PUBLIC SERVICE COMMISSION OF MARYLAND

TEN-YEAR PLAN (2006 – 2015) OF ELECTRIC COMPANIES IN MARYLAND

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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State of Maryland
Public Service Commission

Kenneth D. Schisler, Chairman
Harold D. Williams, Commissioner
Allen M. Freifeld, Commissioner
Charles R. Boutin, Commissioner

O. Ray Bourland Executive Secretary	Gregory V. Carmean Executive Director	Susan S. Miller General Counsel

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

[The Commission's Energy Resources and Markets Division (John O. Sillin, Director) produced this report in cooperation with the Engineering Division (J. Richard Schafer, Chief Engineer). Electric companies under the Commission's jurisdiction provided most of the data in the Appendix.]

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APPENDIX

I. INTRODUCTION

This report constitutes the Maryland Public Service Commission's (Commission or PSC) Ten-Year Plan (2006 - 2015) of electric companies[1] operating in Maryland. The Ten-Year Plan is submitted annually by the Commission to the Secretary of the Department of Natural Resources in compliance with Section 7-201 of the Public Utility Companies Article (PUC Article), *Annotated Code of Maryland*. It is a compilation of information pertaining to the long-range plans of Maryland's electric companies. This report also includes summaries of major events that have or may affect the electric utility industry in Maryland in the near future.

Section II addresses the status of competition in Maryland's electric and gas markets at the retail level. The Electric Customer Choice and Competition Act of 1999 (Electric Act)[2] enabled the restructuring of the electric industry, by *inter alia*, deregulating the generation of electricity and allowing electric customers to choose a retail electricity supplier. The Natural Gas Supplier Licensing and Consumer Protection Act of 2000 (Gas Act)[3] established explicit oversight of gas suppliers by the Commission. Both the Electric Act and the Gas Act provide for specific consumer protection rules for customers choosing a supplier other than the local distribution utility. This section also discusses the results of the auctions pertaining to electric companies that resulted from the Standard Offer Service proceedings (Case Nos. 8908, 9037 and 9056) and gives an update on the competitive activities of licensed electricity and gas suppliers. Finally, it addresses various regulatory matters (such as Case Nos. 9063, 9069, 9073, 9074, and 9089) pertaining to Senate Bill 1, namely Chapter 5, 2006 Maryland Laws, 1st Special Session.

Section III provides information on distribution reliability in Maryland, including utility procedures for periodic inspection and maintenance of system equipment and responses to major storms and blackouts. Topics covered also include the management of distribution outages, distribution reliability assurance, and regional distribution and transmission planning throughout the various regions of the State.

Section IV presents data and information on generation (including Certificates of Public Necessity and Convenience and CPCN exemptions) and transmission activity in Maryland and affecting its regional transmission organization (RTO), PJM Interconnection, LLC (PJM)[4]. In the current restructured environment, the Commission must increasingly take a regional approach in its mission to ensure adequate generation and a robust transmission grid. A summary and update of recent issues and activities at PJM is also included in this section. Issues that received a great deal of attention in 2006 included the status of PJM's Reliability Pricing Model (RPM) for capacity markets and the formation of new transmission planning working groups to consider how PJM processes can build major interstate transmission corridors.

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1 Section 1-101(h) of the Public Utility Companies Article defines an "electric company" as a "person who physically transmits or distributes electricity in the State of Maryland to a retail electric customer" with certain exceptions for self-supply or generating electricity on-site.

2 See PUC Article §7-504 *et seq.*

3 See PUC Article §7-601 *et seq.*

4 PJM is the RTO for the electric grid in the Mid-Atlantic region and ensures its reliability by coordinating the movement of electricity in all or in parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

Section V provides a summary of utility efforts since January 1, 2006, to implement conservation programs and to promote and utilize renewable resources and cogeneration. Implementation of the Renewable Energy Portfolio Standard (RPS) Legislation, the passing of the Maryland Healthy Air Act (HAA), the initiation of the Regional Greenhouse Gas Initiative (RGGI), the continued efforts of the Mid-Atlantic Distributed Resources Initiative (MADRI), and the promotion of small generators interconnection and net metering are significant topics that are discussed in this section. The section also discusses the recent formation of the Demand Response/Distributed Generation (DRDG) Working Group.

Section VI presents information on national energy issues that have an impact on Maryland. Important topics include the implementation of the Energy Policy Act (EPAct) of 2005, formation of the Electric Reliability Organization (ERO) to oversee the reliability of the North American Bulk-Power System, the North American Electric Reliability Council (NERC) reliability study, the Department of Energy (DOE) congestion study, and the Federal Energy Regulatory Commission (FERC) Staff report on demand response and advanced metering. This section also discusses the impacts of volatile commodity prices on wholesale electricity markets.

Finally, 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 generating energy projects, and planned transmission enhancements for each utility.

The map of Maryland below shows a geographic breakdown of the State's regulated electric utilities. In all, there are four investor-owned systems, five municipal systems, and four electric cooperative systems, two of which are rate-regulated.

Map I-1: Electric Utilities and their Territories in Maryland

II. RETAIL CUSTOMER CHOICE IN MARYLAND

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.

Although this report is specifically directed to electric companies with some attention to electricity suppliers, it is helpful to mention natural gas activities also, since many of the electricity suppliers/brokers are also natural gas suppliers/brokers.[5] On May 18, 2000, the Natural Gas Supplier Licensing and Consumer Protection Act of 2000 was enacted. The Gas Act directed the Commission to "adopt licensing requirements and procedures for gas suppliers that protect consumers, the public interest, and the collection of all state and local taxes." [6]

As of July 1, 2000, all retail electric customers of investor-owned utilities in the State of Maryland 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 electric utilities. Under the Electric Act utilities are required to offer Standard Offer Service (SOS) for a period of not less than four years. On July 1, 2004, and July 1, 2006, the temporary rate caps and freezes that went into effect due to electric restructuring were lifted for many utility customers. In Case No. 8908 (discussed later in this section), the Commission established the framework for supplying market-based SOS, and the first electric procurements were conducted during 2004.

The introduction of competition into the electric industry provided the potential for significant benefits to electric customers. Some reasons for moving to a competitive electric market were to:

- Put downward pressure on costs, thus providing consumers with the lowest possible electricity prices;
- Allow all customers the opportunity to select their electricity supplier;
- Provide incentives for the creation and development of innovative products and services;
- Ensure reliability by creating a competitive market structure that provides power plant developers and owners with the necessary economic incentives to ensure that additional generating facilities will be planned and built when needed; and,
- Attract new business development, retain existing businesses, and enhance overall economic growth.

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5 As of November 30, 2006, the Commission has issued 28 electricity supplier licenses, 17 electricity broker licenses, 23 natural gas supplier licenses, and 3 natural gas broker licenses. In addition, 14 companies had both electricity and natural gas licenses; 7 companies had both electric and natural gas broker licenses; and 1 electricity aggregator license. The Commission has issued a total of 93 electricity and natural gas related licenses (see Appendix Table A-7).

6 PUC Article §7-603(b).

Electric service is currently available to most classes of Maryland customers via SOS. Among the four large investor owned utilities (IOUs)[7] only residential customers of Allegheny continue to receive service through fixed price power supply tariffs offered by Maryland's electric companies pursuant to settlements filed with the Commission in its electric restructuring dockets.

A. Status of Retail Electric Choice in Maryland

By Order No. 75608, in Case No. 8738 issued September 10, 1999, the Commission approved the procedures developed by the Supplier Authorization Working Group to license electricity suppliers and electric generation services providers in Maryland pursuant to §7-507 of the Public Utility Companies Article. The licensing process approved by the Commission requires an applicant to provide proof of:

- Technical and managerial competence;
- Compliance with applicable requirements of the Federal Energy Regulatory Commission (FERC), and any ISO or transmission operator to be used;
- Compliance with applicable federal and state environmental laws and regulations that relate to the generation of electricity; and,
- Financial integrity and qualification to do business in the State of Maryland.

On July 12, 2002, the Commission published in the *Maryland Register* regulations governing electricity and gas supplier license requirements. Numerous comments were received by the public comment date of August 12, 2002, and final regulations were adopted in 2003. Table II-1 (next page) shows the number of accounts and the percentage of peak load obligation served by electricity suppliers for each of the major distribution utilities in Maryland. Reversing recent trends, the percentage of peak load obligation served by electricity suppliers increased slightly for residential customers. These competitive suppliers continued to make significant gains in share of the peak load obligation for commercial and industrial (C&I) customers. The percentages of peak load obligation served by competitive suppliers approximately doubled for mid-sized C&I customers and increased six-fold for small C&I customers. The overwhelming majority of peak load obligation for large C&I customers continues to be served by electricity suppliers. Electricity suppliers now serve approximately 69% of the peak load for all types of commercial and industrial customers and 37% of peak load for all customers.

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 remains in its early stages for residential customers. This may be due in part to the fact that many customers in Maryland have only recently ceased to receive service through fixed price power supply tariffs offered by Maryland's electric companies pursuant to settlements filed with the Commission in company-specific electric restructuring dockets. As of July 1, 2006, only residential customers of AP remain is this situation. In cases where settlements have ended, the shift in load from utility service to competitive supply has been significant. The Commission's monthly enrollment reports indicate that this shift in load is largely the result of choices by C&I customers (see Table II-1 on the next page).

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[7] The four IOUs in Maryland are The Potomac Edison Company d/b/a Allegheny Power (AP or Allegheny), Baltimore Gas and Electric Company (BGE), Delmarva Power & Light (DP&L or Delmarva), and Potomac Electric Power Company (Pepco).

Table II-1: Electric Choice Enrollment in Maryland

Number of Customers Served by Electricity Suppliers[8]

Utilities	Residential	Small C&I[9]	Mid C&I[10]	Large C&I[11]	All C&I	Total
AP	9	1,977	615	108	2,700	**2,709**
BG&E	12,323	25,812	5,514	566	31,892	**44,215**
Delmarva	339	2,772	447	74	3,293	**3,632**
Pepco	25,695	8,328	6,655	503	15,486	**41,181**
Total	**38,366**	**38,889**	**13,231**	**1,251**	**53,371**	**91,737**

Percentage of Peak Load Obligation Served by Electricity Suppliers

Utilities	Residential	Small C&I	Mid C&I	Large C&I	All C&I	Total
AP	0.0%	15.0%	54.8%	92.2%	70.4%	**43.1%**
BG&E	1.3%	27.7%	64.2%	95.3%	68.5%	**34.6%**
Delmarva	0.2%	19.8%	64.2%	93.8%	54.8%	**24.7%**
Pepco	6.7%	28.0%	61.0%	93.3%	72.7%	**42.1%**
Total	**2.5%**	**24.8%**	**62.3%**	**94.1%**	**69.1%**	**37.0%**

Source: Public Service Commission of Maryland, *Electric Choice Enrollment Monthly Report*, Month Ending October 2006. 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.

The total statewide number of distribution service accounts eligible for electric choice, as of October 27, 2006, was 2,173,717 of which 1,944,711 were residential and 229,006 were non-residential. An indication of the effect of the end of capped and frozen rates is demonstrated by the most recent choice enrollment report indicates that only 4.2 percent of all utility distribution customers took service from an electricity supplier. There were 91,737 customers served by electric suppliers. Of these customers, suppliers served 38,366 residential, 38,889 small C&I, 13,231 mid-sized C&I, and 1,251 large C&I customers. Pepco experienced the highest degree of supplier participation with 25,695 residential accounts and 8,328 non-residential C&I accounts served by suppliers. Between December 2005 and October 2006, the total number of customers statewide served by electricity suppliers increased from 39,527 to 91,737 customers. The

8 As of October 31, 2006, 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: 6 serving residential load, 29 serving industrial load, 31 serving commercial load, and 9 serving other types of load (such as government).

9 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 Standard Offer Service (SOS) if they do not switch to a supplier.

10 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.

11 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.

increase was the result of a significant rise in the numbers of residential and small C&I customers served by suppliers in the BGE service territory. The number of customers served by electricity suppliers in BGE's service territory increased from 3,932 (October 2005) to 44,215 (October 2006). Of these 44,215 customers, 21,389 switched after July 1, 2006.

The overall demand in peak load obligation served by all electric suppliers at the end of October 2006 was approximately 4,809 megawatts (MW), of which about 116 MW were residential and 4,653 were non-residential. BGE had the highest peak load obligation served by suppliers at approximately 2,412 MW. The total statewide peak load obligation available for choice was 13,008.9 MW of which 6,274.2 MW were residential and 6,734.7 MW were non-residential. Statewide, at the end of October 2006, electric suppliers served 2.5 percent of eligible residential peak load and 69.1 percent of eligible non-residential peak load obligation.

On May 16, 2006, the Commission issued a Notice of Retail Market Status Conference[12] to address issues pertaining to the status of residential and non-residential retail electricity markets. The Commission invited all license suppliers, all electricity customers, the Commission Technical Staff, the Office of People's Counsel (OPC) and other interested parties to submit comments on the issues noted below.

- The status of retail competition in Maryland.
- The type(s) of competitive offerings being made by electricity suppliers for residential, Type I and Type II customers, including the time periods relative to these offerings.
- The method(s) by which different customer classes are being contacted.
- Whether customers comprehend the terms, conditions and prices of competitive offerings.
- Whether the enrollment process for competitive electricity offerings is clear and effective.
- What criteria may customers use to evaluate competitive service offerings?
- What technical or other improvements could be readily implemented to facilitate retail competition?

Comments were received from environmentalists, trade associations, residential and commercial customers, suppliers, utilities, OPC and Commission Staff.

B. Standard Offer Service (SOS) – Cases and Procurement Results

The Commission established Case No. 8908 for the purpose of investigating options for the competitive provision of SOS to electric customers once the obligation imposed on electric companies expires. On November 15, 2002, a settlement was presented to the Commission by a diverse group of parties proposing the terms and procedures for the provision of standard offer and default service to customers through the competitive selection of wholesale supply at the end of existing fixed price offers. The fixed price offers have expired for all customers with the exception of Allegheny residential customers, for whom they remain in effect until January 1, 2009. On April 29, 2003, the Commission issued Order No. 78400 that required electric utilities to continue to provide electricity supply to their customers. The Order approved the settlement that establishes the procurement and pricing methodology for this service. SOS is the alternative

[12] See Administrative Docket PC6.

to purchasing electric supply from a competitive supplier. By law, the Commission oversees the availability, procurement, and pricing of SOS.

The settlement agreement represented Phase I of a two-part process. Phase I established the policy framework for a competitive wholesale supply procurement methodology. Phase II established the technical details supporting the SOS policy framework. Phase II is currently being used to implement utility-provided SOS at market prices to Maryland's retail electric customers as their utility-specific restructuring settlements expire in the 2004 to 2008 timeframe. The Commission is requiring the IOUs operating in the State to provide these services based on its conclusion that a competitive retail electricity supply market in Maryland has not yet fully developed. Thus, the Commission cannot relieve these utilities of their obligation to provide electric supply to residential and small commercial customers. The passage of Senate Bill 1[13] (SB1) in June 2006 will impact the provision of SOS for these customers and is discussed later in the next section of this report. Limited changes will be made regarding how rate-regulated cooperative utilities provide SOS to their customers.

By Order No. 78710 issued in Case No. 8908, Phase II, on October 1, 2003, the Commission established the procedures for procuring SOS. The Commission adopted procedures that will help bring stable, market-based retail electricity supply rates to Maryland ratepayers. The Commission believes Phase II produced a reasonable and workable wholesale procurement process. The Commission will oversee the entire process to ensure that it is implemented in a fair and consistent manner for all wholesale market participants.

Phase II established a Request for Proposals (RFP) procurement methodology structured to have up to four bidding rounds. Each of the four IOUs have conducted separate, yet simultaneous bidding processes under identical rules and schedules and issued RFPs for full-requirements, wholesale electricity supply to meet their SOS obligations. For the first two SOS procurements to solicit bids to serve load for 2004-2005 and 2005-2006, approximately 6,200 and 3,590 MW were available for bid, respectively. The contracts for electricity supply by type of service were Residential – one to three years; Type I Non-residential – one or two years; Type II Non-residential – one year, and Type III Non-residential – one year. Since the initial procurement, Type III Non-residential is no longer bid and is now an hourly service.

For the third SOS procurement to solicit bids to serve load for 2006-2007, the bidding rounds began in December 2005 and concluded in August 2006. Supply services under these contracts began as early as June 1, 2006, and approximately 8,912 MW were available for bid. Listed below is a summary of the third procurement of SOS bids for all four major electric distribution companies in Maryland. It should be noted that a competitive wholesale procurement process was used to solicit offers for Full Requirements Service. The contracts for electric supply by type of service were:

- Residential SOS – 5,003 MW of one-, two- and three-year contracts;
- Type I SOS Non-residential – 1,222 MW of one- and two-year contracts;
- Type II-B SOS Non-residential – 582 MW of one-year contracts;
- Type II-A SOS Non-residential – 1,452 MW of 4 to 7 month contracts (summer); and,

13 Senate Bill 1 is now Chapter 5, 2006 Maryland Laws, 1st Special Session.

- Type II-A SOS Non-residential – 653 MW of 5 to 8 month contracts (non-summer).

Some of the key dates in the process leading up to the bidding were:

- October 2005**:** The utilities held a joint pre-bid conference in Baltimore; over 20 suppliers attended and/or showed interest in this process;
- November - December 2005: Technical Consultant met with distribution utilities to discuss its role, logistics and specific mechanics for the evaluation of bids and credit applications, and other issues. Dry-runs of the bid-day evaluation process, were also held;
- December 2005 - February 2006: Bids for the first three tranches were conducted; blocks offered were fully subscribed in all four utilities. The tranche dates were December 5, 2005; January 23, 2006; and February 21, 2006; and,
- June 2006 – August 2006: Bids for the fourth tranche (Type II-A Non-Residential, non-summer only) were conducted. The planned June 19, 2006, procurement was postponed until August 21, 2006 per Order No. 80858 in Case No. 9037 issued on June 16, 2006.

