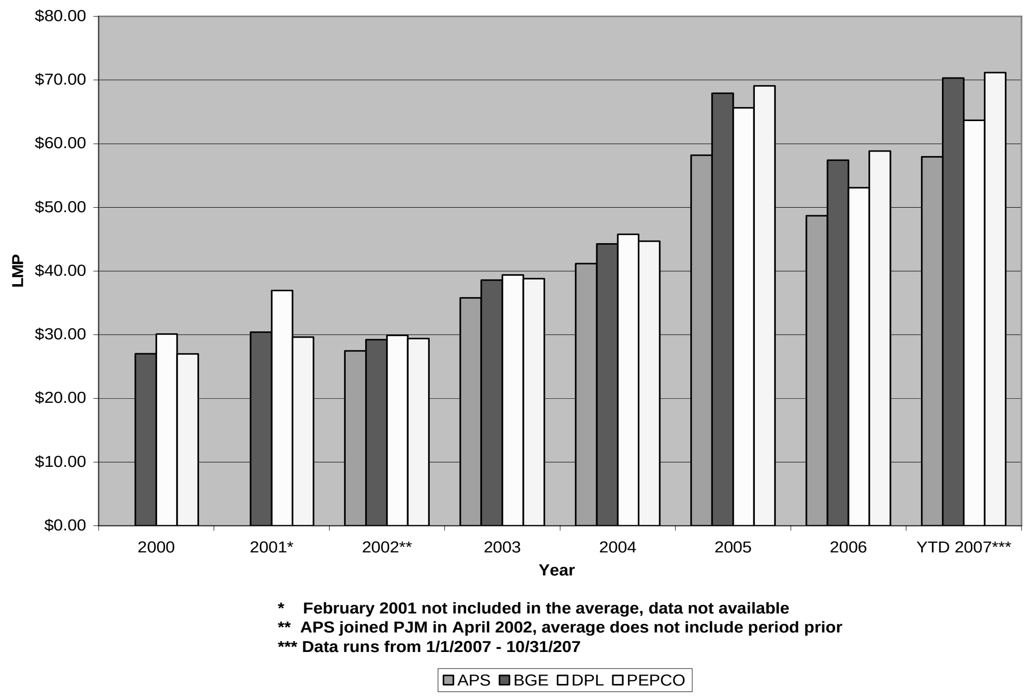


Chart IV.C.1 above shows the average LMP figures for the PJM zones that comprise electricity delivered to the State of Maryland. Western Maryland is served by Allegheny Power, Central Maryland consists of Baltimore Gas and Electric Company and Pepco, and Delmarva Power and Light serves the Eastern Shore. When viewing the column chart above, one can see that the annual average for LMPs found in Maryland had been rising steadily from 2002 to 2005. The data show a decrease for 2006 followed by an increase for 2007 year-to-date ending on October 31, 2007. Measures taken to improve transmission, coupled with the moderation of fuel prices, have served to reverse the increasing LMP trend in 2006. However, it appears the trend was upwards in 2007. From year 2005 to 2006 the LMPs for BGE and Pepco have decreased by 15.5% and 14.8%, respectively. DPL and AP have experienced the greatest decreases with declines of 19.1% and 16.3%. As a comparison from year 2005 to the year-to-date data for 2007, BGE and Pepco increased by 3.5% and 3.0%, respectively. During the 2005 to 2007 period, DPL decreased by 3.0% and AP decreased by 0.5%.

The two graphs located below show the average hourly LMP figures for the periods spanning June 1, 2007 through August 31, 2007 and June 1, 2006 through August 31, 2006, respectively. AP, BGE, DPL, and Pepco are all zones that provide service in Maryland. A comparison of the results between LMP values from the summers of 2006 and 2007 yield some interesting outcomes. While LMPs were generally higher for the Maryland zones during the day for 2006, the LMP figures for the Maryland zones were lower in 2007 during the peak hours of 3:00 PM to 5:00 PM. All of the Maryland zones, except for BGE, displayed lower average LMPs for the 2:00 PM hour in 2007 as compared to 2006. Both DPL and Pepco have a lower average LMP for the 6:00 PM hour in 2007 than in 2006. This could be indicative of better peak load management of the electricity grid; however, the aforementioned figures confirm that Maryland's problem of relatively high LMPs is not solved.

Chart IV.C.2: Average Hourly LMP (6/1/2007 – 8/31/2007)

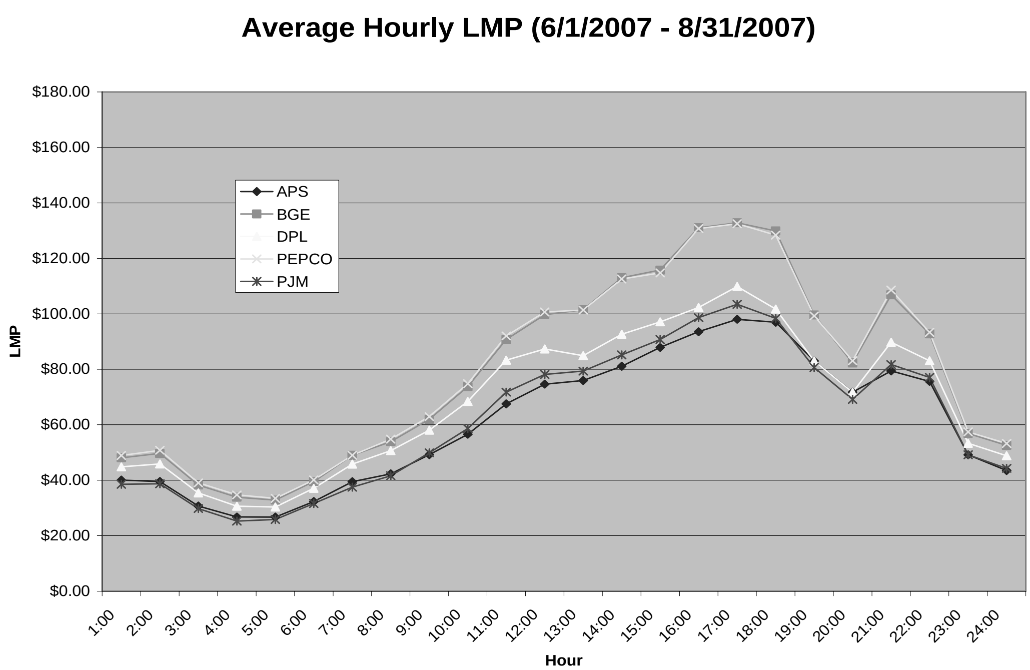
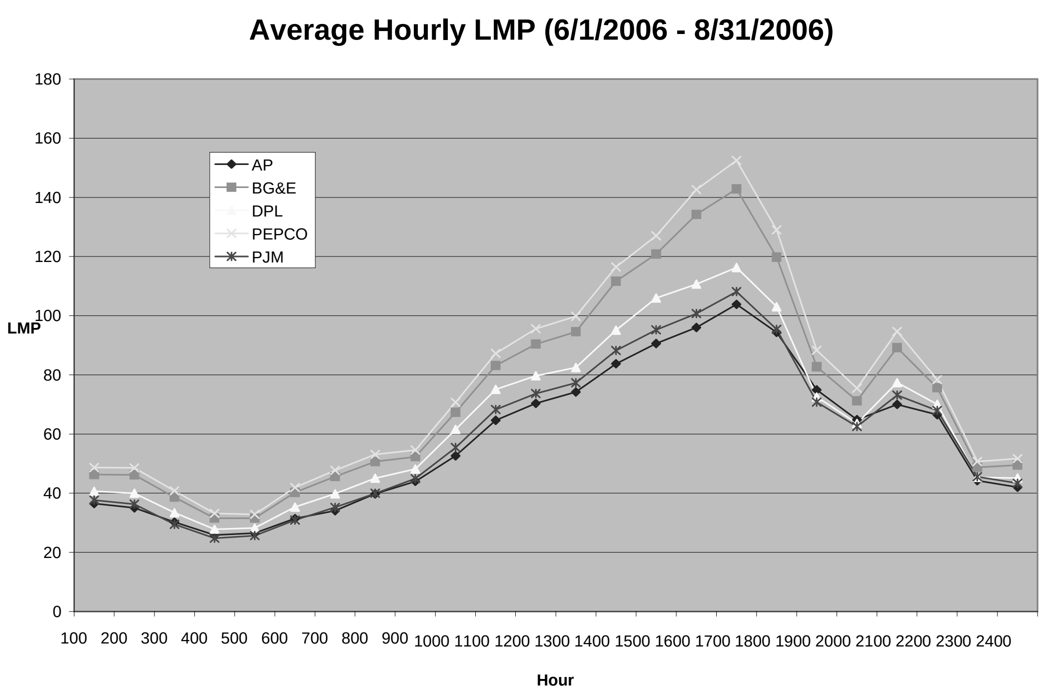


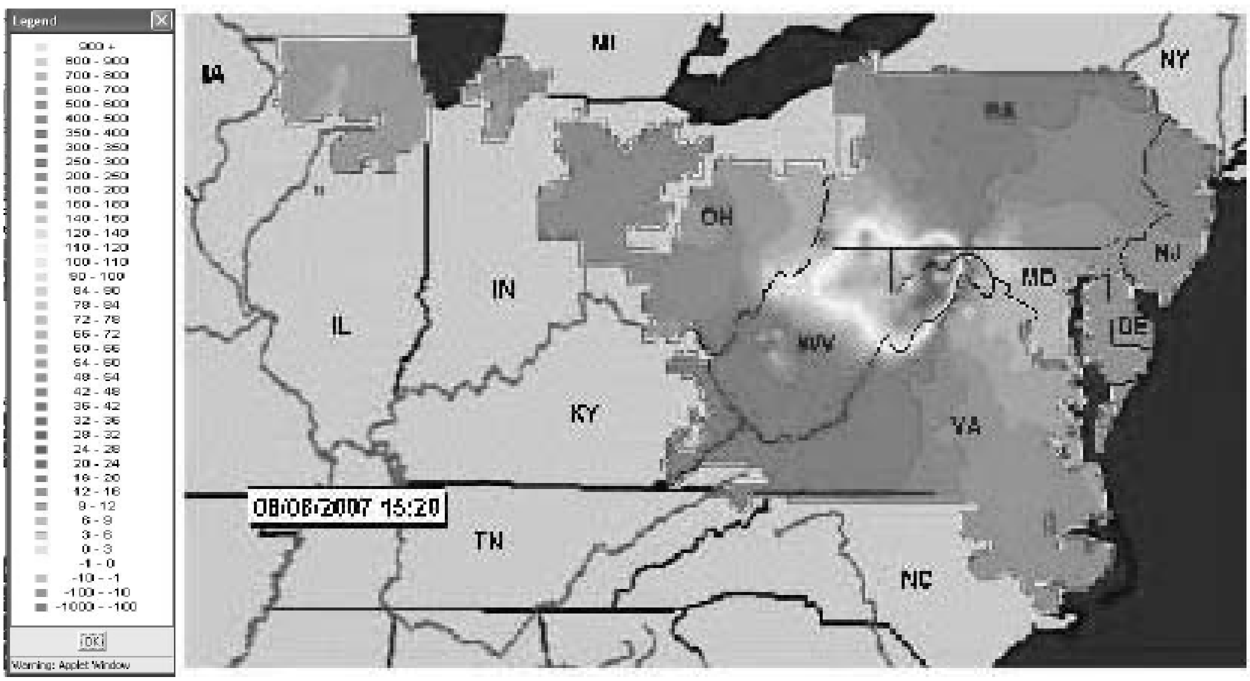
Chart IV.C.3: Average Hourly LMP (6/1/2006 – 8/31/2006)



The elevated LMP levels are indicative of the fact that the zones serving Central Maryland are forced to meet high load demands by using less cost-effective measures to provide electricity (e.g., using local higher cost generation sources instead of coal-by-wire). The higher LMPs caused by congestion premiums are found in the areas discussed in Section IV-B.

As stated in the DOE Transmission Congestion Study, Maryland is directly affected by congestion areas located on the Delmarva Peninsula and the Baltimore – Washington D.C. area. The Delmarva Peninsula has existed as a load pocket for a significant amount of time. The power prices have been higher and the reliability has been lower there than in adjoining areas. As it exists today, the Delmarva Peninsula is not densely populated. However, this area is experiencing a significant growth in population and load demand.

<u>Map IV.C.1: Summer Peak Congestion LMP Map (8/8/2007)</u>



The Baltimore – Washington D.C. area is in a situation where the congestion of the electricity transmission grid warrants attention. The United States DOE stated that without transmission upgrades, the reliability criteria established for critically important loads will not be met over the next 15 years.[12] Map IV.C.1, above, shows an LMP map taken from the PJM's eData site on August 8, 2007. One can see that the central portion of Maryland experienced significantly higher LMP prices than Western Maryland and the rest of PJM. This portion of Maryland is caught in the epicenter of the area with LMPs that were above $900 per MWh. Both the Department of Energy and PJM have concluded that in order to alleviate this recurring congestion problem, upgrades to the PJM transmission system need to be initiated and completed.

12 Source: U.S. Department of Energy, National Electric Transmission Congestion Study, August 2006.

D. FERC Order 890 and Maryland

On February 16, 2007, under Dockets RM05-17-000 and RM05-25-000, the Federal Energy Regulatory Commission issued Order No. 890. The Order required RTOs to clarify and expand upon the obligations of transmission providers to ensure that transmission service is provided on a non-discriminatory basis, in particular at both the local and regional level. FERC directed transmission providers to submit a compliance filing with a revised Attachment K to the Open Access Transmission Tariff by October 11, 2007. In a subsequent Order, FERC directed its Staff to hold a series of technical conferences at various locations, required the RTOs to post a draft of Attachment K by September 14, 2007, and delayed the compliance due date to December 7, 2007.[13]

In response to the Order, PJM initiated review activities within the Regional Planning Process Working Group and identified a list of actions required by FERC Order 890. Of the approximately 285 items identified by PJM, the major ones were as follows:[14]

- Changes to the Available Transfer Capacity calculations and posting of information to create more transparency in the process (Attachment C, OATT)

- PJM would file a revised RTEP process that incorporated nine FERC principles:

    1. PJM should meet with transmission and interconnected RTOs to develop transmission plans on a nondiscriminatory basis;
    2. Transmission planning meetings must be open to all affected parties including customers, state commissions, and other stakeholders;
    3. PJM must disclose all planning criteria, assumptions, and data that underlie plans and provide opportunity for demand resources to participate;
    4. PJM must develop guidelines and a schedule for the submittal of planning information;
    5. Customer demand resources should be considered on a comparable basis with generation resources, as appropriate;
    6. PJM shall have a dispute resolution process that addresses both substantive and procedural planning issues;
    7. The regional planning process must be open and inclusive of both reliability and economic considerations and coordinated with nearby RTOs;
    8. PJM must provide a mechanism by which stakeholders can request economic and reliability studies; and
    9. The planning process must address the allocation of costs of new facilities.

[13] Docket RM05-17-000 and RM05-25-000, FERC Order Extending Compliance Date and Establishing Technical Conferences, July 27, 2007.

[14] http://www.pjm.com/committees/mrc/downloads/20070705-order-890.xls.

- PJM would address pricing issues related to energy and generator imbalances, credits for customer owned facilities, posting of sales or assignments of capacity, and unreserved use penalties.

- Schedule modifications to open reactive supply and voltage control, regulation and frequency response, energy imbalance, spinning reserves, and imbalance services to demand response as appropriate.

The PJM RPPWG and other groups continued to work through the requirements of FERC Order 890 for most of 2007. As a result, PJM agreed to establish a sub-regional RTEP Committee to focus on the planning requirements of transmission expansion at voltages below 230 kV, to improve inter-regional coordination, to facilitate data sharing, and to provide opportunity for supplemental projects (those not necessarily needed for reliability or economic compliance).

PJM filed its response to FERC Order 890 on December 7, 2007, noting that it had complied with all nine principles. PJM would establish three sub-regional planning groups: the mid-Atlantic, western area, and southern area of PJM. These groups would provide additional opportunity for regional input to the planning process.[15]

FERC's direction in Order 890 and PJM's response clearly point out the importance of open, transparent, and non-discriminatory planning. It provides additional opportunity for states such as Maryland to actively participate in planning discussions and to encourage plans that address the economic and reliability concerns of Maryland energy consumers. More active participation in the PJM planning process is an absolute essential for this Commission.

[15] http://www.pjm.com/documents/ferc/documents/2007/20071207-oa08-xx-xxx.pdf.

V. ENERGY EFFICIENCY, CONSERVATION AND DEMAND RESPONSE

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, reduces congestion, and limits environmental impacts, while reducing overall energy costs. The Commission encourages energy service providers to offer DSM programs to customers where appropriate. Distribution companies have been tasked with providing cost-effective DSM programs, particularly for mass market residential and small commercial customers. The Commission's Interim Report notes that the PSC will, as part of a pending proceeding, require the utilities to implement aggressive and cost-effective demand management and energy conservation programs.[16]

A. Statutory Requirements

By statute each utility is required to develop and implement programs and services that encourage and promote the efficient use and conservation of energy by consumers and utilities alike. See PUC Article §7-211.

Under PUC Article § 7-510(c), energy efficiency and conservation were specifically provided for as part of standard offer service. PUC Article §7-510(c)(4)(ii)2C provides that the Commission shall

> …require or allow the procurement of cost-effective energy efficiency and conservation measures and services with projected and verifiable energy savings to offset anticipated demand to be served by standard offer service, and the imposition of other cost-effective demand side management programs.

The Commission was directed to investigate the implications of soliciting bids for cost-effective DSM by Chapter 5, Maryland Laws, 1st Special Session. Most recently, the General Assembly in Senate Bill 400 directed the Commission to consider establishing a long-term goal for savings for residential customers through the procurement and implementation of cost-effective energy efficiency conservation programs and services. The Commission is required to report its findings to the General Assembly regarding the implementation and success of these programs on or before December 31, 2008. Senate Bill 400 was specific that the required investigation and reporting was separate from and did not preclude action under PUC Article § 7-211.

<u>Demand Side Management</u>

Demand side management includes any activity that reduces the consumption of electricity by an end user. These activities may be conservation, energy efficiency, distributed generation, or demand response. Conservation and energy efficiency are the more traditional DSM programs; examples of energy efficiency include the use of high efficiency appliances and compact fluorescent bulbs. Energy efficiency has been defined as the amount of energy savings that

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[16] Interim Report of the Public Service Commission of Maryland to the Maryland General Assembly, Part I: Options for Re-Regulation and New Generation, December 3, 2007, page 2.

could be achieved if all customers installed the most efficient devices without considering long lag times or other practical constraints, such as cost.[17]

In determining whether a program or service encourages and promotes the efficient use and conservation of energy, PUC Article § 7-211 requires that the Commission consider, among other factors, the (1) impact on jobs, (2) impact on the environment, (3) impact on rates, and (4) cost-effectiveness.

Because there are issues pertaining to demand side management and advanced metering infrastructure that are common to Maryland's electric utilities, the Commission docketed Case No. 9111[18] establishing an AMI/DSM collaborative to consider the issues of AMI technical standards and operational capabilities for AMI, competitive neutrality issues related to DSM, cost recovery, and appropriate cost-effectiveness tests.

The Commission directed participation in the AMI/DSM Collaborative by Maryland's investor-owned electric companies, the State's two large electric cooperatives, and Commission Staff, and invited participation in the collaborative from OPC, other interested State agencies, electricity suppliers, providers of advanced metering and DSM equipment and services, environmental and public interest groups, and consumer organizations.

During the course of the AMI/DSM Collaborative, the Commission ordered all electric companies to develop and file comprehensive energy efficiency, conservation, and demand reduction programs. At the close of 2007, all IOUs had filed such plans. Additional plans are expected from the large cooperatives and the municipal electric companies in 2008. Revision and expansion of some plans filed may be accomplished based on the results of various pilot programs and continuing exploration of these matters by the electric companies.

By Order No. 81637, issued September 28, 2007, the Commission established standards for AMI programs, defined the appropriate methods of cost recovery for companies to follow, and assigned electric usage-savings goals to each electric company. The AMI Standards and targets are discussed elsewhere in this report. Cost recovery is dependent on the measurement of cost-effectiveness.

Cost-effectiveness is a measure of program costs in comparison with energy and demand savings. The measure is expressed as a ratio of the cost of the program relative to the savings realized.[19] Five screening tests are commonly used to evaluate the cost-effectiveness of DSM Programs. These tests include the Participant Test, the Utility/Program Administrator Test, the Rate Impact Measure Test (sometimes referred to as the "no losers" test), the Total Resource

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[17] See Timothy J. Brennan (1998), "Demand-Side Management Programs Under Retail Electric Competition," Discussion Paper No. 99-02, Resources for the Future, October 1998, p. 2.

[18] Re In the Matter of the Commission's Investigation of Advanced Metering Technical Standards, Demand Side Management Cost Effectiveness Tests, Demand Side Management Neutrality, and Recovery of Costs of Advanced Meters and Demand Side Management Programs.

[19] See the U.S. Department of Energy report "State and Regional Policies that Promote Energy Efficiency Programs Carried Out by Electric and Gas Utilities: A Report to the United States Congress Pursuant to Section 139 of the Energy Policy Act of 2005.

Cost Test (sometimes called the “All Ratepayers” test), and the Societal Test. These tests are described in the California Standard Practice Manual.[20]

In Case Nos. 8063, Phase II, and 8057, the Commission, relying on precedent, determined that as a matter of policy a utility’s initial screening test for assessing cost-effectiveness should be the All Ratepayers test.[21] Under the All Ratepayers test the direct costs of implementation must not exceed the marginal cost of supply. However, the AMI/DSM collaborative process recommended that the Commission adopt the Societal Test, which considers the direct cost of implementation plus the economic effects of externalities, such as emissions reductions, to be supplemented by the RIM Test, under which the sum of the direct costs of implementation and the utilities’ lost revenues must not exceed the marginal cost of supply. The RIM test measures the change in a customer’s bill resulting from changes in revenues and operating expenses attributable to program implementation. This requires an examination of the impact by class and, if applicable, by usage. According to the Collaborative this enables potential equity problems (for example the inter- or intra-customer class distribution of costs and benefits) to be highlighted. The Commission recognized the strengths of the various tests in Order No. 81637 and directed the electric companies to use the four tests in order to properly reflect the full range of benefits and costs for all DSM programs.

B. Current Utility Activities

As discussed above, Maryland’s four investor-owned electric companies filed energy efficiency and conservation plans during 2007. The plans consisted of “fast track” programs and, for three of the four IOUs, more comprehensive long-term programs. The “fast-track” programs are designed to take advantage of “low hanging fruit” on an expedited basis. The purpose of these programs is to provide residential customers with an opportunity to reduce electricity usage and electricity costs and to enjoy energy cost savings quickly and without significant capital expenditures.

BGE

BGE filed with the Commission an application seeking authority to implement three “fast-track” Energy Star conservation and energy efficiency programs as follows: (1) compact fluorescent light bulbs; (2) window air conditioner replacement; and (3) rebates for certain large appliances (such as clothes washers, freezers, and refrigerators).

After considering the matter at the June 20, 2007 Administrative Meeting, the Commission approved BGE’s “fast-track” conservation and energy efficiency programs and accepted the cost recovery surcharge associated with the programs. The Commission reserved the right to extend the cost recovery or otherwise revisit the cost recovery method and directed BGE to file monthly reports advising the Commission of the implementation progress, penetration rates, program expenditures, and other relevant matters. The efficiency surcharge, effective November 17, 2007, was set at $0.00067 per kWh through June 30, 2008.

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[20] See California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects, July 2002.

[21] *Re Potomac Electric Power Company*, 80 MD PSC at 544, 555 (1989).

As of December 23, 2007, BGE indicated that it has spent $2.5 million for the three "fast-track" programs. According to BGE, the three "fast-track" programs will achieve estimated annual bill savings of $4,491,084 and $40.7 million in life cycle bill savings. The 624,493 CFL bulbs sold through BGE's program will result in an estimated 32.7 million kWh saved annually. Life cycle savings for the fast-track programs, based on Energy Star assumptions, are expected to result in approximately 301.1 million kWh savings. The 503 Energy Star room air conditioners installed for low-income customers as of December 23, 2007 are anticipated to result in 109,714 kWh annual savings. Under BGE's third "fast track" program, 4,157 processed appliance rebates (1,837 clothes washers, 2,198 refrigerators, and 122 freezers) are expected to generate 474,000 kWh annual savings and 5.6 million kWh lifetime savings.

BGE proposed additional energy efficiency and conservation programs. These have not yet been approved. BGE estimates that these additional conservation programs will cost $274,232,718 ($237,353,053 for the five residential programs and $36,879,665 for the small commercial program, which is a basket of energy efficiency programs) over the next eight years (2008-2015). BGE proposes to amortize the program costs over five years. BGE projects estimated savings from the electric programs of 964,266 MWh in energy reductions (794,266 MWh in energy reductions for the residential class and 170,660 MWh in energy reductions for the small commercial class). BGE estimated 15,079,781 therms in total gas energy reductions (15,034,707 therms for the residential class and 45,074 therms for the small commercial class). According to BGE, the conservation usage reductions yield an estimated annual electric energy use reduction of 5.3% for the electric residential and small commercial classes and 3.2% gas use reduction for the gas residential and small commercial. These percentages would represent BGE's contribution to the EmPower Maryland goals.[22]

Pepco and Delmarva

On March 21, 2007, Pepco and Delmarva filed applications for authority to establish DSM surcharges, AMI surcharges, company-specific DSM Collaboratives, and company-specific AMI Advisory Groups. Each company had produced a document entitled Blueprint for the Future Plan. The purpose of PHI's Blueprint Plans is to set forth Pepco's and Delmarva's comprehensive visions of the future whereby their Maryland customers will have increased utility-provided energy efficiency, demand response, and pricing options that are enabled by new programs and technology.

The critical components of each utility's Blueprint Plan are: 1) comprehensive utility-provided energy efficiency programs that are designed to provide savings opportunities for all electric distribution customers; 2) demand response programs designed to reduce electricity demand during periods of high market prices; 3) deployment of an advance metering system for all customers to support time-differentiated rate options for customers and to provide customers with improved electric distribution service; and 4) proposed cost recovery mechanisms that permit Pepco and Delmarva to recover utility investments to implement the Blueprint Plans.

[22] Governor Martin O'Malley announced EmPower Maryland on July 2, 2007. EmPower Maryland is an initiative that envisions a 15% per capita reduction statewide in total electric usage by 2015.

DSM programs are designed to enable customers to better control their electric bills. The proposed DSM programs would fall into two categories: energy efficiency and demand response. Energy efficiency programs, such as HVAC and lighting, are designed to lower customer energy usage through more efficient lighting, air conditioning, and appliances, which lead to lower electric bills. Demand response programs are designed in a manner that allows the customer to "respond" to price signals, actively or passively, thereby lowering energy demand during critical periods of high electricity prices. A smart thermostat can be programmed to automatically increase the thermostat setting in response to high electricity prices.

On September 19, 2007, by Order No. 81618, the Commission directed Pepco and Delmarva to implement the Residential CFL programs and associated Energy Awareness Campaign necessary to support the CFL programs. The Commission found the CFL programs to be cost-effective energy efficiency and conservation programs that will afford each residential customer who participates in the CFL programs an opportunity to save both energy and money. The Commission authorized Pepco and Delmarva to recover the costs associated with the CFL programs, and both utilities are required to submit quarterly CFL program reports to the Commission.

Allegheny

On September 14, 2007, Allegheny filed with the Commission an application seeking authority to implement two "fast-track" "Energy Star" conservation and energy efficiency programs. The proposed programs included: (1) CFLs and (2) a residential awareness campaign. Allegheny requested an effective date of October 3, 2007 to implement these programs.[23]

Allegheny estimates that the two "fast-track" programs will cost $2,501,600 ($2,405,600 for the CFL and $96,000 for the awareness campaign) and will save customers approximately $6,843,700. Allegheny believes that through the CFL program, residential electricity consumption can be reduced by 105,000 MWh. Residential customers can save about $30 over the lifetime of each CFL. Demand savings derived from the programs are estimated at 10 MW.

Allegheny estimates an environmental cost saving of $0.0079 per kWh that yields a net present value of $7.48 million in program benefits. Allegheny's analysis shows a total resource cost ratio of 2.38, which implies that for every dollar spent on CFLs, $2.38 is generated in lifetime energy savings. On September 26, 2007, the Commission authorized Allegheny to implement the two fast-track Energy Star and energy efficiency programs.

C. Mid-Atlantic Distributed Resources Initiative

MADRI was established by "classic" PJM State Commissions, DOE, and PJM at a meeting in Baltimore, held on June 14-15, 2004. 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.

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[23] It should be noted that this effective date coincides with the National ENERGY STAR® "Change a Light" campaign, which encourages commitment to energy efficiency.

There has been much participation by a large number of stakeholders, including utilities, FERC, service providers, and consumers. MADRI has activities in the following areas:

- Advanced metering study, including concepts ranging from simple one-way remote (automatic) meter reading to complex two-way "smart" meters that perform numerous power monitoring functions through advanced metering infrastructure. The AMI Toolbox on the MADRI website[24] may be the best one-stop source of AMI information. In 2008, MADRI will continue to look at regional response to long-term AMI issues such as the economic justification of AMI.

- Benefits assessments for demand response and distributed generation. MADRI provides the evaluation framework of the market environment for DR and DG from the perspective of a buyer or service provider. This is intended to highlight where incentives could be added or programs changed, if existing conditions do not favor DR or DG. On June 13, 2006, MADRI released a policy statement in support of the Mid-Atlantic distributed energy resources initiatives. According to the policy statement, distributed energy resources "can provide benefits to electric customers through increased system reliability, mitigation of wholesale energy prices and other wholesale market risks, improved power quality, improved air quality, reduced line losses and avoided wires investments."[25]

- Development of model small generation interconnection standards, which has been a highly contentious process between utilities and small generation (particularly solar) providers. MADRI's work on this issue is complete.

- Reconciliation and standardization of environmental regulation and DG. For example, allowing emergency generation to operate during PJM system emergencies, prior to "lights out", to prevent an actual blackout. In 2006, MADRI considered several DG pilot programs as part of its business models for states' considerations. These programs included: smart thermostat, combined heat and power initiative, internet access to RTO demand response program, AMI initiatives, model decoupling and dynamic pricing, and distribution system deferral. MADRI will continue to monitor these activities.

- Removal of general distribution regulation barriers to DG and DR. If DR or DG reduces billed kWh or kW, where distribution revenue is based largely on system usage, there is a revenue reduction problem that can be a disincentive to utility acceptance of DG, DR, and conservation. Other issues include cost allocation and rate design for SOS and distribution services, and locational differences in distribution system operation and load growth costs.

- Exchange of information between utilities, PJM, and curtailment service providers. This involves data on customer demand baseline and curtailment under PJM programs, when there is a "two supplier" problem with different retail suppliers serving a customer.

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24 Source: http://www.energetics.com/MADRI/.
25 The policy statement can be found online at: http://www.energetics.com/madri/pdfs/PolicyStatement.pdf.

- On January 29, 2007, The Brattle Group released a study titled, "Quantifying Demand Response Benefits in PJM." The study quantified the economic benefits of demand response by comparing prices with and without demand reductions during the top 20 five-hour periods in 2005 for each utility. The five utility zones were Baltimore Gas and Electric, Delmarva, PECO, Pepco, and Public Service Electric and Gas Company.
  - The study examined the effects of reducing electricity use by three percent during the highest use hours of the year for the five utility zones.
  - A 3% reduction during peak use hours for each utility would have reduced energy market prices by $8 to $25 per MWh. In addition to reductions in electricity prices, demand response participants were estimated to save between $9 million and $26 million for energy charges annually and another $73 million for capacity charges.

D. Maryland 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 or 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.

As previously discussed, three Maryland IOUs filed proposals for long-term DSM and advanced metering initiatives in 2007. On January 23, 2007, BGE filed for authority to initiate an AMI pilot, a DSM pilot program, and for approval of a process in which additional DSM programs could be considered and implemented. On February 21, 2007, the Commission granted BGE's request for a Demand Response Pilot Program. On April 13, 2007, the Commission approved BGE's request for the AMI Pilot Program and its request to establish a regulatory asset in connection with the cost of the AMI Pilot.

On March 31, 2007, Pepco and Delmarva filed applications for authority to establish DSM surcharges, AMI surcharges, and PHI-specific DSM collaboratives, and AMI advisory groups. By Letter Order, dated June 9, 2007, the Commission established a DSM Collaborative for the purpose of discussing and recommending DSM programs for implementation by Pepco and Delmarva. The Collaborative was directed to report any recommendations on or before July 6, 2007.

Also on June 8, 2007, the Commission issued Order No. 81448 which established a collaborative process to consider four issues pertaining to both AMI and DSM programs. The four issues were:

- Technical standards for and operational capabilities of advanced meters;
- The extent to which demand side management programs are to be offered in the State on a competitively-neutral basis;
- Recovery of costs of demand side management programs; and,
- The appropriate measure(s) of cost-effectiveness of demand side management programs to be employed by the State.

On July 6, 2007, the collaborative issued the Report of the Advanced Metering Initiatives and Demand Side Management Collaborative. In its report the Collaborative concluded that the Collaborative reached a consensus on cost recovery and cost-effectiveness test recommendations to the Commission. The Collaborative Report recommended that the traditional cost recovery mechanism used previously for Maryland demand side programs apply to new programs developed by the electric companies. Specifically, the Collaborative recommended that:

- Expenses associated with conservation and energy efficiency programs be amortized over a five-year period;
- Capital investments be amortized over a period that represents the useful life of the investment;
- Program costs be appropriately allocated to each rate class based on its eligibility to participate in each program and the benefits it derives from the program;
- Annual carrying costs of any unrecovered expenditures should equal the company's approved rate of return;
- Cost recovery be in the form of a distribution rate surcharge similar to mechanisms that existed in the 1990's for many utilities in Maryland; and,
- Plans not be precluded from proposing incentive mechanisms, however, parties have the opportunity to take any position they believe appropriate on proposed incentives.

The Collaborative was unable to achieve any consensus on advanced metering infrastructure/ meter data management standards and operational requirements or demand side competitive neutrality. Participants were given the opportunity to file comments on the non-consensus issues on July 6, 2007, with reply comments on July 20, 2007.

On September 28, 2007, the Commission issued Order No. 81637 that addressed three of the four issues established by Order No. 81148. The Commission established technical standards for, and operational capacities of, advanced meters; accepted the collaborative recommendation for the appropriate mechanism to recover costs for DSM programs; and established the appropriate measures of cost-effectiveness of DSM programs.

The Commission directed the investor-owned utilities (BGE, Pepco, Delmarva and Allegheny) to file conservation, energy efficiency and peak demand reduction plans to address the Governor's EmPower Maryland goal of a 15% per capita reduction in usage by 2015. The Commission provided a range of energy-savings targets: a "low case" of electric usage reduction targets for 2015 of 8,625 GWh using the PPRP's load forecast (about 0.6% annual rate of growth in consumption) and a "high case" goal of 17,936 GWh using historic growth rates (about 1.9% annual growth rate).

The IOUs submitted their plans on October 26, 2007; the parties submitted comments on the IOU's plans on November 2, 2007; and the Commission held hearings on the plans on November 8 and 9, 2007.

The utility plans achieved 40% of the PPRP forecast based EmPower Maryland goal and 19% of the high forecast case. The plans assumed that larger commercial and industrial customers achieve usage reductions through energy service providers, their own energy management actions, and investments or other non-utility means. The total cost through 2015 for the four utility plans was approximately $760 million. These costs include conservation and energy efficiency programs and demand response, but do not include costs for AMI.

BGE has started to implement its Demand Response Initiative for its residential customers, effective January 3, 2008. The purpose of the program is to reduce customer demand of electricity during the peak summer period. Under this voluntary demand response program for residential customers, BGE will cycle off customers' central A/C or heat-pump units 50%, 75%, or 100% during specified periods. The maximum number of periods that the cycling will occur is ten times per program year and the maximum time that an A/C or heat-pump unit can be cycled off is six hours. The cycling off of the A/C and heat-pump units can be invoked by a PJM emergency event or by a local emergency on the distribution system. The cycling can also occur if BGE determines that economic considerations (very high energy prices) warrant a cycling event to occur. BGE will offer participants incentives of $50, $75, or $100 for signing up for the 50%, 75%, or 100% cycling options, respectively.

BGE estimates that significant savings can be achieved for its residential customers. BGE also indicates that because of spillover effects, significant benefits will accrue to non-residential customers, as well as other customers not in its service, particularly in Southwest MAAC. BGE estimates that if it is successful in implementing the DRI program, the DRI program will generate overall benefits of $1.123 billion (in present value terms) over a 15-year period. The expected 15-year costs of the program are $158 million, also in present value terms. The benefit-to-cost ratio of implementing the DRI program is approximately seven-to-one.

BGE states that it believes that enrolling 50% (450,000) of its eligible customers with central A/C or heat-pump units is achievable by the end of 2011. BGE states that it can achieve an average of 1.38 kW demand reduction per A/C or heat pump unit. Overall, BGE estimates a benefit of 600 MW of demand reduction from implementing the DRI program.

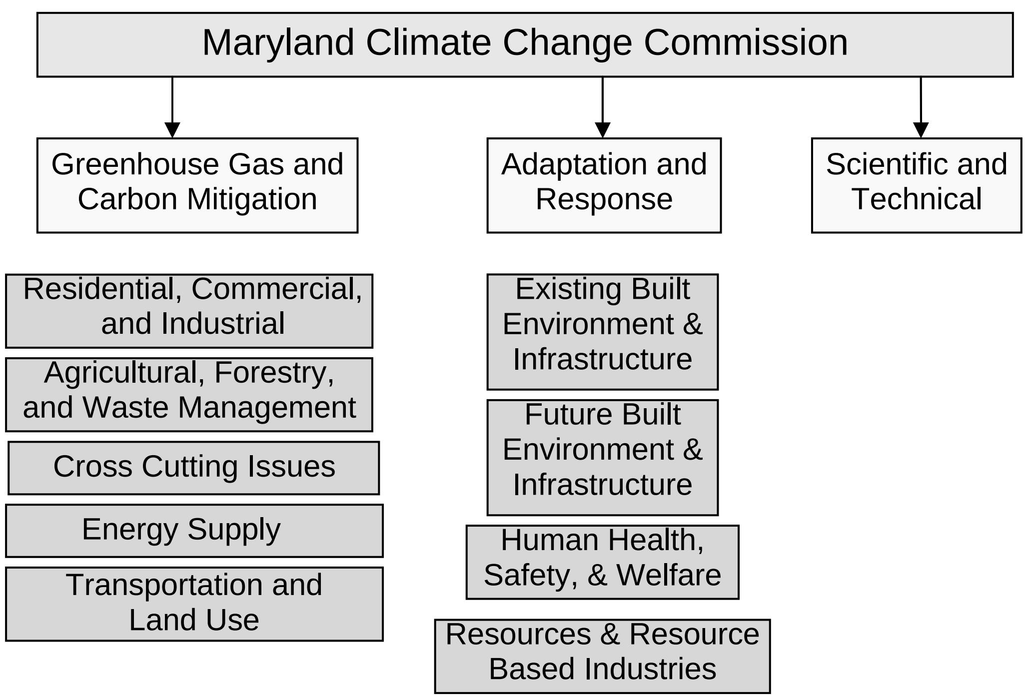
VI. ENERGY, THE ENVIRONMENT AND RENEWABLES

The Maryland environment and Maryland's environmental impact on the world's climate is an ever present concern. Recent State legislative activity shows that minimizing carbon and other pollutants should be a consideration in all energy decisions. Maryland has recently joined with other RGGI states to implement a cap-and-trade program designed to stabilize carbon emissions at current levels through 2015 and thereafter reduce the emissions by 10% by 2019. In addition, Maryland continues to manage a Renewable Energy Portfolio Standard Program, designed to require increasing amounts of supply from renewable resources. This past year, the legislature added a solar requirement to the RPS designed to increase the amount of solar generation installed in Maryland. Environmental issues are becoming an increasing national, state and local concern and will be considered in all supply issues before the Commission.

A. Maryland's Climate Change Commission

On April 20, 2007, Governor O'Malley signed Executive Order 01.01.2007.07 establishing the Maryland Commission on Climate Change. Fifteen State agency heads and six members of the General Assembly comprise the Climate Change Commission. The principle charge of the Climate Change Commission is to develop a plan of action to address the drivers of climate change, to prepare for its likely impacts in Maryland, and to establish goals and timetables for implementation.

Chart VI.A.1: Maryland Climate Change Commission Working Groups



The Maryland Department of Environment is the lead agency and the Climate Change Commission's work is facilitated by a consultant, The Center for Climate Strategies. The base assumption of the Climate Change Commission is that excess carbon dioxide released by human activity is causing global warming. The working groups and technical working groups are focused on identifying actions that have the potential to reduce greenhouse gases and thus stop and reverse the effects of global warming.

There are three working groups established to support the Climate Change Commission, whose members were appointed by the Secretary of the Environment. Two of the working groups are supported by technical working groups that are responsible for developing the straw proposals for policy options to be implemented for purposes of achieving the Climate Change Commission objectives.

The proposals of the technical working groups are considered complete and final unless five members of the main working group object, in which case the matter would be returned to the technical working group for resolution.

The Climate Change Commission's goals are based on greenhouse gas reductions from a 2006 base year, and are purposely very aggressive.

Table VI.A.1: Maryland Climate Change Commission Goals

Year	Maryland's Goals (From a 2006 Base Year)
2012	10% Reduction from 2006 Levels
2015	15% Reduction from 2006 Levels
2020	Minimum Goal - 25% Reduction From 2006 Levels
2020	Aspiration Goal - 50% Reduction From 2006 Levels
2050	90% Reduction From 2006 Levels
2100	Zero Emissions or Carbon Neutral

Current versions of presentations and technical working group proposals, which exist along with other climate change information, can be viewed on the Climate Change web site.[26] Some of the materials, especially the TWG proposals of the Greenhouse Gas and Carbon Mitigation work group are still evolving in near real time. The Climate Change Commission has identified as many as 500 proposals of which 50 are planned to be the focus of 2008 legislative efforts. Other information, such as the original presentations, has remained relatively stable since they were issued.

B. The Regional Greenhouse Gas Initiative

The Regional Greenhouse Gas Initiative is a cap-and-trade program to limit the total CO_2 emissions from electricity sources in ten member states on the East Coast from Maryland to Maine.[27] "RGGI, Inc." is a non-profit corporation formed to provide technical and scientific advisory services to participating states in the development and implementation of the CO_2 Budget Trading Program.

26 Source: http://www.mdclimatechange.us/index.cfm.

27 Currently, the participating states are: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island and Vermont.

The member states of RGGI, in a collaborative effort, developed a specific proposal in the form of a Memorandum of Understanding, ultimately signed by each of the participating states. Maryland signed the RGGI MOU on April 20, 2007. Each RGGI state has an annual allocation of emission allowances (expressed as tons of CO_2) for a three-year compliance period. Sources must purchase these allowances in a periodic sequence of auctions, such that on the compliance date for each three year compliance period, each CO_2 emissions source holds sufficient allowances to cover its emissions over the compliance period. The first compliance period is 2009 to 2011, with subsequent compliance periods thru 2018.

The member states then developed a Model Rule for a regional CO_2 cap-and-trade program for the electricity generation sector. The MOU and the Model Rule specify that each state must allocate at least 25% of its budgeted CO_2 allowances to a consumer benefit or strategic energy purpose account.[28] The participating states will next proceed with the required legislative or regulatory approvals within each state to adopt the program. Pending the completion of this process, the RGGI program will take effect on January 1, 2009.

The participating states are developing a regional auction platform to sell CO_2 allowances and plan to begin auctions in the second half of 2008. The proceeds from the sale of the allowances, to be sold at auction, must be used to promote energy efficiency, assist in the development of low-carbon energy technologies, or mitigate electricity ratepayer impacts.

By design, the RGGI program will be expandable and flexible, permitting other states to seamlessly join in the initiative when they deem it appropriate. RGGI is the first mandatory cap-and-trade program for CO_2 emissions in the history of the United States.

Size and Structure of Cap[29]

Under RGGI, the participating states will launch a regional cap-and-trade system that utilizes emissions credits or allowances to limit the total amount of CO_2 emissions. Beginning in 2009, emissions of CO_2 from power plants in the region would be capped at current levels — approximately 188 million tons annually — with this cap remaining in place until 2015.

The RGGI MOU calls for signatory states to stabilize power sector CO_2 emissions over the first six years of program implementation (2009-2014) at a level roughly equal to current emissions, before initiating an emissions decline of 2.5% per year for the four years 2015 through 2018. This approach will result in a 2018 annual emissions budget that is 10% smaller than the initial 2009 annual emissions budget. The first three-year compliance period would begin January 1, 2009.

28 Individual participating states may choose how to allocate the majority of their allowances, pursuant to provisions in the MOU, but the clear trend among many of the RGGI states is to auction all of their allowances and dedicate the proceeds to support consumer benefits. NY, MA, VT, RI, CT, and ME have all publicly stated their commitment to auction 100%, or nearly 100%, of their allowances to support consumer benefit programs (CT, ME, RI, and VT have statutory requirements to this effect).

29 The information provided in this description was largely obtained from the RGGI website. For additional information on the RGGI program, you can visit the RGGI website at www.rggi.org.

The initial base annual emissions budget for the 2009-2014 periods is as follows:

Table VI.B.1: Annual Emissions Budget (2009 –2014)

State	Carbon Dioxide Allowances (2009 – 2014)
Connecticut	10,695,036 short tons
Delaware	7,559,787 short tons
Maine	5,948,902 short tons
Maryland	37, 505,984 short tons
Massachusetts	26,660,204 short tons
New Hampshire	8,620,460 short tons
New Jersey	22,892,730 short tons
New York	64,310,805 short tons
Rhode Island	2,659,239 short tons
Vermont	1,225,830 short tons
Total[30]	188,078,977 short tons

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

This phased approach with initially modest emissions reductions is intended to provide market signals and regulatory certainty so that electricity generators begin planning for, and investing in, lower-carbon alternatives throughout the region, but without creating dramatic wholesale electricity price impacts and attendant retail electricity rate impacts. The RGGI MOU apportions CO_2 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."

TableVI.B.2: Regional Annual CO_2 Emissions Budget

Year	Regional Annual CO2 Emissions Budget
2009-2014	188,078,977 short tons
2015	183,375,052 short tons
2016	178,673,127 short tons
2017	173,971,203 short tons
2018	169,269,278 short tons

The states would then begin reducing emissions incrementally over a four-year period to achieve a 10% reduction by 2019. Compared to the emissions increases the region would see from the sector without the program, RGGI will result in an approximately 35% reduction by 2020. Under the cap-and-trade program, the states will issue one allowance, or permit, for each ton of CO_2 emissions allowed by the cap. Each plant will be required to have enough allowances to

[30] The initial regional cap is 188.1 million short tons of CO_2, which is approximately 4% above average regional emissions during the period 2000-2002. It is based on the current ten members of RGGI (including Maryland). Overall RGGI totals will be revised incrementally as additional Member States become participants in RGGI.

cover its reported emissions. The plants may buy or sell allowances, but an individual plant's emissions cannot exceed the amount of allowances it possesses. The total amount of the allowances will be equal to the emissions cap for the ten-state region. Electric generating units with a capacity of 25 MW or more will be included under RGGI. The RGGI states have agreed that at least 25% of a state's allowances will be dedicated to strategic energy or consumer benefit purposes, such as energy efficiency, new clean energy technologies, and ratepayer rebates. A power plant also could purchase these allowances for its own use. The funds generated from these sales are to be used for beneficial energy programs.

RGGI Inc.

RGGI Inc. is a non-profit Delaware corporation with offices to be located in New York City in space collocated with the New York Public Service Commission at 90 Church Street. 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), also serving as board members, constitute a steering committee that provides direction to the Staff Working Group and allows in-process projects to be conditioned for Board Review. Two Board of Directors meetings were held in 2007.

Committee members from the RGGI Board are (at this writing) conducting a search for an Executive Director, and additional permanent staffing will be selected once the Executive Director is chosen. Operationally, RGGI has begun a series of procurements to select a vendor to conduct and administer the auction planned to start in 2008, as well as additional vendors to manage the Offset function and a support system for Emissions and Allowance Tracking referred to as the "EATS" system. Selection of the vendors will be made in early 2008.

C. The Renewable Energy Portfolio Standard Program

Under PUC Article § 7-701 et seq., referred hereafter as the RPS Legislation, electricity suppliers are required to meet a Renewable Energy Portfolio Standard. The RPS Legislation requires, among other things, that the Commission implement the RPS. Additional information regarding the current status of the Maryland RPS will be available in the Renewable Energy Portfolio Standard Report of 2008 to the General Assembly. Implementation of the RPS is required to be accompanied by a system that facilitates the trading of Renewable Energy Credits representing the generation of electricity using renewable resources.

A REC is equal to the renewable attributes associated with one megawatt-hour of energy generated using specified renewable resources. Each supplier must present, on an annual basis, RECs equal to the percentage specified by the RPS Legislation. Generators and suppliers are allowed to trade RECs using a Commission-sanctioned or established REC registry and trading system. A REC has a three-year life during which it may be transferred, sold, or otherwise redeemed. The RPS Legislation allows generators and electricity suppliers to accrue RECs as of January 1, 2004. Suppliers that do not meet the annual RPS are required to pay a compliance fee, the amount of which is prescribed in the RPS Legislation. Compliance fees will be a source of funding for the Maryland Renewable Energy Fund. The Maryland Renewable Energy Fund is designed to promote the development of renewable energy resources in Maryland. The

Commission is responsible for creating and administering the overall RPS Program; responsibility for developing renewable energy resources has been vested with the Maryland Energy Administration.

The RPS obligation applies to anyone that has completed an electricity sale at retail to customers in the State of Maryland. In order to verify that each electricity supplier, broker, aggregator, and electric company has met its RPS obligation, the Commission requires that all licensed electricity suppliers and electric companies file a Supplier Annual Report[31] prior to April 1. The April 1 deadline provides time for electricity suppliers to calculate their electricity sales for the compliance year that ends on December 31 based on settlement data. The April 1 deadline also allows suppliers time to purchase any RECs needed to fulfill their respective RPS obligations.

The Generation Attributes Tracking System operated by PJM – Environmental Information Systems, Inc. is used for crediting RECs to generators and for trading and retiring RECs in supplier accounts. Under COMAR 20.61.01.05(G), a supplier that is required to file a report must maintain a GATS account in good standing.

Calendar year 2006 marked the first compliance year for Maryland's Renewable Portfolio Standard Program. Annual reports required under COMAR 20.61.04.02 were filed and as of December 18, 2007, the PSC received reports from 68 electric companies and electricity suppliers. Of these 68 reports, 13 were from utilities, 35 were from licensed suppliers, and 20 were from electricity brokers. With over 90% of the reports received by the Commission, an overall picture of the number of RECs needed for compliance is available. Based upon information received from the reports, 552,874 Tier 1 RECs were used to meet Tier 1 RPS obligations and 1,322,069 Tier 1 and Tier 2 RECs were used to meet Tier 2 obligations for all licensed electricity suppliers, brokers and utilities. The total for all compliance fees paid was $38,209.45. The compliance fees are remitted to the Comptroller of Maryland, who disperses them to the Maryland Renewable Energy Fund, which is managed by the MEA to fund renewable energy projects in the State of Maryland.

In keeping with the PUC Article § 7-708, the GATS system developed and operated by PJM-EIS serves to monitor the generation of the participating units and creates monthly RECs monthly based on the amount of renewable electricity output from those units. This information is uploaded directly from PJM-interconnected facilities. Facilities that are not interconnected with PJM will be required to submit periodic verifications of the amount of electricity that is being generated from renewable sources. Facilities that exist in PJM adjacent states, which are interconnected with another RTO such as the Midwest ISO, or which sell electricity directly to a utility, fall under this classification. Ideas to address this facet of the program in the future include a cost-effective smart meter that would automatically upload the renewable electricity generation data on a monthly basis.

The chart below exhibits the amount of rated capacity that is currently registered for the RPS program and shows the geographical allocation of the RECs that are being created:

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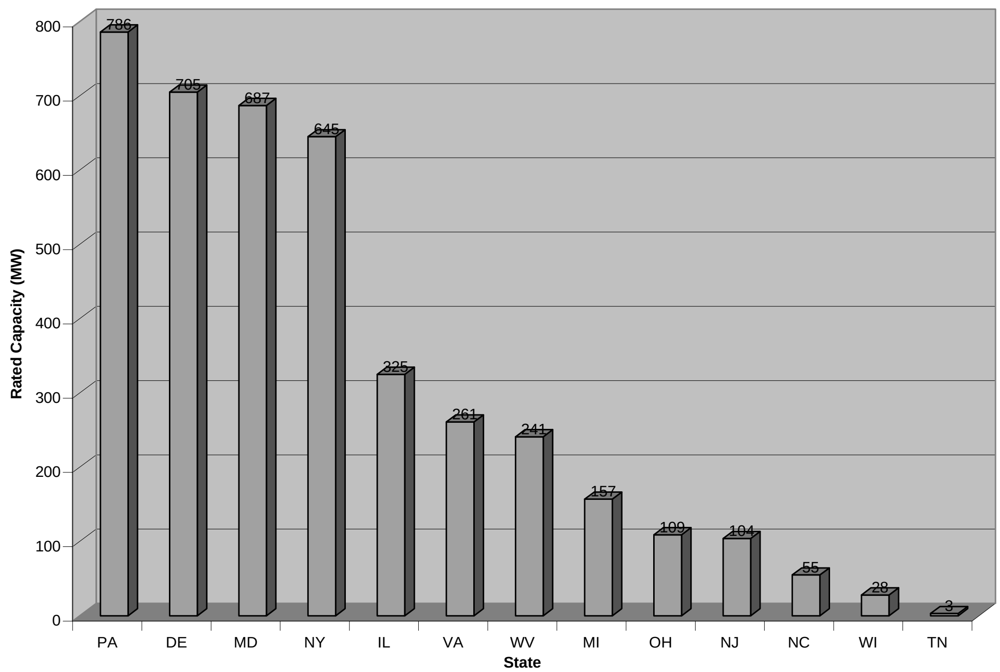
[31] These reports have been filed under PUC Article § 7-705 and Section 20.61.04.02 of the Code of Maryland Regulations. COMAR 20.61.04.02 is included as Appendix A.

Chart VI.C.1: MD RPS Certified Rated Capacity by State (as of 11/2/2007)



One can see that the majority of the facilities currently registered are found in the mid-Atlantic region. Delaware, Maryland, Pennsylvania, West Virginia and Virginia are listed as five of the top six states in terms of REC qualifying electricity-generating capacity. One aspect of the program to be cognizant of is that a significant number of RECs will be produced in areas that are outside of Maryland's immediate surroundings. New York, Michigan, Ohio, Illinois, North Carolina, Wisconsin and Tennessee all have facilities that are certified to accumulate and sell RECs. Funds funneled to these areas have the potential to reward pre-existing renewable generation while not working towards the aim of the RPS program to spur the growth of renewable electricity sources in Maryland and the immediate surrounding areas.

Tending towards renewable generation in the Maryland area could provide environmental benefits to the State. A partial reduction in the footprint where Tier 1 and Tier 2 resources may be sited could serve to increase the value of RECs; however, the increase in the cost of RECs without funds being paid into the Maryland Renewable Energy Fund may over time increase the cost of compliance and ultimately the cost of electricity. Tier 1 Solar Renewable Energy Facilities must be sited in Maryland. The changes made to PUC Title 7, Subtitle 7 by Senate Bill 595 call for electricity generated from a Tier 1 solar renewable source to be connected with the electric distribution grid that will be serving Maryland by January 1, 2012, in order for the generation to be eligible for Maryland RECs.

Compliance reports for year 2007 are due on April 1, 2008. The Renewable Energy Facility Certification, On-Site and Behind the Meter Generation Reports, Application for Industrial Process Loads, Applications for the Waiver of Compliance Fee, 2006 Annual Compliance Report, Compliance Fee Remittance Report and Marketed Renewable Electricity Sales Report forms are currently available on the Maryland Renewable Portfolio Standard website.[32] The aforementioned forms are all currently being processed. Forms that will be posted in the future are forms that will provide information associated with the registration of renewable energy facilities that produce electricity using solar energy as a fuel source.

PUC Article § 7-701 et seq. was updated through Senate Bill 595[33] and House Bill 1016. Senate Bill 595 requires new regulations to implement the requirement that electricity suppliers in the State offset a specified percentage of their Maryland retail electricity sales with a specified percentage of Solar Renewable Energy Credits.[34] The legislation established January 1, 2008 as the statutory start date for the Solar REC requirement, with the compliance year 2008 being the first year that mandates the solar RPS requirement.