The summary results of the third RFP bid process were as follows:[14]

- The utilities conformed to their Bid Plans as required by Commission Orders, and there were appropriate security measures on all bid days.
- There were sixteen (16) eligible bidders in this process of which thirteen (13) suppliers actually submitted bids and eleven (11) suppliers won some portion of the load offered this year. As of June 2006, twelve (12) different suppliers are serving SOS customers for the June 1, 2006 to May 31, 2007 time period.
- On average, the number of MWs that bidders offered was about two times greater than the number of MWs awarded, compared to over eight times in last year's solicitation.
- The bid prices reflected general economic conditions including high and rising prices for the fuels used to produce electricity as well as increased transmission congestion in parts of Maryland. The rising price of fuels reflects a worldwide increase in demand and tightening supply for energy resources, and unfortunately the affects of Hurricanes Katrina and Rita magnified the increase.

For the fourth SOS procurement to solicit bids to serve Residential and Type I load for 2007-2008, the bidding rounds will begin in January 2007 and conclude in April 2007 (January 2008 for the quarterly Type II load). As part of the transitional phase to semi-annual bidding for two-year contracts, the RFP includes two tranches in January and February 2007 for supply services to commence June 1, 2007. Subsequently, there will be another tranche in April 2007 for supply services to commence October 1, 2006. Further, there will be additional tranches in June 2007, October 2007, and January 2008 to implement the quarterly Type II procurements. The joint-utility pre-bid conference was held on December 12, 2006 in Baltimore. At the conference the following were reviewed: the general RFP structure and process, the specific utility bid plans, and the power supply contract. The 2007-08 procurement of SOS bids will be for approximately 4,933 MW of 3-, 4-, 12-, 16- and 24-month contracts, including:

- 195 MW for AP, 2,590 MW for BGE, 565 MW for Delmarva and 1,583 MW for Pepco.
- 3,416 MW Residential, 607 MW Type I, and 910 MW Type II.

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[14] Boston Pacific, the Commission's Technical consultant in the SOS process, also contributed to this summary.

On May 26, 2005, the Commission docketed Case No. 9037*, In the Matter of Default Service for Type II Standard Offer Service Customers*. The Phase I settlement of Case No. 8908 had a provision for the Commission to docket a major policy review proceeding covering this type of SOS service. On October 12, 2005, the Commission issued Order No. 80342, which is summarized as follows:

- Current Type II SOS approach for BGE and Pepco Type II customers with demands less than 100 kW is continued and now called Type II-B.
- New Type II-A SOS is created for all current AP and Delmarva Type II customers and all BGE and Pepco Type II customers with demands equal to or greater than 100 kW.
- Type II-A SOS will be bid twice a year (summer and non-summer).
- Hourly metering for all customers with demands equal to or greater than 500 kW and for all standby and backup service customers.
- Type II-A and II-B services will be in effect through May 31, 2007.
- Process will be started to review what happens to SOS for all residential, commercial, and industrial customers following current SOS ending dates.

On February 17, 2006, the Commission docketed Case No. 9056, *In the Matter of the Commission's Investigation into Default Service for Type II Standard Offer Customers*. From February to April 2006, parties filed interventions and direct and reply testimony. Hearings were held on May 8-10, 2006 and briefs were filed in early June. In response to Senate Bill 1, the Commission directed parties to file supplemental testimony in August. On August 28, 2006, the Commission issued Order No. 81019 to address the provision of SOS Type II customers. Two modifications to the Type II service described in Order Nos. 80272 and 80342 were adopted: Type II-A and Type II-B customers were reunited as a single class, and electric supply will be procured for all Type II customers on a quarterly basis, beginning June 1, 2007.

On May 10, 2006, the Commission docketed Case No. 9064 to conduct a major policy review covering the provision of SOS to residential and small commercial customers. Pepco and DPL initiated this request on January 24, 2006, and OPC supported it on January 31, 2006. Interventions, motions and comments were filed in May and June. However, the scope of this case changed somewhat upon the passage of Senate Bill 1 in June 2006 to focus on shorter term transitional issues for the 2007-2008 SOS procurement (see Section II-C for the discussion of longer-term SB1 procurement issues in Case No. 9063). From July to September 2006, parties filed motions, issue lists, and direct and reply testimony. Hearings were held on September 26-27, 2006 and briefs were filed in October. On November 8, 2006, the Commission issued Order No. 81102, with highlights summarized as follows:

- The IOUs will procure SOS for Residential and Type I Commercial customers using two-year contracts with bidding twice per year, with appropriate transitional contracts.
- An IOU may file a proposal to develop retail time-of-use SOS rates.
- A definition[15] of a small commercial customer was established.

[15] A small commercial customer is a commercial customer that does not have: a metered 30-minute demand that equals or exceeds 25 kW; energy consumption in excess of 6,000 kWh in any two consecutive winter billing months; or a monthly energy consumption that exceeds 7,500 kWh for a single summer billing month.

- The 2007 SOS procurement schedule contained in the Report on the 2006 Procurement Improvement Process (PIP) was approved, subject to necessary modifications to conform to Order No. 81102, as well as the modifications contained in this document.
- Bidding will conclude at 4:30 p.m. with contracts awarded by 8:30 p.m. on bid day.
- The utilities may not reject any bids from SOS bidders won under the Commission's prescribed bidding procedures.
- Type I SOS will have a Price Anomaly Threshold (PAT) mechanism.
- Residential SOS will contain a volumetric risk mitigation mechanism.
- The SOS procurement modifications will not apply to AP's Residential SOS at this time.

On November 14, 2003, the Commission docketed Case Nos. 8985 and 8987 in order to address the SOS procurement issue for the Southern Maryland Electric Cooperative, Inc. (SMECO) and the Choptank Electric Cooperative (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 (ODEC), 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.

C. Senate Bill 1 Case Nos. 9063, 9069, 9073, 9074, and 9089

As previously mentioned the Maryland General Assembly passed Senate Bill 1. This section discusses some of the highlighted cases that have been docketed by the Commission to consider specific portions of the legislation. Most of these cases are still ongoing and some will result in the issuance of a Commission Report to the General Assembly as soon as December 31, 2006.

<u>Case No. 9063: Optimal Structure of the Electric Industry in Maryland</u>

Section 7 of SB1 requires the Commission "to initiate an evidentiary proceeding to study and evaluate the status of electric restructuring in the state as it pertains to the 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." SB1 also requested the Commission to consider changes necessary to provide residents the benefit of a reliable electric service at the best possible price. The areas to be investigated included:

- Options for re-regulation if advisable;
- Allowing electric companies to develop a portfolio of electricity supply that provides electricity at the lowest cost with the least volatility;

- Requiring or allowing investor-owned to purchase electricity by competitive or negotiated contracts;
- Requiring or allowing investor-owned electric companies to construct, acquire or lease power plants;
- Providing a process for the solicitation of energy efficiency and conservation;
- Providing a process to allow investor-owned electric utilities to obtain a portion of their electric supply through bilateral contracts; and
- Allowing opt-out aggregation of residential electric demand by local governments.

On May 10, 2006, prior to passage of SB1 the Commission instituted an investigation (Case No. 9063) into the optimal structure of the electric industry in Maryland in response to a request by OPC in a letter to the Commission dated March 16, 2006. The hearings took on added urgency with the passage of SB1 on June 20, 2006. On August 3, 2006 the Commission set the procedural schedule for Case No. 9063.[16] The schedule was amended by Commission orders on August 22, 2006, and October 31, 2006. The final schedule resulted in:

- Direct Testimony submitted on September 29, 2006;
- Rebuttal Testimony submitted on November 3, 2006;
- Hearings (including live surrebuttal testimony) being held on November 16 and 17, 2006;
- Briefs filed on December 8, 2006.

The case docket is extensive with participation by electric utilities, electricity suppliers and their representatives, OPC and Staff. The information contained in the docket will be used by the Commission to complete its report due to the General Assembly by December 31, 2006, as well as to decide the case.

<u>Case No. 9069: Merger between Constellation Energy Group and FPL Group, Inc.</u>

In December 2005 Constellation Energy Group, Inc. and FPL Group, Inc., announced their intention to merge. BGE as a subsidiary of Constellation initially filed an application to merge on January 23, 2006, and the Commission docketed Case No. 9054. Subsequent to passage of SB1 the Commission closed Case No. 9054 without prejudice.

SB1 in Section 6-105 set criteria for approval of the merger, among them being that the merger should provide benefits and no harm to consumers. On July 21, 2006, BGE as a subsidiary of Constellation filed a second petition for Constellation to merge with FPL. The Commission subsequently opened Case No. 9069 to consider the merger. The Commission established a procedural schedule to review the merger, with a final decision anticipated by early February 2007.

On October 25, 2006, BGE, Constellation and FPL Group, Inc. jointly petitioned the Commission to withdraw Constellation's application to merge with FPL Group, Inc. On October 30, 2006, the Commission issued a Notice of Cancellation of Procedural Schedule and Termination of Proceeding.

[16] *In the Matter of the Optimal Structure of the Electric Industry in Maryland.*

Case No. 9073: Stranded Costs due to Electric Industry Restructuring

Section 5 of this Senate Bill 1 requires the Commission to investigate, among other items, the "general regulatory structure, agreements, orders, and other prior actions of the Public Service Commission under the Electric Customer Choice and Competition Act of 1999, including the determination of and allowances for stranded costs; …"[17] On August 17, 2006, the Commission docketed Case No. 9073[18] to investigate these matters. On August 30, 2006, the Commission held a pre-hearing conference and on September 13, 2006, the Commission issued a notice of procedural schedule with the following dates:

Filing of Initial Testimony	December 15, 2006
Reply Testimony	January 26, 2007
Hearings	February 15-16, 2007
Briefs	March 8, 2007

Case No. 9074: Study on the Impact of Rising Fuel Costs on Residential Customers

Section 11 of SB1 requires the Commission to study the impact of rising fuel prices on residential consumers and potential programs to mitigate the impact of these costs on low-income residential customers. Section 11(a)(1) expressly directs the Commission to obtain the following information:

- the number of residential utility turn-off notices issued in Maryland;
- the number of residential customer turn-offs in Maryland;
- the number of residential re-connections established in Maryland; and,
- the gross amount of residential customer arrearages for each class of residential customer in Maryland.

This information is to be obtained from both electric and gas companies. According to Section 11, the information should pertain to each "category of service." By Letter Order dated August 17, 2006 the Commission notes that residential customers generally are not divided into classes for service by gas and electric companies in Maryland. Consistent with the requirements of SB1, combination gas and electric companies were required to report information, if available, separately for gas and electric service**.** The Commission requested that reports on residential customer arrearages[19], reporting for turn-offs and recommendations for Maryland be limited to those residential customers whose service is terminated for the non-payment of bills. When

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17 Senate Bill 1 imposes this requirement on "the Public Service Commission appointed in accordance with Section 12 or 22" of the Act. While the Commission has not been appointed in accordance with Section 12 or 22 of the Act, given the General Assembly's express interest in these matters, the Commission has determined to undertake this investigation.

18 *In the Matter of the Investigation Required by Section 5, 2006 Maryland Laws, 1st Special Session, Public Service Commission – Electric Industry Restructuring.*

19 The Commission filed its first report on arrearages and terminations on September 30, 2006. The report covers the period spanning January 2006 through August 2006.

reporting the gross amount of residential customer arrearages, each company was requested to report the number of residential accounts with arrearages.[20]

To this end, the Commission docketed Case No. 9074[21] on August 17, 2006. On August 30, 2006, the Commission held a pre-hearing conference and on August 31, 2006, it issued the following schedule:

Filing of Direct Testimony	October 3, 2006
Reply Testimony	October 31, 2006
Hearings	November 28-29, 2006
Briefs/Position Papers	December 11, 2006
Report to General Assembly	December 29, 2006

As noted on the procedural schedule, on December 29, 2006, the Commission expects to issue to the General Assembly a final report based on the examination of potential programs to mitigate the impact of the cost of electric increases as they impact low-income residential customers.

Case No. 9089: Financing of Rate Stabilization Costs for BGE

Section 1 of SB1 allows for an IOU to apply for a Qualified Rate Order (QRO) in order to finance its rate stabilization costs by issuing asset-backed bonds. On November 3, 2006, BGE filed its application for a QRO pursuant to Sections 7-526 and 7-548(a)(4) of the PUC Article. BGE included a motion that Section 7-529 of the PUC Article provides the Commission will make its final decision on the QRO application within 60 days of its filing. The Commission issued a Notice of Procedural Conference on November 8, 2006, and held this Procedural Conference for Case No. 9089[22] on November 16, 2006. Intervenor Reply Testimony was filed on December 6, 2006 and a hearing was held on December 14, 2006. It is expected that a Commission Order will be issued on January 2, 2007 and that BGE will issue approximately $635 million in rate stabilization bonds in the March-April 2007 timeframe.

D. National Retail Access Activities

Currently, retail electricity access (electric restructuring) is available in 16 states in the nation (including the District of Columbia).[23] The states offering retail access enacted restructuring legislation or issued regulatory orders to achieve that goal. Six (6) states have either passed legislation or issued regulatory orders to delay implementing retail electric access, while retail access has been suspended in California. Finally, the remaining states (26) are not

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20 "Arrearage" means the amount of money owed by a customer to a gas or electric company, which is 21 days or more past due.

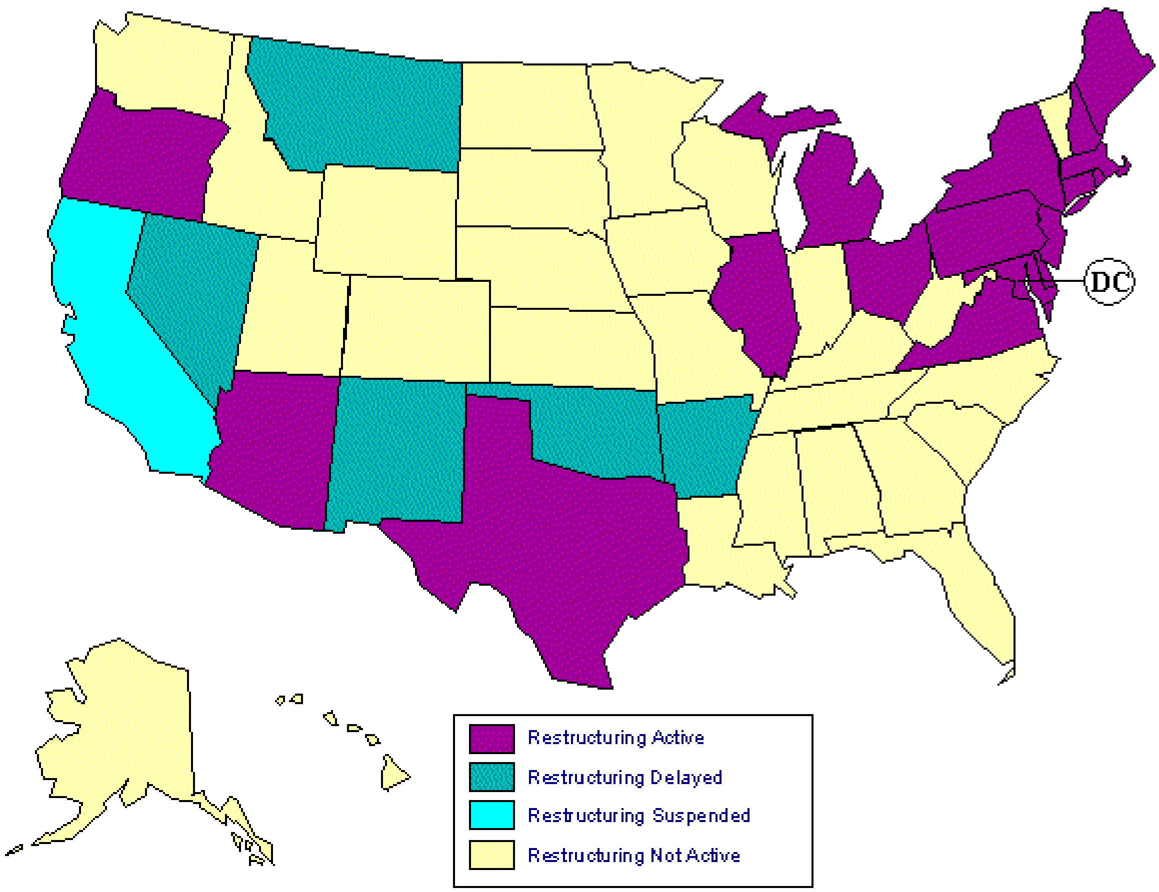
21 *In the Matter of the Investigation Required by Section 11, 2006 Maryland Laws, 1st Special Session, Public Service Commission – Electric Industry Restructuring.*

22 *In the Matter of the Application of the Baltimore Gas and Electric Company for a Qualified Rate Order to Finance Rate Stabilization Costs, and for Related Purposes.*

23 Nevada and Oregon allow retail access only for larger customers.

actively pursuing restructuring and/or retail access in the electric industry. The activity map noted below depicts the status of electric restructuring in each state.[24]

Map II-1: Status of Electric Restructuring



[24] Source: Energy Information Administration website, *Status of State Electric Industry Restructuring* of February 2003); <http://www.eia.doe.gov/cneaf/electricity/chg_str/restructure.pdf>.

III. DISTRIBUTION RELIABILITY IN MARYLAND

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.

A. Management of Distribution Outages

Perhaps the most important tool developed in recent years for managing electric distribution system outages is the computerized Outage Management System (OMS). When an outage occurs, a fully developed OMS accepts information 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 (MDS) using two-way radio communication. After repairs are made or other actions taken to end the outage, related outage information is entered as additional input 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 (CIS):</u> When a customer calls in an outage, the customer interacts with elements within the utility that have access to the CIS such as a Customer Service Representative, an automated Interactive Voice Response (IVR) unit or a High Volume Call Service (HVCS). The CIS contains the customer's address, can identify the distribution system transformer that serves the customer, and passes this information on to the OMS. The OMS then 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 (EMS):</u> The EMS includes an electronic diagram of the electric system showing how elements are connected electrically. The EMS also uses remote monitoring devices so that information related to the operational condition of important, major pieces of electric system equipment can be passed on to the OMS.
- <u>Geographic Information System (GIS):</u> The GIS includes a map of key landmarks, such as streets, and it shows the location of important elements of the electric system relative to those landmarks. This relationship is clearly important in the effort to get repair crews to the heart of the matter. In addition to providing information to the OMS, both the EMS electric system diagram and the GIS map can be displayed on computer monitors and are used by dispatchers to direct the efforts of repair crews.
- <u>Mobile Dispatch System (MDS) and/or Work Management System (WMS):</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 (ETR) and other information can be fed back to the CIS, in order that customers who are affected by a particular ongoing outage may be kept informed.
- Information concerning outages can be extracted from the OMS in near real-time to feed Internet 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 investor-owned electric utilities operating in Maryland and the SMECO and Choptank electric cooperatives have implemented OMS, each with functionality developed generally to the extent described above.