Shown in the table below are the Tier 1 and Tier 2 REC requirements of the previous and updated versions of the Maryland RPS. The Tier 2 percentage requirement of an electricity supplier's retail electricity sales remain unchanged with the amendments made to the Maryland RPS. The overall Tier 1 requirement is increased by the proportion of RECs specifically required to come from Tier 1 Solar resources. RECs derived from a Tier 1 Solar resource may be applied toward an electricity supplier's regular Tier 1 or Tier 2 RPS obligation, and regular Tier 1 RECs can be applied toward an electricity supplier's Tier 2 RPS obligation.

Table VI.C.1: Updated RPS Percentage Requirements

Year	Current RPS		New RPS		
	Tier 1	Tier 2	Tier 1*	Tier 1 solar	Tier 2
2006	1.000%	2.500%			
2007	1.000%	2.500%			
2008	2.000%	2.500%	2.005%	0.005%	2.500%
2009	2.000%	2.500%	2.010%	0.010%	2.500%
2010	3.000%	2.500%	3.025%	0.025%	2.500%
2011	3.000%	2.500%	3.040%	0.040%	2.500%
2012	4.000%	2.500%	4.060%	0.060%	2.500%
2015	5.000%	2.500%	5.250%	0.250%	2.500%
2018	7.000%	2.500%	7.900%	0.900%	2.500%
2020	7.500%	0.000%	9.000%	1.500%	0.000%
2022	7.500%	0.000%	9.500%	2.000%	0.000%

* Includes the mandatory Tier 1 Solar Requirement. Tier 1 Solar RECs are a sub-set of Tier 1 RECs.

32 The Maryland RPS homepage can be found at: http://www.psc.state.md.us/psc/electric/rps/home.htm.

33 Senate Bill 595 was passed by the General Assembly on April 9, 2007, and signed by Governor O'Malley on April 24, 2007.

34 A renewable energy credit represents the attributes associated with one megawatt-hour of electricity generated from a renewable source. A Solar REC is one in which the generation is supplied through solar energy.

D. Solar Power Requirements in Maryland

Through House Bill 1016 and Senate Bill 595, legislation was passed amending Maryland's Renewable Portfolio Standard. The legislation raised the net metering cap from 200 kW to 2 MW and required that starting in 2008, 0.005% of Maryland's electricity supply be generated from solar electricity. This amount increases incrementally each year until reaching the required 2.000% by 2022. If an electricity supplier fails to offset the applicable percentage of retail electricity sales with electricity derived from solar resources or from Tier 1 renewable energy credits coming from solar resources, then the electricity supplier is responsible for making an alternative compliance payment as set forth in PUC Article § 7-705(b). Table VI.C.1 found in Section VI.C summarizes the changes made to the Tier 1 and Tier 2 REC percentage requirements of the Maryland RPS through 2022.

The Maryland Solar RPS also changed the compliance fee structure. Table VI.D.1 below shows some of the changes through 2022 made to the compliance fee to reflect the solar portion of Maryland's RPS that was added. The compliance fee figures are on a dollars per MWh basis. One can see that the Tier 1, Tier 2 and Industrial Process Load compliance rates have not changed and the main change is the addition of the Tier 1 solar subset of the Tier 1 RECs. The solar compliance fee rate begins at $450 per MWh in 2008, decreases to $400 per MWh in 2009, and then decreases by $50 per MWh every other year thereafter until 2023. After 2023, the compliance fee rate remains constant at $50 per MWh. The increased compliance fee rate should increase the value of a solar REC in relation to its non-solar Tier 1 counterpart. Compliance fees that are paid as a result of a failure to meet the solar component of Maryland's RPS support the Maryland Renewable Energy Fund, which is administered by the MEA. The Maryland Renewable Energy Fund is to be used for the creation of solar renewable energy projects located within the State of Maryland.

Table VI.D.1: Updated RPS Compliance Fee Schedule

Year	Current RPS				New RPS				
			Industrial Process Load					Industrial Process Load	
	Tier 1	Tier 2	Tier 1	Tier 2	Tier 1	Tier 1 solar	Tier 2	Tier 1	Tier 2
2006	$20	$15	$8	$0					
2007	$20	$15	$8	$0					
2008	$20	$15	$8	$0	$20	$450	$15	$8	$0
2009	$20	$15	$5	$0	$20	$400	$15	$5	$0
2010	$20	$15	$5	$0	$20	$400	$15	$5	$0
2011	$20	$15	$4	$0	$20	$350	$15	$4	$0
2012	$20	$15	$4	$0	$20	$350	$15	$4	$0
2022	$20	$15	$2	$0	$20	$50	$15	$2	$0

The intent of Senate Bill 595 is, "[to] improve the State's use of solar energy"[35] by not only establishing Solar REC requirements, but also increasing the allowable size of customer generation. Senate Bill 595 also requires the purchase of Solar RECs via standard contracts and ensures customer rights to the Solar RECs produced by their facilities. The contract requirements vary by the rated capacity of a given solar installation. The Maryland Solar RPS 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 electricity supplier purchasing RECs directly from a renewable on-site generator to meet the solar component of the Maryland RPS is that the contract terms for the RECs must be for no less than 15 years.[36] This requirement does not apply to an electricity supplier that purchases RECs from a third party intermediary that can purchase and sell RECs without being subject to a minimum 15-year contact term.

An electricity company that purchases solar RECs 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 RECs at a price that is determined by the Commission. The up-front purchase of RECs is intended to aid in financing the construction of this type of solar installation. The current proposed level of payment[37] for the RECs 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.

Unlike most Tier 1 and Tier 2 RECs that may originate from Commission-certified renewable energy facilities that are located in PJM and PJM adjacent states, the intent of the Maryland solar RPS is for Tier 1 solar RECs to originate from solar renewable energy facilities that are interconnected with the electricity distribution grid serving Maryland.

Tier 1 solar renewable energy facilities will have to be sited in Maryland by January 1, 2012. The changes made to PUC Title 7, Subtitle 7 by Senate Bill 595 call for electricity generated from a Tier 1 solar renewable source to be connected with the electric distribution grid that will be serving Maryland by January 1, 2012 in order for the generation to be eligible for Maryland RECs. Prior to January 1, 2012, Tier 1 solar renewable energy facilities located in a PJM or PJM adjacent state are eligible to provide RECs eligible for the Maryland RPS only if offers for RECs derived from Tier 1 solar renewable energy facilities interconnected with the grid are not made to electricity suppliers that would apply these RECs towards compliance with the Maryland RPS. A renewable energy facility has to apply for certification with the Commission to be designated as a Maryland renewable energy facility, prior to it being eligible to create Maryland-eligible RECs. By restricting the footprint and ease of sale of out-of-state Tier 1 solar RECs for compliance with the Maryland RPS, the value of the Tier 1 solar RECs coming from Maryland based Tier 1 solar REFs may increase.

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35 Dept. of Legislative Services, Revised Fiscal And Policy Note, Senate Bill 595, May 7, 2007.

36 PUC Article § 7-709.

37 Maryland PSC Rulemaking No. 32.

It is important that Maryland implement and monitor an RPS that includes a specific solar requirement and fosters a sustainable renewable generation program in Maryland that maximizes the renewable generation resource benefits for Maryland consumers.

E. Small Generators Interconnection

The Energy Policy Act of 2005, Title VII, Subsection E, required state commissions to consider certain standards for electric utilities. Section 1254 of EPAct 2005 required that electric utilities make available, upon request, interconnection[38] service to any electric consumer that the electric utility serves. In addition, it specified the interconnection services shall be governed by the Institute of Electrical and Electronics Engineers: IEEE Standard 1547 for interconnecting Distributed Resources with Electric Power Systems.

The Commission established a Notice of Inquiry (Case No. 9060) on April 4, 2006, which invited jurisdictional electric companies and other interested parties to file comments regarding the standard and the Mid-Atlantic Distributed Resources Initiative. The Commission received intervention petitions, notices of appearance and/or comments from a number of companies, government agencies, and organizations. The comments included a variety of critiques for the standards or models that had been proposed in the notice as well as other interconnection standards or models that have been proposed or adopted in recent years. Unfortunately, none of the comments clearly outlined a recommended standard for the Commission to adopt, and most of the comments did not go beyond a general critique of certain models or standards. Some comments recommended the Commission establish a working group to address the numerous technical and policy issues involved in developing interconnection standards that strike the appropriate balance between the potential benefits resulting from the interconnection of distributed generation and the safety and reliability of the electric distribution system.

On October 17, 2006, the Commission issued its letter order instituting the Interconnection Working Group to establish the interconnection policies and technical guidelines which electric utility companies and distributed generators would agree to follow. On January 11, 2007, Commission Staff held the initial Interconnection Working Group meeting in Baltimore. By the end of March 2007, six additional working group meetings had been held, and the participants of those meetings had reached agreement on an interconnection framework. On April 20, 2007, Staff issued its Interconnection Working Group report to the Commission, and the Commission solicited comments from interested parties. On July 10, 2007, a special session of the working group was held to allow commenting parties to resolve differences that existed on certain aspects of the Interconnection Rules. Staff issued its Supplemental Report to the Commission on August 7, 2007, providing a detailed description of the final issues on which the parties had reached consensus and the small number of issues on which the parties were not in agreement.

Based on the reports, Staff proposed a set of interconnection regulations, which the Commission subsequently heard as Rule Making No. 31 on October 10, 2007 and October 23, 2007. The regulations are currently pending publication in the *Maryland Register*.

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[38] Interconnection service means service to an electric customer under which an on-site generating facility on the customer's premise shall be connected to the local distribution facilities.

The regulations allow for four categories of interconnection. Level 1 to 3 provide for expedited review of an application in order to minimize the cost and time required to interconnect a small generator while allowing the utility to ensure that safety and reliability considerations are addressed.

- **Level 1 <10 kW Expedited Review** applies to Interconnections of up to 10 kW inverter based systems such as photovoltaic solar applications equipped with an inverter based on the UL 1741 standard. The Interconnection rule provides for standard application forms and maximum intervals for the electric utility's review of the interconnection request.

- **Level 2 – 10 kW to 2 MW Expedited Review** applies to Interconnections larger than 10 kW but no larger than 2 MW. These systems must use equipment approved by a nationally recognized testing laboratory or must have been previously approved by an electric utility under a study process. Systems in this size range do not have to be inverter based and are expected to use a variety of technologies, micro turbans, fuel cells, small wind generators and combined heat and power units. Level 2 procedures also provide for the interconnection of systems less than 50 kW to area networks.

- **Level 3 – 10 kW to 10 MW Expedited Review.** These systems qualify for expedited review if they use special equipment to ensure they will not export power from the customer premises to the electric distribution system. The vast majority of small generators that qualify for review under this category are expected to be standby generator facilities that interconnect at distribution system voltages and operate in parallel for more than 100 milliseconds. Net metered small generators are not eligible for a Level 3 Review.

- **Level 4 – 2 MW to 10 MW Study Process.** Small generators that do not qualify for expedited review, or have not been accepted under an expedited review already conducted, will be evaluated under the procedures spelled out in this category. Because the small generators reviewed in this category are expected to be larger and are expected to use application specific interconnection equipment, there needs to be a more in-depth evaluation of the potential impacts of the small generator on the electric distribution system. For this reason, reviews conducted under a Level 4 evaluation are expected to be more involved and are expected to take more time.

The regulations create the opportunity for additional distributed generation such as residential and commercial solar applications to be deployed in Maryland.

VII. DISTRIBUTION RELIABILITY IN MARYLAND

While concerned about short and long-term supply issues, one cannot forget about the need to maintain a reliable delivery system to provide supply to the ultimate consumers. The Code of Maryland requires utilities to have written Operation and Maintenance procedures and the reporting of distribution system performance on an annual basis. Delivery reliability is an additional concern that will play an increasingly important role in Commission decisions.

The Commission has been charged historically with ensuring safe and reliable utility service throughout Maryland. This obligation was reaffirmed in the Electric Act and the Commission continues its ongoing review of the maintenance and operation of electric utility distribution facilities in the State. The Commission requires that electric distribution companies continue to invest in appropriate mitigation or expansion measures to ensure the reliability of their distribution systems. Reliability of electric service for Maryland consumers is an important part of a utility's performance and it may be appropriate to establish minimum performance standards in support of the requirement for operation and maintenance procedures.

A. Distribution Reliability Assurance

Electric utilities serving 40,000 or more Maryland customers are required to file an Annual Reliability Report[39] with the Commission. The reports contain measurements of reliability for the preceding calendar year of each utility distribution system in terms of both the frequency of outage occurrence and outage duration for the average customer served by the utility. Each IOU also reports the reliability measurements for a group of the least reliable electric feeders in their systems for the year, along with the remedial actions it has taken to improve the reliability of those feeders. The same feeders are not permitted under COMAR 20.50.07.06 to appear on a utility's least reliable list in any two successive years. This is 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, along with the remedial actions taken to improve reliability within those districts.

An important way to assure reliability of the electric distribution system is to create and follow procedures for periodic inspection and maintenance of the system equipment. All electric companies serving Maryland have developed written O&M procedures, pursuant to COMAR 20.50.02.04. The procedures 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 file the written O&M procedures with the Commission and file annual updates when changes in procedures are made. 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.

In substations, periodic attention is typically given to power transformers, various relays and circuit breakers (used primarily for equipment protection), devices charged with controlling voltage (such as capacitors and regulators), and banks of batteries (that provide backup power for

[39] See COMAR 20.50.07.06. The four large investor-owned electric utilities operating in Maryland, along with SMECO and Choptank, file the annual reports.

the substation). For distribution feeder lines, inspection and maintenance attention is typically focused on the electrical conductors, capacitors and other voltage regulators, re-closing circuit breakers (reclosers), electronic monitoring/control devices, vegetation management, and support poles for overhead equipment. A recloser is a switch in a distribution circuit that is designed to turn power off and then on again, perhaps several times in short order. This switching sequence is designed to allow something such as an animal or tree branch causing a short circuit on the line to clear itself. Finally, if the short circuit is not cleared after this switching sequence, the recloser will "lock out" – turn the power off and leave it off in order to protect equipment and living things from abnormally high electrical current in the line. Many utilities use infrared imaging technology to identify substation and feeder line equipment that is operating at a temperature higher than the normal range for proper operation. The value in this procedure is that abnormally hot spots in equipment can often be detected and corrected long before the equipment fails due to over-heating.

Each utility is required under COMAR to keep sufficient records to give evidence of compliance with its O&M procedures. The Commission's Engineering Division makes yearly inspection visits to the electric utilities to examine these records, in a continuing effort to assure distribution system reliability. For occasions when a utility fails to show compliance with its O&M procedures, the Engineering Division issues a letter of non-compliance, with expectations that the utility will take remedial actions, usually within 30 days.

The Engineering Division monitors electric utility actions and programs designed to assure reliability. Increasingly, fuses, switches and reclosers are being added to distribution system feeder circuits to sectionalize them into smaller protective zones. If a short circuit or outage-causing event occurs somewhere along a distribution feeder circuit, the number of customers exposed to the outage can be reduced by the increased use of the sectionalizing devices. A decrease in the number of customers that are exposed to any given outage results in an overall decrease in the frequency of outages per customer served by the feeder and the system, an important reliability goal.

Automation of such distribution feeder devices and other similar mechanisms is increasing, with the potential to reduce both frequency and duration of sustained electric service outages. In years past, reclosers installed on three-phase distribution circuits would typically act on all three phase lines at the same time, switching the power on and off to all phases, even if a problem or short circuit was occurring on only one of the phase lines. Increasingly, utilities are installing "triple-single" reclosers that are capable of acting on just one of the phases or all three, depending on programming or the situation at hand. Residential customers are typically connected to just one of the phase lines of a three-phase distribution circuit. Using this more selective type of recloser, electric service reliability is in general increased since, as an example, customers connected to the "B" or "C" phase lines of a circuit need not experience a disturbance or interruption of service due to a problem occurring only on the "A" phase line of the circuit.

Substations are key elements in electric distribution systems. They house the transformers used to convert higher level transmission voltages into distribution-level voltages used on distribution circuits originating at the substations. In addition, they contain equipment to regulate distribution circuit voltages within an acceptable range and protective equipment such as circuit breakers.

Most of the substations in Maryland now feature two-way electronic communications with the utilities' headquarters or operations centers by way of a system generically referred to as SCADA, or Supervisory Control and Data Acquisition. Remote and speedy data acquisition by SCADA of substation operation information such as electrical loading on the various feeders, number of operations counts by reclosers or circuit breakers, and distribution system voltages allows for quick decisions related to system operation, with a positive affect on reliability. In addition, SCADA data can be used to intelligently administer a utility's equipment maintenance program. Examples of supervisory control through SCADA, as related to service reliability, include the ability to quickly and remotely reset a substation recloser that has locked out and to remotely control voltage regulation equipment within the substation.

For several years, the electric utilities have realized that a collaborative effort among members of the electric utility community can be very useful for assuring reliability when severe weather hits hard. As members of mutual assistance groups, the utilities share restoration crew manpower and other resources when outages increase beyond normal levels. Such assistance serves directly to reduce outage duration, a common measurement of reliability. In addition to crew sharing, the groups hold conference calls for storm preparation, 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.

Other examples of reliability assurance activity performed by utilities include the ongoing replacement of aged overhead and underground conductors, injections to existing underground cable to increase its life expectancy, capacitor bank installations for voltage integrity, utility pole maintenance/replacement, and vegetation management, including dangerous tree removals.

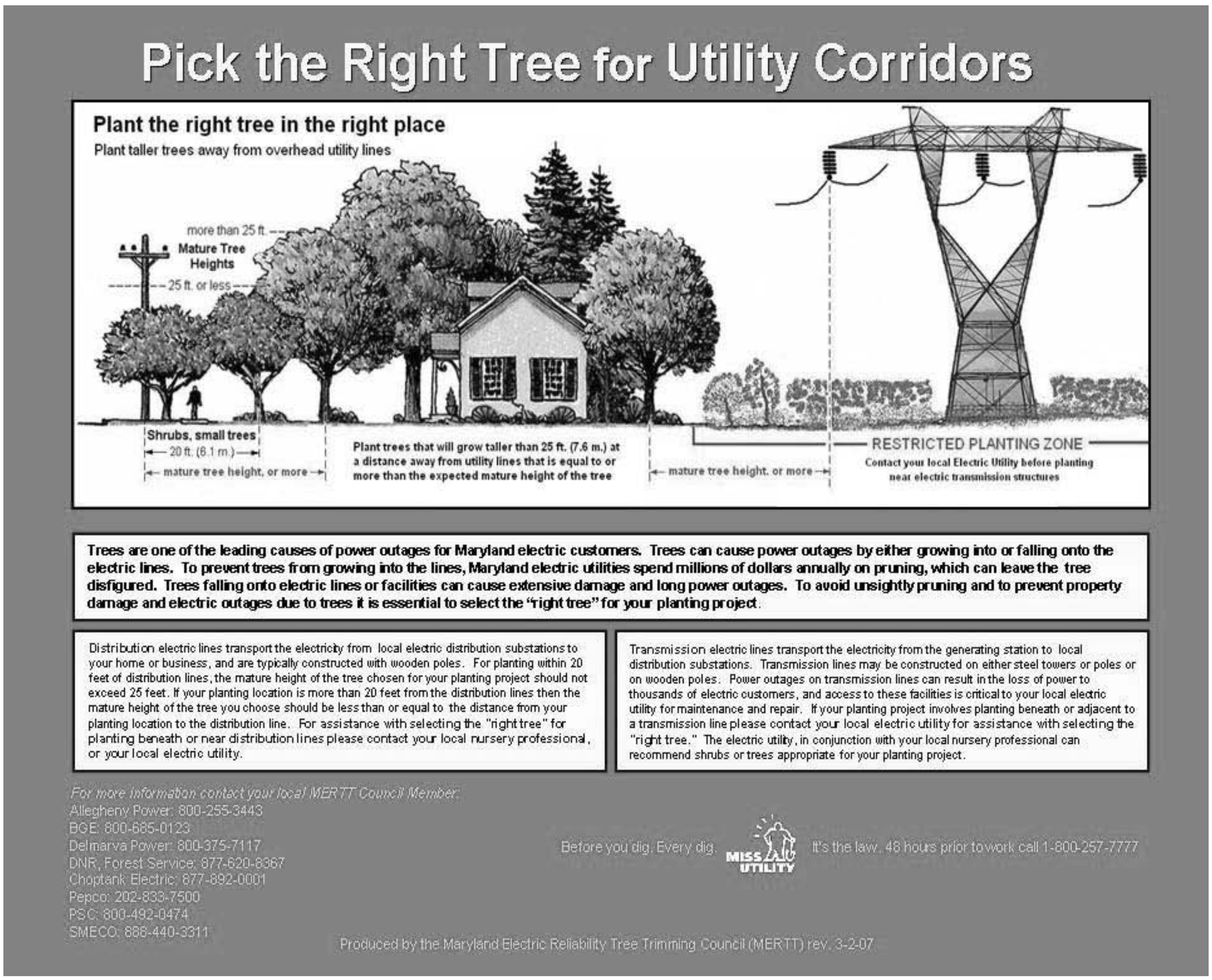
B. Distribution Reliability Issues

The large amount of electric system damage and numbers of electric service outages that large trees or branches cause when they fall on overhead electric distribution lines or facilities is a persistent reliability issue. Often taken down by stormy weather, falling trees or tree limbs caused most of the lost hours of electric service during major storms in Maryland in 2007 to date, as was the case for all of 2006. In two of the three Major Storm Reports[40] filed with the Commission in 2007, utilities reported a total of approximately 3 million hours of electric service interruption during stormy weather associated with a major storm. Of that total, approximately 1.85 million of those lost hours, or about 62%, were caused by fallen trees or tree limbs.

[40] Electric Utility Major Storm Report filings are required by COMAR 20.50.07.07.

Trees cause a significant number of electric service interruptions throughout any given year, often during less severe weather events not classified as major storms. While electric utilities are usually able to control trees within clearly defined and established rights-of-way, a utility cannot always control trees near, but outside, these ROWs. In addition, often the physical dimensions and legal rights associated with a ROW are not clearly defined. The ROW may consist of little more than the physical path that overhead electric lines follow, within which the right to control trees or other vegetation may be disputed.

Figure VII.B.1: MERTT Council "Right-Tree-Right-Place" Poster



The Maryland Electric Reliability Tree Trimming Council[41] continues to meet in an effort to deal with the electric service reliability problems caused by privately-owned and publicly-owned trees near overhead power lines. In 2007, the MERTT Council completed a major effort to

[41] The MERTT Council was established in the aftermath of the Floyd storm in 1999. Its membership has consisted of Utility Foresters, representatives from the DNR-Forest Service and Power Plant Research Program, the PSC's Engineering Division Staff, and other interested parties. Through various efforts, the MERTT Council has worked to establish practices and communication channels concerning how best to manage the mix of vegetation with overhead electric lines.

develop a full color poster depicting the "Right-Tree-Right-Place" concept. As shown above, the poster is meant to be a planting guide, designed to show how leaves and lines can exist together peacefully. The Council hopes that the poster will be widely distributed in the State to increase awareness of the existing problem and, more importantly, to show how trees can be planted now to avoid tree-related reliability problems in the future.

More work and commitment are needed by more stakeholders, if reliability of electric service as related to trees is to be optimized. The prevention of utility damage and service outages caused by privately and publicly owned trees is simply another element of disaster preparedness. Just as it has been recognized from the experience of major hurricanes in recent years that disaster preparedness and restoration is a community-wide effort, with public utilities playing an expanded role, a community-wide effort must be undertaken if electric system damage and outages due to privately and publicly owned trees are to be reduced. Large tree species take years to grow to a size capable of damaging overhead electric power distribution lines and facilities. The key to preparedness and prevention is to use the advantage of time, to begin action now to encourage the planting of smaller trees with innate height limitations near overhead lines.

Although the electric utilities already know that the larger tree species cause significant numbers of service outages, it is hoped that the presentation of specific archived data will help gain support from all stakeholders for future efforts to reduce outages by these trees. To this end, the MERTT Council has begun a research project to determine the scope and degree of impact that trees outside the right-of-way have on electric service reliability in Maryland. The MERTT Council has established the specific data to be collected, and training in the use of data collection hardware is largely complete. In addition to data on tree species and their location relative to the ROW, data on tree health and defects will also be recorded for selected trees that are involved in electric service outages. Although the data collection effort is beginning during the fourth quarter of this year, there has thus far been little data to collect for some areas in the State. Storm activity, along with associated outages due to trees, has been relatively low in most of the utilities' service territories. Data collection for the project is to be performed by the vegetation management units of the six largest electric utilities.

C. Distribution Planning Process

The role of an electric distribution system planner begins with identification of customer needs, both for the near-term and for the future. 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 of the system, with a forecast horizon of a few years. Longer-term planning, with a forecast horizon of perhaps 10 to 20 years, may include expectations of new technologies and altered business climate, in addition to looking out for expanded load growth and the reliability of the system.

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

Allegheny Power – Western Maryland

- To serve the area north of Hagerstown, AP plans to complete the Paramount substation in 2008. Also in 2008, the Montgomery substation serving Clarksburg, and the Lime Kiln substation serving the area south of Frederick, will be upgraded to receive power at higher transmission voltages. In addition to providing more capacity for these areas, electricity transport efficiency and reliability generally increase with the use of higher voltages. New underground primary distribution feeders will be installed from the Montgomery station to serve the Clarksburg development. AP expects to complete construction of a new distribution feeder to serve an area southwest of New Market in 2008.

- In 2009, construction of four substations is scheduled to provide additional service to the southern Frederick, Clear Spring, Jefferson and Poolesville areas. AP plans to replace facilities and increase capacity of the Lappans substation, serving the Lappans Crossroads area, and to extend distribution feeders serving the Western Maryland Health System medical facilities east of Cumberland in 2009. Completion of work to supply the Urbana substation at a higher transmission voltage is expected in 2009.

- AP plans to upgrade two substations in 2010 to serve the Urbana and Ridgeville areas.

- Construction of two substations is planned for 2011 to serve the south-central part of Washington County and Emmitsburg areas.

- During the period 2011-2015, current AP plans are to build a substation to provide additional service to the north-central part of Montgomery County.

- Upgrades of three substations that serve the north-central parts of Montgomery County are currently planned for the period 2011-2015.

- Upgrades to a substation are scheduled for 2015 to provide service to the planned Villages of Urbana subdivision.

BGE – Central Maryland

- Scheduled for completion in late 2008, a new substation will serve planned business parks along the Route 43 extension in White Marsh. For northeastern Prince Georges County, BGE plans to construct the Buena Vista substation in 2008. Various locations in the BGE electric distribution system will receive new distribution equipment with new technology designed to increase service reliability in 2008.

- Construction of the Paca Street substation in downtown Baltimore and associated upgrades to the downtown electric infrastructure to increase load serving capability and overall reliability in the downtown area is planned. This substation is now scheduled for completion in late 2009. To serve northwestern Baltimore City, BGE plans to complete construction in late 2009 of the Arlington Training Center substation. To increase capacity and improve reliability in northern Calvert County, BGE will add a distribution transformer and new feeder at the Chesapeake Beach substation in 2009. A new substation or substation upgrades to serve Havre de Grace, West Aberdeen, Annapolis, Glen Burnie, Broadneck Peninsula in Anne Arundel County, Perry Hall, Gibson Island, northern Prince Georges and Montgomery Counties, and Timonium are planned for 2009.

- In 2010, new substations are planned for central Harford County and Perryman. A new substation to serve Fort Meade and the surrounding area is planned for 2010. Capacity upgrades are planned for Annapolis and eastern Anne Arundel County, southern Carroll County, and northern Howard County. Substation upgrades are planned for Middle River, northern Baltimore County, central and southern Baltimore City, and southern Baltimore County in 2010.

- New substations are planned for construction in 2011 to serve load growth in Fallston, Bel Air, Perry Hall, northeastern Baltimore City, and the Carroll/Calverton area of Baltimore City.

<u>Choptank – Eastern Shore</u>

- By the spring of 2008, Choptank plans to complete work on its Allen substation in Federalsburg and its associated sub-transmission line to receive power from Delmarva Power's new 69-kV line from Hurlock to Federalsburg. In 2008, Choptank expects to begin construction to upgrade capacity on its 69-kV line from St. Martins to Ocean City. The utility also plans, in 2008, to increase transformer capacity at its Hillsboro substation to accommodate load growth.

- Choptank is obtaining easements for a 69-kV sub-transmission line from its Oil City substation to its Williston substation in Caroline County. The Williston substation is currently fed by lower voltage distribution lines from the Choptank Hobbs substation, which receives its power from Delmarva Power distribution lines. Completion of the 69-kV line is scheduled for 2009, and is expected to improve service reliability to Choptank customers in Caroline County. Construction of substations to serve the Rockawalkin (Salisbury) and Denton areas are planned for 2009. Choptank also plans, in 2009, to complete construction of a substation to handle load growth along the Route 301 corridor near Warwick. Distribution feeder improvements to serve the Hillsboro, Williston, Edgewood, Rockawalkin, Mt. Olive, and Ocean Pines areas are planned for 2009.