BGE has recently renovated its Transmission System Operations and Distribution System Operations Control Rooms. The Distribution System Operations Control Room features improved lighting, acoustics, and ergonomically designed computer system layouts, providing a better environment for outage management efforts. BGE has also upgraded its Energy Control System (part of the EMS), used to monitor and operate BGE substations and transmission lines. Computer servers and software have also been updated.

The Choptank Cooperative has implemented a newer version of its customer call system, with increased capacity for taking outage calls. The system is integrated with the EMS, and can provide a prediction of the location of problems causing outages in the electric system. Choptank has also upgraded its IVR system and its backup IVR system. The primary IVR system received new hardware and is now housed in a fire retardant room. The remote backup IVR system, providing extended call-handling capability, is scheduled to be improved with increased capacity.

Pepco has made several software modifications to its OMS to improve functionality and increase its efficiency in light of lessons learned during the 2005 storm season. In the coming years, the OMS will continue to be an important tool for identifying and clearing electric service outages, as well as for related communication and record keeping. The utilities will continue to gain experience in the use of the systems to maximize their efficiency. Improvements to OMS data quality and processing will be made. New OMS features and functions will probably be added.

While the OMS is a valuable tool, there is of course more to the management of distribution outages. Widespread outages caused by some severe weather events in recent years have brought increased awareness of the role utilities must play in the community-wide disaster preparedness and restoration effort.

Maryland electric utilities are filling this role in several ways. The utilities continue to work and communicate with local Emergency Management Agencies during storms and emergencies. Several utilities routinely engage in storm drills and exercises, both in-house and in cooperation with local and State emergency management agencies.

Maryland electric utilities report that they are regularly updating their emergency response plans. Learning from storm experiences, they are improving procedures, better defining the roles of utility personnel and working toward improved handling of outside personnel resources when they are employed for storm restoration. Increasingly, electric utilities are incorporating the structure of the Incident Command System (ICS) as defined in the National Incident Management System. The ICS utilizes well-defined procedures and command structure to deal with emergencies of all types. The larger electric utilities in Maryland report expanded implementation of and training in an ICS structure designed to provide an effective and controlled response to a full array of potential emergency situations, in addition to electric outage restoration.

Internet web sites that allow monitoring of electric service outage numbers and locations in near-real time are now provided by the six largest electric utilities in the State. While Allegheny Power has maintained an outage web site for use by emergency management and other government agencies for several years, the utility introduced a public web site with outage information in 2006. In addition to current outage information, the utility web sites typically provide useful information concerning preparation for outages and emergencies.

For several years, the electric utilities have realized that a collaborative effort among members of the electric utility community can be very useful for outage management 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. 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.

B. Distribution Reliability Assurance

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 Operation and Maintenance (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 the substation.

For distribution feeder lines, inspection and maintenance attention is typically focused on the electrical conductors in general, capacitors and other voltage regulators, re-closing circuit breakers (reclosers), electronic monitoring/control devices, vegetation management, and support poles for overhead equipment.

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 the heat.

Each utility is required by the COMAR provision to keep sufficient records to give evidence of compliance with its O&M procedures. The Commission Engineering Division (PSCED) 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 PSCED issues a letter of non-compliance, with expectations of remedial utility actions within 30 days.

Electric utilities serving 40,000 or more Maryland customers are required to file an Annual Reliability Report[25] 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. The investor-owned utilities also report the reliability measurements for a group of the least reliable electric feeders in its 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 to appear on a utility's least reliable list in successive years, 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.

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

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

customer served by the feeder and the system, an important reliability goal. In addition, automation of such distribution feeder devices and others is increasing, with the potential to reduce both frequency and duration of electric service outages. Other examples of reliability assurance activity performed by utilities include the ongoing replacement of aged overhead and underground conductors, injections of underground cable to increase its life expectancy, capacitor bank installations for voltage integrity, utility pole maintenance/replacement, and vegetation management, including dangerous tree removals.

The annual Summer Reliability Conference was held at the Commission on May 16, 2006. Electric utilities filed comments, and discussions were held concerning utility preparedness to meet the expected peak load demand for the coming summer. The utilities expressed confidence in their personnel, distribution system equipment, procedures, system improvements and load forecasts to meet the peak summer load demand reliably. No significant shortcomings were encountered in that regard during the 2006 summer. In addition, the utilities gave details of their demand-side (DSM) and active load management (ALM) programs for load management during periods of high electricity use.

C. Distribution Reliability Issues

One of the most persistent reliability issues in recent years has been the large amount of electric system damage and numbers of electric service outages that large trees cause when these trees fall on overhead electric distribution lines or facilities. 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 2006 to date. In six Major Storm Reports[26] filed with the Commission in 2006 to date, utilities reported a total of approximately 6.5 million hours of electric service interruption during stormy weather. Of that total, approximately 4.3 million of those lost hours, or about 66%, were caused by fallen trees or tree limbs.

Trees receive much public attention during and immediately following hurricanes or tropical storms, but large trees cause significant numbers of electric service interruptions throughout any given year. While electric utilities are able to control trees within clearly established rights-of-way, the utility cannot always control trees near, but outside, the rights-of-ways that are capable of causing outages. In Order No. 79159, the Commission recognized the ongoing efforts of the Maryland Electric Reliability Tree Trimming Council (MERTT Council)[27] to deal with the problem of outages caused by privately-owned trees that are located near power lines. The order states, in part:

> The Commission believes that the MERTT [Council] is best suited to address the complicated issue of privately-owned trees and their relationship to electric power lines and utility rights-of-way. Staff and the electric utilities are directed to work

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

[27] The MERTT Council was established in the aftermath of the Floyd storm in 1999. Its membership has consisted of Utility Foresters, a DNR-Forest Service representative, Power Plant Research Program (PPRP) personnel, PSCED 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.

> through the MERTT [Council] to develop a detailed recommendation for specific actions that utilities can take to best manage privately owned trees near utility rights-of-way. The recommendation will include a workable plan for implementing the actions as well as provide any draft regulations or legislation that may be deemed necessary or appropriate.

On October 5, 2005, the MERTT Council filed *Recommendations for the Management of Privately Owned Trees in Maryland* with the Commission, pursuant to the order. The recommendations concern communication and cooperation with various stakeholders, establishing funding for managing the trees, and how to further the science of risk identification of hazardous defects in trees.

The MERTT Council did not reach a consensus to recommend regulation or legislation, but instead recommended a research project. The Council recommended that MERTT member utilities participate "in data collection and archiving activity that supports the research project to determine the scope and degree of impact that off right-of-way privately owned trees have on electric service reliability in Maryland." The MERTT Council has largely established the specific data to be collected, and training in the use of data collection hardware has begun. The data is to be collected by the vegetation management units of the major utilities. Although the exact dimensions of utility rights-of-way are not always known by all, or even clearly established, one goal of the data collection effort is to document the number and percentages of outages caused by trees that are outside the control of the utilities. Although the utilities already know that the degree of impact that these trees have in causing service outages is significant, 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. Commission Order No. 79159 directed Staff and the electric utilities to work through the MERTT Council to develop a detailed recommendation for specific actions that utilities can take to best manage privately owned trees near utility rights-of-way. However, it has become very clear that the specific actions that the utilities are able to take alone are limited, and these actions have not been sufficient to significantly reduce outages and damage to overhead electric facilities caused by trees near utility rights-of-way.

The efforts of the MERTT Council to reduce the risk privately owned trees pose to overhead electric facilities is notable, but more work and commitment is needed. Just as it has been recognized that disaster preparedness and restoration is a community-wide effort with utilities playing an expanded role, a community-wide effort must be undertaken if electric system damage and outages due to privately owned trees, and also sometimes publicly owned trees, are to be reduced.

The prevention of utility damage and service outages caused by privately and publicly owned trees is simply another element of disaster preparedness. Trees take years to grow to the size capable of damaging overhead electric power distribution lines and facilities. While work will continue in the effort to remove the threat by existing large trees to overhead electric facilities, that work is hard and slow since many citizens have grown attached to those trees. The key to preparedness and prevention is to use the advantage of time, to begin action now to remove currently existing saplings of large-tree species and to disallow planting of large tree species near overhead electric distribution facilities.

It is likely that the problems associated with currently existing large trees near power lines will be resolved over time. Some trees will be removed by agreement between utility and owner, and some will fall. Over time, all can be replaced by many alternate species of trees, having innate height limitations, that are compatible with the lines. Lists of such utility compatible trees have existed for some time. The MERTT Council and others continue to work to promote the "Right-Tree-Right-Place" concept. The Council is working on a poster depicting the concept, to be distributed to tree nurseries within the state.

D. Regional Distribution and Transmission Planning

The role of an electric 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 largest electric distribution system projects and programs, ongoing, planned, or in development by Maryland's large electric companies, follows.

1. <u>Central Maryland -- BGE</u>

- Electric System Redesign Program: Began in 2004, the five-year plan is to reduce the frequency and duration of outages throughout the BGE electric distribution system, utilizing new equipment, technologies, circuit design standards and reliability analysis methods. A key element of this program is the integration of automated or electronically controlled devices into the distribution system. Locations to benefit from the program in the first two years are Mt. Washington in Baltimore City, Lipins Corner, Earleigh Heights, Hereford, and Bowie.
- Ongoing underground cable replacement program to improve distribution reliability.
- For 2007, replace existing BGE internal radio communications system with a digital wireless system, a more robust, reliable, secure system with more functionality than the existing analog system.
- New distribution substations to be built to serve the Havre de Grace, Aberdeen, Westminster, Hampstead, Manchester, Owings Mills, Catonsville, Woodlawn, and Westview areas in 2007.
- Upgrade sub-transmission feeders to increase electric capacity to north central Baltimore County in 2007.
- 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. The goal is to have this substation in service by

mid-2008. Other new substations planned for 2008 will serve north/northwestern Baltimore City, northeastern Prince George's County, Ft. Meade and surrounding areas of Anne Arundel County, Middle River, White Marsh, and Sykesville.

- Construction of a new Westport switching station and multiple underground cables to serve downtown Baltimore load growth, scheduled for completion in the timeframe of 2007 to 2010.
- A new substation or substation upgrades to serve Havre de Grace, West Aberdeen, Annapolis, northern Calvert County, Glen Burnie, Broadneck Peninsula in Anne Arundel County, Perry Hall, Gibson Island, northern Prince George's and Montgomery Counties, and Timonium are planned for 2009.
- In 2010, new substations are planned for central Harford County and Perryman. Substation upgrades are planned for Middle River, northern Baltimore County, central and southern Baltimore City, and southern Baltimore County.
- New substations are planned for the period 2011-2013 to serve eastern Baltimore City and County, southwestern Harford County, Halethorpe, Landsdowne, Brooklyn, the Middletown and Mt. Carmel areas of northern Baltimore County, the Govans, Anneslie and Rogers Forge areas of Baltimore City/County, western Harford County, southern Baltimore City, and Randallstown.
- New substations are planned for the period 2014-2016 to serve the Coldspring Lane corridor in Baltimore City, northwestern Baltimore County, northeastern Carroll County, northeastern Howard County, southern Anne Arundel County, northern Calvert County, Joppatowne, and central Harford County.

2. <u>Central Maryland -- Pepco</u>

- For 2007, build two new distribution feeders and extend three others to serve the National Harbor Development and the Gaylord National Hotel and Conference Center.
- Upgrade a substation and extend distribution feeders to serve the Largo, Crain Highway, and Oak Grove areas of Prince George's County in 2009.
- Upgrade a substation to serve the Gaithersburg, Hunting Hill, and Shady Grove areas of Montgomery County in 2009.
- In 2010, upgrade a substation to serve University Town Center and Metro Center Development.
- Upgrade a supply feeder for an existing substation to serve the Sligo area of Montgomery County in 2010.
- Construct a new feeder and extend an existing feeder in 2010 to serve the National Harbor Development and the Gaylord National Hotel and Conference Center.
- For 2011, build a new substation to serve the Bureau of Standards, Hunting Hill, and Shady Grove areas of Montgomery County.
- A new substation is planned for construction in 2012 to serve the Beltsville area of Prince George's County. Plans are to upgrade to a substation in 2012 to serve the Colesville, Rossmoor, and Fairland areas of Montgomery County.
- 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 the electric system serving the Bells Mill area of Montgomery County.

- In 2014, upgrade the substation serving the Bureau of Standards, Hunting Hill, and Shady Grove areas of Montgomery County.
- Current Pepco plans for 2017 include building a new substation to serve the Germantown Area of Montgomery County.

3. Western Maryland -- Allegheny Power

- Construction of two substations, to provide additional capacity to serve the anticipated load growth in the area north and west of Hagerstown, is projected for completion in mid-2007. Upgrades of substations serving the Lappans Crossroads, Clarksburg, northwest Frederick areas, and the Western Correctional Institute near Cumberland are planned for 2007.
- Upgrade substations in 2008 to serve the Frederick, Clarksburg, and Taneytown areas.
- In 2009, construction of four substations is scheduled to provide additional service to the southern Frederick, Clear Spring, Jefferson, and Poolesville areas.
- Upgrade two substations in 2010 to serve the Urbana and Ridgeville areas.
- Construction of two substations in 2011 to serve the south-central part of Washington County and Emmitsburg areas.
- During the period 2011-2015, build a substation to provide additional service to the north-central part of Montgomery County.
- Upgrade three substations that serve the north-central parts of Montgomery County, during the period 2011-2015.
- Upgrades to a substation are scheduled for 2015 to provide service to the planned Villages of Urbana subdivision.

4. Eastern Shore -- Delmarva Power

- Construction of a distribution substation, due to be completed in May 2007, is expected to address load growth in the Salisbury area. A new substation scheduled for completion late in 2007 will serve the Centreville area. Installation of a new unit substation in 2007 will benefit the North East area of Cecil County.
- New installations, extensions or upgrades of electric distribution feeders planned for 2007 will benefit the Grasonville, Salisbury, Centreville, St. Michaels, Bishop, Stevensville, North East, Keeney, Elkton, Rising Sun, and Colora areas.
- For 2008, upgrades to substations are planned to serve the Centreville, Chestertown, Massey, Bishop and St. Michaels areas. 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 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.
- Upgrades of substations and feeders in 2010 to serve the Bozman, Queen Anne, Stockton, Centreville, Salisbury, Eastern Neck Island, and North East areas.
- Electric distribution feeder upgrades are planned for 2011 that would benefit the Cambridge area.

5. Eastern Shore -- Choptank

- In 2007, the completed Oil City substation will benefit the Denton area and also provide service to Choptank's Hobbs and Hickman substations. New installations, extensions or upgrades of electric distribution feeders planned for 2007 will benefit the Earleville, Millington, Hillsboro, Talbot County, Federalsburg, East New Market, Denton, Cambridge and Ocean Pines areas.
- For 2008, construction of a substation to serve the Cambridge area is planned. For 2008, distribution feeder improvements are planned for the Kennedyville, Hillsboro, Federalsburg, Denton, Cambridge, Princess Anne, Mt. Olive and Westover areas.
- Construction of substations to serve the Rockawalkin (Salisbury) and Denton areas is planned for 2009. 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.
- Substations to serve the Chestertown, West Denton and Mt. Zion areas are planned for 2011, along with feeder improvements that will benefit the West Denton, Kennedyville, Longwoods, Hickman, and Kingston areas.
- A substation is planned for 2012 to serve the Sharptown area near Salisbury. Feeder improvements in 2012 are planned to benefit the Millington, Kennedyville, Barclay, Williston, Tanyard, Sharptown, Mardela Springs, and Walston areas.
- In 2013, distribution feeder improvements are planned to serve the East New Market, Cambridge, Edgewood, Princess Anne, and Worcester County areas.
- For 2014, construction of a substation near Cambridge is planned. Feeder improvements are planned in 2014 to serve the Barclay, Hillsboro, Talbot County, West Denton, Edgewood, and Kingston areas.
- A substation is planned for construction in 2015 to serve the area east of Cambridge. Feeder improvements are planned for 2015 that would benefit the Federalsburg, Tanyard, East New Market, and Kingston areas.
- Construction of a substation to serve Chestertown is planned for 2016. Plans for feeder improvements in 2016 will benefit the Chestertown, I.B. Corners, Talbot County, West Denton, Mardela Springs, Ironshire, and Worcester County areas.

6. Southern Maryland -- SMECO

- Scheduled to energize six new distribution feeders, and complete a capacity upgrade of the Tompkinsville substation by the end of 2006
- Completed construction of a substation to serve northern Calvert County and began construction of another substation to serve Saint Mary's County, in 2006.
- A 66-kilovolt sub-transmission bypass configuration project is underway at the LaPlata substation. The bypass project will provide an alternate sub-transmission electric source to be used during unexpected outage situations in the area surrounding LaPlata.
- Major installation during 2006 of capacitors on distribution feeders, to maintain the quality of electric distribution power.

- Updated the Emergency Response Plan for 2006. Working to establish additional agreements with contractors to provide assistance with emergency outage restoration work.
- Permanent cable replacement was completed in April 2006 on the 6770 circuit, for which a submarine portion across the Patuxent River had failed in early 2005.
- Recently completed construction projects to relieve electrical loading on the highest loaded distribution feeders.
- Began phasing in a full-featured computerized OMS in November 2005. Most features of the OMS are now operational.

IV. GENERATION AND TRANSMISSION IN MARYLAND AND PJM

The Commission has been charged historically with ensuring safe and reliable utility service throughout Maryland. This obligation was reaffirmed in the Electric Act. See PUC Article §7-505(a). As a consequence of electric restructuring, the Commission has limited statutory responsibility for oversight of generation facilities, but it continues its ongoing review of the maintenance and operation of electric utility transmission facilities in the State.