- In 2010, substation construction is planned to serve the Chestertown and Snow Hill areas. In 2010, feeder improvements are planned to serve the Chestertown, New Hope, Mt. Olive, and Talbot County areas.

- A new substation to serve the Cambridge area is planned for 2011, along with feeder improvements that will benefit the West Denton, Kennedyville, Longwoods, Hickman, and Kingston areas.

- A new substation east of Cambridge, near Linkwood, is planned for 2012 to serve increasing industrial electrical load in the area.

- Choptank plans to build a substation north of Goldsboro in 2013, to serve some of the electrical load currently served by its Barclay substation. The Barclay substation is currently fed by Delmarva Power distribution lines, for which Choptank has little control of service reliability. By 2015, Choptank currently expects to transfer the rest of the load served by Barclay to another new substation to be built near Price, in Queen Anne County.

- A substation to be built east of Salisbury, near Pittsville, is currently planned for 2016.

- For 2017, Choptank plans to build a new substation near Sharptown to serve as a backup supply for the existing Mardela Springs substation. By 2017, another substation near Snow Hill may be built to accommodate load growth along the Route 113 corridor near the town.

Delmarva Power – Eastern Shore

- DPL completed the Price substation to serve the Centreville area in October 2007. Installation of a new unit substation in August 2007 will serve growing electrical load in the Elkton area of Cecil County.

- For 2008, DPL expects to complete construction of the Jacktown substation in the Salisbury area to relieve heavy load on other nearby substations. Upgrades to substations are planned to serve the areas of Centreville, Chestertown, Massey, and Bishop. New installations or upgrades of distribution feeders are planned to serve the Bishop, Massey, Centreville, North East, and Winchester Village (Cecil County) areas.

- Construction of a new substation in 2009 is planned to serve the Queenstown area. Substation and feeder upgrades in 2009 to serve the Centreville, Chestertown, Kings Creek, Bozman, North East, and North East Creek Development areas are planned.

- Upgrades of substations and feeders in 2010 to serve the Bozman, Queen Anne, Stockton, Centreville, Salisbury, Eastern Neck Island, and North East areas are currently planned.

- DPL plans to install a higher capacity transformer in the Massey substation by 2011 to meet increasing electrical demand and maintain reliability of service in the area. For the same reasons, the utility plans an upgrade of line capacity for two feeder circuits in the Cambridge area in 2011.

Pepco – Central Maryland

- In 2007 Pepco completed the construction of two new distribution feeders and extended three others to serve the National Harbor Development and the Gaylord National Hotel and Conference Center.

- In 2009, Pepco expects to complete a capacity upgrade to its Oak Grove substation and extend distribution feeders to serve the Largo, Crain Highway, and Oak Grove areas of Prince Georges County. Pepco plans to upgrade a substation serving the Gaithersburg, Hunting Hill, and Shady Grove areas of Montgomery County in 2009.

- During 2010, Pepco plans to complete an upgrade to a substation serving University Town Center and Metro Center Development. Construction of a new feeder and the extension of another is planned to meet the electrical load of the National Harbor Development and the Gaylord National Hotel and Conference Center. Plans for 2010 also include upgrading a supply feeder serving the Sligo area of Montgomery County.

- For 2011, Pepco plans to build a new substation to serve the NIST, Hunting Hill, and Shady Grove areas of Montgomery County. This construction is expected to relieve heavy electrical loading on other nearby substations. Pepco expects to increase the capacity of its Gaithersburg substation in 2011.

- A new substation is planned for construction in 2012 to serve the Beltsville area of Prince Georges County. A capacity upgrade to Pepco's Colesville substation is planned for 2012 to serve the Colesville, Rossmoor, and Fairland areas of Montgomery County. Also, current plans for 2012 call for a voltage upgrade for the supply to the Sligo substation.

- For 2013, Pepco plans to build a new substation to serve the Fernwood Road area. Additional plans for 2013 include capacitor bank installations to maintain the integrity of electric power serving the Bells Mill area of Montgomery County.

- To accommodate the projected demand for electricity in the Beltsville area, Pepco's current plans include the construction of the Ammendale substation in 2014. The utility currently plans to increase the capacity of the Darnestown substation in 2014, to meet the electricity demand of the Bureau of Standards, Hunting Hill and Shady Grove areas of Montgomery County.

- Pepco's current plans include building a new substation to serve the Germantown area of Montgomery County in 2017.

SMECO – Southern Maryland

- SMECO plans to build two new substations in 2008, the Bryans Road and Huntingtown substations, to meet load growth and provide backup capacity for other substations during service outages. During 2008, one new distribution feeder circuit will be added to the Solomons substation. One new distribution feeder will be added to the Leonardtown and Lexington Park substations to accommodate load growth. SMECO also intends to upgrade and increase the capacity of the West Brandywine substation in 2008.

- Planned distribution system projects to be completed in 2009 include increasing the capacity of the Westlake substation by replacing two of the transformers with higher capacity models. SMECO currently expects to add one new distribution feeder circuit to each of the Bertha and Mattawoman substations in 2009 to meet expected load growth. The new Bertha substation feeder would serve southern Calvert County and the new Mattawoman substation feeder would provide additional capacity for the Waldorf area.

D. Managing Distribution Outages

Perhaps the most important tool developed in recent years for managing electric distribution system outages is the computerized Outage Management System. When an outage occurs, a fully developed OMS accepts information inputs 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 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 to the OMS. The OMS then knows what customers were affected by the outage, usually what caused the outage, and when it started and ended.

Typical information inputs to the OMS:

- <u>Customer Information System:</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 unit, or a High Volume Call Service. 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 knows, with assistance from the next two listed inputs, the location of the customer, both in terms of electrical position in the system diagram and geographic position.

- <u>Energy Management System:</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 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:</u> The GIS includes a map of key landmarks, such as streets, and 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 outage. 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:</u> After an outage is cleared, a work order is closed out within the WMS, or 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:

- 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 and other information can be fed back to the CIS, so customers calling in can receive updates on a particular ongoing outage.

- Information concerning outages can be extracted from the OMS in near real-time to feed Internet web-sites 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 IOUs operating in Maryland and the SMECO and Choptank electric cooperatives 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. The Commission continues to monitor the efforts of Maryland's public service companies to improve customer service.

VIII. MARYLAND ELECTRICITY MARKETS

The Electric Customer Choice and Competition Act of 1999 established the legal framework for the restructuring and revised regulation of the electric industry in Maryland. The Electric 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. As of 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 have two choices, 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 Customer Choice and Competition Act of 1999. The Electric 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 December 31, 2007, the Commission has issued 48 electricity supplier licenses and 24 electricity broker licenses.[42]

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 has largely excluded residential customers, of whom only 3.2% are no longer served by a utility. However, competitive suppliers have not been able to consistently make offers below SOS rates for the residential class. The Commission's monthly enrollment reports indicate that the shift in load to suppliers is primarily the result of choices by C&I customers. (See Table VIII.A.1)

The total statewide number of distribution service accounts eligible for electric choice, as of November 2007, was 2,195,660 of which 1,966,099 were residential and 229,561 were non-residential. Electric choice has not been an overwhelming success for the mass market in Maryland, as demonstrated by the most recent choice enrollment report. Only 5.3% of all utility distribution customers take service from a competitive energy supplier. There were 117,160 customers served by competitive electric suppliers and of those, 54,295 were residential, 46,696 were small C&I, 14,860 were mid-sized C&I, and 1,309 were large C&I customers. Pepco continues to experience the highest degree of supplier participation on a percentage basis with 26,187 residential accounts and 16,343 C&I accounts served by suppliers. Between December 2005 and November 2007, the total number of customers statewide served by electricity suppliers increased from 39,527 to 117,160 customers. The increase, while significant, was principally the result of higher BGE SOS rates. The number of customers served by electricity

[42] As of December 31, 2007, the Commission has issued 30 electricity supplier licenses, 14 electricity broker licenses, 21 natural gas supplier licenses, and 1 natural gas broker licenses. In addition, 18 companies had both electricity and natural gas supplier licenses; 9 companies had both electric and natural gas broker licenses; and 1 company had an electricity broker and natural gas supplier license. The Commission has issued a total of 94 licenses that are currently active, net of any withdrawn or rescinded licenses (see Appendix Table A-7).

suppliers in BGE's service territory increased from 3,932 (October 2005) to 61,816 (November 2007). Of these 61,816 customers, 38,990 switched after July 1, 2006.

The overall demand in peak load obligation served by all electric suppliers at the end of November 2007 was approximately 4,988 MW, of which about 215 MW were residential and 4,733 MW were non-residential. BGE had the highest peak load obligation served by suppliers at approximately 2,602 MW. The total statewide peak load obligation available for choice was 13,288 MW of which 6,619 MW were residential and 6,669 MW were non-residential. Statewide, at the end of November 2007, electric suppliers served 3.3% of eligible residential peak load and 71.6% of eligible non-residential peak load obligation.

Table VIII.A.1: Electric Choice Enrollment in Maryland

Number of Customers Served by Competitive Electricity Suppliers[43]

Utilities	Residential	Small C&I[44]	Mid C&I[45]	Large C&I[46]	All C&I	Total
AP	12	4,569	762	116	5,447	**5,459**
BG&E	26,422	28,731	6,067	596	35,394	**61,816**
Delmarva	1,674	4,932	665	84	5,681	**7,355**
Pepco	26,187	8,464	7,366	513	16,343	**42,530**
Total	**54,295**	**46,696**	**14,860**	**1,309**	**62,865**	**117,160**

Percentage of Peak Load Obligation Served by Competitive Electricity Suppliers

Utilities	Residential	Small C&I	Mid C&I	Large C&I	All C&I	Total
AP	0.0%	25.8%	66.4%	84.4%	61.0%	**29.5%**
BG&E	2.7%	32.0%	68.2%	96.4%	72.3%	**36.7%**
Delmarva	1.7%	32.2%	72.6%	91.1%	63.1%	**30.8%**
Pepco	6.7%	30.9%	64.4%	95.2%	76.3%	**44.6%**
Total	**3.3%**	**30.8%**	**67.0%**	**94.5%**	**71.6%**	**37.5%**

Source: Public Service Commission of Maryland, *Electric Choice Enrollment Monthly Report*, Month Ending November 2007. The Electric Choice Enrollment Report is updated monthly and can be obtained at the following website: http://www.psc.state.md.us/psc/home.htm.

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43 As of November 30, 2007, the following list indicates the number of companies in Maryland that have registered on the Commission's website as actively soliciting new customers in any service territory: 7 serving residential load, 33 serving industrial load, 36 serving commercial load, and 10 serving other types of load (such as government).

44 Small C&I customers are commercial or industrial customers with demands less than or equal to 50 kW for AP, 60 kW for BGE and Delmarva and 25 kW for Pepco. These customers are eligible for "Type I" fixed price utility SOS if they do not switch to a supplier.

45 Mid-sized C&I customers are commercial or industrial customers with demands greater than the level for small C&I service (Type I SOS) for each utility 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 discussion of Case Nos. 9037 and 9056 to see more information on the Type II customer class.

46 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 is offered by electric companies to any customer who does not choose a competitive supplier. The electric companies provide the service by procuring wholesale power contracts of various lengths through sealed bid auctions. Since the end of residential price freeze service in July 2004, SOS rates have experienced dramatic increases.

During the 2007 session, the General Assembly passed Senate Bill 400[47], legislation that modified some portions of Section 7-510 of the PUC Article to require wholesale power procurements which were "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."[48]

On August 16, 2007, the Commission docketed Case No. 9117, *In the Matter of the Commission's Investigation of Investor-Owned Electric Companies' Standard Offer Service for Residential and Small Commercial Customers in Maryland* to consider other approaches to supply SOS in a competitive process under this standard. In particular, the Commission directed parties to present testimony that would compare the actively managed portfolio approach of SMECO to the RFP process used by the major IOUs. Additionally, the Commission wanted to consider a Direct Energy Services, LLC proposal to serve Electric Universal Service Program participants on an aggregated basis. On September 25, 2007, the Commission initiated Phase II of the case to consider proposals for procedures to be used to solicit bids for cost-effective energy efficiency and conservation programs and services and to obtain comment on the option of directing electric companies to build, acquire or lease peak-load or other generating plants to avert a potential reliability problem in Maryland. Initial and reply testimony was filed in September 2007 for Phase I and in October 2007 for Phase II. Hearings for both phases were held during October and November 2007 and the Commission expects to issue an order during the first half of 2008.

On November 14, 2003, the Commission docketed Case Nos. 8985 and 8987 in order to address the SOS procurement issue for SMECO and Choptank, respectively. On September 29, 2004, the Commission issued Order No. 79503 in Case No. 8985 to address SOS for SMECO during the 2005 to 2008 period. The Order permits SMECO to procure power for its SOS service on the wholesale market using a managed portfolio approach for the 2005 through May 31, 2008 period. The Commission will docket another proceeding at an appropriate time to determine what if any changes should be made for the service effective June 1, 2008. On April 25, 2005, the Commission issued Order No. 79922 in Case No. 8987 to address SOS for Choptank. In this Order, the Commission adopted a settlement regarding continued provision of SOS by Choptank, including continued procurement of full-requirements wholesale service through the Old Dominion Electric Cooperative and a modification of its power cost adjustment mechanism. The original time period during which Choptank will provide SOS was extended by five years, beginning on July 1, 2005, and ending on June 30, 2015.

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[47] Chapter 549, 2007 Maryland Laws.

[48] PUC Article § 7-510(c)(4)(ii).

C. Legislation and Compliance Reporting

The passage of Senate Bill 1 in June 2006 and Senate Bill 400 in April 2007 placed new requirements on the Public Service Commission. In June 2006, the Maryland General Assembly convened a special session to pass legislation that would mitigate the 72% rate increase on BGE residential customers resulting from the 2006-07 RFP for SOS service. Senate Bill 1 capped the increase at 15% from July 1, 2006, through May 31, 2007, but allowed BGE to recover its cost of procuring the electricity that led to the increase through bonds financed over ten years.

In Case No. 9089,[49] on December 28, 2006, the Commission issued a Qualified Rate Order via Order No. 81181 and a Financing Credit Order via Order No. 81182 that allowed BGE to place a surcharge on residential customers' bills to recover all of the costs of issuing $623 million in rate stabilization bonds during June 2007. In addition, the General Assembly imposed mandatory credits designed to offset in part the costs of financing the deferred costs of the rate increase for BGE residential customers. These credits included a suspension of a portion of an administrative charge BGE collected as its SOS margin and the suspension of collection of charges from customers to fund the decommissioning of the Calvert Cliffs nuclear facilities.

During the 2007 session, the General Assembly passed Senate Bill 400, legislation that modified some portions of Senate Bill 1 and reiterated its 2006 request of the need for the PSC to conduct a series of inquiries and to issue comprehensive reports on aspects of the State's electricity industry. These inquiries included options to re-regulate the Maryland market,[50] to review previous actions and settlements of the PSC relating to the transfer of the generating assets of the utilities as part of the restructuring of the Maryland market,[51] and to examine methods used by the IOUs to procure power. Specifically, Senate Bill 400 appropriated $3 million for the studies:

> The Public Service Commission shall conduct hearings, including the use of any necessary outside experts and consultants, to study and evaluate the status of electric restructuring in the State as it pertains to the current and future availability of competitive generation to residential and small commercial customers and the structure, procurement, and terms and conditions of standard offer service for residential and small commercial customers. In its evaluation, the Commission shall consider changes that are necessary to provide residential and small business customers the benefit of a reliable electric system at the best possible price, including options for re-regulation, if advisable, and to allow electric companies to develop a portfolio of electricity supply that provides electricity at the lowest cost with the least volatility. In its evaluation, the Commission shall also consider the availability of adequate transmission and generation facilities to serve the electrical load demands of all customers in the State, pricing and physical constraints on the electrical transmission and distribution grids in the State, and options and policy recommendations to provide

[49] See Case No. 9089, *In the Matter of the Application of Baltimore Gas and Electric Company for a Qualified Rate Order to Finance Rate Stabilization Costs, and for Related Purposes.*

[50] See Case No. 9063, *In the Matter of the Optimal Structure of the Electric Industry in Maryland*.

[51] See Case No. 9073.

> an adequate, safe and reliable supply of electricity at a reasonable cost to all customers in the State.[52]

In conducting the analysis described above, the General Assembly specifically directed the PSC to consider the implications of certain approaches:

- Requiring or allowing investor-owned electric companies to purchase electricity by competitive or negotiated contracts of various durations or through other appropriate methods to minimize price volatility;
- Requiring or allowing investor-owned electric companies to construct, acquire, or lease peak-load or other generating plants and associated transmission lines;
- Providing a process, at the time bids by investor-owned electric companies for electricity supply are obtained for the standard offer service, to solicit bids for the procurement of cost-effective energy efficiency and conservation programs and services if energy efficiency and conservation programs are less expensive than electricity generation;
- Establishing a long-term goal for savings over a period of time of the total residential retail energy consumed in a year in an electric company's service territory through the procurement and implementation of cost-effective energy efficiency and conservation programs and services;
- Providing a process to allow investor-owned electric companies to obtain a portion of their electricity supply for standard offer service through the negotiation of bilateral contracts with wholesale electricity suppliers, either in conjunction with or outside of procurement through competitive wholesale auctions;
- Allowing opt-out aggregation of residential electric customer demand and small commercial electric customer demand by local governments in the service territories of investor-owned electric companies;
- Establishing an office of retail market development; and,
- Requiring investor-owned electric companies to purchase accounts receivable of electricity suppliers for residential and small commercial accounts.[53]

The PSC has already initiated proceedings, including Case Nos. 9111 and 9117 (discussed elsewhere in this Ten-Year Plan), to evaluate most of the approaches listed above. Senate Bill 400 directed the PSC to file by December 1, 2007, an interim report that at a minimum identifies the issues relating to options for re-regulation including the costs and benefits of options of returning to a regulated electric supply market for residential and small commercial customers. In addition, the PSC will issue a final report on all matters requested no later than December 1, 2008. The PSC retained a team of lawyers and consultants led by the law firm of Kaye Scholer LLP and the economics consulting firm of Levitan & Associates.

The PSC plans to issue five Interim Reports to the General Assembly by the end of April 2008, on the following topics:

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[52] Senate Bill 400, § 7(a)(1)-(3).
[53] Senate Bill 400, § 7(b)(1)-(7).

- Part I: Options for Re-regulation
- Part II: Analysis of Stranded Cost Settlements
- Part III: Wholesale Markets
- Part IV: SOS Procurement
- Part V: Constellation/BGE

On December 3, 2007, the PSC issued Part I of its Interim Report on the options for re-regulation, with the term "re-regulation" in Senate Bill 400 defined more broadly than simply to mean a return to the pre-restructuring regime. In fact, the initial threshold question of the hypothetical possibility of returning Maryland's generation fleet to its regulated utilities was dismissed as an unrealistic and prohibitively expensive approach and ruled out quickly by the PSC and its consultants. Thus, the term "re-regulation" is used to encompass the full range of possible PSC and legislative responses to ensure that the deregulated markets ensure reliable, cost-effective electricity for Maryland consumers.

The key factual premise underlying Part I is "unless steps are taken now, the State of Maryland faces a critical shortage of electricity capacity that could force mandatory usage restrictions, such as rolling black-outs, by 2011 or 2012."[54] Maryland faces this crisis due to the fact that it is located in a highly congested portion of the PJM grid and the State consumes far more electricity than it generates. Due to capacity shortages and transmission constraints, most Maryland consumers pay much higher than average prices for wholesale (and thus retail) electricity. Therefore, the Commission has reached the following conclusions in Part I:

- The State will need to add more capacity (either through new generation or transmission) as well as reduce the amount of electricity it uses;
- It is not in the public interest to rely exclusively on market forces to address Maryland's reliability concerns and the high wholesale electricity prices paid; and,
- The State does not have the luxury of waiting for the markets to address Maryland's reliability and pricing problems.

The Commission recommends and plans to undertake a series of interventions designed to respond directly to these problems:

- If necessary, the PSC will force an increase in the available supply of electricity, both to ensure a reliable supply and to relieve some of the upward pressure on wholesale prices. Unless generators substantially increase their committed electricity capacity supply in the January and May 2008 capacity (RPM) auctions, the PSC will direct the Maryland IOUs to enter into new, long-term contracts to induce electricity supply;
- As noted earlier in the Case No. 9111 discussion, the PSC will require utilities to implement aggressive and cost-effective demand management and energy conservation programs, consistent with the Governor's EmPower Maryland initiative;
- As noted earlier in the Case No. 9117 discussion, the PSC will rule imminently on whether – and if so how – the SOS process by which utilities purchase electricity for

54 Part I of the *Interim Report of the Public Service Commission of Maryland to the Maryland General Assembly*.

residential and small commercial customers could be modified to achieve better and more stable prices for these customers; and,

- The PSC will continue to expand and elevate its presence at FERC, PJM, and other forums as an advocate on behalf of Maryland's energy future, reasonable rates, and fairness in the wholesale electricity markets.

The Commission notes that these obviously are not the final and only actions that it will take and that it will continue to review and analyze these issues in the months and years to come to ensure that the wholesale markets provide a reliable electricity supply to Maryland consumers at just and reasonable prices in the short and intermediate term. Also in Part I, the PSC's consultants analyzed the viability and economic impact of a wide range of longer-term new generation and transmission options. Utilizing a set of base assumptions regarding the state of the Maryland and regional electricity markets, the consultants performed a rigorous economic analysis of different options under a number of economic scenarios upon which the Commission's recommendations and analysis flow.

In conjunction with the comprehensive studies prepared by Kaye Scholer and Levitan, the Commission notes the relative merits of different available options:

- New transmission offers the highest total economic value added compared to its costs, as it affects both capacity and energy costs due to its ability to relieve physical constraints on the grid. While the most attractive option economically, it is also the most uncertain because other state and federal officials determine its fate;
- The nuclear case provides the highest cumulative EVA in all scenarios, but price benefits likely are not realized for ten years until 2017 given the associated lead time;
- The addition of 1,200 MW of excess power from combined cycle gas plants beyond the amount needed to maintain reliability provides the most substantial benefit in the short and intermediate term;
- The wind option modeled by the consultants – a mix of onshore and offshore wind farms – does not provide either short or long term economic benefits. However, wind can represent a source of clean, emissions-free (including carbon-free) power; and,
- The full attainment of the EmPower Maryland goal yields a large, positive EVA for Maryland customers, greater than the 1,200 MW combined cycle gas option.

Part I of the Interim Report, including separate extensive Kaye-Scholer (a comprehensive review of electricity restructuring option in Maryland and elsewhere) and Levitan (a detailed, rigorous economic analysis of the costs and benefits of new electricity capacity in the State) reports are available on the Commission's website. Parts II through V of the Interim Report will also be found there when they become available early in 2008.

IX. PJM AND REGIONAL ENERGY ISSUES AND EVENTS

In the Electric Act of 1999, Maryland (as did many other states) relinquished much of its jurisdiction over generation activities. However, the Commission still has jurisdiction over the retail (or distribution) function of electric companies. Absent regulation of generation,[55] in order to ensure that all aspects of electricity supply and distribution work appropriately, there needs to be a functional wholesale electric market.

As in other restructured states in this region, Maryland is reliant on the PJM RTO for energy, capacity, and ancillary services. Recently there have been questions raised with respect to the high costs of energy and whether such costs are truly representative of a "competitive" market. New market approaches, including the Reliability Pricing Model, designed to incent new capacity installations and marginal losses, designed to reflect the locational aspect of transmission losses and to enhance the current economic dispatch approach, have been initiated in market operations. While there are still questions on the success of these efforts, the economic impact of higher capacity prices has been seen in recent wholesale energy bids.

A. Overview of PJM, OPSI, and Reliability First

Before discussing major regional issues, it would be useful to begin with an overview of several organizations that play a critical role in the functioning and reliability of the regional wholesale markets. PJM is the RTO that encompasses all of Maryland and to which all of the State's electric companies belong; OPSI is a recently-formed organization to which the state regulatory bodies of PJM belong; and Reliability First is the reliability organization that includes all of Maryland and almost the entire footprint of PJM.

PJM Interconnection, LLC

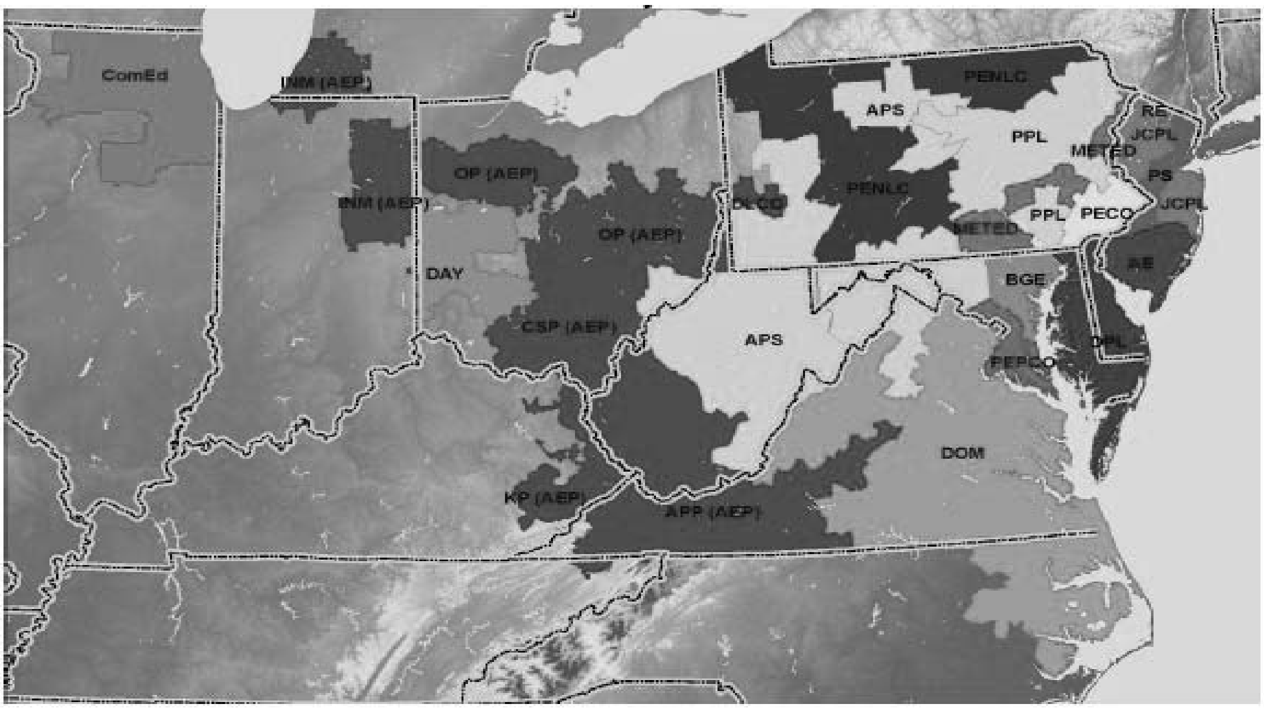
Maryland resides in a portion of a regional electric grid that is operated by PJM. PJM is the largest power grid in North America and also operates the world's largest competitive wholesale electricity market. PJM was first established as a power pool in 1927 as an association of utilities in Pennsylvania, New Jersey, and Maryland. On March 31, 1997, PJM became an independent entity and, with its own Board of Governors, was renamed PJM Interconnection, LLC. On January 1, 1998, PJM became the first operational independent system operator in the United States and became responsible for the safe and reliable operation of the transmission system in addition to the administration of the competitive wholesale electric power market. Market participants can buy and sell energy, schedule bilateral transactions, and reserve transmission service. In December 2002, FERC awarded PJM full Regional Transmission Organization status.

As listed on its website, PJM now operates a centrally dispatched competitive wholesale electricity market with more than 450 market buyers, sellers and traders of electricity in region that is comprised of more than 51 million people. The PJM footprint includes all or parts of 14 political jurisdictions including Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New

[55] PUC § 7-510(c)(6) states that "… the Commission may require or allow an investor-owned electric company to construct, acquire, or lease, and operate, its own generating facilities...".

Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. Currently PJM's electricity market has a generating capacity of about 165,000 MW, peak demand of nearly 145,000 MW, and about 56,250 miles of transmission lines.[56] The winter peak load for the 2006-2007 season was about 120,000 MW. PJM projects a 1.5% annual growth rate in summer peak load in the Mid-Atlantic region. The Mid-Atlantic region has continued to experience spikes in locational marginal prices, due either to congestion of the grid or lack of sufficient economical resources. PJM has at times indicated the possibility of future deliverability problems for central Maryland – a condition that could lead to load shedding and which may be resolved with more generation or transmission.

Map IX.A.1: PJM Zones



Over the last several years the PJM footprint (see Map IX.A.1 above) has expanded dramatically, more than doubling in size as measured by capacity and peak demand. The expansion has been to the west and to the south, so that the PJM footprint includes nearly all of Virginia, eastern North Carolina, and nearly all of northern Illinois inclusive of Chicago.

Organization of PJM States, Inc.

On May 13, 2005, the Organization of PJM States, Inc., of which the Maryland PSC is a member, was formed. OPSI is a non-profit, 501(c)(4) Delaware corporation. OPSI's members include all fourteen state regulatory commissions (inclusive of the District of Columbia Public Service Commission) within the PJM footprint. OPSI provides a means for the PJM states to act in concert with one another when it is deemed to be in the common interest of their consumers.

56 Source: http://www.pjm.com/about/territory-served.html.

According to its articles of incorporation, OPSI will undertake such activities as data collection and dissemination, market monitoring, issue analysis, policy formation, advice and consultation, decision-making and advocacy related to:

- PJM operations;
- The electric generation and transmission system serving the PJM States;
- FERC matters; and,
- The jurisdiction and role of the PJM States to regulate and promote the electric utilities and systems within their respective boundaries.

Each state commission has a member on the OPSI Board of Directors. The OPSI executive committee consisting of the president, vice-president, secretary, and treasurer, in conjunction with the Board of Directors sets general policy direction. The Maryland Commission has been an active participant in OPSI and was represented on its executive committee at its inception. Other significant information concerning OPSI is that it is a voluntary organization, addresses regional issues directly related to PJM, and OPSI positions do not bind individual commissions and are not official actions of any member state. The fourteen members are grouped into the following three regions:

- Mid-Atlantic: Delaware, District of Columbia, Maryland, New Jersey, Pennsylvania
- West: Illinois, Indiana, Michigan, Ohio, West Virginia
- South: Kentucky, North Carolina, Tennessee, Virginia

Reliability First Corporation

Beginning January 1, 2006, Reliability First Corporation sets reliability standards for PJM, excepting the portions of Virginia and North Carolina in PJM. The SERC Reliability Corporation[57] sets reliability standards for those two states and the rest of the Southeast and part of the Midwest. The purpose of these corporations is to ensure the reliability and security of the bulk electric supply systems of the regions through coordinated operations and planning of their generation and transmission facilities. RFC and SERC have oversight over transmission facilities at a voltage level of 230 kV and above within their respective service territories.

Reliability First Corporation is the successor organization for areas from three former NERC Regional Reliability Councils: the Mid-Atlantic Area Council, the East Central Area Coordination Agreement, and the Mid-American Interconnected Network organizations. RFC's primary responsibilities involve monitoring compliance with reliability standards for all owners, operators and users of the bulk electric power system within the region. RFC membership currently consists of 43 regular members and 19 associate members. RFC serves more than 72 million people in an area covering all of the states of Delaware, Indiana, Maryland, Ohio, Pennsylvania, New Jersey, and West Virginia, plus the District of Columbia; and portions of Illinois, Kentucky, Michigan, Tennessee, Virginia, and Wisconsin.

57 http://www.serc1.org/Application/HomePageView.aspx.

B. PJM Summer Peak Events of 2006 and 2007

Peak demand is a term that is often used to describe a sustained period where it is anticipated that electricity will be required at a significantly higher than average level. Fluctuations in peak demand may occur on various cycles and in this section we will examine peak demand events that occur within a given year. The actual point of peak demand is an hourly period that is representative of the highest point of electricity consumption by the customers.

Utilities plan and build for peak demand in an effort to maintain reliability and the total generation capacity of a grid is scaled to be commensurate with the total peak demand with a built-in reserve margin. The margin of error allows for a surge capacity and allows for unforeseen events. Grid operators will usually plan to use the least expensive generating capacity to meet demand and utilize an economic dispatch order in an effort to mitigate the marginal cost of electricity.

Like peak demand, the coincident peak is the load or draw on a system that occurs at the hour of the highest load in a given period. PJM publishes coincident peak information[58] referred to as 5CP. This is done to assist EDCs in calculating their peak load contributions each summer. Each summer the hourly metered load and load drop estimate data is accumulated for the period spanning June 1 to September 30. The RTO unrestricted loads are then created by adding the load drop estimates to the metered load. After this, the five highest unrestricted daily peaks are identified.

Table IX.B.1: Summer 2006 and Summer 2007 Coincident Peaks and Zone LMP

Summer 2006 Coincident Peaks				Zone LMP During the Peak				
Day	**Date**	**Hour**	**MW**	**AP**	**BGE**	**DPL**	**PEPCO**	**PJM**
Wednesday	8/2/2006	17:00	145,951	$346.12	$674.61	$527.62	$721.07	$213.85
Tuesday	8/1/2006	17:00	145,309	$697.58	$810.46	$803.79	$812.89	$752.37
Monday	7/17/2006	17:00	139,373	$247.45	$291.71	$326.83	$284.49	$286.44
Monday	7/31/2006	17:00	138,639	$179.47	$176.77	$167.39	$200.66	$190.04
Thursday	8/3/2006	16:00	136,534	$299.24	$711.01	$550.84	$755.13	$411.76
Summer 2007 Coincident Peaks				**Zone LMP During the Peak**				
Day	**Date**	**Hour**	**MW**	**AP**	**BGE**	**DPL**	**PEPCO**	**PJM**
Wednesday	8/8/2007	17:00	141,049	$471.48	$1,045.53	$1,031.27	$1,030.20	$675.06
Tuesday	8/7/2007	17:00	134,674	$150.84	$165.10	$150.76	$168.82	$148.52
Monday	7/9/2007	17:00	134,632	$199.62	$174.83	$166.95	$179.42	$142.12
Thursday	8/2/2007	17:00	134,104	$135.96	$140.31	$138.32	$142.07	$143.72
Wednesday	6/27/2007	16:00	131,347	$145.43	$142.37	$126.26	$171.44	$126.12

58 Additional information regarding this process can be found in PJM Manual 19 Load Forecasting and Analysis.

Over the course of 2007, PJM had summer peak events that were comparable to events that occurred in 2006. Table IX.B.1 above shows the summer 2006 and 2007 coincident peaks and the average LMP by zone during that time period. The summer 2006 coincident peak occurred on August 2, 2006 at 5:00 PM Eastern Daylight Time. This peak was 145,951[59] MW of total load within the PJM region. The summer 2007 peak was 141,049[60] MW and occurred on August 8, 2007 at 5:00 PM Eastern Daylight Time.

The coincident peaks that occurred in the summers of 2006 and 2007 resulted in elevated LMPs in the Maryland zones. Generally the LMP levels for the BGE, Delmarva, Pepco, and Allegheny zones were at or higher than for PJM as a whole. Outside of the summer peak event for the summer of 2007, the LMP price levels for 2007 appear to be lower than their 2006 counterparts during the summer peak events.

PJM's 2006 peak load of approximately 144,644 MW occurred on August 2, 2006. PJM was able to meet this peak load with economic generation and load management in the mid-Atlantic region. PJM did not have to load maximum emergency generation nor did PJM require a voltage reduction. PJM's 2007 peak load of approximately 139,428 MW occurred on August 8, 2007. PJM was able to meet this peak load with the issuance of a voltage reduction of 5% for the mid-Atlantic region.

Overall, generation and transmission upgrades implemented have been beneficial to Maryland and other portions of eastern PJM. Summer peak events still occur and drive congestion throughout PJM. More transmission upgrades or new electricity generation in eastern PJM will need to be introduced in order to meet the growing load demand in the areas that require electricity imports. The electricity grid is designed to handle peak loads. During average load periods, Southwest MAAC experiences higher LMP levels than surrounding zones and this trend carries over during peak load situations, despite an apparent moderation of the overall LMP pricing levels from 2006 to 2007, during the coincident peaks within the PJM system.

C. PJM State of the Market Report

PJM's Market Monitoring Unit issued its 2006 State of the Market Report on March 8, 2007. Within this report, PJM analyzed the amount of generating capacity and the strength of competition in the centrally dispatched competitive wholesale energy market. Expansion in the total amount of market buyers, sellers, and traders as well as the growth in the number of people residing in the region are points conveyed within the report.

The robustness of the energy and capacity markets was examined by PJM in the 2006 State of the Market Report and determined to be competitive. According to the MMU, it could not be determined if the results of the regulation market were competitive or noncompetitive. Competitive results were also given to the synchronized reserve markets and the FTR Auction markets.

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59 Source: http://www.pjm.com/planning/res-adequacy/downloads/summer-2006%20-peaks-and-5cps.pdf.

60 Source: http://www.pjm.com/planning/res-adequacy/downloads/summer-07-peaks-and-5cps.pdf.

At the end of 2006, PJM's 162,143 MW installed capacity[61] fuel source distribution was 41.0% coal, 29.0% natural gas, 18.5% nuclear, 6.6% oil, 4.4% hydroelectric and 0.4% solid waste. Over the course of calendar year 2006, PJM's total generation capacity by fuel source was 56.8% coal, 34.6% nuclear, 5.5% natural gas, 2.0% hydro, 0.3% oil, 0.7% solid waste and 0.1% wind.

Another indicating figure is the RSI[62]. For calendar year 2006, the average three pivotal RSI was 0.50. This figure indicates that market power existed. The average hourly LMP decreased by 15.2% from $58.08 per MWh in 2005 to $49.27 per MWh in 2005. The load-weighted LMP decreased 15.9% from $63.46 in 2005 to $53.35 in 2006. The main factor in this price increase appears to be a reduction in the cost of fuel. Keeping fuel costs constant from 2005 to 2006, the load-weighted LMP would have been $59.89 instead of the actual $53.35 per MWh. That being said, if fuel prices did not decrease, the 2006 load-weighted LMP would still have been lower than the 2005 figure but at a lesser magnitude. The average, median and standard deviation figures for the LMP trends can be seen in the following chart. Note that the 2006 figure is fuel-cost adjusted and load-weighted, as opposed to the 2005 figure which is only load-weighted. In 2006, coal was on the margin 70% of the time, while natural gas was on the margin 25%.

Table IX.C.1: PJM Fuel Cost-adjusted, Load-weighted LMP

(Dollars Per MWh)	2005 Load Weighted LMP	2006 Fuel Cost Adjusted Load Weighted LMP	Change
Average	$63.46	$59.89	-5.63%
Median	$52.93	$49.99	-5.55%
Standard Deviation	$38.10	$38.34	0.63%

D. Installed Reserve Margin

Installed reserve margin is the installed capacity percent above the forecasted peak load required to satisfy a Loss of Load Expectation of one day in ten years. For a given delivery year, IRM is one of the two primary inputs needed for calculating the Forecast Pool Requirement.

The IRM study was conducted in accordance with the process outlined in the PJM Reserve Requirements Manual (M-20) and based on the assumptions and study activities outlined for a specific year by PJM Planning Committee. IRM is approved by the Reliability Committee based on analysis performed by PJM and reviewed by the Load and Capacity Subcommittee and Planning Committee. Judgment must always be used when assessing the correct IRM level to establish for future delivery years. Long-term trends and the influence of different modeling practices and assumptions should be important considerations in establishing the IRM. The chart and the table on the next page show the PJM four-year forecasted total load, including reserve margin, for PJM beginning with the 2007/2008 planning year.[63]

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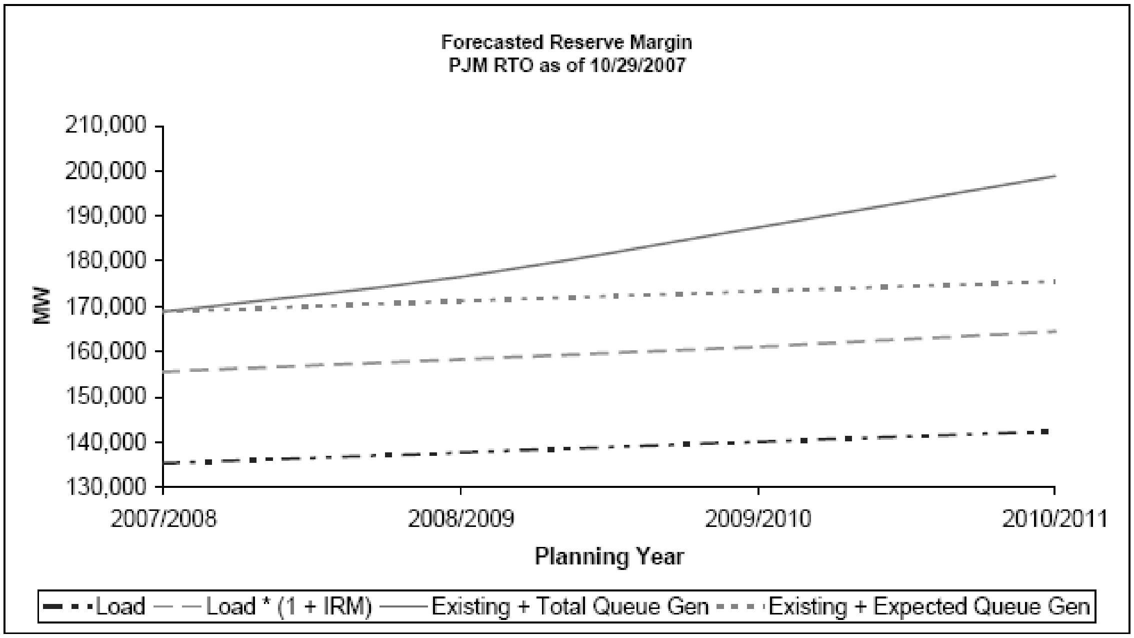
61 Installed capacity is the as-tested maximum net dependable capability of the generator, measured in MW.

62 Residual Supply index is equal to (total supply – largest seller's supply)/(total demand). The RSI is a measure used to determine market power. The RSI is not a bright line test, an RSI less than 1.0 for a single generation owner clearly indicates market power, a RSI greater than 1.0 does not guarantee that there is no market power.

63 Each PJM Planning Year begins on June 1 and ends May 31 of the following year.

Chart IX.D.1: PJM Forecasted Reserve Margin



PJM RTO - 10/29/2007

Planning Year	Forecasted Summer Peak Net Internal Demand	Forecasted Peak Net Internal Demand + Reserve Requirement	Existing Installed Capacity as of 10/29/07	Total Inter-connection Queue Generation by June 1st	Expected Interconnection Generation Additions by June 1st	Announced Retirements	Existing Total Interconnection Queue Generation	Existing Expected New Generation Additions	Summer Peak Fore-casted Reserve Margin %
2007/2008	135,288	155,581	168,826	0	0	19	168,808	168,808	24.8
2008/2009	137,669	158,319	168,826	8,002	2,661	285	176,525	171,183	24.3
2009/2010	140,037	161,043	168,826	11,437	2,711	501	187,461	173,393	23.8
2010/2011	142,409	164,482	168,826	11,377	2,162		198,838	175,555	23.3
2011/2012	144,731	167,164	168,826	14,103	2,437	682	212,258	177,309	22.5

Column A: PJM Total Demand - Active Load Management. Forecast is calculated as a diversified sum of zonal forecasts.
Column B: Column A multiplied by the Reserve Requirement of 1.15 for planning period 2007/2008-2009/2010
and 1.155 for planning period 2010/2011-2011/2012
Column C: Installed Capacity as of 10/29/2007. This number represents "iron-in-the-ground" inside of the PJM electrical territory. This number excludes externa sales/purchases and does not necessarily represent generation controlled by PJM.

Column D: For planning year 2007/2008, the value in Column D represents the Queue Generation from 10/29/2007 to 5/31/2008
-- For all other years, the applicable time period is from June 1st of the first year listed to May 31st of the second *year listed*
Column E: Queue Generation * Commercial Probability (by project status)
Column G: Existing Installed Capacity + Total Queue Generation - Announced Retirements
Column F: Announced Future Generator Retirements
Column G: Existing Installed Capacity + Total Queue Generation - Announced Retirements
Column I: [Column H/Column A] -1
Source: www.pjm.com/planning/res-adequacy/downloads/20071029-forecasted-reserve-margin.pdf
*Each planning year row represents a snapshot of the system as of the first day of the planning year (June 1st)

E. Electricity Imports and Exports within PJM

States that consume more electricity than they generate are classified as net importers of electricity. As mentioned earlier in this report, Maryland is a large importer of electricity. The 2006 Maryland energy profile shows that the state imports almost 30% of the electricity that it consumes. Table IX.E.1 below shows the net imports for Maryland over the five-year period from 2002-2006, a time period in which net imports have averaged 30.4% per year. Please note that it is not possible to determine the actual levels of imports into and exports out of Maryland, but it is possible to impute an annual net imports figure adjusted for transmission losses.

Table IX.E.1: Maryland Electricity Net Imports, 2002-2006

Year	2002	2003	2004	2005	2006	5-Yr Avg.
Sales + T&D Losses	73,850	76,959	72,273	73,835	68,227	**73,023**
Generation	48,279	52,244	52,053	52,662	48,957	**50,839**
Net Imports	25,571	24,715	20,190	21,173	19,270	**22,184**
Net Import Pct.	34.63%	32.11%	27.95%	26.68%	28.24%	**30.38%**

Source: EIA. All figures in GWh. T&D Losses are assumed to be 8.0%

Many other northeastern PJM states are also net importers of electricity. D.C., for example, imports over 99% of its total consumption. D.C., therefore, is completely reliant on electricity exports from other PJM states to satisfy its electricity demand and is an extreme example of a net importing state. Several other PJM states—while not as reliant on imports as D.C.—share a similar importing profile: Delaware imports 42.5% of the electricity that it consumes; Virginia imports 36.6%; New Jersey imports 29.5%; and Tennessee imports 16.3%. Table IX.E.2 lists those states within PJM that import electricity to satisfy their consumption needs.

Table IX.E.2: State Electricity Imports for Year 2006

State	Retail Sales (Consumption)	Sales + T & D Loss	Generation	Net Imports	Pct. of Sales Imported
D.C.	11,396,424	12,308,138	81,467	12,226,671	**99.34%**
Delaware	11,554,672	12,479,046	7,182,179	5,296,867	**42.45%**
Virginia	106,721,241	115,258,940	73,069,537	42,189,403	**36.60%**
New Jersey	79,680,947	86,055,423	60,700,139	25,355,284	**29.46%**
Maryland	63,173,143	68,226,994	48,956,880	19,270,114	**28.24%**
Tennessee	103,931,744	112,246,284	93,911,102	18,335,182	**16.33%**
N. Carolina	126,698,979	136,834,897	125,214,784	11,620,113	**8.49%**
New York	142,238,019	153,617,061	142,265,432	11,351,629	**7.39%**
Ohio	153,428,844	165,703,152	155,434,075	10,269,077	**6.20%**
Michigan	108,017,697	116,659,113	112,556,738	4,102,375	**3.52%**

Source: EIA. All figures in MWh. T&D losses are assumed to be 8.0%.

North Carolina, New York[64], Ohio and Michigan each import less than 10.0% of their consumption, and therefore, are not significant importers of electricity on a net basis. Michigan and Ohio are also in the Midwest ISO, and only a small section of North Carolina is in PJM. As with Maryland, it is not possible to determine the gross level of imports and exports for a given state. In some cases, it is likely that large amounts of electricity are imported in one portion of a state and exported from another. In Maryland, most electricity imports likely come from states such as Pennsylvania and West Virginia. However, Maryland exports a significant amount of its own generation to the District of Columbia and northern Virginia, both areas being large net importers of electricity. Further, even if the net imports for Maryland or another state remain nearly constant, the absolute levels of imports and exports may continue to rise and cause strain on the grid at locations where there are transmission constraints that limit the amount of power that may flow at peak times of the day.

In addition to states that import electricity, there are some states that export more electricity than they generate. West Virginia, Pennsylvania, Illinois, Indiana and Kentucky export their excess electricity to states that do not generate enough electricity to meet their demand. West Virginia, for example, exports more than half of the electricity that it generates. Table IX.E.3 lists the states within PJM that export a portion of the electricity that they generate on a net basis.

Table IX.E.3: State Electricity Exports for Year 2006

State	Retail Sales (Consumption)	Sales + T & D Loss	Generation	Net Exports	Pct. of Generation Exported
West Virginia	32,312,126	34,897,096	80,537,427	45,640,331	**56.67%**
Pennsylvania	146,150,358	157,842,387	218,811,595	60,969,208	**27.86%**
Illinois	142,447,811	153,843,636	192,426,958	38,583,322	**20.05%**
Indiana	105,664,484	114,117,643	130,489,788	16,372,145	**12.55%**
Kentucky	88,743,435	95,842,910	98,792,014	2,949,104	**2.99%**

Source: EIA. All figures in MWh. T&D losses are assumed to be 8.0%.

The tables above illustrate a recurring theme within the PJM system: the energy needs of several states are supported by electricity exports from West Virginia and Pennsylvania. Illinois and Indiana are electricity exporters, but the majority of those states are in the Midwest ISO region. The import and export profile of PJM states highlights the need for an adequate, reliable, and efficient transmission grid. PJM, through its regional planning process, recognizes the importance of an effective grid and continues to work with its members to ensure the transmission infrastructure is adequate to facilitate this electricity trade between states. PJM has two main options to assist electricity movement within the ISO: upgrade existing transmission or build new transmission. See Section X.E for a discussion of the DOE National Interest Electric Transmission Corridors, as well as a description of the three bulk transmission projects (TrAIL, PATH, and MAPP) that have been approved recently by the PJM Board.

64 New York is not a member of PJM. New York is a member of the New York ISO.

F. PJM's Reliability Pricing Model

On August 31, 2005, more than one year after introducing it at a Commission proceeding,[65] PJM filed its Reliability Pricing Model proposal with FERC for approval to "address current serious inadequacies" in existing capacity rules. In this filing, PJM proposed to replace its then-current capacity construct with RPM on June 1, 2006, and requested that FERC issue its final order on the filing no later than January 31, 2006. The RPM filing met with significant opposition from many PJM members and other stakeholders, including many state commissions within the PJM footprint. Their principal concerns appeared to be that:

- RPM would result in significantly higher payments by load serving entities;
- New investment would not result;
- RPM would encourage the construction of peaking capacity only (not baseload);
- There was no apparent role for long-term transmission projects; and,
- Demand response resources received few incentives.

The Commission filed comments with FERC on RPM on October 19, 2005. In its comments, the Commission said, "The Maryland Commission views RPM as a means to an end: a transitional mechanism to secure resource adequacy where it is needed now and to serve as a bridge toward mature electricity markets that do not require regulatory intervention to ensure resource adequacy. Although the MDPSC generally supported moving forward with a next-generation capacity market design, several questions required more in-depth exploration."

During 2006, FERC managed settlement discussions between all the affected parties including PJM, state commissions (including the Maryland Commission), and PJM members:

- Over 150 individuals representing more than 65 parties engaged in the discussions;
- The final settlement gained broad support across diverse stakeholder interests[66]; and,
- The new capacity market construct would be implemented on June 1, 2007.

Changes to RPM that occurred during settlement discussion included: (1) addition of explicit performance metrics for generators to deliver energy during peak period hours; (2) a revised demand curve with generally lower capacity reference prices; (3) addition of a fixed resource requirement (opt-out) alternative; (4) inclusion of various market power mitigation provisions; (5) addition of cost of new entry reference price adjustment based on empirical data from actual capacity market activity; and (6) additional integration with the PJM RTEPP.

When fully transitioned, PJM will hold a centralized auction three years in advance of a given June 1 to May 31 planning year, with several incremental auctions held to fine-tune the process. PJM has held three of the four planned capacity auctions for the 2007/2008 to 2010/2011 Planning Years, with each auction separated by a period of several months in order to effect the transition and set up the initial three-year planning horizon. The first three transitional auctions were held the weeks of April 2, 2007; July 2, 2007; and October 1, 2007.

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65 See Case No. 8980, *In the Matter of the Inquiry into Electric Generating Resource Adequacy*.
66 The Maryland PSC participated in the discussions, but abstained in the final vote on the RPM settlement.

The final transitional auction is scheduled for the week of January 21, 2008 (for 2010/2011) and the first regular auction is scheduled for the week of May 5, 2008 (for 2011/2012). Additionally, the entire PJM footprint was not transitioned at once; instead, regions will be layered-in over time. PJM has implemented plans to add the LDAs as follows and the results of the first three RPM auctions are shown in Table IX.F.1 below:

- 2007/2008 and 2008/2009 Planning Years: EMAAC[67], SWMAAC[68], and the entire RTO;
- 2009/2010 Planning Year: EMAAC, SWMAAC, MAAC[69] plus Allegheny (MAAC + AP), and the entire RTO;
- 2011/2012 Planning Year: MAAC, SWMAAC, DPL South, RTO, and RTO less FRR.

Table IX.F.1: Results for First Three RPM Transitional Auctions

RTO[70]	**Resource Clearing Price**	**Net Load Price**	**Total Resources[71]**	
			Offered	**Cleared**
2007/2008	$40.80	$40.80	130,843.7 MW	129,409.2 MW
2008/2009	$111.92	$111.92	131,880.6 MW	129,597.6 MW
2009/2010	$102.04	$102.04	133,551.0 MW	132,231.8 MW

SWMAAC	**Resource Clearing Price**	**Net Load Price**	**Total Resources**	
			Offered	**Cleared**
2007/2008	$188.54	$140.16	10,201.2 MW	10,201.2 MW
2008/2009	$210.11	$180.58	10,626.1 MW	10,621.2 MW
2009/2010	$237.33	$218.12	10,311.7 MW	9,914.7 MW

EMAAC	**Resource Clearing Price**	**Net Load Price**	**Total Resources**	
			Offered	**Cleared**
2007/2008	$197.67	$177.51	30,827.2 MW	30,797.8 MW
2008/2009	$148.80	$143.51	31,379.4 MW	30,231.3 MW
2009/2010	$191.32	$188.55	31,684.2 MW	31,650.6 MW

MAAC + AP	**Resource Clearing Price**	**Net Load Price**	**Total Resources**	
			Offered	**Cleared**
2009/2010	$191.32	$188.55	72,997.9 MW	72,547.7 MW

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67 The EMAAC LDA, consistently mostly of New Jersey and the Delmarva Peninsula, is the Atlantic Electric, Delmarva, Jersey Central, PECO, Public Service, and Rockland zones.

68 The SWMAAC LDA consists solely of the BGE and PEPCO zones.

69 MAAC includes all of SWMAAC and EMAAC and three Pennsylvania zones (MedEd, Penelec, and PPL).

70 RTO numbers include MAAC+APS and MAAC+APS numbers include SWMAAC and EMAAC.

71 Total Resources Offered and Cleared is represented in Unforced Capacity MW (adjusted for EFORd) and includes both generation and demand resources.

As mentioned earlier, the final transitional RPM auction is scheduled to commence the week of January 21, 2008. Most of the zones for this auction are new, as the EMAAC LDA is dropped and the MAAC LDA and the Delmarva South LDA have been added. On November 2, 2007, PJM notified its members that it would not implement a new Central PJM LDA, which would have included Southwest MAAC and portions of other zones circling the Baltimore-Washington region. This new LDA was scheduled to be added to the fourth transitional auction for the 2010/2011 Planning Year, but PJM delayed considering implementing this LDA until the first regular RPM auction is held in May 2008.

For the initial regular RPM auction for the 2011/2012 Planning Year, there are currently 23 LDAs defined: five "global" study areas (Mid-Atlantic, Eastern Mid-Atlantic, Western Mid-Atlantic, Southern Mid-Atlantic, and PJM Western Area) and 18 "zonal" study areas (including subzones such as Delmarva South and PSE&G North). In addition, PJM proposed to implement new, higher CONE values to reflect the price inflation of raw materials, labor, and other inputs into building new generation facilities in time for the May 2008 auction for the 2011/2012 Planning Year. A FERC decision on the proposed increase to the CONE value is expected from FERC before the auction takes place.

G. Implementation of Marginal Losses in PJM

In March 2006, the PHI Companies filed a complaint against PJM alleging that PJM was in violation of its tariff because PJM was using an average loss method of determining transmission losses rather than the locational marginal loss method required by Section 3.2.5 of the Operating Agreement. On May 1, 2006, FERC found that PJM was in violation of its tariff and set October 2, 2006 as the date by which PJM was required to implement a locational marginal loss method as contained in its tariff.