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

There has been very little change to the amount and the mix of generation in Maryland so far this decade. No significant generation has been added in the past three years and no units have retired since the Gould Street plant (101 MW) in the BGE zone ceased operations in November 2003. Table IV-1 lists the current profile of Maryland-based generating units:

Table IV-1: Maryland Generating Capacity Profile

	Capacity		Vintage 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	4,958.0	39.7%	3.6%	13.0%	13.5%	69.9%
Dual-fired *	3,107.2	24.9%	13.8%	24.7%	39.4%	22.1%
Nuclear	1,735.0	13.9%	0.0%	0.0%	100.0%	0.0%
Natural/Other Gases	1,121.1	9.0%	57.2%	0.0%	0.0%	42.8%
Petroleum	885.0	7.0%	1.3%	1.9%	1.4%	95.4%
Hydroelectric	566.0	4.5%	0.0%	0.0%	0.0%	100.0%
Other Renewables	127.0	1.0%	49.4%	5.3%	45.3%	0.0%
TOTAL	**12,499.3**	**100.0%**	**10.6%**	**11.5%**	**29.6%**	**48.3%**

Source: Energy Information Administration, as of January 1, 2005.
* -- Primary fuel types of dual-fired plants: 81.7% petroleum, 18.3% natural gas.

Coal plants[28] represent about 40% of summer peak capacity, but the only units built during the last thirty years were the two Brandon Shores plants (643 MW each, 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 27% of all capacity burns oil either as the primary or the sole fuel source and many of these facilities are aging as well. Overall, only about 22% of the State's generating capacity has been constructed in the past twenty years. The Maryland generating profile differs considerably from its capacity profile. In 2005, Maryland plants produced 52,537 gigawatt-hours (GWh) of electricity,[29] generated 55.8% by coal and 28.0% by nuclear plants. Thus, Maryland coal and nuclear facilities generate 83.8% of all electricity, although they represent only 53.6% of capacity. In contrast, oil and gas facilities generate but

[28] Ownership breakdown of coal plants is as follows: Mirant Corp. 2,473 MW, Constellation Energy Group, Inc. 2,130 MW, AES Corp. 180 MW, Allegheny Energy Supply Co. LLC 115 MW, and New Page Corp. 60 MW.

[29] Source: EIA. The 52,537 GWh of electricity generated in 2005 consists of the following: coal 55.8%, nuclear 28.0%, petroleum 7.1%, natural gas 3.5%, hydroelectric 3.3%, other renewables 1.7%, and other gases 0.7%.

10.6% of all electricity, despite representing 40.9% of instate capacity. The State remains a net importer of electricity. In 2005, Maryland retail sales were 72,711 GWh (including a 6.25% loss factor),[30] meaning that 20,174 GWh (27.8%) 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 New Jersey, PJM has granted the request of four older facilities to retire in the next two years: 285 MW at Martins Creek in September 2007, 447 MW at B.L. England in December 2007, 453 MW at Sewaren in September 2008, and 383 MW at Hudson in September 2008. In addition, it is possible that some older units that cannot meet stricter environmental standards at the federal or state level may similarly shut down. In the next section, there is a discussion of CPCNs filings made by six of Maryland's coal facilities for various environmental upgrades for compliance with the Maryland Healthy Air Act (HAA). As well, other older Maryland coal units may yet be at-risk to retire if the emissions restrictions (including for carbon) found in the HAA make these plants uneconomic to operate in the future.

B. Certifications for New Electric Plants and Environmental Upgrades at Existing Plants

During the past four years, the Commission has granted several CPCNs for generating projects in Maryland. When constructed, the electricity generated by these projects will be available for Maryland and the PJM region. Below, Table IV-2 identifies all proposed generating projects for which the Commission has granted a CPCN. No CPCN applications for new construction are pending. All of the projects listed in this table have plans to interconnect with PJM's regional market.

Table IV-2: New Generating Resources Planned for Construction in Maryland

Resource Developer And Location	Capacity & Fuel	Expected In-Service Date	Interconnected w/Regional Mkt.	CPCN Status
Eastern Landfill Gas, LLC, Baltimore Co.	4.2 MW L.F. Gas	In-service Sept. 2006	Yes	Granted 7/19/2005
Clipper Windpower, Inc., Garrett Co.	101 MW Wind	4th Qtr. 2006	Yes	Granted 3/26/2003
Savage Mountain US Wind Force LLC, Allegany and Garrett Cos.	40 MW Wind	4th Qtr. 2007	Yes	Granted 3/20/2003
Sempra Energy, Catoctin Power LLC / EastAlco, Frederick Co.	640 MW Gas	2009	Yes	Granted 4/25/2005
Synergics Wind Energy, Roth Rock Windpower Project, Garrett Co.	40 MW Wind	2008	Yes	H.E. Order 10/31/2006
INGENCO Wholesale Power, New-land Park Landfill, Wicomico Co.	6.0 MW L.F. Gas	1st Qtr. 2007	Yes	Granted 4/8/2006

[30] Source: EIA. The 72,711 GWh of electricity consumed in 2005 consists of the following: residential 41.8% (30,338 GWh), commercial 26.1% (18,942 GWh), industrial 31.5% (22,902 GWh), transportation 0.7% (529 GWh). All data includes the 6.25% loss factor.

Growth in power plant development has been modest and has lagged load growth in Maryland. Since 2000, only about 700 MW of new generation have been constructed. Natural gas (97%) has been the fuel of choice for these new peaking and mid-merit units. Renewal of federal tax credits has encouraged the development of wind farms in Western Maryland. Maryland's Renewable Energy Portfolio Standard and the Energy Policy Act of 2005 may promote this development further. In March 2003, the Commission approved CPCNs for Clipper Windpower, Inc.[31] and Savage Mountain US Windforce LLC[32]. The in-service dates for both of these facilities have been delayed due to ongoing court challenges. On October 31, 2006, a Commission Hearing Examiner (H.E.) issued a proposed order for the Synergics Wind Energy, LLC[33] project. This proposed order has been appealed by several parties and the Commission has not issued a final order. There have been no recent applications for large baseload plants.

On October 27, 2005, Constellation Energy announced[34] its intention to apply to the Nuclear Regulatory Commission (NRC) for a combined construction and operating license. The company mentioned that two of the sites under consideration include its existing Calvert Cliffs Nuclear Power Plant in Southern Maryland and the Nine Mile Point Nuclear Station in upstate New York. In summer 2006, Constellation submitted into a PJM generation queue two potential nuclear power facilities that would be located at Calvert Cliffs. The two proposed units would each have a generating capacity of 1,640 MW (3,280 MW in total) and have projected in-service dates of 2015 and 2016, respectively. Given the lack of nuclear generation built in the United States in recent decades, it is very difficult to predict if the new Calvert Cliffs units will be built.

Governor Robert L. Ehrlich, Jr., signed into law on April 6, 2006 the Maryland Healthy Air Act. The act requires affected electricity generating facilities to collectively reduce their emissions of various nitrogen oxides (NO_x), sulfur dioxide (SO_2), and mercury. The facilities must be in compliance with the law beginning on January 1, 2009 for NO_x and January 1, 2010 for SO_2 and mercury. Table IV-3 on the next page identifies the affected facilities, their planned upgrades, and their respective case numbers with the Commission. For additional discussion on the HAA, including carbon issues, please see sections V-D and V-E of this report.

The Commission began receiving applications for CPCNs for modifications to coal power plants beginning August 23, 2006 with the application of Constellation Power Source Generation, Inc. (CPSG) for modifications to its Brandon Shores Power Plant in Anne Arundel County, Maryland. The application provides for installation of flue gas desulfurization (FGD) systems for the associated coal power plant. The Brandon Shores project is typical for including wet flue gas desulfurization systems. The project will substantially decrease the emissions of the primary air emissions emitted from the plant, including SO_2, particulate matter (PM) and particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}) and mercury (Hg). The project will consist of the following components:

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31 See Case No. 8938, *In the Matter of the Application of Clipper Windpower, Inc. for a Certificate of Public Convenience and Necessity to construct a 101 MW Generating Facility in Garrett County, Maryland.*

32 See Case No. 8939, *In the Matter of the Application of Savage Mountain Windforce, LLC. for a Certificate of Public Convenience and Necessity to construct a 40 MW Generating Facility in Allegheny and Garrett Counties, Maryland.*

33 See Case No. 9008, *In the Matter of the Application of Synergics Wind Energy, LLC. for a Certificate of Public Convenience and Necessity to construct a 40 MW Wind Power Facility in Garrett County, Maryland.*

34 Source: Constellation Energy press release dated October 27, 2005.

- Wet FGD system and associated facilities;
- Fabric filter baghouse on each unit;
- Sorbent injection equipment for removal of mercury and sulfuric acid mist;
- Enhancements on the steam turbine to improve efficiency of the steam cycle and any necessary enhancements to the transmission interconnection facilities.
- Upgrades to the existing steam boilers to enhance performance. The upgrades may increase the maximum heat input of the units;
- Material handling equipment for limestone, other reagents, and gypsum;
- Water and wastewater treatment facilities; and,
- Handling and storage systems for water and wastewater treatment solids and fabric filter waste.

Brandon Shores is a coal-fired power plant that consists of two pulverized coal units (Units 1 and 2), with a combined nominal generating capacity of 1,370 MW (1,286 MW summer peak). Brandon Shores is currently the largest coal-fired electric generating plant in Maryland, providing more than 10 percent of the state's total generating capacity.

Table IV-3: New Environmental Upgrades Planned for Existing Generation Plants

Company and Plant	Case No.	Requested In-Service Date	Description of Upgrades
Constellation (Brandon Shores)	9075	Jan. 2010	Reduce emissions of sulfur dioxide and particulate matter. Install air quality control systems (AQCS), including wet flue gas desulfurization systems (FGD), and associated enhancements.
Mirant (Chalk Point)	9079	Jan. 2009	Reduce emissions of nitrogen oxide. Install air emissions control technology that includes a Selective Catalytic Reduction (SCR) system and associated equipment
Constellation (Herbert A. Wagner)	9083	Jan. 2009	Install systems to reduce emissions of nitrogen oxide and mercury.
Constellation (Charles P. Crane)	9084	Jan. 2009	Install systems to reduce emissions of nitrogen oxide and mercury. (Note: Staff is aware this plant is not a candidate for FGD due to space constraints.)
Mirant (Morgantown)	9085	Nov. 2009	Reduce emissions of sulfur dioxide and mercury. Install a flue gas desulfurization (FGD) system and associated equipment.
Mirant (Chalk Point)	9086	Jan. 2010	Reduce emissions of sulfur dioxide and mercury. Install a flue gas desulfurization (FGD) system and associated equipment.
Mirant (Dickerson)	9087	Jan. 2010	Reduce emissions of sulfur dioxide. Install wet flue gas desulfurization (FGD) system and associated enhancements.

CPSG claims the project at Brandon Shores promises significant environmental benefit in the form of reduced emissions and will enable CPSG to comply with Maryland's Healthy Air Act (Chapter 23, 2006 Md. Laws--Senate Bill 154 and House Bill 189). Engineering and construction of the project are very complex and will require three years or more to complete. Because HAA compliance is required by 2010, CPSG requests that the Commission complete its review process such that CPSG can begin construction by May 1, 2007. Modifications to the boilers and steam turbine generators are expected to provide additional electrical output to supply the power requirements of the new emissions control equipment. CPSG expects outages of the plant during some portions of the construction schedule. These outages will need to be coordinated with PJM to insure minimal impact to the transmission grid.

C. CPCN Exemptions for On-site Generation

Under PUC Article §7-207.1, which became effective October 1, 2001, and was modified effective October 1, 2005, the Commission can exempt certain power generation projects from the CPCN process when the proposed projects meet the following conditions:

- The generating station produces on-site generated electricity;
- The capacity of the generating station does not exceed 70 megawatts; and,
- Any electricity exported for sale is sold only on the wholesale market pursuant to an interconnection, operation, and maintenance agreement with the local electric company.

As of October 1, 2005, the Commission can also exempt certain generating stations from the CPCN process when the proposed projects meet the following conditions:

- The generating station does not exceed 25 megawatts;
- Any electricity exported for sale 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 is consumed on-site.

An applicant must submit a completed application that is signed by an officer of the company or entity who can legally bind the applicant to the terms and conditions of PUC Article §7-207.1. In addition, the applicant must submit an interconnection, operation, and maintenance agreement with the local electric distribution company (EDC) or a written statement from the local EDC that such an agreement is not required. 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 Maryland Department of the Environment's (MDE) Air and Radiation Management Administration.

Since October 2001, the Commission considered applications that included generation of approximately 346.1 MW. While it appears that most units are used to supply emergency needs when power is not available from the grid, there are instances when such units are being operated as part of load management and load responsiveness programs, as well as for onsite generation. Deployment may occur for a handful of hours during the course of the year, and such hours often coincide with "code red" or unhealthy air quality conditions in Maryland.

Table IV-4: CPCN Exemptions Granted, Since October 2001

Period Approved	Applications	No. of Units	Total MWs
Calendar Year 2002	22	34	30.8 MW
Calendar Year 2003	29	53	79.4 MW
Calendar Year 2004	42	60	59.0 MW
Calendar Year 2005	39	69	124.4 MW
Calendar Year 2006	30	43	52.5 MW
Grand Totals*	**162**	**259**	**346.1 MW**
Applications Pending	2	2	25.0 MW

* -- Cumulative totals as of November 30, 2006.

D. PJM State of the Market Report

PJM's Market Monitoring Unit (MMU) issued its *2005 State of the Market Report* on March 8, 2006. 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 covered are points conveyed within the report.

Prior to expansion in 2005, PJM operated a centrally dispatched competitive wholesale electricity market with about 330 market buyers, sellers and traders of electricity in a region that included more than 45.3 million people. These persons conducted business in Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM's electricity market also had a generating capacity of approximately 144,000 MW. Over the course of 2005, PJM integrated new members from parts of North Carolina and additional parts of Pennsylvania and Virginia resulting in a growth in the competitive wholesale electricity market. The figure below illustrates PJM's expansion over the course of 2005.

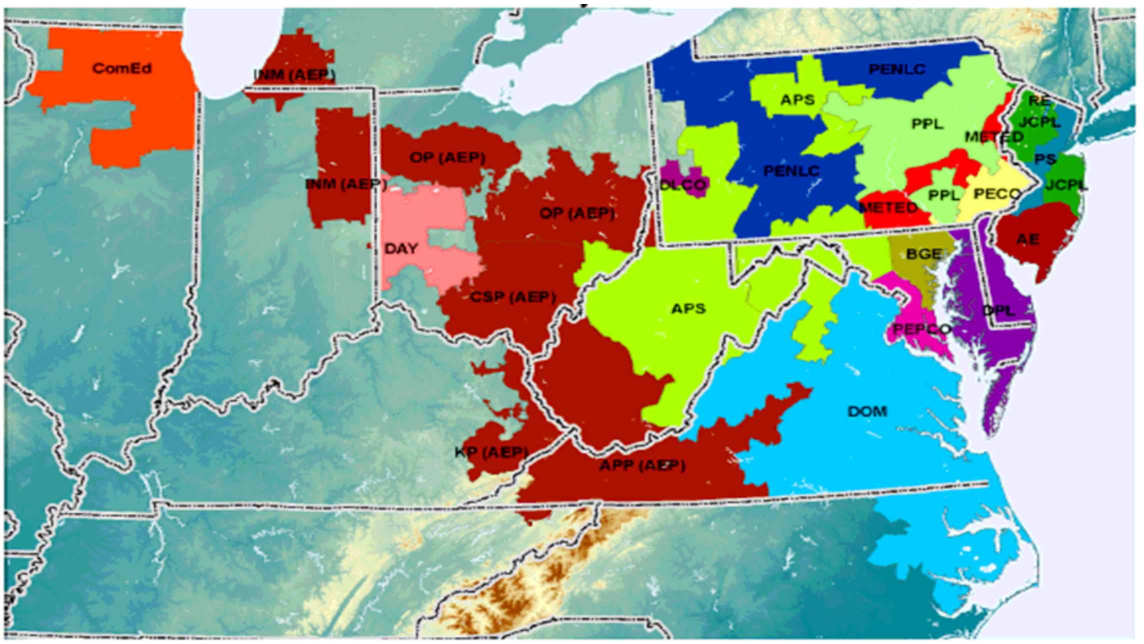
Table IV-5: PJM's Recent Expansion Integration

Utilities	States	Integration Date
Duquesne Light Co (DLCO)	Pennsylvania (Western)	1/1/2005
Dominion	Virginia, North Carolina	5/1/2005

As listed in the *2005 State of the Market Report*, PJM now operates a centrally dispatched competitive wholesale electricity market with about 390 market buyers, sellers and traders of electricity in region that is comprised of more than 51 million people. These people live in Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM's generating capacity has also grown by about 14% through the expansion occurring in year 2005.

Currently PJM's electricity market has a generating capacity of about 163,471 MW. The scale of expansion in 2005 is lower than the growth exhibited in 2004. PJM's current footprint can be seen in the graphic below that can be found on the PJM website.[35]

Map IV-1: PJM Zones



The robustness of the energy and capacity markets was examined by PJM in the *2005 State of the Market Report*. The MMU concluded that the energy market results and the PJM capacity market results were competitive. The results of the regulation market were also deemed to be competitive in instances where cost-based and market-based offers alike set the market prices. Competitive results were also given to the spinning reserve markets as the markets were cleared on cost-based offers.

The *2005 State of the Market Report* analyzed many facets of the PJM energy grid. Various statistics serve as indicators regarding the attributes of the energy grid as a whole. One such marker is that PJM was a net exporter of power over the course of 2005. During the first four months of 2005, after the addition of the DLCO control zone, the net gross monthly exports averaged 1.2 million MWh. After the addition of the Dominion Control Zone and through the end of 2005, PJM continued to exist as a net exporter of power with net gross monthly exports that averaged 1.5 million MWh. With the growth of the installed capacity, due to expansion, the allocation of capacity by fuel source shifted slightly. At the end of 2005, PJM's 163,471 MW installed capacity[36] fuel source distribution was 41.5% coal, 27.5% natural gas, 19.1% nuclear, 7.2% oil, 4.3% hydroelectric and 0.3% solid waste. Over the course of calendar year 2005, PJM's total generation capacity by fuel source was 66.6% coal, 25.2% nuclear, 5.6% natural gas,

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35 http://www.pjm.com/documents/maps/pjm-zones.pdf

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

1.3% hydro, 0.9% oil, 0.4% solid waste and 0.1% wind. Another indicating figure is the RSI[37]. For pivotal suppliers, the average RSI was 1.84, showing that the PJM markets were competitive. This is up from 1.64 from the previous year. The average hourly locational marginal price (LMP) increased by 37% from $42.40 per MWh in 2004 to $58.08 per MWh in 2005. The load-weighted LMP increased 43.1% from $44.34 in 2004 to $63.46 in 2005. The main factor in this price increase appears to be the cost of fuel. The fuel-cost-adjusted, load-weighted LMP figures increased by 1.5%, going from $44.34 in year 2004 to $45.02 in year 2005. The average, median and standard deviation figures for the LMP trends can be seen in the adjacent chart. The proportion of the types of fuel used by the marginal units in 2005 were 62% coal, 26% natural gas and 11% petroleum.