By way of explanation, there are always transmission losses in any grid system between the time the energy is generated and finally delivered. Typically such losses are heat losses generated during transmission of energy and transformation losses that occur when energy voltages are transformed for delivery to load. Such losses have always been paid for by the load. PJM has historically used an overall system average to charge losses equitably to all loads. Since losses can vary by energy delivery paths (different lines and transformers have different loss characteristics) and the distance of the delivery (nearby generators versus far away generators), the use of average loss costing meant that loads close to generation paid a higher than actual portion of the loss costs and loads further away from generation sources paid a lower than actual portion of the loss costs. Since all load paid the same average loss costs, only transmission congestion and generation dispatch contributed to the locational marginal pricing concept. In addition, the use of average losses ignored the true impact of losses when choosing which generators to dispatch. By charging load for marginal losses, the locational marginal price more accurately reflected the locational costs.

Within the PHI complaint, FERC and other parties concentrated their concerns on over-collection of loss costs using the marginal costing approach. With the use of marginal loss costing, it is a fact that the marginal cost of losses will always be higher than the actual average cost. As PJM would be recovering marginal loss costs from load, there would always be an over collection of actual system loss costs by PJM. The complaint further noted that PJM estimated the total load savings in implementing marginal losses would be $100 million annually, with some $76 million accruing to the PHI companies, although actual savings and how it should be allocated was a central issue of concern.

PJM's tariff provided that PJM would implement marginal loss costing when its computer systems, software, and other resources were sufficient to implement such system. The complaint argued that PJM did have sufficient resources and should have implemented marginal loss costing. PJM agreed that it did have sufficient resources and could implement marginal loss costing. While the estimated benefit to load and the allocation of the surplus was in dispute by the various parties, FERC agreed that marginal loss costing ensured that load paid the proper marginal cost for the power it was purchasing. FERC further noted that the issue for PJM to deal with was not whether marginal loss costing was appropriate, but rather what accounting treatment would be appropriate for the over-collection of loss costs (surplus revenue). The application of marginal costing was appropriate and load should pay the appropriate marginal cost.[72]

On June 2, 2006, PJM filed a motion requesting the deferral of the October 2, 2006 date to June 1, 2007. PJM cited potential impact on many different market segments and argued the delay would provide for a more orderly transition to a marginal loss accounting method. PJM agreed to file its proposal by August 3, 2006. On June 19, 2006, FERC granted PJM's request for a delay in the implementation of marginal losses to June 1, 2007. On August 3, 2006, PJM filed its proposal for implementing marginal losses. In that filing, PJM put forth three possible ways to distribute the surplus marginal revenues. On November 6, 2006, in addressing rehearing requests, FERC denied the requests for rehearing and further selected the majority approach to distributing the revenue surplus. The majority approach provided for distribution of the marginal loss surplus to load on a megawatt load ratio basis.[73]

Effective June 1, 2007, PJM implemented its marginal loss methodology, which included changes to economic dispatch of generation to include consideration of marginal losses. The PJM Marginal Loss working group was re-chartered in December 2007 and charged with discussing issues related to the PJM implementation of marginal losses based on the actual data since June 1, 2007, and with making any recommendations for rules and procedures changes, as applicable, by May 1, 2008.[74]

As PJM continues to monitor marginal losses and the approved accounting methodology, load continues to pay for the locational losses as part of the locational marginal price for energy. Generation continues to be economically dispatched, including consideration for marginal losses and subject to system constraints. Surplus revenues are distributed monthly to load, based on the megawatt load ratio share.

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72 FERC Docket EL-06-55-000, Order on Complaint Requiring Compliance with Existing Tariff Provisions and Related Filings, issued May 1, 2006.

73 FERC Docket EL-06-55.001/002, Order on Rehearing and Compliance Filing, issues November 6, 2007.

74 PJM Marginal Loss Working Group Charter, draft dated 12/21/2007.

The implementation of PJM's marginal loss methodology is another example of energy costs that are dependent on location within the PJM network. Energy costs now reflect the costs of congestion and the full value of marginal losses related to energy. Importing states, such as Maryland, will likely encounter moderately higher energy costs to account for marginal losses between external generation sources and load sinks.

H. Demand Response in PJM Markets

Demand response in PJM, also known as demand side response, continues to be actively promoted within the wholesale electricity markets. While there is a significant level of potential demand side response in the market, it is a relatively small part of what may be available in the transition to a fully functional demand side energy market. A fully developed demand side program will include retail programs and an active, well-articulated interaction between wholesale and retail markets."[75]

PJM has three basic programs: Active Load Management, Economic Load-Program, and Emergency Load-Program. The latter two programs are the core of demand side response programs. The goal is to provide economic incentives for end-use customers to curtail the electricity usage in the circumstances of either peak periods or unexpected outages.

<u>Economic Load-Response Program</u>

The economic program is designed to provide an incentive to customers or curtailment service providers to reduce consumption when PJM LMPs are high. On March 15, 2002, PJM submitted filing amendments to the OATT and to the OA to establish a multi-year economic load response program.[76] On May 31, 2002, FERC accepted the economic program, effective June 1, 2002, with a December 1, 2004, sunset provision.[77] On October 29, 2004, FERC extended the economic program until December 31, 2007.[78] On February 24, 2006, FERC approved changes to the PJM Tariff to permit demand side resources to provide ancillary services and to make the economic program permanent.[79]

The PJM economic load response program is a PJM-managed accounting mechanism that provides for payment of the real savings that result from load reductions to the load reducing customer. Such a mechanism is required because of the complex interaction between the wholesale market and the incentive and regulatory structures faced by both LSEs and customers. The broader goal of the economic program is a transition to a structure where customers do not require mandated payments, but where customers see and react to market prices or enter into contracts with intermediaries to provide that service. The economic program represents a minimal and relatively efficient intervention into the market. The participating sites and registered peak-day MWs in the program have generally increased steadily since 2002.

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75 PJM 2006 State of the Market Report, March 8, 2007.
76 PJM Tariff Amendments, Docket No. ER02-1326-000 (March 15, 2002). 2006 State of the Market Report, p. 89.
77 99 DERCII 61,227 (2002).
78 PJM Letter Order, Docket No. ER04-1193-000 (October 29, 2004).
79 114 FERC II 61,201 (February 24, 2006).

A recent study (Walawalkar, et al. 2007)[80] of the Carnegie Mellon Energy Electricity Industry Center concludes that the economic welfare gain from PJM's economic program outweighs the market distortion caused by the incentive payment during the peak time. The study evaluated the social economic welfare gain based on the current PJM program structure and a trigger price level of $75/MWh.

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. On February 14, 2002, the PJM Members Committee approved a permanent emergency load response program.[81] On March 1, 2002, PJM filed amendments to the OATT and to the OA to establish a permanent emergency load response program.[82] By order dated April 30, 2002, FERC approved the emergency program effective June 1, 2002. Like the economic program, a sunset date for it was set for December 1, 2004.[83] On October 29, 2004, FERC extended the program until December 31, 2007, thereby making it coterminous with the economic program.[84] On February 24, 2006, FERC approved changes to the PJM Tariff to make the emergency program permanent, including energy only and full emergency options.[85]

Table IX.H.1: Emergency Program Registration: Within 2002 to 2006

Date[86]	**Sites**	**Peak-day Registered MW**
August 12, 2002	64	509.3
August 22, 2003	84	475.4
August 3, 2004	3,857	1,395.5
July 26, 2005	3,867	1,455.5
August 2, 2006	4,427	1,081.0

The total MWh of load reductions and the associated payments under the Emergency Program are shown in Table IX.H.2. There was no activity in the program during 2004 because of the mild weather conditions and associated prices. At 3,662 MWh, 2005 had the largest load reduction since the program began. In 2005, payments under the program were $508 per MWh of actual load reduction per peak-day, registered MW. There was no activity in the Emergency Program in calendar year 2006.

80 *Analyzing PJM's Economic Demand Response Program*. 2007 Working paper by Rahul Walawalkar, Seth Blumsack, Jay Apt, and Stephen Fernands at Carnegie Mellon Electricity Industry Center. http://wpweb2.tepper.cmu.edu/ceic/PDFS/CEIC_07_13_ape.pdf

81 PJM Tariff Amendments, Docket No. ER02-1205-000 (March 1,2002).

82 PJM Tariff Amendments, Docket No. ER02-1205-000 (March 1,2002).

83 99 DERCII 61,139 (2002).

84 PJM Interconnection, LLC., Letter Order, Docket No. ER04-1193-000 (October 29, 2004).

85 114 FERC II 61,201 (February 24, 2006).

86 2006 PJM State of the Market Report, Volume II, p. 90, Table 2-55.

Table IX.H.2: Performance of Emergency Program Participants

Year[87]	Total MWh	Total Payments	$/MWh	Total MWh per Peak-Day, Registered MW
2002	551	$282,756	$513	1.1
2003	49	$26,613	$543	0.1
2004	0	$0	$0	0.0
2005	3,662	$1,859,638	$508	2.5
2006	0	$0	$0	0.0

Energy Efficiency and PJM's Capacity Market

On August 31, 2005, PJM filed its RPM proposal to address some serious violations in its capacity rules. FERC, in an order issued on April 20, 2006, found that PJM's existing market rules were unjust and unreasonable.[88] In a subsequent December 22, 2006 Order[89], FERC approved, with conditions, a settlement filed by PJM and PJM market participants concerning the RPM. The settlement established new market rules that will allow PJM to reliably meet the capacity needs of its consumers.

The December 22 Order also required "PJM to conduct a forum for discussions to identify and rectify barriers to entry of demand response within 60 days of the date of the order, and to file a report on the status of the additional process for pursuing demand response and incorporating energy efficiency applications within 240 days of the date of the order."[90] In compliance with the December 22 Order, PJM established the Demand Side Response Working Group. On September 24, 2007, PJM filed a report with FERC describing the process for pursuing demand response and integrating energy efficiency into the PJM markets.[91]

According to the September 24, 2007 report, the DSRWG is the forum at PJM to address issues pertaining to demand response and market design. The DSRWG held a series of discussions on incorporating energy efficiency into the PJM capacity market. The report has identified a list of barriers to energy efficiency[92] that PJM and members of the DSRWG have begun to address.

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87 2006 PJM State of the Market Report, Volume II, p. 92, Table 2-57.

88 *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079 (2006) (April 20 Order) at pp. 1-6.

89 *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,631 (2006) (December 22 Order).

90 December 22 Order, at p. 5.

91 See *PJM Interconnection, L.L.C.*, Docket Nos. ER05-1410-000, -001 & EL05-148-000, 001 (September 24, 2007).

92 Discussions are focusing on energy efficiency resources for large customers with interval meters. The report notes that Synapse Energy Economics and PJM will develop a proposal for customers without interval meters. See page 5 of the September 24, 2007 report. Paul Peterson and Doug Hurley of Synapse, in a presentation given at the DSRWG Meeting of July 12, 2007, noted some of the barriers to energy efficiency resources: lack of awareness and information; limited product availability; high transaction costs; split incentives; and regulatory and rule barriers. The report can be found at: http://www.pjm.com/committees/working-groups/dsrwg/downloads/20070712-item-05-dr-principles.pdf.

X. FEDERAL AND NATIONAL ENERGY ISSUES IMPACTING MARYLAND

FERC regulates PJM (the regional transmission organization for Maryland) and the wholesale market providing energy in Maryland. As the regulatory agency dealing with wholesale issues, FERC has had a major impact on the resulting retail prices in Maryland. In efforts to further develop energy markets and to ensure a continued reliable supply of energy, Congress passed the Energy Policy Act of 2005, provided for the establishment of a National Electric Reliability Organization with enforceable standards, established the authority of the DOE to designate National Interest Electric Transmission Corridors and required state authorities to review important issues that could have energy market implications.

Throughout the implementation of these FERC and DOE mandates, PJM has continued its efforts to improve wholesale markets and its reliability and economic planning process. Through extensive stakeholder meetings, PJM has continued to facilitate discussions on important energy issues and has filed proposed tariff changes as it considered appropriate. The Commission has been actively monitoring and participating in these federal activities and will continue to be active with both PJM and FERC on important energy policy matters.

A. Energy Policy Act of 2005

During 2005, the United States Congress passed the Energy Policy Act of 2005, possibly the most significant piece of national energy legislation enacted since 1992. EPAct 2005 changed the energy landscape and required state commissions to consider possible standards for net metering, fuel sources, fossil fuel generation efficiency, time-based metering and interconnection standards. Major actions taken under EPAct 2005 include:

- The Public Utility Holding Company Act was repealed providing opportunity for mergers and acquisitions;
- Financial incentives were established to encourage siting and development of energy facilities;
- Tax credits and loan guarantees were established for nuclear power;
- DOE was granted authority to designate National Interest Electric Transmission Corridors to encourage new transmission infrastructure;
- Production tax credits for renewable energy options were adopted to provide incentives for new development;
- Direct grants, loan guarantees and accelerated depreciation were made available for new power generation approaches such as clean coal technology;
- FERC authorized NERC as the designated Electric Reliability Organization; and,
- Commissions considered possible standards for net metering, fuel sources, fossil fuel generation efficiency, time-based metering, and interconnection standards.

B. Energy and Security Act of 2007

The Energy and Security Act of 2007 focuses on energy efficiency, demand response, promotion of renewable energy, and transmission improvement. Development in each of these areas is thought to be important to solving looming reliability and pricing issues.

Improved Standards for Appliances and Lighting

Under ESA 2007 revised energy efficiency standards were adopted or required to be developed for various devices including external power supplies, boilers (gas, oil, and electric), electric motors, and residential appliances including certain types of air conditioners and heat pumps. New energy standards were mandated for general service incandescent light bulbs, intermediate base lamps, and candelabra lamps. The new standards will be phased in between June 2008 and 2015.

Accompanying the new standards are requirements that efficiency standards be reviewed on specific periodic bases, various required rulemakings pertaining to energy efficiency standards and labeling, and mandated research, development, and demonstration of improved energy efficiency for appliances and mechanical systems.

Energy Savings in Buildings and Industry

ESA 2007 offers incentives for energy conservation and efficiency in residential and commercial buildings, in industry for waste energy recovery, and in institutions such as schools and local governments. The incentives include increased funding for weatherization at the federal level and attention to energy efficiency, energy sustainability, and renewable energy uses. Research into techniques to maximize efficiencies in energy intensive industries and for various demonstration projects are partially funded, and certain types of education and technical assistance is mandated.

Energy Savings in Government and Public Institutions.

ESA 2007 encourages energy efficiency and the use of renewable energy at the federal level through authorization of and funding for a feasibility study of the construction of photovoltaic roofs for the House and Senate Office Buildings and of carbon capture sequestration technologies and other strategies to reduce emissions at the Capital Power Plant. The bill promotes long term energy savings performance contracts (at least 25 years) with verifiable savings by allowing agencies through various means including cogeneration and sale or transfer of power from on-site renewable energy.

Additional energy efficiency promotional practices include requiring and funding a photovoltaic system for the United States DOE, requiring that at least 30% of hot water demand in new or revived federal buildings be met using solar hot water heaters (if cost-effective), requiring federal agencies to buy or list products that use one watt or less of stand by power and energy star products. The federal agencies will be required to submit annual efficiency reports to the Office of Management and Budget which will in turn submit an annual report to both Houses of Congress.

By July 2009, FERC is required to issue a National Assessment of Demand Response report that includes state estimates of five and ten year demand response potential, policy recommendations to achieve that potential, and identification of and recommendations for overcoming any barriers to needed programs. Based on this report and after stakeholder involvement FERC is to issue a National Action Plan on Demand Response including recommendations to Congress regarding the plan's implementation. Ten million dollars is authorized each year for this purpose for three fiscal years.

Research and Development for Renewable Energy and Energy Storage

Research and development is authorized that will develop thermal energy storage technologies, provide assistance in the demonstration and commercial application of direct solar renewable energy sources. DOE is directed to conduct a study on cost-effective methods to integrate concentrating solar power and utility-scale PV systems into regional transmission systems and to identify new transmission upgrades needed to bring electricity from solar facilities to load centers, improve reliability, and reduce natural gas use for electric power.

ESA 2007 aims to expand the use of geothermal energy through research and development that would develop exploration of undiscovered resources and identify potential adverse environmental impacts of geothermal energy development and use. In addition commercial applications of existing technologies, technology transfer, and demonstration projects will be supported. DOE will report to Congress in three to five years regarding advanced concepts and technologies to maximize geothermal resource potential in the United States and the examination of any legal, regulatory, or other barriers to development of geothermal resources.

DOE is to establish an R&D, demonstration, and commercial application program to expand marine and hydrokinetic renewable resource production with grants to institutions of higher learning.

DOE is to establish a research, development and demonstration program that integrates basic and applied research regarding energy storage as it relates to transmission and distribution. The objectives of this project is to use energy storage to improve grid stability and recovery, security to emergency response infrastructure, emergency backup power for consumers, integration with renewable energy resources, and peak load management.

Carbon Capture Sequestration

ESA 2007 accelerates research on storage and large scale demonstrations of CO_2 storage in a range of geologic formations concentrating on CO_2 from industrial sources. The Secretary of the Interior is required to develop a methodology for geologic storage assessment, to inventory CO_2 stored within public lands, and for managing geologic carbon storage activities on public lands. This and related legal and regulatory issues are to be reported on to Congress.

Smart Grid

ESA 2007 states that it is policy of the United States to support modernization of the country's electricity transmission and distribution system in order to maintain a reliable and secure electricity infrastructure that can meet future growth in demand. DOE is required to prepare a biennial report that surveys smart grid deployment and any regulatory or governmental barriers to continued smart grid development. A federal task force is to coordinate federal government activities relating to smart grid development and research including the development of smart grid standards and protocols, the relationship of smart grid technologies to electricity regulation, infrastructure development, system reliability and security, and to electricity supply, demand, transmission distribution and policy.

DOE, in consultation with FERC, utilities, and stakeholders is to create a Power Grid Digital Information Technology Program to develop advanced technologies for measuring peak load reductions and energy efficiency savings from smart metering, demand response, distributed generation, and electricity storage systems. NIST, with input from FERC, and other relevant federal and state agencies, is directed to develop standards and protocols to achieve interoperability of smart grid devices and systems. When FERC determines there is sufficient consensus with regard to NIST's work, it is to institute a rulemaking to adopt standards and protocols necessary to insure smart grid functionality and interoperability in interstate transmission and regional wholesale electricity markets.

Specific state considerations include an amendment to PURPA that would require states to consider adopting standards requiring consideration of smart grid investments prior to making non-smart grid investments. Under this standard, Maryland and other states must consider whether to authorize rate recovery for smart grid investments and recovery of the remaining value of any equipment rendered obsolete by new smart grid equipment. The states are further required to consider adopting a standard for smart grid information that would require electricity purchasers to be given information on time-based retail and wholesale electricity prices, usage, projection of day-ahead price information, and generation sources, including greenhouse gas emissions.

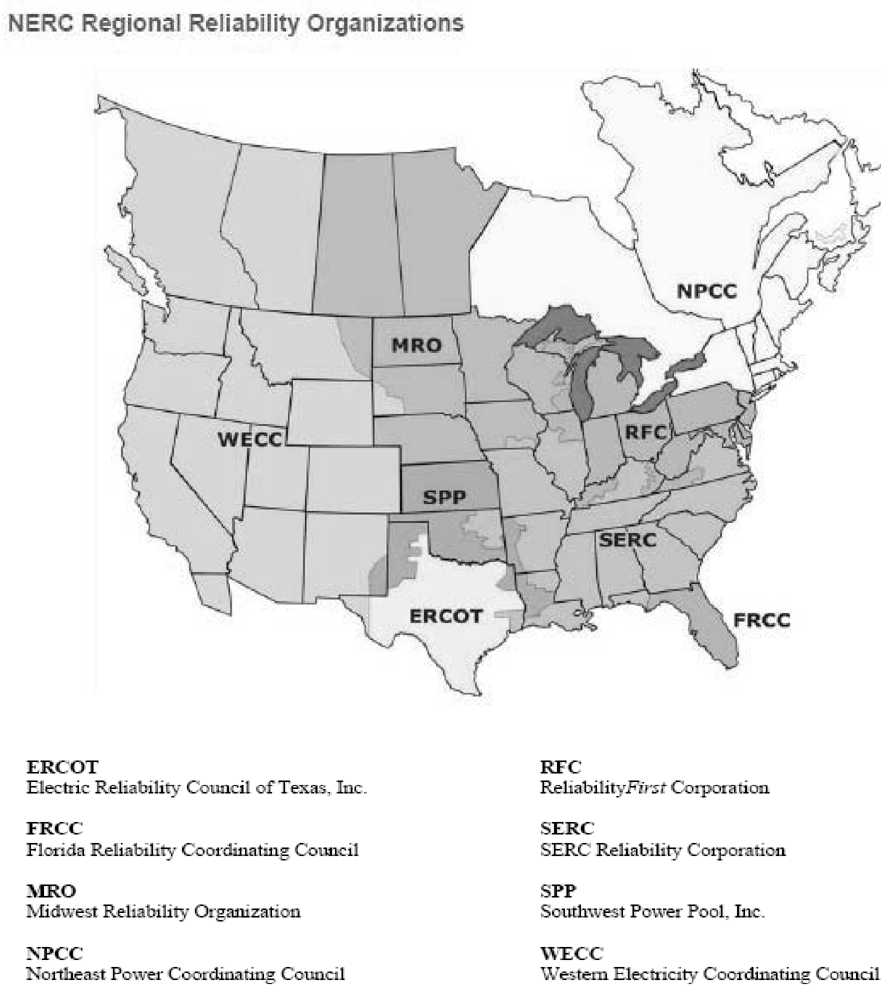
DOE in conjunction with the states and other entities is directed to study and issue a report by December 2008 regarding laws affecting the siting of privately-owned electric distribution wires on and across public rights-of-way. The study is to include an evaluation of the effect of the laws on combined heat and power facilities, a determination of the operating, cost and reliability impacts, and an assessment of whether privately owned wires that would result in duplicative facilities are necessary and desirable. By July 2009, DOE is to submit to Congress a quantitative assessment and determination of the existing and potential impacts of smart grid systems on improving the security of the electricity infrastructure and operating capability, including making the system less vulnerable to intentional disruptions.

C. Formation of a National Electric Reliability Organization

EPAct 2005 required the formation of an ERO with mandatory and enforceable standards. FERC was authorized by EPAct 2005 to designate an organization to serve as the ERO. NERC submitted an application and qualifications to be the ERO to FERC and on July 20, 2006, FERC approved NERC's application.

The ERO must file with FERC each reliability standard that it proposes to be made effective and enforceable. FERC may approve the proposed standard by rule or order if it determines that the standard is "just, reasonable, not unduly discriminatory or preferential, and in the public interest." FERC must give due weight to the technical competence of the ERO or any regional entity organized on an interconnection-wide basis, but is not to defer as to the effect of the standard on competition. If FERC disapproves a standard, it must remand the standard to the ERO for further consideration – it cannot modify the standard itself. FERC may direct the ERO to submit a new or modified standard if it deems that action appropriate to carry out the purposes of the section.

Map X.C.1: NERC Regional Reliability Organizations



NERC Reliability Standards

NERC is an industry organization that has developed standards for the reliability of the electric supply in North America. Due to regional differences throughout the United States, standards are customized by regional corporations. There are eight Regional Reliability Corporations as shown on Map X.C.1. PJM uses the Reliability First Corporation (for almost the entire footprint) and the SERC Reliability Corporation (North Carolina and parts of Virginia) reliability criteria.

With the authorization for enforceable reliability standards, NERC is continuing to examine its approach to maintaining bulk system reliability. NERC has undertaken a massive revision of its standards following the Northeast Blackout of 2003. EPAct 2005 authorized a maximum civil penalty that FERC could assess as $1 million per day per violation. FERC's Office of Enforcement issues reports providing summaries of all of the enforcement actions taken since EPAct 2005. It provides an analysis of the level of fines assessed to entities that either self-reported or were audited or investigated by the Office of Enforcement. Under Docket AD07-13-000, FERC held a technical conference in November 2007 on its enforcement policy. Industry was given the opportunity to provide suggestions with Commission reaction. Individual standard requirements are still being refined through a voting process of the NERC membership.

As the designated ERO, NERC is required to assess and periodically report on the adequacy of the bulk-power system. Reliability legislation defers to the states matters related to the local distribution system.

D. NERC Report to FERC on 2007 Summer Operations and Standards Compliance

NERC has three reliability reports: a Long-Term Reliability Assessment, a Winter Reliability Assessment, and a Summer Reliability Assessment. The Long-Term Reliability Assessment views electric reliability for a ten-year period and the Winter and the Summer Reliability Assessments predict electric reliability for each coming season, respectively. These reports are based on the analysis, data and information submitted by the eight Regional Reliability Organizations to assess current and future electricity demand, and the adequacy of the bulk power system to meet that demand. Related issues, such as power generation, transmission, fuel delivery and demand side options, are factored into the assessment reports. The 2007 Summer Reliability Assessment Report[93] is discussed below.

2007 Summer Reliability Assessment Report[94]

The 2007 Summer Assessment represented NERC's independent judgment of the reliability and adequacy of the bulk power system on North America for the upcoming summer peak demand period. NERC's report identified areas of concern. The NERC's Assessment summary consisted of five major areas. They were:

- Improvements made since 2006 summer on reliability issues. Several items highlighted in NERC's Long-term Reliability Assessment issued in October 2006 were addressed in this Assessment. The amount of demand represented by customer interruptible demand and direct control load management programs increased since 2006. Many regions are studying the interdependence of fuel delivery and reliability and improving coordination between fuel suppliers and generators. Of several regions that improved reliability conditions, the Southeast region including Maryland utilities invested more than $1.21 billion in transmission in 2006.

93 ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/2007-SA-051807.pdf. The Summer Reliability Assessment report was published in May, 2007.

94 The Winter Reliability Assessment: ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/winter2006-07.pdf. The Long-Term Reliability Assessment: ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/LTRA2006.pdf.

- Sustained extreme weather could be a threat to supply adequacy. Procedures are in place to ensure reliable operation of the grid under most conditions. The 2006 summer had wide-spread, sustained extreme weather (high temperature, high humidity) that caused demands to exceed forecast by over 3%. The forecasts of performance for 2007 summer are based on a 50/50 percent chance of having either higher or lower than the expected weather. If an extreme weather period similar to 2006 occurs in summer 2007, it could be a threat to resource supply adequacy.

- Capacity margins for the 2007 summer are comparable to 2006. The capacity margins projected for the 2007 summer are comparable to 2006 and similar performance is expected overall. Capacity margins are intended to mitigate the higher load levels associated with extreme weather events and any unplanned loss of generation capacity. In this way capacity margins provide sufficient operating margins. Comparing the summers of 2007 and 2006, the United States reported a 1.0% drop in projected capacity margins and Canada reported a 0.9% increase. The forecasted 2007 summer demand growth is 2.1% for normal weather conditions compared to the 2006 forecast. Extreme summer weather experienced across much of North America in 2006 drove actual peak demand 3.1% higher than was forecast. Overall, the 2007 summer forecast demand is 0.8% lower than the 2006 actual summer demand, assuming that the year 2007 has a normal weather pattern.

- Reliability in the Southern California, Connecticut and Boston load pockets. These areas of the country have faced reliability concerns due to chronic congestion.

- Flooding forecasted in British Columbia could impact system reliability. Flooding could impact areas from the U.S. border, up through the central interior and the northwest and the northeast.

Other items discussed in the Assessment report include the following:

- Industry investments focused on reliability. All regional reliability organizations have seen increased investment by their members in the bulk power system reliability improvement.

- Amplified understanding of the fuel and electric delivery system interdependency. Many regions have initiated studies on gas and coal deliverability to understand potential risks and to develop operational plans. These analyses support energy security and higher coupled delivery system reliability.

- Increased wind generation can affect transmission loading volatility. Wind generation in Texas, Minnesota, and the Dakotas can influence the volatility and reduce the predictability of transmission flows and has resulted in development of new operational guidelines to support their system integration. Several regional reliability organizations and their members are performing wind integration studies to increase the potential benefits and ensure reliable operation and delivery.

- Hydro-electric reservoirs are lower than normal. Overall, hydro-electric reservoirs in the United States are lower than normal, but can adequately serve peak demands. The lower water levels can impact off-peak reliability, though this situation will be managed through operating procedures in all regions.

- Overall increase in interruptible demand and direct load control management programs. These specific programs directly empower operators to interrupt load to support operational reliability requirements. NERC-wide application of these specific demand response programs had increased by 5.8% (about 1,200 MW) from 2006 summer assessment, which helps support resource adequacy.