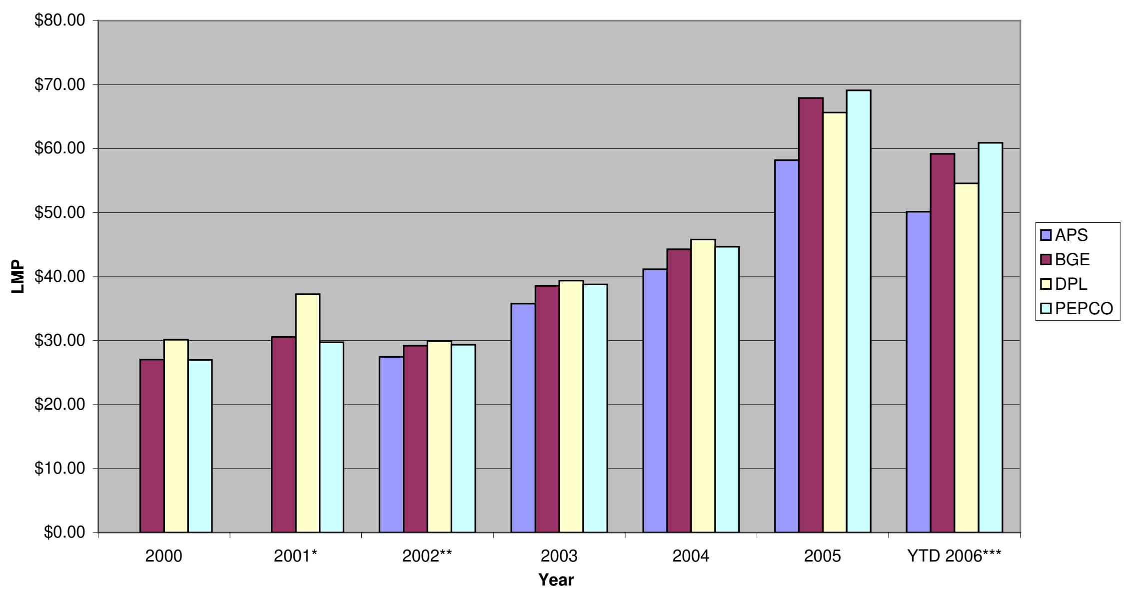
Table IV-6: PJM fuel-cost-adjusted, load-weighted

(Dollars Per MWh)	2004	2005	Change
Average	$44.34	$45.02	1.53%
Median	$40.16	$38.75	-3.51%
Standard Deviation	$21.25	$25.68	20.85%

E. Transmission Congestion in Maryland

In last year's *Ten-Year Plan* the Commission identified that most of Maryland is subject to significant transmission congestion. The result is that the locational marginal prices in Maryland are among the very highest in PJM. While some progress has been made in the last year in reducing both the LMP and the LMP differential with other states and regions in PJM, Maryland continues to experience significant transmission congestion and high LMPs.

Chart IV-1: Average Locational Marginal Price



* February 2001 not included in the average, data not available
** APS joined PJM in April 2002, average does not include period prior
*** Average thru October 31, 2006

37 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, an RSI greater than 1.0 does not guarantee that there is no market power.

Chart IV-1, shown above shows the average LMP figures for the PJM zones that provide electricity to the State of Maryland. Western Maryland is powered by Allegheny Power (APS), Central Maryland receives energy from Baltimore Gas and Electric Company (BGE) and Pepco, and Delmarva Power and Light (DPL) services the Eastern Shore. When viewing the above column chart, one can see that annual average for LMPs found in Maryland had been rising steadily from 2002 to 2005. The data show a decrease for 2006 year to date ending on October 31, 2006. Measures taken to improve transmission coupled with the moderation of fuel prices have served to reverse the increasing LMP trend. From year 2005 to the figures for 2006 the LMP figures for BGE and Pepco have decreased by 12.86% and 11.84%, respectively. DPL and APS have experienced greater decreases with declines of 16.87% and 13.85%.

Chart IV-2: Average Hourly LMP (6/1/2005 - 8/31/2006)

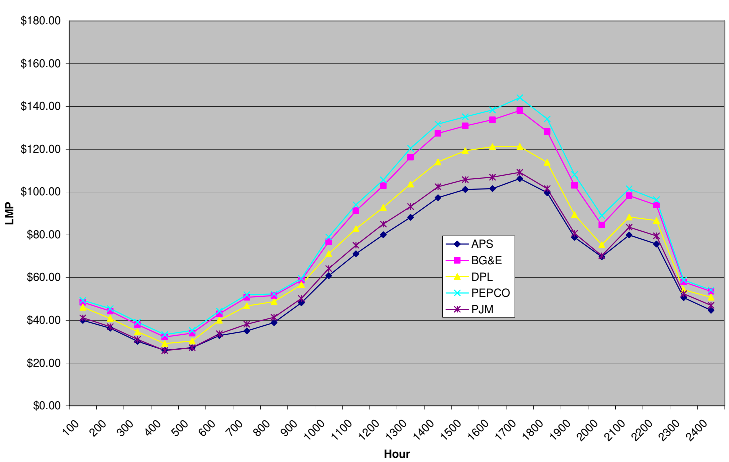
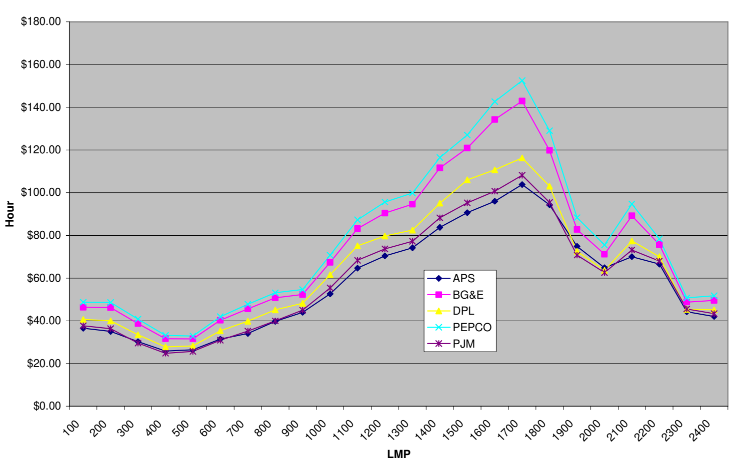


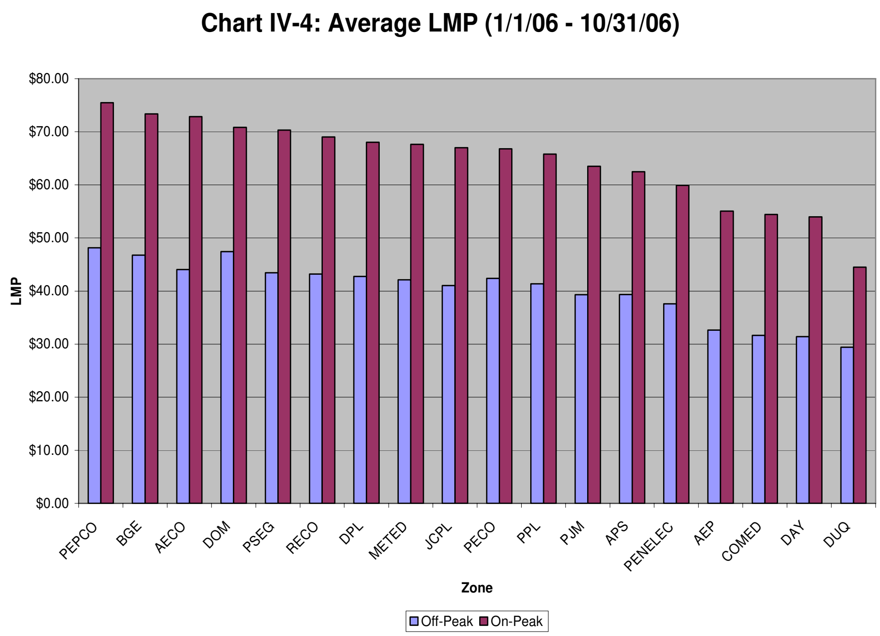
Chart IV-3: Average Hourly LMP (6/1/2006 - 8/31/2006)



The two graphs located to the left (Charts IV-2 and IV-3) show the average hourly LMP figures for the periods spanning June 1, 2005, through August 31, 2005, and June 1, 2006, through August 31, 2006, respectively. APS, BGE, DPL and PEPCO are all zones that service Maryland. A comparison of the results between LMP values from the summers of 2005 and 2006 yield some interesting outcomes. The LMPs for the DPL zone were lower across the board in 2006 than they were in 2005. The LMPs in the APS zone increased, from the summers of 2005 to 2006, in only two of the 24-hour periods. BGE's LMP grew in three of the 24-hour periods and PEPCO's LMP rose in five of the 24-hour periods. Overall, the LMP levels in Maryland zones decreased over the summer periods of 2005 and 2006. This leads to the notion that the decrease is partially attributable to lower congestion costs. Congestion costs result from an insufficient transmission system and minor enhancements made in the energy grid surrounding the zones that service Maryland appear to have a tangible effect on the LMP levels experienced in the state. Further upgrades in the transmission system could serve to prolong this decline in local LMP figures.

While the aforementioned figures are very encouraging, Maryland's problem of relatively high LMPs is not solved. Evidence of this can be found in the chart below. Chart IV-4 displays the average on-peak and off-peak LMP levels for the PJM energy grid. The PJM grid is partitioned by the various company zones and the time period averaged runs from January 1, 2006 to October 31, 2006. The map shown in section IV-D provides the area covered by each company's zone.

According to data published on PJM's website[38], the zones that serve the central Maryland areas have the highest averages during both on and off peak periods. On-Peak periods are periods of increased usage and are defined by PJM to be weekdays, except NERC holidays[39] from the hour ending at 8:00 a.m. until the hour ending at 11:00 p.m. Off-peak periods are the periods during which overall demand is decreased. PJM deems these periods to be "all NERC holidays and weekend hours plus weekdays from the hour ending at midnight until the hour ending at 7:00 a.m."



The chart above (Chart IV-4), compiled from the data found on PJM's website, shows that Central Maryland has some of the highest LMP levels in the entire PJM Interconnection energy grid. The on-peak levels of Pepco and BGE were the highest in the entire regional transmission organization (RTO) and Pepco and BGE took first and third respectively, in terms of setting the bar for the off-peak LMP levels over the period spanning January 1, 2006 through October 31, 2006.

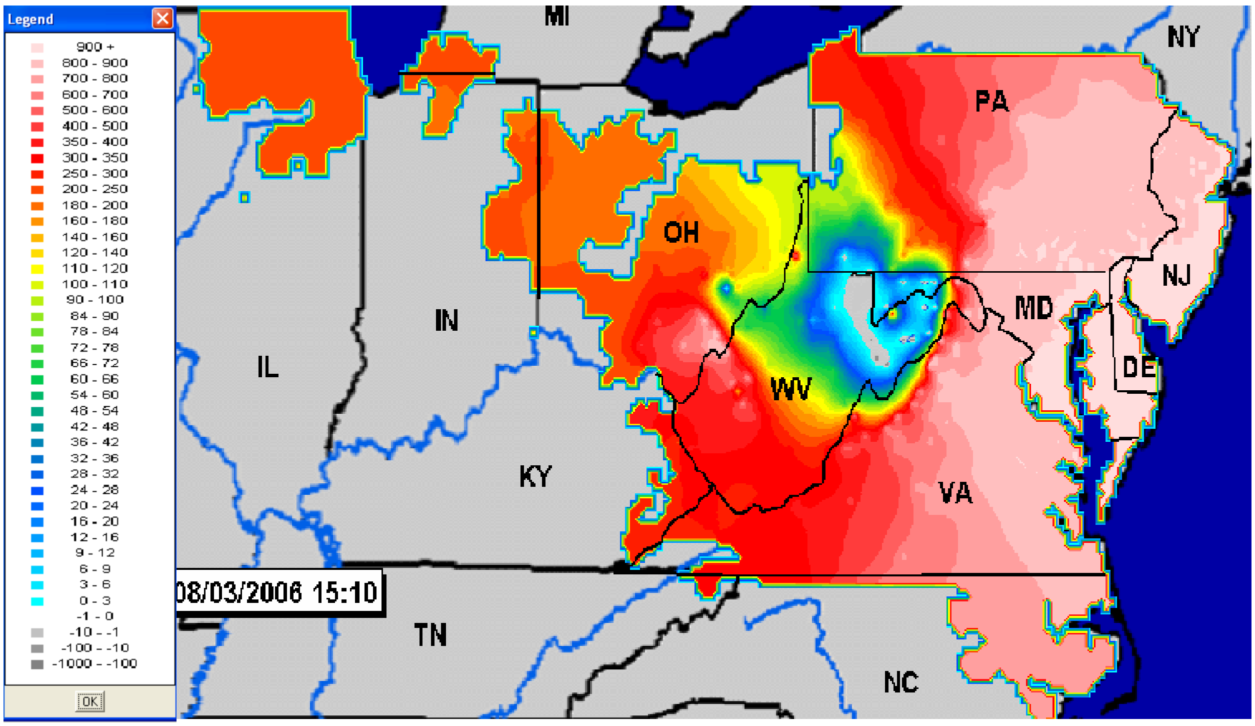
The elevated LMP levels are indicative of the fact that the zones servicing central Maryland are forced to meet load demand by using less cost effective measures to provide electricity (e.g., using local higher cost generation sources instead of coal-by-wire). The higher LMPs caused by congestion premiums are found in the areas as mentioned in Section VI-D.

As stated in the Department of Energy (DOE) Transmission Congestion Study, Maryland is directly affected by congestion areas located on the Delmarva Peninsula and the Baltimore – Washington DC area. The Delmarva Peninsula has existed as a load pocket for a significant

38 Monthly LMP data for PJM can be found at: ftp://www.pjm.com/pub/account/lmpmonthly/index.html.
39 NERC Holidays are New Year's Day Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

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. In an effort to alleviate this congestion problem, several small-scale transmission upgrades have been completed. There is a transmission line being proposed would bring new capacity and energy to Delmarva. This line would approach from the south after crossing the Chesapeake Bay.

Map IV-2: PJM LMP Map (8/03/2006 at 15:10)



The Baltimore – Washington DC area is in a situation where the congestion of the electricity transmission grid warrants attention. PJM stated that without transmission upgrades, the reliability criteria established for critically important loads will not be met over the next 15 years[40]. Map IV-2 above shows an LMP map taken from the PJM's *eData* site on August 3, 2006. One can see that the eastern portion of PJM experienced significantly higher LMP prices than the western section. Caught in the epicenter of the area with LMPs that were above $900 are Central Maryland and the Eastern Shore. 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.

The long-term solution to this situation could be significant upgrades in the energy transmission grid. PJM is proposing a Loudoun County 500 kV line. This line is expected to cost about $850 million and is expected to reduce the congestion charge by a figure ranging from $500 million to $1 billion. The State of Maryland is expected to realize about 40-50% of these benefits. More information regarding this can be found in Section IV-G.

[40] Source: US Department of Energy, National Electric Transmission Congestion Study, August 2006.

F. The Regional Transmission Expansion Planning Protocol (RTEPP)

Planning the enhancement and expansion of transmission capability on a regional basis is one of the primary functions of an RTO such as PJM. PJM implements this function pursuant to the Regional Transmission Expansion Planning Protocol (RTEPP) set forth in Schedule 6 of the PJM Operating Agreement.

PJM annually develops an RTEPP 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 Regional Transmission Expansion Plan (RTEP) Report.

As a regional planning effort, 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 five-year horizon to identify transmission constraints and other reliability concerns. Since transmission line projects require a long lead-time, this planning horizon is being extended to fifteen years. The Reliability Planning Process Working Group (RPPWG) was started last year to prepare the next RTEP to cover a full fifteen year planning horizon.

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 its much larger footprint. While previously the RTEPP concentrated on generation interconnections, its focus is now on ensuring reliability throughout the expanded footprint and ensuring that essential transmission infrastructure is built to support system integration and more robust wholesale power markets.

Major changes to the RTEPP include:

- Expanding the planning horizon from five to fifteen years;
- Conducting reliability analysis to include scenarios that address load growth, loop flow, and generation addition uncertainties;

- Adding a market efficiency-planning component to determine whether there are net economic benefits in building a transmission facility or accelerating the in service date of a project that is needed for reliability. Until now economic analysis was limited to a historical review of congestion that could not be physically hedged. The new market efficiency analysis will look at both gross and unhedgeable transmission congestion, and other economic measures and on a forward looking basis to assess the potential benefits of transmission additions; and,
- Conducting sensitivity analyses on the market efficiency analysis to test for uncertainties in fuel prices, load growth, capacity additions and retirements, and environmental costs associated with emission controls.

The Transmission Expansion Advisory Committee (TEAC) is the primary forum for stakeholders to discuss the RTEPP results. It has met several times this year, most recently October 30, 2006. The MPSC 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 and transmission assets. The baseline reliability assessment identifies areas where the planned system is not in compliance with applicable North American Electric Reliability Council (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, if so, 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 fully hedge through financial transmission rights (FTRs). 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. Consistent with this development a FERC administrative law judge recently recommended that the costs of all existing transmission facilities in PJM be allocated evenly across the system (a tariff arrangement called "postage stamp"), since all members of PJM benefit from the existing infrastructure.

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 (IPSAC) facilitates stakeholder review and input into the Coordinated System Plan (CSP). 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.