The Reliability First Corporation region expected the capacity resources and the transmission system to be adequate for the expected operating conditions during the summer of 2007. Capacity margins were comparable to those projected for summer 2006. It was expected that generation re-dispatch, the NERC Transmission Loading Relief procedure and operator intervention would be necessary, at times, to mitigate contingencies and reduce loading of certain critical flow gates. These procedures and actions were well understood by the system operators and would be used as needed to maintain transmission reliability.

The addition of significant transmission and distribution capacitors that affected Washington, D.C. has improved reliability in that area over last summer. Although generation from Mirant's Potomac River Plant in Arlington, Virginia (just outside of Washington, D.C.) was restricted due to environmental regulation, it was available for system emergencies.

E. DOE Congestion Study and National Interest Electric Transmission Corridors

In response to the Federal Policy Act amendments required by the Energy Policy Act of 2005, the Secretary of Energy was tasked with conducting a nationwide study of electric transmission congestion, and based upon that study and other relevant considerations, to designate "any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects customers as a National Interest Electric Transmission Corridor."[95]

In response, DOE conducted a congestion study in 2006 and identified several critical congestion areas. DOE reported that, "there were areas where a large-scale congestion problem exists or may be emerging, but more information and analysis appear to be needed to determine the magnitude of the problem and the likely relevance of transmission expansion and other solutions."[96] The DOE Report further noted that there are critical congestion areas where it is critically important to remedy congestion problems.

DOE identified two such areas that are densely populated and economically vital to the nation: 1) the Atlantic coastal area from metropolitan New York southward through Northern Virginia and 2) Southern California.

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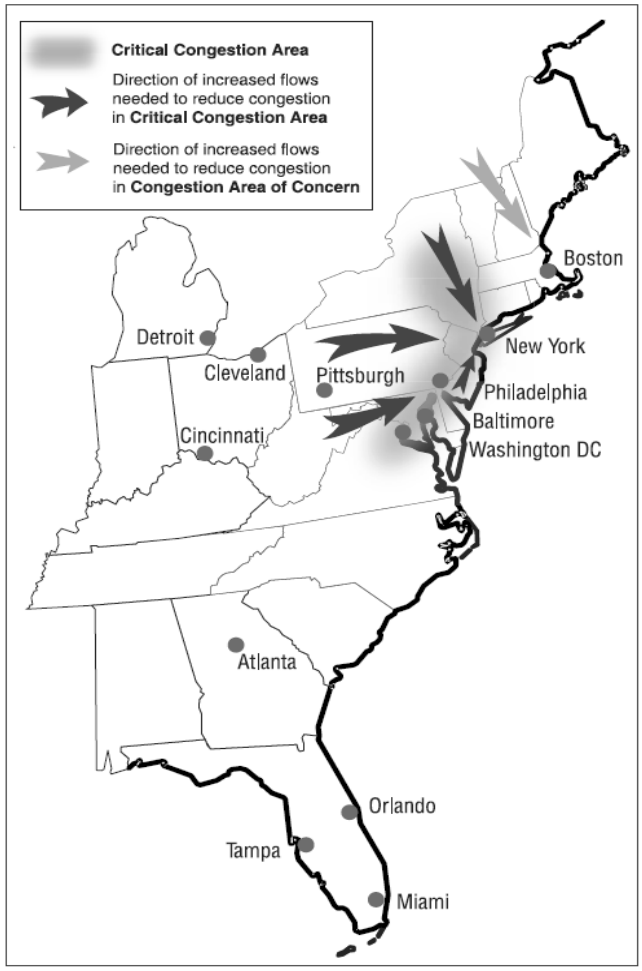
95 U.S. DOE, National Interest Electric Transmission Congestion Study, August 2006, page vii.
96 Ibid, page viii.

Map X.E.1: Mid-Atlantic Corridor of Concern



In its congestion study report[97], DOE noted that it might be appropriate to designate one or more National Corridors to relieve transmission congestion and set forth a Notice of Intent to consider such designation, requesting comments from stakeholders on three questions by October 10, 2006.

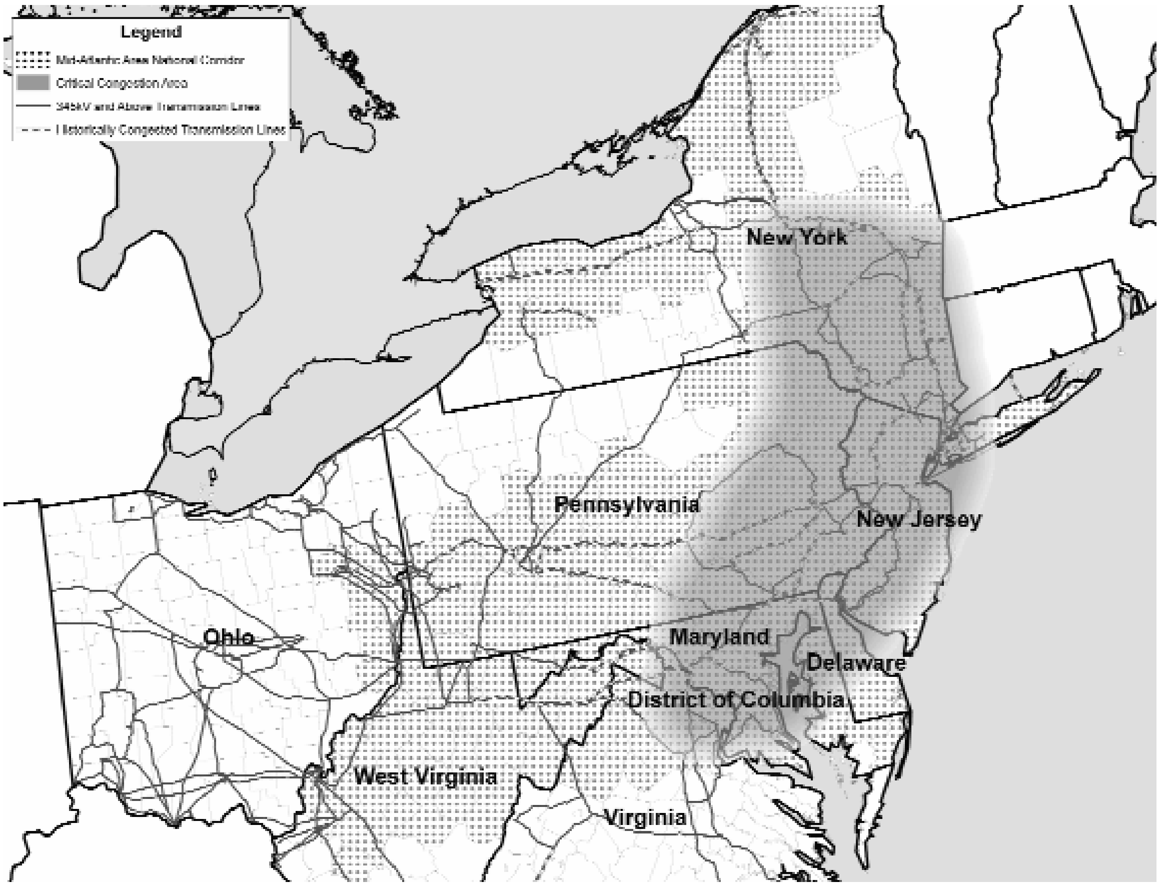
- Would designation of one or more National Corridors in relation to these areas be appropriate and in the public interest?
- How and where should DOE establish the geographic boundaries for a National Corridor?
- To the extent a commenter is focusing on a proposed transmission project, how would the costs of the facility be allocated?[98]

In addition, DOE set expectations that RTOs would continue to show leadership in working with stakeholders and transmission experts to develop solutions to the congestion problems identified in their respective areas.

In its news release of October 2, 2007, DOE designated the Southwest Area and Mid-Atlantic Area as NIETCs. DOE noted that in making such designation it was carrying out its responsibilities under Section 216 of the Federal Power Act, as amended by EPAct 2005. In the press release, Secretary of Energy Samuel W. Bodman is quoted as saying, “The goal is simple – to keep reliable supplies of electric energy flowing to all Americans. By designating these National Corridors, we are encouraging stakeholders in these regions to identify solutions and take prompt action."[99] DOE further noted that the EPAct 2005 authorized FERC to issue, under certain circumstances, permits for new transmission facilities within a National Corridor. Generally, if an applicant did not receive approval from a state to site a proposed new transmission project within a National Corridor within a year, FERC could consider whether to issue a permit and to authorize construction of the project. Map X.E.2 on the next page shows the Mid-Atlantic NIETC as noted in the DOE press release.[100]

[97] DOE News Release, October 2, 2007.
[98] U.S. Dept. of Energy, National Electric Transmission Congestion Study, August 2006, page x.
[99] DOE News Release, October 2, 2007.
[100] Ibid, Page 2.

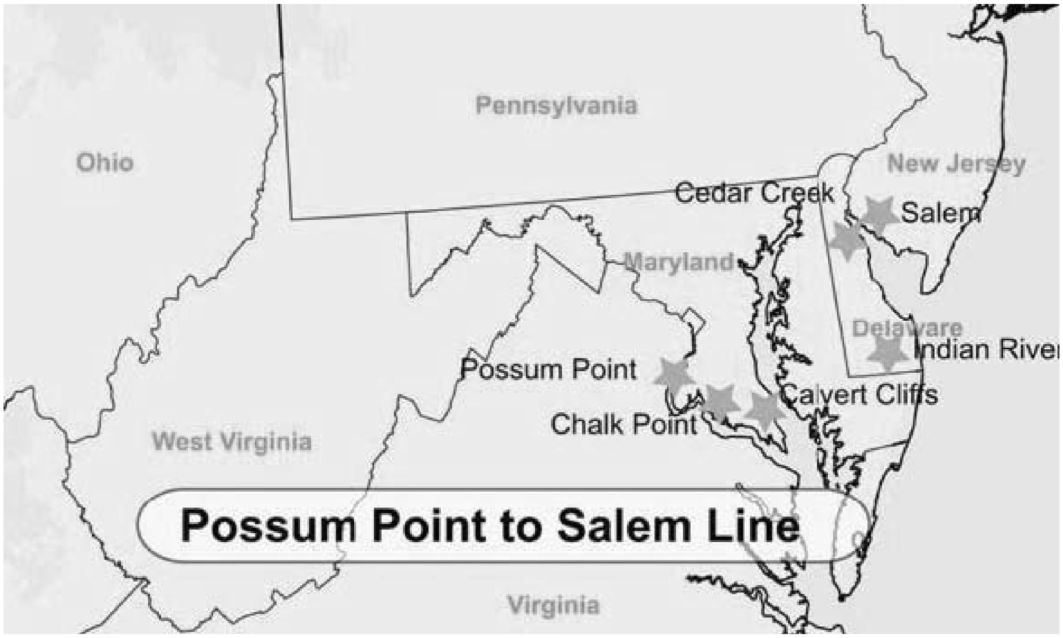
Map X.E.2: Mid-Atlantic NIETC



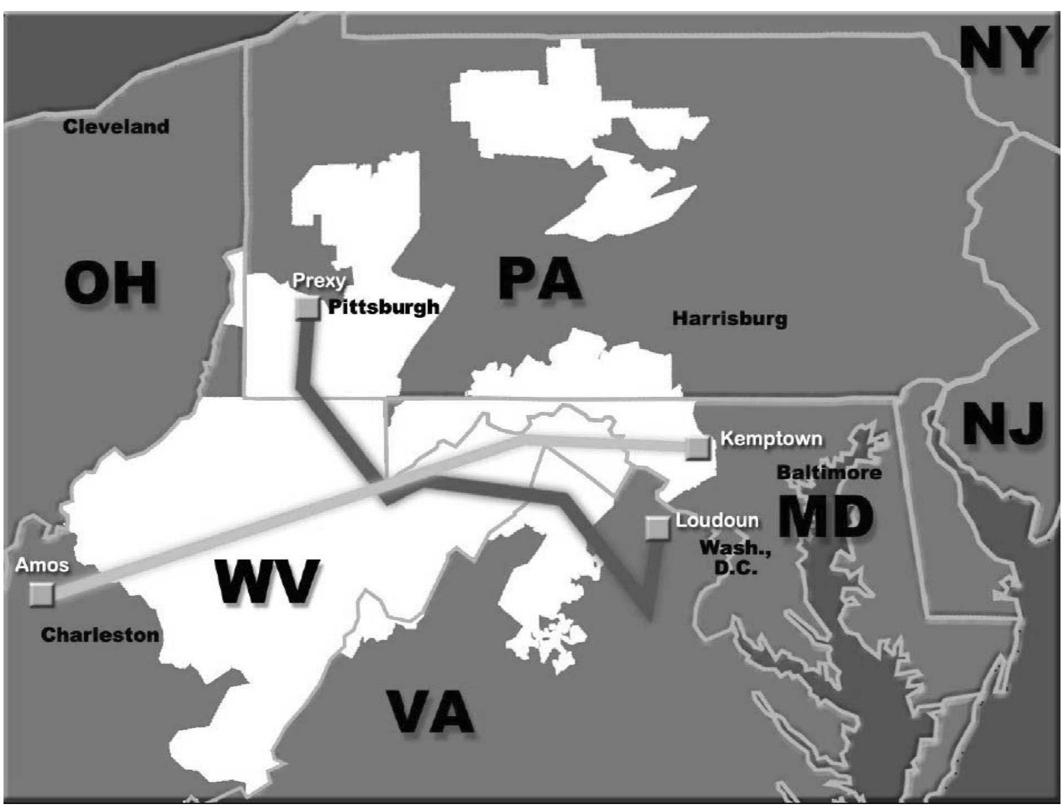
Needless to say there has been extensive criticism of the designations, ranging from the overly broad footprint that covers almost the total state of Maryland and Delaware along with large portions of West Virginia, Virginia, Pennsylvania, New Jersey, and New York, to concerns with the federal infringement on state rights to permit transmission construction. With respect to major transmission in Maryland, PJM's Board of Directors has recently approved the inclusion of three major high voltage transmission lines in the Regional Transmission Expansion Plan, under which member transmission companies are required to build such facilities. While this Commission agrees with the need for additional transmission infrastructure, it is concerned that the potential federal override of state authority to permit such infrastructure may not always be in the best interest of Maryland citizens.

The three major bulk transmission projects approved by the PJM Board were the Mid-Atlantic Power Pathway Line (on October 17, 2007), the Potomac-Appalachian Transmission Highline (on June 22, 2007), and the Trans-Allegheny Interstate Line (on June 23, 2006). On the next page, the two maps show the planned routes of the MAPP, PATH and TrAIL projects. MAPP (Map X.E.3) was proposed by Pepco Holdings at an estimated cost of $1.05 billion with an in-service date of June 2014; PATH (the light green line on Map X.E.4) was proposed jointly by AEP and Allegheny Power at an estimated cost of $1.8 billion with an in-service date of June 2012; and TrAIL (the dark blue line on Map X.E.4) was proposed jointly by Allegheny Power and Dominion at an estimated cost of a little over $1 billion with an in-service date of June 2011.

Map X.E.3: MAPP Project



Map X.E.4: PATH and TrAIL Projects



Listed below are some more details about the three proposed bulk transmission lines:

- MAPP is a 230-mile, 500-kV line that would run from Possum Point (on the Virginia side of the Potomac River) and traverse Southern Maryland (through the Chalk Point and Calvert Cliffs stations) before heading across the Chesapeake Bay. The line would continue to Vienna (MD) and Indian River (DE) before heading north through Delaware and crossing the Delaware Bay into the Salem station (NJ). MAPP is planned to be built in segments, with the Possum Point to Calvert Cliffs segment in-service June 2011 and the Calvert Cliffs to Indian River segment in-service June 2012. PHI has not yet applied for a CPCN for the MAPP project with the Maryland PSC.

- PATH is a 300-mile, mostly 765-kV line from the Amos Station (near Charleston WV) and terminating at a new Kemptown station (near Frederick MD); the short Maryland portion of PATH is dual 500-kV lines. Allegheny Power has not yet applied for a CPCN for the PATH project with the Maryland PSC.

- TrAIL is a 240-mile, 500-kV line starting at the Prexy station (near Pittsburgh PA) that would run through West Virginia (just avoiding traversing Maryland) and terminating at the Loudoun (VA) station in northern Virginia. Since it does not cross Maryland, TrAIL will not be filed at the Maryland PSC. However, hearings are expected to be held in West Virginia, Virginia, and Pennsylvania during the first quarter of 2008. Each of these states is expected to rule on TrAIL by the end of summer 2008.

F. FERC Staff Report on Demand Response Programs and Advanced Metering

Section 1252(e)(3) of EPAct 2005 requires FERC to annually assess electric demand response resources and advanced metering. The first FERC Staff Report, Assessment of Demand Response and Advanced Metering, was published in August 2006. In the report, FERC summarized the results of a comprehensive nationwide survey on electric industry demand response and identified areas and programs for consideration by the electric power industry. The first report was an informational assessment of demand response and advanced metering.

The second FERC Staff Report was published in September 2007 and updated the development of demand response and advanced metering. FERC reported on two levels of demand response programs, the wholesale market and retail market response. The wholesale market includes the demand response programs developed in RTO and ISO groups, while the latter focuses on electric retailers and distribution utility demand response programs.

<u>Demand Response in Wholesale Markets</u>

In the 2007 Report, FERC reported on the important role of demand response in reducing peak demand nationwide in summer 2006. The demand reductions during the heat wave of 2006 came from a combination of actions and programs of RTOs, ISOs, utilities, load serving entities, and non-utility demand response service providers. Many utilities, in and out of RTOs and ISOs, invoked emergency demand response programs, interruptible programs, and direct load control to manage their peak demand and maintain local area reliability. RTOs and ISOs activated reliability-based demand response programs and appealed for load reductions to reduce the system peak and to maintain system reliability. Participants in RTO and ISO demand bidding programs curtailed load in response to high wholesale prices during the heat wave event.

The peak electricity reduction for the various regions was reported to vary between 1.4% and 4.1% during the summer of 2006. A detailed peak demand reduction during the peak time in 2006 among RTOs and ISOs is shown in Table X.F.1. The California Independent System Operator had the highest percentage reduction, 4.1%, while PJM's was 1.4 %. Table X.F.1 also gives the estimated total enrollment in demand response programs for each RTO or ISO for 2007. The programs included in RTOs and ISOs for 2007 include interruptible, reliability, economic and direct load programs. In PJM, reliability and economic programs have an equal share, 50% for each, of a total enrollment of 3,733 MW.

Table X.F.1: Summer 2006 Demand Response Reductions and 2007 Program Enrollments

RTO or ISO	2006 Peak Day Demand		2007 Estimate Enrolled Total MW	Percent Change of 2007 Enroll. Vs. 2006 (%)
	Reduction* (MW)	Percent (%)+		
CAISO	2,066	4.1	2,789	35.00
Midwest ISO	2,651	2.3	4,099	54.62
ERCOT	N/A	N/A	1,125	N/A
SPP	70	negligible	N/A	N/A
NYISO	948	2.8	2,199	131.96
ISO-NE	597	2.1	1,037	73.70
PJM	2050	1.4	3,733	82.10

* The reduction is the load response reduction on Peak days in summer 2006.
+ The percent is the percent reduction of peak load.

Two new wholesale developments since the 2006 report are the inclusion of demand resources in forward capacity markets and ancillary services markets at RTOs and ISOs and the development of new reliability-based demand response programs. PJM held the first capacity auction in its forward capacity market (RPM) in April 2007 for the June 2007 to May 2008 planning year. 41% of demand response offers, or 128 MW, cleared in the auction. Demand response cleared offers quadrupled to 536 MW in the second auction held for 2008-2009. The RPM auction process was designed to send locational price signals to attract resources to areas where they are most needed. The forward capacity market allows five categories of demand resources to participate: energy efficiency; load management (both emergency and economic); distributed generation; and real-time demand response.

FERC reported summer 2006 energy prices in various RTOs and ISOs were significantly reduced by demand response. Reduction in wholesale prices varied regionally. PJM reported that demand response achieved on August 2, 2006 (its record peak day) "reduced wholesale energy prices by more than $300 per MWh during the highest usage hours." It was estimated that the reductions in use resulted in system-wide savings in energy payments of $230 million during the peak hours that day and more than $650 million in energy payments for the week.[101]

In its 2007 Staff Report, FERC pointed out that the roles of the peak demand response programs, analyzed by Lawrence Berkeley National Laboratory, were different in the summer of 2006. First there were different response rates between reliability-based programs and economic programs such as demand bidding. Reliability-based programs had high participation rates when called upon. The response rate in California utility interruptible programs and the California Power Authority's Demand Reserves Partnership was 83%; the response rate in NYISO's capacity market program, ICAP/Special Case Resources, was 62%. Economic demand bidding programs had lower response rates: the maximum load reduction achieved in the demand bidding programs, offered by California utilities, was 19% of enrolled resources. In PJM, the Day-Ahead Load Response Program, maximum load reduction was 4% of enrolled resources.

In establishing NERC as the organization responsible for the development of mandatory, enforceable reliability standards, FERC also selected NERC to address the demand response infrastructure work needed to establish uniformity. Of an 83 approved enforceable reliability standards, there are twelve[102] that are related to demand side issues and demand response. These standards are the first steps that FERC took to set up consistent standards of demand response in system modeling, data, analysis, and reporting. The standards are intended to promote the validation of demand response information and to establish uniform evaluations of demand response to facilitate system operator confidence in relying on such resources.

Demand Response in Retail Programs

The 2007 FERC Staff Report identified several states and individual utilities that took actions to introduce more opportunities for demand response and price-responsiveness at the retail level since the previous 2006 assessment. Five states' legislative and regulatory activities were summarized in the Report. They were California, Connecticut, Illinois, Maryland, and Michigan. Their actions included the adoption of time-based rates and the adoption of demand response policies (which includes deployment of enabling technologies such as advanced metering). FERC suggested that activity growth in the retail sector should improve demand responsiveness and partially address the need for wholesale-retail coordination identified in the 2006 FERC Demand Response Assessment.

The utility demand response activities reported in the 2007 FERC Report included demand response, time-based rates, energy efficiency, and advanced metering. Pepco Holdings had planned to include energy efficiency and demand response programs, coupled with "innovative technologies", for nearly all their operating companies in Maryland.

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101 PJM Interconnection, LLC, press release, August 17, 2006.

102 These 12 reliability standards are Standard BAL-002-0, Standard BAL-005-0, Standard EOP-002-2, Standard MOD-016-01, Standard MOD-019-0, Standard MOD-020-0, Standard MOD-021-0, Standard TPL-001-0, Standard TPL-002-0, Standard TPL-003-0, Standard TPL-004-0, and Standard VAR-001-0. See 2007 FERC Staff Report on p. 10 for details.

FERC Staff identified the following demand response trends in the 2007 Report:

- Bidding of demand into RTO/ISO capacity markets and auctions;
- Growing participation of demand response in ancillary services markets;
- Increased participation in ISO demand response programs;
- More national and regional attention on measurement and verification of demand;
- Increased focus on the development of the “Smart Grid”;
- More multi-state and state-federal demand response working groups;
- More reliance on demand response in strategic plans and state plans; and,
- Increased activity by third parties in aggregating and providing demand response.

Barriers Remain

Regulatory barriers identified in the 2006 FERC Staff Report remain as follows:

- Disconnect between retail pricing and wholesale markets;
- Utility disincentives associated with offering demand response;
- Cost recovery and incentives for enabling technologies;
- Need for additional research on cost-effectiveness and measurement for reduction;
- Existence of specific state-level barriers to greater demand response;
- Specific retail and wholesale rules that limit demand response;
- Barriers to providing demand response services by third parties;
- Insufficient market transparency and access to data; and,
- Better coordination of federal-state jurisdiction affecting demand response.

FERC Staff in their 2007 report identified two additional regulatory barriers to demand response programs in addition to the regulatory barriers indentified in the 2006 report.

1. Lack of sufficient real-time information sharing; and
2. Continuing barriers to implementing critical peak pricing tariffs,

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 fifteen years, by utility. It also includes a list of all licensed electricity and natural gas suppliers and brokers in Maryland, renewable energy projects, planned transmission enhancements, and power purchase agreements for each utility.

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

Table A-1: Utilities Providing Retail Electric Service in Maryland	
Utility	**Service Territory**
A&N Electric Cooperative (A&N)	Smith Island in Somerset County
Baltimore Gas & Electric Company (BGE)	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 (Berlin)	Town of Berlin.
Choptank Electric Cooperative (Choptank)	Portions of the Eastern Shore.
Delmarva Power & Light Company (DPL)/Delmarva	Major portions of ten counties primarily on the Eastern Shore.
Easton Utilities Commission (Easton)	City of Easton.
Hagerstown Municipal Electric Light Plant (Hagerstown)	City of Hagerstown.
Potomac Edison Company (PE)/Allegheny Power (AP)	Parts of western Maryland.
Potomac Electric Power Company (Pepco)	Major portions of Montgomery and Prince George's Counties.
Somerset Rural Electric Cooperative (Somerset)	Northwestern corner of Garrett County.
Southern Maryland Electric Cooperative (SMECO)	Charles and St. Mary's Counties; portions of Calvert and Prince George's Counties.
Thurmont Municipal Light Company (Thurmont)	Town of Thurmont
Town of Williamsport (Williamsport)	Town of Williamsport

Table A-2: Number of Customers by Customer Class (As of December 31, 2006)

	System-Wide						Maryland					
Utility/Co.	**Residential**	**Commercial**	**Industrial**	**Other**	**Sales for Resale**	**Total**	**Residential**	**Commercial**	**Industrial**	**Other**	**Sales for Resale**	**Total**
A&N[103]	10,586	635	3	98	0	**11,322**	N/A	N/A	N/A	N/A	N/A	**N/A**
Berlin[104]	1,727	279	89	20	0	**2,115**	1,727	279	89	20	0	**2,115**
BGE	1,093,300	115,500	5,200	N/A	0	**1,214,000**	1,093,300	115,500	5,200	N/A	N/A	**1,214,000**
Choptank	46,188	4,598	20	291	0	**51,097**	46,188	4,598	20	291	0	**51,097**
DPL	451,690	60,394	567	675	0	**513,326**	169,993	25,223	261	273	0	**195,750**
Easton	8,075	2,102	0	92	0	**10,269**	8,075	2,102	0	92	0	**10,269**
Hagerstown	15,188	2,174	125	4	0	**17,491**	15,188	2,174	125	4	0	**17,491**
PE/AP	409,249	55,350	6,111	738	6	**471,454**	215,300	26,570	2,798	346	3	**245,017**
PEPCO	680,358	73,433	0	146	0	**753,937**	469,138	46,696	0	115	0	**515,949**
SMECO	129,547	12,417	6	207	0	**142,177**	129,547	12,417	6	207	0	**142,177**
Somerset	11,926	1,080	0	0	0	**13,006**	756	37	0	0	0	**793**
Thurmont	2,471	331	9	44	0	**2,855**	2,471	331	9	44	0	**2,855**
Williamsport	871	66	36	43	0	**1,016**	871	66	36	43	0	**1,016**
Total	**2,861,176**	**328,359**	**12,166**	**2,358**	**6**	**3,204,065**	**2,152,554**	**235,993**	**8,544**	**1,435**	**3**	**2,398,529**

Note: Some totals may not sum due to rounding.

103 A&N did not provide Maryland-specific figures, but Maryland is a very small fraction of A&N's total number of customers.
104 These are 2005 figures. Berlin did not provide a data response to the Commission for 2006.

Table A-3: Sales by Customer Class (As of December 31, 2006)

	System-Wide						Maryland					
Utility/Co.	**Residential**	**Commercial**	**Industrial**	**Other**	**Sales for Resale**	**Total**	**Residential**	**Commercial**	**Industrial**	**Other**	**Sales for Resale**	**Total**
A&N[105]	121	24	67	1	0	**213**	N/A	N/A	N/A	N/A	N/A	**N/A**
Berlin[106]	23	3	15	0	0	**41**	23	3	15	0	0	**41**
BGE	12,886	15,717	3,455	N/A	N/A	**32,058**	12,886	15,717	3,455	N/A	N/A	**32,058**
Choptank	594	185	82	1	0	**862**	594	185	82	1	0	**862**
DPL	5,239	5,400	2,919	52	0	**13,610**	2,161	1,723	479	13	0	**4,376**
Easton	101	144	0	12	0	**257**	101	144	0	12	0	**257**
Hagerstown	150	64	125	8	0	**346**	150	64	125	8	0	**346**
PE/AP	6,044	3,398	3,548	24	745	**13,759**	3,173	1,985	1,681	12	465	**7,316**
PEPCO	7,792	18,245	0	714	0	**26,751**	5,932	9,010	0	301	0	**15,243**
SMECO	1,996	1,067	199	4	0	**3,266**	1,996	1,067	199	4	0	**3,266**
Somerset	115	45	0	0	0	**160**	7	1	0	0	0	**7**
Thurmont	38	16	27	1	0	**82**	38	16	27	1	0	**82**
Williamsport	9	1	7	1	0	**18**	9	1	7	1	0	**18**
Total	**35,108**	**44,311**	**10,444**	**817**	**745**	**91,424**	**27,069**	**29,917**	**6,071**	**352**	**465**	**63,873**

Note: All sales figures are in GWh. Some totals may not sum due to rounding.