RTEP May 23, 2006 Plan Summary

PJM's most recent Regional Transmission Expansion Plan was presented at the May 23, 2006 TEAC meeting, and was approved by PJM's Board of Governors a month later on June 23, 2006. During the month between presentation and approval PJM members were allowed to submit comments on the proposed RTEP. The RTEP authorized construction of $1.3 billion in electric transmission upgrades, including the 240-mile, 500 kV line from southwestern Pennsylvania to Loudoun, Virginia described earlier. The cost of this line will be about $850 million. The upgrades will ensure continued grid reliability through 2011 according to PJM, and reduce congestion charges by an estimated $200 million to $300 million per year.

The RTEP also covers generation projects within PJM's footprint, which are discussed at TEAC meetings. Since the inception of PJM's open, non-discriminatory planning process in 1997, more than 140,000 MW of new generation requests have been included in PJM's interconnection queues. To date, the system enhancements planned by PJM have accommodated 18,717 MW of new generation, representing over 140 projects, with nearly 3,800 MW of generation under construction. These generation additions enhance system reliability, supply adequacy and competitive markets for PJM's market participants and the customers they serve.

Importantly, the generation additions represent various fuel types, including natural gas, wind, and coal. The interconnection process for generators is discussed in PJM's Manual 14.

Plan Influences

The RTEP has a profound affect on the grid and energy business. Its influences include:

- Regional reliability council reliability assessments;
- PJM's assessment of the deliverability of capacity resources to load;
- PJM members' plans for capacity additions, including new generation and merchant transmission interconnection requests;
- PJM transmission owner plans to develop transmission;
- Interregional transmission development plans; and,
- Long-term firm transmission service requests.

How Do RTEPP-Identified Projects Get Built?

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. As part of the RTEPP, PJM maintains a well-defined interconnection process that identifies the transmission upgrades required to maintain reliability and connect new generation. Market participants may also propose projects that have economic benefits, including relieving costly and persistent congestion. Under the recently approved changes to the RTEPP PJM will recommend a solution with a positive cost-benefit ratio that resolves the congestion. Transmission owners can voluntarily build these projects, or PJM can file with the FERC to request the FERC to order the project to be built. At the State level, CPCN permits are required for new transmission lines 69 kV or larger or modifications to existing facilities. The new RTEPP with its 15-year planning horizon recognizes the long lead times needed for some of these projects, particularly the larger ones.

By helping to bring about the development of more robust wholesale power markets PJM's RTEPP process attracts investment in power plants built at no or reduced risk to ratepayers. A number of factors account for PJM's successful RTEPP process:

- Non-discriminatory processes and independence from financial interests creates a level playing field;
- FERC oversight approval provides the stability necessary for investment;
- Acceptance by state jurisdictions and inclusion of state regulators in the stakeholder process demonstrates confidence in PJM's process;
- Ongoing communication ensures successful implementation of Regional Transmission Expansion Plans; and,
- Compliance with NERC and regional reliability council criteria ensures reliability is maintained.

PJM's Authority from FERC

FERC approved PJM as an Independent System Operator (ISO) 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). Most recently, PJM has amended the RTEPP to include the development of transmission projects to support competition in wholesale electric markets (2003 and subsequently November 2006). This allows PJM 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 (OATT) as approved by FERC. The OATT is the basis for PJM to collect charges to recover the costs of projects owned, constructed, or financed by the transmission owners. Transmission owners file rate schedules with FERC to recover transmission investments made pursuant to the RTEPs approved by PJM Board of Governors.

PJM's success is due in part to the cooperation of local control centers and the oversight of the PJM Office of the Interconnection. PJM has procedures for including transmission lines at various voltage levels in an extensive real-time monitoring program. The PJM Operating Agreement requires its members to comply with the NERC reliability standards, which are being revised as discussed below. Successful implementation of PJM long-term planning process takes into account markets and operations on a regional basis. This depends on PJM's ability to make decisions that are best for the RTO customers as a whole and constitutes decision-making as if all infrastructure were owned by a single entity. PJM's stakeholder process includes input from the major sectors -- generation, transmission, load serving entities, end-use customers, and other suppliers. If approved through sector voting, PJM can make tariff changes with a 205 filing at FERC. Without sector approval, PJM can make changes through a 206 filing. The PJM Board of Directors can approve or deny PJM decisions.

NERC Reliability Standards

The North American Electric Reliability Council 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, NERC standards are customized for regional applications. There are eight Regional Reliability Councils. PJM uses the Reliability*First* and the Southeast Electric Reliability Council (SERC) reliability criteria. NERC has undertaken a massive revision of its standards following the Northeast Blackout of 2003.

EPAct 2005 required the formation of an Electric Reliability Organization (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.

The ERO may impose a penalty (which may include limitations on activities, functions, operations, or other appropriate sanctions) on an owner, operator, or user of the bulk-power system. FERC may also order compliance with a reliability standard and impose a penalty on an owner, operator, or user of the bulk-power system if it finds that the owner, operator, or user has engaged in, or is about to engage in, activity that violates a reliability standard. FERC may also take action against the ERO or a regional entity with delegated enforcement authority to ensure compliance with a reliability standard or any FERC order regarding the ERO or the regional entity.

The ERO is to assess and periodically report on the adequacy of the bulk-power system, but the ERO does not have the authority to set or enforce mandatory standards for adequacy. Nor does the section give the ERO or FERC the authority to require the expansion of generation or transmission. The reliability legislation reserves to the states matters related to the local distribution system.

Reliability*First*

Beginning January 1, 2006, Reliability*First* Corporation (RFC) sets reliability standards for PJM, excepting the portions of Virginia and North Carolina in PJM. SERC set reliability standards for those two states and the rest of the Southeast and part of the Midwest. The purpose of RFC and SERC is to ensure the adequacy, 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 of all facilities at a voltage level of 230 kV and above that are specified on the RFC facilities list as provided by the transmission owning companies geographically within the RFC territory.

Reliability*First* is the successor organization to three former NERC Regional Reliability Councils: the Mid-Atlantic Area Council, the East Central Area Coordination Agreement, and the Mid-American Interconnected Network organizations. Reliability*First*'s primary responsibilities involve monitoring compliance to reliability standards for all owners, operators and users of the bulk electric power system within the region. Reliability*First* membership currently consists of 43 regular members and 19 associate members. Reliability*First* 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.

Effects of Baseline Upgrades on Grid Operations for the Summer of 2006

PJM’s 2006 peak load of approximately 144,800 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 as was required in the Mid-Atlantic/Dominion regions to serve the somewhat lower peak load experienced a year earlier on July 27, 2005.

The enhanced reliability in 2006 versus 2005 in large measure was the result of recent transmission system enhancements. These projects had been proposed in prior RTEP plans. As a result of the projects actually being built and installed, Maryland benefited from an improved grid. The major transmission enhancements put in place prior to the summer of 2006 include the following:

- 360 MVAR Waugh Chapel 230 kV capacitors, 150 MVAR Loudoun 500 kV capacitors, 150 MVAR Ashburn 230 kV capacitors, 150 MVAR Dranesville 230 kV capacitors, 150 MVAR Clifton 500 kV capacitors. These capacitors enabled the delivery of reactive power to their respective locations. Generators were thus able to maintain dynamic VAR reserves. Transmission lines maintained a more stable voltage profile and were better able to survive the potential loss of a facility.
- The rating of the Doubs-Mt. Storm 500 kV line was increased, which permitted additional generation to be loaded economically at Mt. Storm and Bath County. This reduced congestion on the Bedington-Black Oak interface.
- Installation of a Clifton 500/230 kV transformer reduced congestion on the Doubs 500/230 kV and Loudoun 500/230 kV transformers.
- Installation of the Wyoming-Jacksons Ferry 765 k V line reduced congestion on the Kanawha River-Matt Funk reactive interface.
- PJM's planning process identified potential reliability violations and subsequently replaced 500/230 kV transformers at Branchburg and Doubs. This improved the deliverability of power to central Maryland. During its 2006 peak load PJM was able to maintain a voltage profile at the Doubs station that was 8 kV higher than July 27, 2006.
- Installation of the Wyoming-Jacksons Ferry 765 kV line which reduced congestion on the Kanawha River-Matt Funk reactive interface.
- On the Eastern Shore in Delaware, a new 230 kV circuit was installed between Red Lion-Milford-IndianRiver.
- Also on the Eastern Shore, the 69 kV circuit between Edgewood-North Salisbury 69 kV was upgraded to provide a higher facility rating. PJM performed an evaluation of expected congestion savings for this project and found a net present value of approximately $1.5 million from 2006 through 2016.

Most upgrades were required to resolve reliability problems on the PJM system. Accordingly, PJM has not performed any evaluation of avoided congestion for these reliability-based upgrades. PJM's current economic planning process is focused on historical unhedgeable congestion. Implementation of enhancements to the economic planning process, after approval by FERC, will provide the means for PJM to address potential economic benefits of major transmission projects. PJM has not performed an analysis to determine the additional electricity capacity that can be imported into Maryland as a result of these upgrades. Table A-11 of the Appendix identifies all the relevant RTEP upgrades completed in the past two years. The total cost for utilities in Maryland was about $64 million.

PJM's 2006 RTEP

PJM's first 15-year RTEP was approved by the PJM Board of Managers on June 22, 2006. As part of the plan, PJM authorized construction of $1.3 billion in electric transmission upgrades, including a 240-mile, 500-kilovolt transmission line from southwestern Pennsylvania to Virginia to be constructed by Allegheny Power and Dominion. The totality of plan upgrades will ensure continued regional grid reliability through 2011 and is estimated to reduce regional congestion costs by $200 million to $300 million annually. To meet long-term needs through 2021, PJM directed additional studies and evaluation of ten significant transmission line proposals totaling $10 billion of potential new investment, including the high-voltage transmission line projects by American Electric Power, Allegheny Power and Pepco Holdings Inc. The results of PJM's most recent baseline analysis and RTEP are summarized in Table A-12 of the Appendix.

Table A-8 of the Appendix summarizes scheduled transmission enhancements in Maryland as reported by the transmission owners. The Sempra Energy 640 MW project at EastAlco has been delayed. An in-service date beyond 2008 would be expected for the required transmission upgrades to the EastAlco 230 kV bus. The current RTEP upgrades for Maryland include transmission enhancements required for the deactivation of the Mirant Potomac River Station in Virginia. Those enhancements include two new 230 kV circuits between Palmers Corner and Blue Plains and contributions to the dynamic reactive device at Black Oak. BGE also expects to file for a CPCN to upgrade its Graceton-Raphael Rd line in 2007.

G. Proposals for New High Voltage West-to-East Transmission Lines in PJM

On May 23, 2005, PJM announced the need for a major new transmission line to ensure long-term reliability and relieve transmission congestion on west to east power flows. The name of the project is the Trans-Allegheny Interstate Line (TrAIL). TrAIL, if it receives state siting approvals and proceeds, will be a 240-mile, 500-kV transmission line running from Prexy substation in southwest Pennsylvania, through West Virginia and the tip of southwestern Maryland, terminating at a substation in Loudoun, Virginia. Allegheny Power and Dominion Resources would build the line.

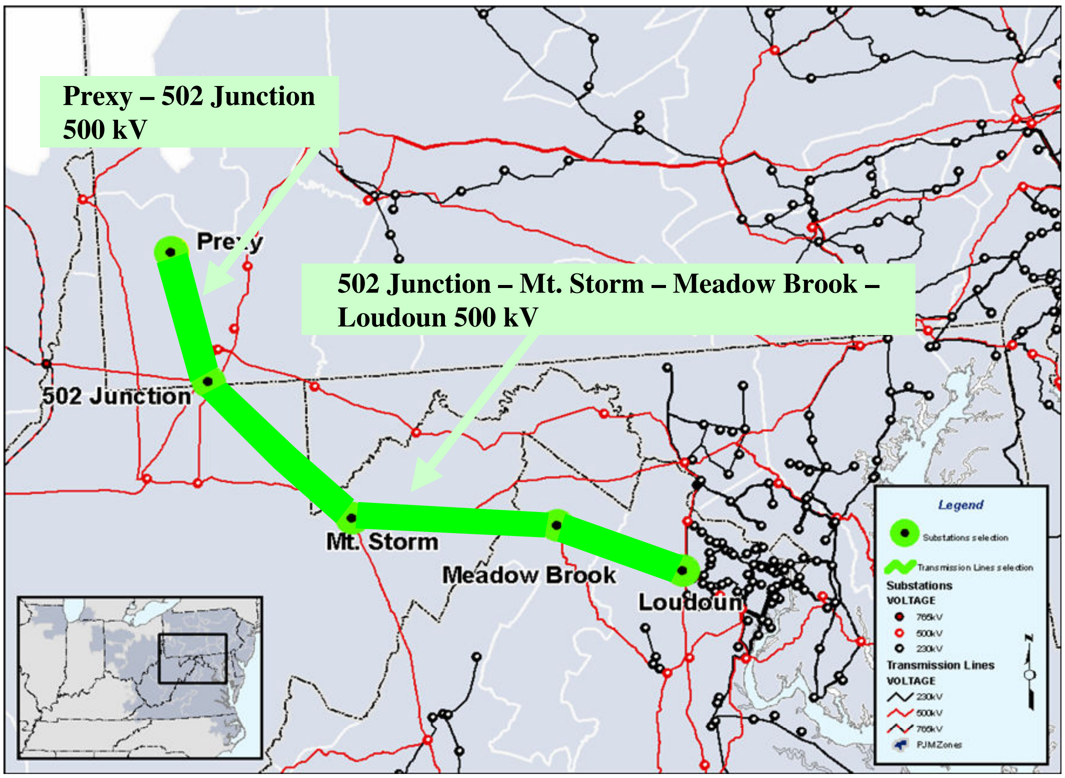
The principal reason for the line is that it addresses imminent reliability problems within the PJM electric transmission system. According to PJM the line is needed by June 2011 to avoid reliability problems that might result in service disruptions. The estimated cost of the project is $850 million. Specific benefits of the line contained in materials provided by PJM, Allegheny and Dominion include:

- Improving system reliability; TrAIL is part of a five-year $1.3 billion transmission upgrade program approved by the PJM Board of Governors to ensure electric reliability in the Mid-Atlantic region, of which Maryland is a part. The economic and social costs of disruptions in electric service can be enormous.
- Meeting the growing demand for electricity. The Mid-Atlantic is the fastest growing region in the PJM footprint, and already is in many respects capacity deficient. As described earlier Maryland imports over 25 percent of its energy needs; and this percentage will grow as the Maryland economy expands while output from existing

generating plants becomes more restricted in response to recently passed emission control legislation and membership in the Regional Greenhouse Gas Initiative (see Section V-E).

- Increasing west-to-east transfer capability, making cost-effective generation available to more consumers. PJM estimates that the TrAIL project will increase west to east power transfer capabilities by about 5,300 MW. PJM also estimates that the TrAIL project would reduce transmission congestion costs, thus the cost of electricity by between $200 and $300 million annually. Maryland would realize a significant portion of these benefits.

Map IV-3: Trans-Allegheny Interstate Line (TrAIL)



The project is an outgrowth of PJM new Regional Transmission Expansion Planning Process (RTEPP). The RTEPP planning horizon has been expanded from five years to fifteen years, and the $1.3 billion of system upgrades identified above is the first result of the new RTEPP. The expanded planning horizon allows PJM and its members to consider the growth and changes in the broad PJM multi-state region. By not being limited to considering just one utility's service territory, the PJM planning process can determine the most cost effective and cost-efficient transmission solution to resolve reliability and congestion constraints no matter where it is located in the region.

In addition to the TrAIL project PJM and its members are evaluating and comparing the potential reliability and economic benefits of several large transmission projects that may be needed in the 2011 to 2021 timeframe. These projects have not been approved by PJM and are not as well defined as TrAIL, still being in the evaluation phase. The projects could include:

- Adding a 765 kV transmission line that would strengthen Mid-West and Mid-Atlantic interconnections within PJM;
- Strengthening 500 kV interconnections into northern New Jersey; and,
- Expanding 500 kV transmission facilities in northern Virginia, Maryland, Delaware, and southern New Jersey.

According to PJM, the projects would be needed to resolve reliability problems within PJM that are projected to occur between 2015 and 2021. According to PJM there will be as many as 17 reliability problems that will need to be addressed, all of which will either directly or indirectly affect Maryland. The transmission additions would also reduce congestion costs by an estimated $1 billion a year, and will be needed to interconnect large new generating facilities that will be needed in the Mid-Atlantic region of PJM. Some of these generating facilities may be located in Maryland.

H. Resource Adequacy and PJM's Reliability Pricing Model (RPM)

In October 2003, the Commission established a proceeding (Case No. 8980) to investigate the best method to maintain electric generating resource adequacy to ensure a continuous, reliable supply of electricity to customers in Maryland. Pursuant to the Maryland Electric Choice and Competition Act of 1999, during the transition to a competitive electricity supply and electricity supply services (retail electric) market, the Commission must maintain electric system reliability in the State. The Commission recognizes that in order to maintain electric system reliability in the future, as well as to ensure the adequate supply of electricity for customers, there must be adequate electric generating capacity to meet customer demand.

The PJM market structure has included a generation capacity market construct as a means to ensure long-term adequacy of supply and adequate availability of generation to meet demand. The current generation capacity product is constructed as a single product, which is applicable across the entire PJM market footprint and across all operational conditions. One of the main reasons for the creation of a generation capacity product was to support overall system reliability. The purpose of the generation capacity construct design was to ensure that generation would be available when needed to maintain reliable electric service consistent with PJM standards.

However, recent operational trends have implied that the single capacity product assumption may not completely support the intent of the original design. Key issues have been raised, which suggest that the current PJM Capacity Market structure is inadequate including:

- A lack of consistency between the current resource adequacy model and other aspects of the PJM planning process;
- The current capacity product does not differentiate by location, generation type, and generation characteristics;
- Insufficient information is being provided to drive behavior;
- Limited forward certainty; and,
- Vulnerability to market power.

Also, the PJM system, in just a few years, has expanded from a system that managed about 60,000 MW of capacity to one that manages approximately 165,000 MW. In addition, PJM now encompasses all or part of thirteen states and the District of Columbia, versus five states and DC as recently as five years ago. Thus the capacity market construct that was adequate for a smaller more compact PJM footprint may not be suited for the much larger, more disperse system that exists today.

By notice on October 15, 2003, the Commission established a proceeding to review electric generation resource adequacy in Case No. 8980. At a July 8, 2004, hearing held by the Commission, in the matter of resource adequacy, PJM presented its new Reliability Pricing Model proposal. This model is designed to address transmission system reliability and the competitiveness of the wholesale capacity markets. PJM also presented its timeline for developing this model through its stakeholder process. After requesting comments from interested stakeholders, the Commission held a legislative-style hearing on November 8, 2004, to address the issue of resource adequacy in general and the proposed RPM in particular.

Several factors affect a system's ability to meet reliability criteria, including the load growth, generation additions, and generation retirements. According to PJM, a large number of generation retirements announced during the last three years have caused multiple reliability criteria violations in eastern PJM. Steady load growth and declining or flat generation additions contribute to those violations. PJM has concluded that if present trends continue, reliability violations will appear in New Jersey, and spread to other areas of PJM where similar conditions exist:

- PJM estimates that in the Mid-Atlantic Region, which includes nearly all the Maryland zones, electricity demand will increase from 58,742 MW in 2006 to 68,417 MW by 2016, an increase of nearly 10,000 MW. Presently there is just under 800 MW of generation under construction in the Mid-Atlantic region.
- In the Western Region of PJM electricity demand is forecast to grow from 58,303 MW to 68,563 MW over the 2006 through 2016 timeframe, and increase of just over 10,000 MW. Presently there is 3,850 MW of generation under construction in the Western Region, including the APS zone.
- In the Southern Region of PJM, which includes Virginia, electricity demand is forecast to increase from 18,398 MW in 2006 to 22,175 MW in 2016, an increase of just under 5,000 MW.
- Overall electricity demand is forecast to increase be about 25,000 MW, while slightly less than 4,900 MW is under construction throughout PJM. In addition, owners have requested they be allowed to retire or deactivate over 1,800 MW of capacity, primarily in New Jersey and elsewhere in the Mid-Atlantic region.

While plans exist to build generation beyond that under construction, there is considerable uncertainty about how much of will eventually enter into service. The Reliability Pricing Model is a major portion of PJM's effort to address the above and related conditions. RPM is designed to coordinate the price paid to generation capacity with overall system reliability requirements. The model stresses that overall system reliability requirements extend beyond measuring system-wide installed generation reserve. The result of the RPM construct is that each generator may be paid a different price for capacity, which leads to more targeted compensation to the generation that has better contribution to reliability metrics.

On August 31, 2005, PJM filed its RPM proposal with the FERC for approval to "address current serious inadequacies" in existing capacity rules. In this filing, PJM proposed to replace its 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 has met with significant opposition from many PJM members and other stakeholders, including many state commissions within the PJM footprint. Their principal concerns appear to be that:

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

The Commission filed comments with the 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 supports moving forward with a next-generation capacity market design, several questions require more in-depth exploration."

Over the course of the last year FERC has managed settlement discussions between all the affected parties including PJM, state commissions (including the Maryland PSC), and PJM members:

- Over 150 individuals representing more than 65 parties engaged in the settlement discussions;
- The final settlement gained broad support across diverse stakeholder interests (the Maryland PSC abstained in the final vote on the settlement); and,
- The new capacity market construct will be implemented on June 1, 2007.

Changes to the reliability pricing model that occurred during settlement discussion included: (1) addition of explicit performance metric 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 if 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 plans to 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 proposed to hold four consecutive capacity auctions for the 2007/2008 to 2010/2011 Planning Years, each auction separated by a period of several weeks, in order to effect the transition and set up the initial three-year planning horizon. These transitional auctions are scheduled to commence in the first half of 2007. Additionally, the entire PJM footprint would not be transitioned at once; instead, regions will be layered in over time. PJM filed plans to add the LDAs as follows:

- 2007/2008 Planning Year: PJM Mid-Atlantic Region plus the Allegheny Power System; and an area comprising the PJM West and South Regions (ComEd, AEP, Dayton P&L, Duquesne, Allegheny Power, and Dominion).

- 2008/2009 and 2009/2010 Planning Years: PJM Mid-Atlantic Region plus the APS zone; an area consisting of the zones of ComEd, AEP, Dayton, Dominion, and Duquesne; the eastern PJM region consisting of the zones of Public Service Electric & Gas, Jersey Central Power & Light, Philadelphia Electric Company, Atlantic City Electric Company, Delmarva Power & Light Company, and Rockland Electric Company; and the region consisting of the Pepco and BGE zones.

- 2010/2011 Planning Year and beyond: A full complement of local deliverability areas corresponding to the areas tested in the RTEP process. LDAs will be the Mid-Atlantic Region; the PJM West Region consisting of the zones of ComEd, AEP, Dayton, APS, and Duquesne; the PJM South region consisting of Dominion; the eastern Mid-Atlantic Region; the southwestern Mid-Atlantic region; the western Mid-Atlantic region consisting of the zones of Pennsylvania Electric Company, Metropolitan Edison Company, and PPL; the ComEd zone; the AEP zone; the Dayton zone; the Duquesne zone; the APS zone; the AE zone; the BGE zone; the Delmarva zone; the PECO zone; the Pepco zone; the PSEG zone; the JCPL zone; the MetEd zone; the PPL zone; the Penelec zone; the PSEG North region; and the Delmarva South region.

On November 8, 2006 PJM held its first RPM Stakeholder Implementation meeting, during which a Settlement Agreement Overview and RPM Implementation timetable were presented. Additional RPM Stakeholder Implementation meeting are scheduled for December 18, 2006, and January 10, 2007.

V. ENERGY CONSERVATION, RENEWABLES AND THE ENVIRONMENT

A. Statutory Requirements

Section 7-201(b) of the PUC Article requires the Commission to "evaluate the cost-effectiveness of the investments by electric companies in energy conservation to reduce electrical demand and in renewable energy sources to help meet electric demand." This includes:

(a) An electric company's promotion and conduct of a building, audit and weatherization program;
(b) Utilization of renewable resources;
(c) Promotion and utilization of electricity from cogeneration and wastes; and,
(d) Widespread promotion of energy conservation programs.

Section 7-211 of the PUC Article requires gas and electric utilities in Maryland to develop and implement energy efficiency and conservation programs, subject to review and approval by the Commission. This section further states that the Commission requires a utility to establish any such program or service that the Commission finds to be both cost-effective and appropriate. The Commission is required to adopt ratemaking policies for programs that encourage energy efficiency and conservation. Further, the Commission is empowered to consider reasonable financial incentives to participating utilities.

B. Current Utility Activities

This section provides a summary of utility efforts since January 1, 2006, to implement the provisions of Section 7-201 of the PUC Article. The information presented below in Table V-E are summaries of responses to a data request indicating what efforts were made during 2006 to analyze energy efficiency and conservation programs, including the weatherization of buildings, renewable energy, cogeneration, and widespread promotion of energy conservation programs.

Table V-1: Summary of Conservation, Renewable Resources, and Cogeneration Activities

Distribution Utility	Summary Of Conservation, Renewable Resources, and Cogeneration Activities Since January 1, 2006
BGE	BGE continues to offer active load management and conservation programs, including interruptible tariffs and water heater and air-conditioning cycling programs; operates its low-income conservation home improvement program (CHIP); provides net metering to eligible customers for installing an electric generating facility; offers Rider 5 AC Switch,[41] Rider 6 WH Switch,[42] and Rider 24 Load Response Program to customers under Schedules G, GS, and GL or P. Rider 18 provides net metering to eligible customers for installing an electric generating facility.

[41] Under Rider 5, an eligible residential customer receives a $40 annual bill credit, paid in $10 increments in each summer month June through September for the installation of a direct load curtailment switch on his electric conditioner.

[42] Under Rider 6, an eligible residential customer receives a $20 annual bill credit in $5 increments for the installation of a direct load curtailment switch on his electric water heater.

Choptank	Choptank (in conjunction with Old Dominion Electric Cooperative) has an agreement with All Phase to conduct building audit and weatherization programs for Commercial and Industrial accounts. Choptank has worked with the largest customer on Choptank's system on a lighting survey to see where the plant can increase fixture efficiencies. Choptank continues to offer residential audits. Since January 1, 2005, Choptank has not performed any analysis on the utilization of renewable energy resources, nor has Choptank performed any analysis on promotion of cogeneration and waste.
Pepco	Pepco reports that it continues to monitor and study energy conservation technologies, distributed generation technologies and renewable resources.
Potomac Edison	Allegheny Power participates in a working group to address low-income weatherization, which was part of the Electricity Universal Service Program.
SMECO	SMECO continues to offer a combination of rebate and non-rebate programs to encourage the installation of high-efficiency heating and cooling equipment in new home construction and to assure the proper installation of heating, ventilating, and air-conditioning (HVAC) equipment. SMECO has filed a draft Residential Net Metering tariff to allow residential customers to operate their own solar electric generating facilities. SMECO has one photovoltaic[43] [PV] -Net Metering residential customer. The system is reportedly a 2.2 kW system. SMECO has done no active promotion of cogeneration or waste, and there are no cogeneration or waste to energy facilities interconnected with SMECO's electric system at this time.

C. Renewable Energy Portfolio Standard Program (RPS)

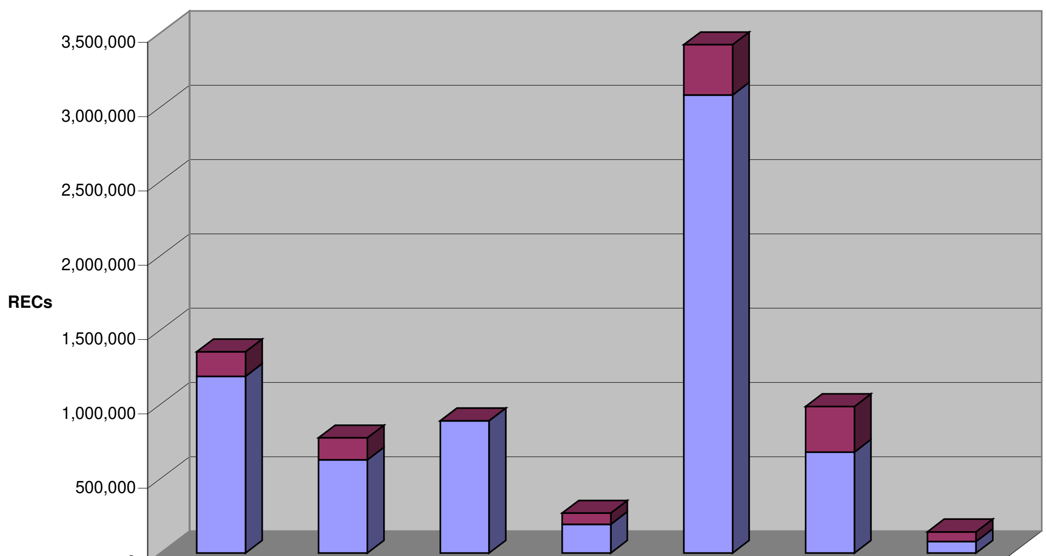
Under PUC Article § 7-701 et seq. (RPS Legislation) electricity suppliers are required to meet a Renewable Energy Portfolio Standard (RPS). The legislation requires, among other things, that the Commission implement the RPS. Implementation of the RPS is required to be accompanied by a system that facilitates trading of Renewable Energy Credits (RECs) 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.

43 Photovoltaic is viewed as the direct conversion of sunlight to electricity through semiconductor material.

With the regulations in place, the Maryland Renewable Portfolio Standard is in the midst of its first compliance year. The deadline for applications requesting credit for 2004 and 2005 Retroactive RECS passed on May 31st, 2006. In keeping with the PUC Article § 7-708(a)(2), the retroactive RECs are tracked by the Generation Attributes Tracking System (GATS) trading system that has been developed and operated by PJM Environmental Information Services, Inc. (PJM-EIS). The GATS system also serves to monitor the generation of the participating units and creates monthly RECs based on the amount of electricity output. 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, that are interconnected with another RTO such as the Midwest ISO or that 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.

Chart V-1: Retroactive RECs awarded



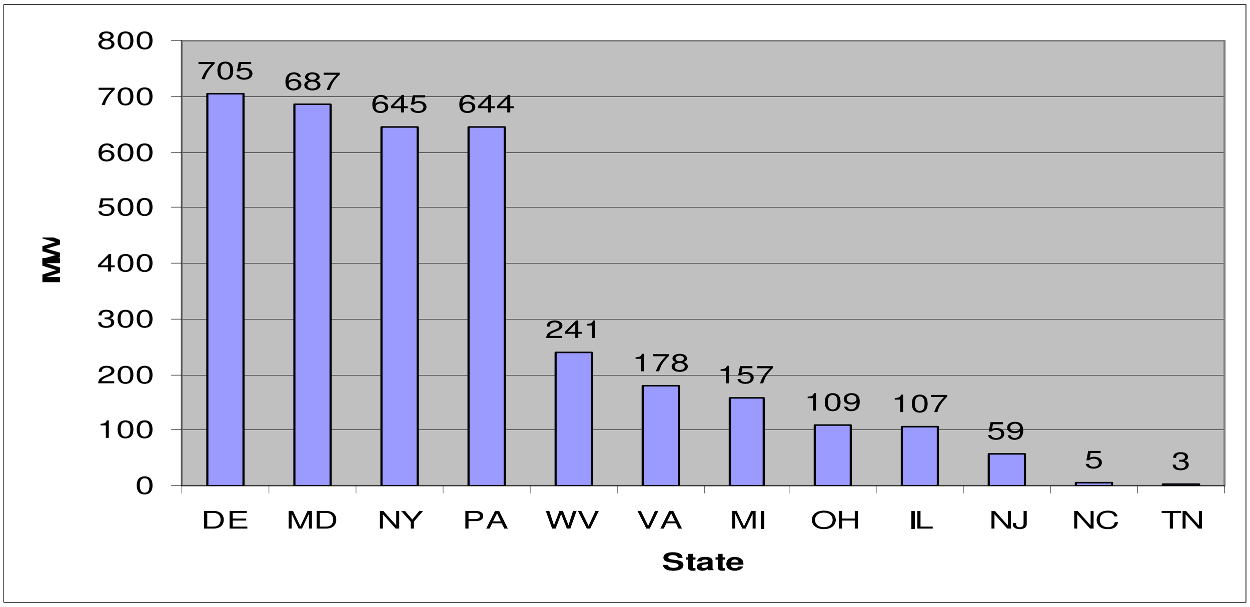
	BLQ - Tier 1	LFG - Tier 1	MSW - Tier 2	WAT - Tier 1	WAT - Tier 2	WDS - Tier 1	WND - Tier 1
2005	165672	149159	0	75887	339627	306631	65171
2004	1189480	627259	890328	193743	3082235	679980	78075

Type

Chart V-1 outlines by tier and fuel source, the number of 2004 and 2005 Retroactive RECS that were certified by the Maryland PSC. RECs generated during calendar year 2004 and from January 1, 2005 to November 24, 2005 are classified as 2004 and 2005 retroactive RECs, respectively. All RECs generated after November 24, 2005 are deemed to be RECs. Retroactive RECs are identical to RECs when utilized for compliance and retroactive RECs have a generation date of December 31st of their respective compliance year. With these figures one can determine the number of RECs that are initially available to facilities that require them to maintain the compliance standards established by the RPS Legislation. The Retroactive RECs can be banked and can be utilized for compliance for a period of three years past the generation date.

This data combined with the amount of rated capacity that is currently certified and the number of RECs that will be needed for compliance can lead to speculation regarding the future price of RECs. The table 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.

Chart V-2: MD RPS Certified Rated Capacity by State (as of 11/6/2006)



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 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. However, the funneling of funds from this region to pre-existing facilities in PJM adjacent states would only serve to provide an economic benefit to other regions of the country that have a less significant impact on the environmental welfare of Maryland.

Compliance reports for year 2006 are due on April 1st, 2007. The Renewable Energy Facility Certification, On-Site and Behind the Meter Generation Reports, Application for Industrial Process Loads, and Applications for the Waiver of Compliance Fee forms are currently available on the Maryland Renewable Portfolio Standard website[44]. The aforementioned forms are currently being processed and the Annual Compliance Forms will soon be made available on-line to meet the standards established in the RPS regulations.

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

D. Maryland's Healthy Air Act

House Bill 189 and Senate Bill 154 from the 2006 Session (the Healthy Air Act or HAA) establish a series of emissions limits that seven[45] coal-fired Maryland power plants must achieve to reduce the release of sulfur dioxide (SO_2), oxides of nitrogen (NO_x), and mercury. The legislation also requires that the Governor include the State as a full participant in the Regional Greenhouse Gas Initiative (RGGI) by June 30, 2007. This section focuses on the NO_x, SO_2 and mercury aspects of the legislation and a general description of the RGGI program is included in the next section (section V-E) of this report.

The Healthy Air Act lists the specific power plants that are required to reduce emissions and the maximum amount of NO_x and SO_2 emissions each plant is allowed to release into the atmosphere. The HAA addresses NO_x, SO_2 and mercury separately. There is a phased in cap for NO_x emissions that requires specific reductions for each of the six affected power plants by 2009 and further reductions by 2012. There is also a phased in cap for SO_2 emissions that requires specific reductions for each of the six power plants by 2010 and 2013. The phased in cap for NO_x emissions requires NO_x emissions be reduced by approximately 45,000 tons per year (69%) from 2002 levels in 2009 and be reduced by 49,000 tons per year (75%) from 2002 levels in 2012. The phased in cap for SO_2 emissions requires SO_2 emissions be reduced by approximately 192,000 tons per year (75%) from 2002 levels in 2010 and be reduced by 205,000 tons per year (85%) from 2002 levels in 2013. Mercury emissions are expressed in terms of ounces per trillion Btu and the phased in cap for mercury emissions requires that mercury emissions be reduced by 75% by 2010 and by 90% by 2013.

Proponents of the HAA claim that many positive things will accrue from the installation of emissions controls to reduce or eliminate specified emissions from coal-fired generating plants in Maryland. It is anticipated that significant improvements in air quality will be realized as the emissions control technologies are installed on Maryland power plants. In all cases, the elimination of most SO_2 from Maryland coal plants should cause a significant reduction of the possibility of acid rain down wind of the power plants. The capture and elimination of most of the NO_x particles from Maryland power plants should reduce the visible plume that sometimes exists under certain weather conditions, and which can contribute to certain health problems. The elimination of most of the mercury from Maryland coal plant emissions should reduce the amount of water born mercury ingested by fish and other marine creatures in our rivers, lakes and the Chesapeake Bay.