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105 A&N did not provide Maryland-specific figures, but Maryland is a very small fraction of A&N's total number of customers.
106 These are 2005 figures. Berlin did not provide a data response to the Commission for 2006.

Table A-4: Number of Residential Space Heating Customers, 2006

Company	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Avg of 12 Months
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	**N/A**
Berlin	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	**N/A**
BGE	300,174	300,480	300,683	300,672	300,700	300,961	301,021	301,339	301,386	301,641	302,195	302,738	**301,166**
Choptank	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	**N/A**
DPL	80,511	80,522	80,639	80,660	80,719	80,685	80,708	80,734	80,751	78,578	78,566	78,669	**80,145**
Easton	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	**N/A**
Hagerstown	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	**N/A**
PE/AP	85,755	85,852	85,890	86,008	86,217	86,267	86,556	86,513	86,865	87,045	87,209	87,389	**86,464**
PEPCO	112,978	113,148	113,244	113,210	113,339	113,589	113,617	113,603	114,145	114,467	114,773	115,236	**113,779**
SMECO	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	**N/A**
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	**N/A**
Thurmont	1,783	1,780	1,793	1,776	1,792	1,789	1,781	1,785	1,790	1,783	1,786	1,791	**1,786**
Williamsport	289	300	295	293	295	296	294	298	299	299	300	299	**296**

Table A-4: Typical Utility Bills in Maryland, Winter 2007

	Energy Use Demand per month			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	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
BGE	750 kWh	10,000 kWh - 40 kW	14,000 kWh - 40 kW	$ 106.97	$ 1,314.00	$ 1,828.00	$0.1126	$0.1111	$0.1111
Choptank	750 kWh	12,500 kWh	200,000 kWh	$ 98.29	$ 1,525.26	$20,912.35	$0.1311	$0.1220	$0.1046
DPL	750 kWh	12,500 kWh	200,000 kWh	$ 103.29	$ 1,502.92	$17,956.63	$0.1377	$0.1202	$0.0898
Easton	750 kWh	12,500 kWh	N/A	$ 76.38	$ 1,243.05	N/A	$0.1018	$0.0994	N/A
Hagerstown	707 kWh	1566 kWh	21,000 kWh / 77kW	$ 69.98	$ 170.47	$ 2,225.83	$0.0989	$0.1088	$0.1059
PE/AP	1,728 kWh	3,837 kWh	14,112 kWh	$ 119.38	$ 444.98	$1,469.24	$0.0691	$0.1160	$0.1041
PEPCO	750 kWh	12,500 kWh	200,000 kWh	$ 103.79	$ 1,510.14	$22,107.28	$0.1384	$0.1208	$0.1105
SMECO									
Somerset	862 kWh	7,200 kWh	None	$ 80.16	$ 802.28	None	None	None	None
Thurmont	750 kWh	12,500 kWh - 50 kW	200,000 kWh - 500 kW	$ 78.95	$ 1,263.59	$17,885.36	$0.1042	$0.0988	$0.0884
Williamsport	750 kWh	12,500 kWh - 50 kW	200,000 kWh - 500 kW	$ 75.56	$ 1,279.86	$18,812.77	$0.0995	$0.1000	$0.0931

Table A-5(a): System-Wide Peak Demand Forecast (Net of DSM Programs)

Year	BGE	Berlin[1]	Choptank	DPL	Easton	Hagers-town	PE/AP	Pepco	Somerset	SMECO	Thurmont	Williams-port
2007	7,091	11	213	4,076	66	79	2,925	6,972	46	845	20	5
2008	7,213	11	223	4,166	68	81	2,997	7,126	47	796	21	5
2009	7,336	11	230	4,256	69	84	3,070	7,238	47	807	21	5
2010	7,443	11	239	4,344	70	86	3,131	7,341	48	817	22	5
2011	7,533	11	248	4,432	72	89	3,197	7,439	48	828	22	5
2012	7,595	12	257	4,490	73	92	3,265	7,515	49	838	22	5
2013	7,683	12	266	4,577	75	94	3,329	7,641	50	848	23	5
2014	7,761	12	276	4,658	76	97	3,389	7,748	51	858	23	6
2015	7,842	12	285	4,742	78	100	3,458	7,853	N/A	868	23	6
2016	7,903	13	293	4,844	79	103	3,527	7,937	N/A	877	24	6
2017	7,986	13	302	4,919	81	106	3,589	8,032	N/A	887	24	6
2018	8,086	13	310	5,004	82	109	3,658	8,123	N/A	896	24	6
2019	8,169	13	319	5,096	84	113	3,720	8,224	N/A	906	25	6
2020	8,252	14	328	5,199	85	116	3,789	8,361	N/A	915	25	6
2021	8,335	N/A	337	5,303	87	119	3,860	8,458	N/A	924	26	6
Change (2007 – 2021)	**1,244**	**3**	**124**	**1,227**	**21**	**40**	**935**	**1,486**	**5**	**79**	**6**	**1**
Percentage Change	**17.5%**	**29.3%**	**58.2%**	**30.1%**	**31.5%**	**51.3%**	**32.0%**	**21.3%**	**10.5%**	**9.3%**	**25.0%**	**23.2%**
Annual Growth Rate	**1.1%**	**1.9%**	**3.1%**	**1.8%**	**1.8%**	**2.8%**	**1.9%**	**1.3%**	**1.3%**	**0.6%**	**1.5%**	**1.4%**

Note: All projected peak demand figures are in MW.
Source: Company data responses to the Commission's 2007 data request for the ten-year plan
1 Based on 2006 Forecasts
N/A Data not available

Table A-5(b): Maryland Peak Demand Forecast (Net of DSM Programs)

Year	BGE	Berlin[1]	Choptank	DPL	Easton	Hagers-town	PE/AP	Pepco	Somerset	SMECO	Thurmont	Williams-port	Total
2007	7,091	11	213	1,049	66	79	1,588	3,654	46	845	20	5	**14,667**
2008	7,213	11	223	1,073	68	81	1,625	3,734	47	796	21	5	**14,896**
2009	7,336	11	230	1,096	69	84	1,664	3,793	47	807	21	5	**15,163**
2010	7,443	11	239	1,118	70	86	1,691	3,847	48	817	22	5	**15,397**
2011	7,533	11	248	1,141	72	89	1,724	3,898	48	828	22	5	**15,620**
2012	7595	12	257	1,156	73	92	1,757	3,938	49	838	22	5	**15,794**
2013	7683	12	266	1,178	75	94	1,788	4,004	50	848	23	5	**16,026**
2014	7791	12	276	1,199	76	97	1,818	4,060	51	858	23	6	**16,267**
2015	7842	12	285	1,221	78	100	1,850	4,115	N/A	868	23	6	**16,400**
2016	7903	13	293	1,247	79	103	1,881	4,159	N/A	877	24	6	**16,584**
2017	7986	13	302	1,266	81	106	1,912	4,209	N/A	887	24	6	**16,791**
2018	8086	13	310	1,288	82	109	1,943	4,257	N/A	896	24	6	**17,015**
2019	8169	13	319	1,312	84	113	1,974	4,310	N/A	906	25	6	**17,230**
2020	8252	14	328	1,339	85	116	2,005	4,381	N/A	915	25	6	**17,466**
2021	8335	N/A	337	1,365	87	119	2,037	4,432	N/A	924	26	6	**17,668**
Change (2007 – 2021)	**1,244**	**3**	**124**	**316**	**21**	**40**	**449**	**778**	**5**	**79**	**6**	**1**	**3,001**
Percentage Change	**17.5%**	**29.3%**	**58.2%**	**30.1%**	**31.5%**	**51.3%**	**28.3%**	**21.3%**	**10.5%**	**9.3%**	**25.0%**	**23.2%**	**20.5%**
Annual Growth Rate	**1.1%**	**1.9%**	**3.1%**	**1.8%**	**1.8%**	**2.8%**	**1.7%**	**1.3%**	**1.3%**	**0.6%**	**1.5%**	**1.4%**	**1.2%**

Note: All projected peak demand figures are in MW.
Source: Company data responses to the Commission's 2007 data request for the ten-year plan
1 Based on 2006 Forecasts
N/A Data not available

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

Year	BGE	Berlin[1]	Choptank	DPL	Easton	Hagers-town	PE/AP	Pepco	Somerset	SMECO	Thurmont	Williams-port
2007	33,224	42	962	13,684	293	363	14,477	26,973	183	3,418	88	20
2008	33,505	43	1,015	13,784	300	374	14,882	27,291	185	3,560	89	20
2009	34,130	44	1,055	13,930	307	386	15,274	27,708	188	3,692	90	20
2010	34,880	45	1,098	14,080	313	398	15,603	28,131	189	3,813	92	20
2011	35,681	46	1,147	14,236	319	409	15,935	28,561	192	3,931	93	21
2012	36,368	47	1,196	14,397	326	421	16,279	28,991	196	4,044	94	21
2013	37,095	48	1,243	14,563	333	434	16,605	29,434	199	4,149	96	21
2014	37,823	49	1,291	14,734	339	447	16,941	29,885	202	4,250	97	22
2015	38,550	50	1,341	14,910	346	460	17,305	30,342	N/A	4,349	99	22
2016	39,278	50	1,381	15,092	352	474	17,651	30,807	N/A	4,447	100	22
2017	40,005	52	1,427	15,279	359	488	17,993	31,279	N/A	4,541	102	23
2018	40,733	53	1,474	15,471	366	503	18,341	31,758	N/A	4,632	103	23
2019	41,460	54	1,519	15,670	372	518	18,680	32,245	N/A	4,717	105	23
2020	42,188	55	1,565	15,874	379	534	19,050	32,739	N/A	4,802	106	24
2021	42,915	N/A	1,611	16,084	386	550	19,405	33,241	N/A	4,882	108	24
Change (2007 – 2021)	**9,691**	**12.40**	**649**	**2,400**	**93**	**187**	**4,929**	**6,268**	**19**	**1,464**	**20**	**4**
Percentage Change	**29.2%**	**29.3%**	**67.4%**	**17.5%**	**31.5%**	**51.2%**	**34.0%**	**23.2%**	**10.4%**	**42.8%**	**23.2%**	**23.1%**
Annual Growth Rate	**1.7%**	**1.9%**	**3.5%**	**1.1%**	**1.8%**	**2.8%**	**2.0%**	**1.4%**	**1.2%**	**2.4%**	**1.4%**	**1.4%**

Note: All projected sales figures are in GWh.
Source: Company data responses to the Commission's 2007 data request for the ten-year plan
1 Based on 2006 Forecasts
N/A Data not available

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

Year	BGE	Berlin[1]	Choptank	DPL	Easton	Hagers-town	PE/AP	Pepco	Somerset	SMECO	Thurmont	Williams-port	Total
2007	33,224	42	962	4,440	293	363	7,710	15,268	183	3,418	88	20	**66,011**
2008	33,505	43	1,015	4,494	300	374	7,942	15,403	185	3,560	89	20	**66,929**
2009	34,130	44	1,055	4,569	307	386	8,125	15,630	188	3,692	90	20	**68,235**
2010	34,880	45	1,098	4,645	313	397	8,284	15,860	189	3,813	92	20	**69,637**
2011	35,681	46	1,147	4,723	319	409	8,438	16,094	192	3,931	93	21	**71,093**
2012	36,368	47	1,196	4,803	326	421	8,595	16,331	196	4,044	94	21	**72,442**
2013	37,095	48	1,243	4,885	333	434	8,759	16,571	199	4,149	96	21	**73,832**
2014	37,823	49	1,291	4,969	393	447	8,917	16,815	202	4,250	97	22	**75,220**
2015	38,550	50	1,341	5,054	346	460	9,083	17,063	N/A	4,349	99	22	**76,416**
2016	39,278	50	1,381	5,141	352	474	9,249	17,315	N/A	4,447	100	22	**77,810**
2017	40,005	52	1,427	5,231	389	488	9,410	17,570	N/A	4,541	102	23	**79,207**
2018	40,733	53	1,474	5,322	366	503	9,578	17,829	N/A	4,632	103	23	**80,615**
2019	41,460	54	1,519	5,415	372	518	9,735	18,092	N/A	4,717	105	23	**82,009**
2020	42,188	55	1,565	5,510	379	534	9,902	18,359	N/A	4,802	106	24	**83,423**
2021	42,915	N/A	1,611	5,607	386	550	10,072	18,629	N/A	4,882	108	24	**84,784**
Change (2007 – 2021)	**9,691**	**13**	**649**	**1,167**	**93**	**187**	**2,362**	**3,361**	**19**	**1,464**	**20**	**4**	**18,772**
Percentage Change	**29.2%**	**29.3%**	**67.4%**	**26.3%**	**31.5%**	**51.2%**	**30.6%**	**22.0%**	**10.4%**	**42.8%**	**23.2%**	**23.1%**	**28.4%**
Annual Growth Rate	**1.7%**	**1.9%**	**3.5%**	**1.6%**	**1.8%**	**2.8%**	**1.8%**	**1.3%**	**1.2%**	**2.4%**	**1.4%**	**1.4%**	**1.7%**

Note: All projected sales figures are in GWh.
Source: Company data responses to the Commission's 2007 data request for the ten-year plan
1 Based on 2006 Forecasts
N/A Data not available

Table A-7: Licensed Electric & Natural Gas Suppliers and Brokers/Aggregators

Company	Electric Supplier License No.	Electric Broker License No.	Natural Gas Supplier License No.	Natural Gas Broker License No.
1. Affiliated Power Purchasers, Inc.		IR-279		
2. Allegheny Power Purchasers, Inc.	IR-229		IR-229	
3. America PowerNet Management	IR-604			
4. AOBA Alliance, Inc.		IR-267		IR-375
5. BGE Home Products and Services d/b/a BGE Commercial Building Systems	IR-228		IR-311	
6. Blue Star Energy Services	IR-757			
7. BOC Energy Services	IR-753			
8. Bollinger Energy Corporation		IR-265	IR-322	
9. BP Energy Company			IR-676	
10. BTU Energy		IR-864		
11. Choice Energy Services		IR-682		
12. Clean Currents, LLC		IR-980		
13. Co-eXprise, Inc.	IR-879		IR-879	
14. Colonial Energy, Inc.			IR-606	
15. Commerce Energy, Inc.	IR-639		IR-737	
16. Compass Energy Services			IR-652	
17. Competitive Energy Services, MD	IR-895		IR-895	
18. Conoco, Inc.			IR-378	
19. Constellation Energy Projects & Services Group	IR-239			
20. Consolidation Edison Solutions	IR-603			
21. Constellation New Energy, Inc.	IR-500		IR-522	
22. Constellation New Energy – Gas Division, LLC		IR-655		
23. Coral Energy Gas Sales, Inc.			IR-360	
24. CQI Associates, LLC		IR-575		
25. Cypress Natural Gas			IR-674	
26. Delta Energy, LLC			IR-645	

Company	Electric Supplier License No.	Electric Broker License No.	Natural Gas Supplier License No.	Natural Gas Broker License No.
27. Direct Energy Services	IR-719		IR-791	
28. Dominion Retail, Inc.	IR-252		IR-345	
29. Downes Associates, Inc.		IR-523		
30. DTE Energy Trading, Inc.	IR-686			
31. Eastern Shore of MD Educational Consortium Energy Trust d/b/a ESMEC Energy Trust		IR-342		
32. Econnergy Energy Company	IR-340		IR-334	
33. Energy Options, LLC		IR-568		
34. Energy Services Management, LLC d/b/a Maryland Energy Consortium		IR-236		IR-312
35. Energy Services Provider Group, LLC		IR-518		IR-519
36. EnergyWindow, Inc.		IR-274		
37. Enron Energy Marketing Corp.			IR-370	
38. Enspire Energy			IR-814	
39. Essential.com, Inc.	IR-259			
40. FirstEnergy Solutions Corp.	IR-225			
41. Gexa Energy	IR-966			
42. Glacial Energy, Inc.	IR-888			
43. Hess Corporation	IR-219		IR-323	
44. Hess Energy, Inc.			IR-337	
45. Horizon Power & Light	IR-704			
46. Houston Energy Services Company, LLC.			IR-403	
47. Hudson Energy Services	IR-1114		IR-1120	
48. Integrys Energy Services	IR-951			
49. Liberty Power Corporation	IR-607			
50. Liberty Power, DE	IR-962			
51. Liberty Power Holdings	IR-957			
52. Liberty Power, Maryland	IR-793			
53. Marathon Oil Company			IR-364	

Company	Electric Supplier License No.	Electric Broker License No.	Natural Gas Supplier License No.	Natural Gas Broker License No.
54. Market Direct d/b/a MD Energy		IR-614		
55. MeadWestvaco Energy Services, LLC	IR-669			
56. Metromedia Energy, Inc.			IR-355	
57. Metromedia Power, Inc.	IR-867			
58. MidAmerican Energy Co.	IR-798			
59. Mid-Atlantic Aggregation Group Independent Consortium, LLC		IR-234		IR-234
60. Mid-Atlantic Renewables	IR-856			
61. Mona Building Technologies, LLC		IR-257		
62. MRDB Holdings	IR-930		IR-1000	
63. MxEnergy.com, Inc.			IR-327	
64. National Energy Consortium		IR-928		IR-928
65. New Power Company IBM Global Services	IR-336			
66. NOVEC Energy Solutions			IR-338	
67. Ohms Energy Company, LLC	IR-679			
68. Pepco Energy Services, Inc. d/b/a Conectiv Energy Services	IR-316		IR-316	
69. Pivotal Utility, Inc.			IR-376	
70. PPL EnergyPlus, LLC	IR-230			
71. Premier Energy Group	IR-942		IR-943	
72. Premier Power Solutions		IR-894		IR-894
73. QVINTA, Inc.		IR-557		IR-530
74. Richards Energy Group, Inc.		IR-818		
75. Reliant Energy Solutions East, LLC	IR-525			
76. Sempra Energy Solutions	IR-442		IR-464	
77. SmartEnergy.com, Inc.	IR-270			
78. South Jersey Energy Co.	IR-740			
79. South River Consulting		IR-863		
80. Sprague Energy Corp.				IR-339
81. Spark Energy	IR-979			

Company	Electric Supplier License No.	Electric Broker License No.	Natural Gas Supplier License No.	Natural Gas Broker License No.
82. Spark Energy Gas			IR-613	
83. Stand Energy Corp.			IR-632	
84. Statoil Natural Gas, LLC			IR-561	
85. Strategic Energy, LLC	IR-437			
86. South Jersey Energy Co.	IR-740			
87. SUEZ Energy Resources	IR-605			
88. TFS Energy Solutions d/b/a Tradition Energy		IR-918		IR-982
89. Tiger Natural Gas			IR-351	
90. UGI Energy Services, Inc.	IR-237		IR-319	
91. Utilitech, Inc.	IR-915		IR-915	
92. Virginia Power Energy Mktg. d/b/a Dominion Sales & Marketing, Inc.			IR-689	
93. Washington Gas Energy Services, Inc.	IR-227		IR-324	
94. World Energy Solutions, Inc.		IR-619		IR-953

No. of Suppliers/Brokers: ➡Electric Suppliers = 30; Electric Brokers = 14; Natural Gas Suppliers = 21; Natural Gas Brokers = 1 ; Electric & Natural Gas Suppliers = 18; Electric & Natural Gas Brokers = 9; Natural Gas Supplier & Electric Broker = 1; ➡ Total = 94.

Table A-8: Transmission Enhancements by Service Area

									From Location		To Location	
Tranmission Owner	#	Voltage (kV)	Length (miles)	No. of circuits	Start Date	End Date	In-Service Date	Purpose	County	Terminal	County	Terminal
Allegheny Power		138	0.1	2	2006		2006	GI		Kelso Gap (new)		Oak Park – Elk Garden
Allegheny Power		138	0.1	2	2007		2007	GI		Savage Mountain		Garrett – Carlos Junction
Allegheny Power		230	0.1	1	2007		2008	BTR		Doubs		Lime Kiln Section 207
Allegheny Power		230	0.1	1	2007		2008	BTR		Lime Kiln		Monacy
Allegheny Power		230	0.1	1	2007		2008	BTR		Lime Kiln		Montgomery
Allegheny Power		138	0.1	2	2007		2008	DA		Paramount No. 1		Halfway – Reid
Allegheny Power		230	0.1	1	2008		2008	BTR		Doubs		Lime Kiln Section DLF1/231
Allegheny Power		230	0.1	1	2008		2008	BTR		Lime Kiln		McCain
Allegheny Power		138	0.1	2	2008		2008	DA		McDade		Halfway – Paramont No. 1
Allegheny Power		230	8	2	2008		2009	BTR		Doubs		Dickerson
Allegheny Power		230	0.1	1	2008		2009	BTR		Frederick "A"		Monacy
Allegheny Power		230	2.1	2	2008		2009	DA		Urbana		Lime Kiln – Montgomery
Allegheny Power		138	8	1	2010		2011	DA		Emmitsburg		Catoctin
Allegheny Power		138	4.8	1	2010		2011	BTR		Marlowe		Halfway
Allegheny Power		230	0.6	2	2010		2011	DA		Ridgeville		Mt. Airy – Damascus
Allegheny Power		230	0.1	2	2010		2011	DA		South Frederick		Monacy Lime Kiln
Allegheny Power		230	0.1	2	2011		2011	DA		Jefferson No. 1		Doubs – Monacy
Allegheny Power		138	0.1	2	2011		2012	DA		Fairplay		Marlowe – Boonsboro
Allegheny Power		138	5	1	2012		2012	DA		Clear Spring		Nipetown – Reid
Allegheny Power		138	0.5	1	2017		2017	BTR		Black Oak		Cumberland
Allegheny Power		230	7.8	1	2017		2017	BTR		Montgomery		Bucklodge
BGE		115	7.4	2	1/04	6/08		BTR, DA	Balt City	Westport	Balt City	Orchard (Paca)
BGE		115	3.3	1	1/07	12/08		DA	Balt Co.	Northwest	Balt Co.	Finksburg
BGE		115	1.6	1	1/04	5/07		BTR	Balt City	Westport	Balt City	Center
BGE		115	3	2	1/07	6/10		DA	Balt City	Westport	Balt City	Wilkens
BGE		230	8.6	1	1/09	6/12		BTR	Harford	Conastone	Harford	Graceton
DPL		69	9	1	9/06	12/07		DA	Todd		Allen	
DPL		69	5.32	1	9/04	12/08		DA	Grasonville		Stevensville	
DPL		69	11.13	1	9/07	5/09		DA	Easton		Bozman	

									From Location		To Location	
Tranmission Owner	**#**	**Voltage (kV)**	**Length (miles)**	**No. of circuits**	**Start Date**	**End Date**	**In-Service Date**	**Purpose**	**County**	**Terminal**	**County**	**Terminal**
DPL		69	2.5	1	1/09	5/10		BTR	Berlin		Worcester	
DPL		138	12.98	1	1/10	5/11		BTR	Easton		Wye Mills	
DPL		69	4.42	1	1/10	5/11		BTR	Vienna		Sharptown	
DPL		138	13.73	1	9/11	5/13		BTR	Vienna		Nelson	
DPL		138	24	1	1/11	5/13		BTR	Church		Wye Mills	
DPL		69	2.61	1	1/12	5/13		BTR	Ocean Bay		Maridel	
DPL		500	43	1	1/10	12/14		MAPP	Calvert		Vienna	
DPL		230	28.28	1	1/10	12/14		MAPP	Vienna		Steele	
DPL		230	18.7	1	1/10	12/14		MAPP	Vienna		Loretto	
DPL		230	9.51	1	1/10	12/14		MAPP	Loretto		Piney Grove	
DPL		500	35	1	1/10	12/14		MAPP	Vienna		Indian River	
PEPCO		230	Bus Upgrade	1	1/09	5/10		BTR		Burtonsville		Sandy Springs
PEPCO		230	10.7	2	1/10	5/11		BTR		Quince Orchard		Dickerson
PEPCO		230	7.2	1	1/10	5/11		BTR		Dickerson		Pleasant View
PEPCO		500	33	1	1/10	1/14		MAPP		Possum Point		Burches Hill
PEPCO		500	19	1	1/10	1/14		MAPP		Burches Hill		Chalk Point
PEPCO		500	20	1	1/10	1/14		MAPP		Chalk Point		Calvert Cliffs
SMECO		230	26	2	2013	2014		DA	Calvert	Holland Cliff Sw. St.	Calvert	So. Calvert Sw. St.
SMECO		230	10.5	2	2015	2016		BTR	Calvert	So. Calvert Sw. St.	St. Mary's	Hewit Road Sw. St.

Purpose Codes

BTR – Baseline transmission reliability
GI – Accommodate for generator interconnection
DA – Distribution Adequacy
TCA – Transmission Customer Adequacy
OTH – Other
AT – Asset Transfer from Government
RLC – Relocation
COR – Contingency Overload and/or Reliability
LG – Load Growth
TAP – Extension to Substation or other Transmission Lines
MAPP – The circuits associated with the MAPP proposal is pending PJM review and approval

Table A-9: Renewable Projects Providing Capacity and Energy to Maryland Customers

Company	Name	Site Location	QF Status (Yes or No)	Fuel	Net Capacity (MW)	2007 Net Generation (MWh)
A&N						
Allegheny Power (PE)	None	None	None	None	None	None
Berlin	None	None	None	None	None	None
BGE	Alternative Energy Associates (AEA)/Brighton Dam	Laurel, MD	Yes	WAT	N/A	0 (under repair)
BGE	BRESCO (Baltimore Refuse Energy Systems Co.)	Baltimore, MD	Yes	MSW	57	303898
Choptank	None	None	None	None	None	None
DPL	None	None	None	None	None	None
Easton	None	None	None	None	None	None
Hagerstown	None	None	None	None	None	None
PEPCO	Panda Brandywine, L.P.	Brandywine, MD	Yes	Natural Gas/Oil[107]	230	286536
PEPCO	Browns Station Landfill Unit 1	Upper Marlboro, MD	Yes	Landfill Met. Gas		2508
PEPCO	Browns Station Landfill Unit 2	Upper Marlboro, MD	Yes	Landfill Met. Gas		5827
PEPCO	None	None	None	None	None	None
SMECO	None	None	None	None	None	None
Somerset	None	None	None	None	None	None
Thurmont	None	None	None	None	None	None
Williamsport	None	None	None	None	None	None

[107] Co-generation facility. Source: Environmental Review of the Panda-Brandywine Cogeneration Project (17.1 MB), Environmental Resources Management, Inc., Versar, Inc., MicroAnalytics, Inc., PPSE-PB-1, February 1997 NTIS No. PB97-153787.

Table A-10: Power Purchase Agreements
(As of December 31, 2007)

Company	Name	Site Location	QF Status (Yes or No)	Fuel	Net Capacity (MW)	2007 Net Generation (MWh)
A&N	None	None	None	None	None	None
Berlin	None	None	None	None	None	None
BGE	Alternative Energy Associates (AEA)/Brighton Dam	Laurel, MD	Yes	Hyrdoelectric*	N/A	0 (under repair)
BGE	BRESCO (Baltimore Refuse Energy Systems Co.)	Baltimore, MD	Yes	Refuse with Nat. Gas	57	303,898
Choptank	None	None	None	None	None	None
DPL	Logan Generating Company	Swedesboro, NJ	Yes	Coal	225	630,938**
DPL	Chambers Cogeneration Limited	Carneys Point, NJ	Yes	Coal	219	517,899**
DPL	Covanta Delaware Valley	Chester, PA		Trash	75	299,106**
Easton	None	None	None	None	None	None
Hagerstown	None	None	None	None	None	None
PE/AP	AES Warrior Run	Cumberland, MD	Yes	Coal	180	1,400,263
PEPCO	Panda Brandywine, L.P.	Brandywine, MD		Natural Gas/Oil	230	286,536
PEPCO	Browns Station Landfill Unit 1	Upper Marlboro, MD		Landfill Methane Gas	Energy Only	2,508
PEPCO	Browns Station Landfill Unit 2	Upper Marlboro, MD		Landfill Methane Gas	Energy Only	5,827
SMECO	None	None	None	None	None	None
Somerset	None	None	None	None	None	None
Thurmont	None	None	None	None	None	None
Williamsport	None	None	None	None	None	None

* Runoff from a water treatment plant
** Data from January 1, 2007 to June 30, 2007