The technologies required to eliminate the majority of NO_x, SO_2 and mercury require the installation of large, expensive equipment on existing power plants. The size of the additional equipment is such that the footprint of each power plant must increase by a significant amount and additional transportation facilities must be made available to import and export the materials required for operation of the capture and sequestration process. The cost of NO_x, SO_2 and mercury mitigation for the coal-fired Maryland power plants that have the available property is estimated to be in the range of \$2 to \$3 billion in capital improvements and in excess of \$500

[45] The 115 MW R. Paul Smith facility may be exempt from these HAA provisions under certain circumstances and face less stringent restrictions if PJM determines the plant is needed to maintain system reliability.

million per year in additional operating costs. It is anticipated that most or all of these costs ultimately will be passed on to consumers in the generation price of electricity via the PJM wholesale energy or capacity markets. Please see section IV-B for more information on the CPCNs that Maryland coal plants have filed to comply with the HAA.

Central Maryland is currently designated as a National Interest Electricity Transmission Corridor (NIETC) by PJM. Other NIETC areas include the Delaware River Corridor to the north and Allegheny Mountain Corridor to the west of Maryland. This is due to the fact that a significant amount of power consumed in Maryland is already imported from surrounding territories via high voltage transmission facilities. The transmission facilities that are presently available are currently importing capacity from the surrounding NIETC areas and the aggregate import capacity of the existing transmission facilities is approaching capacity during periods of peak load. Please see section VI-D for more information on the DOE congestion study.

Certain Maryland power plants may not be able to satisfy the emissions requirements of the HAA due to lack of space to install the necessary equipment. Any existing Maryland coal plants that may have to be retired due to inability to satisfy the requirements of the HAA will make the looming reliability challenge occur earlier and with greater impact than would otherwise occur. The consequences could include periods of voltage reductions and/or rolling outages during peak load periods to keep the system from collapsing. Please see the *Electric Supply Adequacy Report of 2007* for further analysis of the impact of the HAA on reliability.

E. The Regional Greenhouse Gas Initiative (RGGI)

In April 2003, New York Governor George E. Pataki initiated the Regional Greenhouse Gas Initiative (RGGI, pronounced "ReGGIe") process by sending a letter to the governors of the Northeast and Mid-Atlantic States.[46] He invited them to pursue "a course of cooperation" and work together "to develop a strategy that will help the region lead the nation in the effort to fight global climate change." Since then, state representatives have been working to develop the program, which relies on a flexible, market-based approach to curb power plant emissions, while also promoting greater energy efficiency and energy independence. The program's main goal is to develop a multi-state cap-and-trade program covering greenhouse gas (GHG) emissions. The initiative will initially be aimed at developing a program to reduce carbon dioxide (CO_2) emissions from power plants in participating states, while maintaining energy affordability and reliability and accommodating, where feasible, the diversity in policies and programs in individual states. After the cap-and-trade program for power plants is implemented, the states may consider expanding the program to other kinds of sources.

Seven Northeast and Mid-Atlantic states are currently participating in RGGI. Each has agreed to implement a cap-and-trade program whose goal is to reduce CO_2 emissions. This is the first mandatory cap-and-trade program for CO_2 emissions in the history of the United States. Many scientists believe CO_2 emissions to be a major contributor to the climate change phenomenon known as global warming. The states who are currently full participants in RGGI are: Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York and Vermont.

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[46] 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.

In December 2005, the governors from these seven states entered into a memorandum of understanding (MOU) specifying the general framework of the program. On March 23, 2006, the states released draft model regulations that outlined proposed specific requirements for the program. The draft rule was the subject of a 60-day comment period and two public meetings were held. An amended model set of regulations referred to as the "Model Rule" was released on August 15, 2006. It incorporates many of the comments received and provides detailed rules for the program. Each state will use the model rule as a starting point for obtaining legislative or regulatory approval of the program. The participating states will next proceed with the required legislative or regulatory approvals to adopt the program. Pending the completion of this process, the RGGI program will take effect on January 1, 2009.

In April 2006, legislation was signed requiring Maryland to become a full participant in RGGI by June 30, 2007[47]. Current developments indicate that Maryland may be a full participant at an earlier date. By design, the RGGI program will be expandable and flexible, permitting other states to seamlessly join in the initiative when they deem it appropriate. States currently in observer roles to the RGGI process are: the District of Columbia, Massachusetts, Pennsylvania, Rhode Island, the Eastern Canadian Provinces, and New Brunswick. 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 121 million tons annually[48] — with this cap remaining in place until 2015. The initial base annual emissions budget for the 2009-2014 period is as follows:

Table V-2: 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
New Hampshire	8,620,460 short tons
New Jersey	22,892,730 short tons
New York	64,310,805 short tons
Vermont	1,225,830 short tons
Total	**121,257,573 short tons**

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

47 The Maryland evaluation process for RGGI is referred to as the "Maryland On Ramp". Among other activities it includes a study of "Economic and Energy Impacts of RGGI Participation" to be performed by the University of Maryland in conjunction with Johns Hopkins and Towson State Universities. The assessments presented to the State will be based on the best available science, modeling, and economic analysis conducted by the most qualified individuals and institutions to carry out the tasks. Submission of the final report will be in late January 2007, with follow-up activities as appropriate.

48 This 121 million ton figure is based on the current seven members of RGGI (not including Maryland). Overall RGGI totals will be revised incrementally as additional Member States become participants in RGGI.

The states would then begin reducing emissions incrementally over a four-year period to achieve a 10 percent 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 percent reduction by 2020. The Maryland PSC is currently studying the total MWh consumption from both in-state sources and imports from other states.

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 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 seven-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 percent of a state's allowances to 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.

The RGGI program allows power plants to utilize "offsets"— greenhouse gas emission reduction projects from outside the electricity sector — to account for up to 3.3 percent of their overall emissions. Offset projects provide generators with additional flexibility to meet their compliance obligations at the lowest cost. A power plant owner/operator will be allowed to select the lowest cost emission reductions and apply them to a portion of the plant's emissions requirement. Examples of offset projects include natural gas end-use efficiency, landfill gas recovery, reforestation, and methane capture from farming facilities. Under the model regulations and the MOU amendment, offset credits may come from anywhere in the United States, provided offset projects from outside of the participating states must take place under the regulatory watch of a cooperating agency in that state. States or other United States jurisdictions not participating in RGGI will need to enter into a MOU with the RGGI state agencies and agree to take on certain administrative obligations to ensure the credibility of the offset projects.

The model regulations and the MOU amendment also streamline and simplify the so-called "safety valve" provisions of RGGI program, which are designed to ensure that the cost of allowances remains affordable. Under the program, if the average annual price of an emission allowance were to rise above $7, sources will be permitted to use offsets for up to 5 percent of a plant's reported emissions. If the average price rises above $10, then sources will be permitted to use offsets for up to 10 percent of a plant's reported emissions and offsets from international trading programs will be allowed. By allowing offsets to account for a greater percentage of emissions, the program will keep energy prices low while also achieving real reductions in climate changing emissions.

Price impacts of this program are expected to be minimal, according to RGGI analysis. Their estimates project that average household bills could increase by approximately $3-21 annually. However, RGGI anticipates significant new investments in innovative and cleaner technologies and energy efficiency, which could lower electricity rates.

F. Mid-Atlantic Distributed Resources Initiative (MADRI)

The Mid-Atlantic Distributed Resources Initiative (MADRI) was established by "classic" PJM State Commissions, the Department of Energy, 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. 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:

- Studying advanced metering, including concepts ranging from simple one-way remote (automatic) meter reading (AMR) to complex two-way "smart" meters that perform numerous power monitoring functions – advanced metering infrastructure (AMI). The AMI Toolbox on the MADRI website at http://www.energetics.com/MADRI/ may be the best one stop source of AMI information. In 2007, MADRI will continue to look at regional response to long-term AMI issues such as the economic justification of AMI.
- Assessing benefits for Demand Response (DR) and Distributed Generation (DG). 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 (DER) initiatives. According to the policy statement, DER "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."[49]
- Developing 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.
- Reconciling and standardizing 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 (CHP) 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.
- Removing 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.
- Exchanging information between utilities, PJM, and curtailment service providers (CSP). 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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[49] The policy statement can be found online at: http://www.energetics.com/madri/pdfs/PolicyStatement.pdf.

G. Maryland Demand Response and Distributed Generation Initiatives

In the Phase II settlement agreement accepted by the Commission in Case No. 8908[50] on September 30, 2003, the parties to the settlement agreement agreed to the establishment of a working group:

> to continue to explore the development, consistent with the terms set forth in the Phase I and Phase II Settlements, of one or more Experimental Demand Response Services (EDRS) that may be offered, as an optional service, to residential and eligible non-residential customers. Representatives of the Settling Parties and any other interested persons (the "Other Services Workgroup") will continue to meet to monitor ongoing EDRS pilot programs, and related developments in Maryland and other jurisdictions, and may make recommendations to the Commission with respect to EDRS as are deemed appropriate by the workgroup or its members. The Other Services Workgroup will report back to the Settling Parties and the Commission at least annually for the duration of each Utility's Residential and Type I SOS Service Periods, with the first such report on EDRS due ninety (90) days after Commission approval of this Phase II Settlement. After the second annual report, the Other Services Workgroup will advise the Commission as to whether the group needs to continue to meet and report.

On September 13, 2006 the Commission issued a Notice establishing the Demand Response/Distributed Generation (DRDG) Working Group. The Commission directs the DRDG Working Group to discuss and make recommendations to the Commission on existing demand response and distributed generation capabilities in Maryland and to the extent to which additional demand response and distributed generation capabilities can be created in the State. The DRDG Working Group should also review the Mid-Atlantic Distributed Resources Initiative efforts to date and advise the Commission of any MADRI recommendations worthy of implementation in Maryland.

The first meeting of the DRDG Working Group was held on December 13, 2006 with the following proposed agenda:

1. DR/DG Maryland background and current status.
2. DR/DG proposals for analysis, implementation or perspectives.
3. Discussions on how to proceed.

H. Net Metering in Maryland

In 1997, Maryland enacted legislation allowing net metering for residential customers and schools with qualified solar energy systems up to 80 kW in capacity. The limit on net metering capacity is 34.7 MW, which is equal to 0.2% of Maryland's adjusted peak-load forecast

[50] Re *Competitive Selection of Electricity Supplier/Standard Offer Service*, 94 Md. PSC, 113, 286 (2003).

for 1998. Utilities must install a single, bi-directional meter at a customer's facility and must offer net metering at no additional charge or increased electricity rate.

Maryland's net-metering law has been revised several times since its inception. In 2004, the law was expanded by including wind as an eligible technology, and by extending eligibility to commercial facilities. In 2005, the law was expanded by including biomass as an eligible technology, as well as by increasing the maximum system capacity from 80 kW to 200 kW. Furthermore, generators may petition the Commission to allow net metering up to 500 kW.

Senate Bill 167 enacted in April of 2006 made four additional changes to Maryland's net-metering law, which took effect October 1, 2006:

- Net metering is available to customers who operate leased solar, wind or biomass energy systems.
- Net excess generation will be carried over to the customer's next bill for up to 12 months.
- For systems designed to generate more electricity than a customer consumes, the PSC may require a dual meter capable of measuring electricity flow in two directions.
- The PSC will develop a credit formula for systems designed to generate more electricity than a customer consumes.

I. Small Generators Interconnection

The essence of the Energy Policy Act of 2005 (EPAct 2005) Section 1254 is to promote the standardization of interconnection procedures around the IEEE 1547 standard. Section 1254 of EPAct 2005 requires each state regulatory authority to commence consideration of an interconnection standard, based on the IEEE 1547 standard, by August 8, 2006, and to complete its determination by August 8, 2007.

Clear guidelines for meeting Section 1254 are provided by FERC's interconnection rules for small generators (Order 2006), issued in May 2005. The small-generator rules contain provisions for the expedited interconnection of generators in a class less than 10 kW and a class up to 2 MW -- provided, in each case, that the generator complies with IEEE 1547 standards.

The Commission issued a Notice of Inquiry dated April 4, 2006, requesting comments on specific requirements of Section 1254. Based on comments received the PSC issued an Order on October 17, 2006 directing staff to establish a Small Generator Standards Working Group. The Small Generator Standards Working Group is to develop a report for the PSC that outlines policy alternatives or consensus recommendations and provide specific provisions for interconnection standards that could be adopted by the PSC. The report is due by April 1, 2007 so that the PSC can meet the requirements of Section 1254 by the August 7, 2007 deadline established by EPAct 2005.

VI. NATIONAL ENERGY ISSUES IMPACTING MARYLAND

During 2005, the United States Congress passed and President George W. Bush signed the Energy Policy Act of 2005 (EPAct 2005), possibly the most significant piece of national energy legislation enacted since 1992. EPAct 2005 is likely to have significant impacts on electricity issues facing the State, not only currently but also in the future.

A. Energy Policy Act of 2005

EPAct 2005 includes a number of provisions that will affect the cost and availability of energy in Maryland, and the overall structure of the electricity and natural gas industries. In addition, EPAct 2005 encourages state commissions, including the Public Service Commission of Maryland, to undertake a series of studies and analyses. These actions are identified and described in this section as well.

1. <u>Repeal of the Public Utility Holding Company Act (PUHCA)</u>

The repeal of PUHCA in EPAct 2005 may facilitate mergers and acquisitions (M&A) in the electric utility industry. More companies may soon propose to combine with other utilities, in addition to three such proposals recently under consideration including between Exelon-PSEG (failed), Duke-Cinergy (completed), and Constellation-FPL Group (failed).

Strong European companies and nontraditional investors may use this opportunity to purchase or co-invest in U.S. utilities. Also, investment from institutions with large financial resources including banks and insurance companies would be facilitated. The United States Security and Exchange Commission's (SEC) traditional role in reviewing such proposals is gone, as is the requirement for utility combinations to be contiguous or interconnected.

However, M&A approval or success is not assured, as state approval for M&A will still be required, and both the states and the FERC have authority to review utilities' books and records to ensure financial integrity and non-abuse of market power. How that authority is implemented will be critical.

2. <u>Energy Project Siting and Infrastructure Development</u>

EPAct 2005 encourages the siting and development of energy facilities and resources by providing financial incentives and granting new authority to the federal government of the United States. In light of these incentives and the current level of oil and gas prices, efforts are likely to accelerate to find and produce new domestic resources. Federal authority for liquefied natural gas (LNG) siting could be a key factor in encouraging such projects. Maryland is home to the largest LNG terminal in the United States, Dominion's Cove Point facility. Dominion is proposing to expand the storage capacity of the Cove Point LNG plant in Maryland by over 50 percent, with construction slated to begin in spring 2006 assuming receipt of needed approvals.

3. Nuclear Power

Nuclear energy is encouraged in the EPAct 2005. Tax credits and loan guarantees are provided for thousands of megawatts and could substantially lower the cost of those plants to consumers. The first six nuclear power plants that are licensed and built are eligible for production tax credits (1.8 cents per kWh) for the first eight years of operation. Also, financing costs will be reimbursed that result from unnecessary delays caused by the licensing process, and through no fault of the owner. The first six nuclear plants built will be eligible for this compensation, if needed.

Provisions for nuclear energy research and development demonstrate a renewed commitment from the U.S. Federal Government to next-generation facilities. Public opposition will inevitably accompany any proposal to build new nuclear facilities, but those concerns will be handled through the NRC's streamlined licensing process.

4. Electric Transmission

Transmission received a strong push in EPAct 2005. EPAct 2005 allows the United States Department of Energy to designate transmission corridors of "national interest" to upgrade or add transmission for reliability or economic purposes. If states do not act within a year of receiving an application, FERC could require the development of transmission in those corridors. EPAct 2005 also promotes transmission by requiring the setting of common nationwide standards for electric reliability, the setting of incentive rates for transmission, and the creation of a national organization that will monitor the status of the grid.

5. Renewable Energy

Renewable energy is strongly encouraged and there is a window of opportunity to pursue the development of new facilities. EPAct 2005 provides for substantial production tax credits (1.8 cents per kWh) for many renewable energy options for nine years, if they are on-line by the end of 2007.

6. Clean Coal, Coal Gasification

As a result of the incentives in EPAct 2005, the first clean-coal and gasification projects will be in a strong position to come to fruition. EPAct 2005 provides substantial amounts in direct grants, loan guarantees and accelerated depreciation, divided among different technologies and types of fuel, to make this option a reality.

While coal gasification combined cycle power plants may not be built in Maryland, utilities which are in the PJM footprint, including AEP, are proposing to build coal gasification combined cycle (CGCC) facilities in eastern Ohio and West Virginia. Duke Power, in Ohio and Indiana, is also proposing to build CGCC power plants. Some of the power from these facilities could be delivered to Maryland if sufficient transmission capacity can be built.

7. Electricity Title and Required Commission Actions

Subtitle E of Title XII (Electricity) of EPAct 2005 is of specific concern to state utility regulators. Subtitle E incorporates amendments to the Public Utility Regulatory Policy Act of 1978 (PURPA). Sections 215, 1251, 1252 and 1254 of EPAct 2005 add net metering, fuel sources, fossil fuel generation efficiency, time-based metering and interconnection standards to 16 U.S.C. §2621(d). Within the deadlines discussed below, 16 U.S.C. §2621(a) requires the Commission to consider and determine whether it is appropriate to implement the standards in 16 U.S.C. §2621(d)(11-15) to carry out the purpose of Title 16 of the U.S. Code. The procedural requirements for consideration and determination are set forth in 16 U.S.C. §2621(b). FERC is given the authority to implement any of these standards in 16 U.S.C. §2621(c).

Section 215(c) of the Federal Power Act (FPA) authorizes FERC to certify an entity as an Electric Reliability Organization (ERO). As a result, FERC amended its regulations to incorporate the following criteria pertaining to ERO (see Section VI-B):

(1) Criteria that an entity must satisfy to qualify to be the Electric Reliability Organization which FERC will certify as the organization that will propose and enforce Reliability Standards for the Bulk-Power System in the United States, subject to FERC approval;
(2) Procedures under which the ERO may propose new or modified Reliability Standards for FERC review;
(3) A process for timely resolution of any conflict between a Reliability Standard and a FERC-approved tariff or order;
(4) A process for resolution of an inconsistency between a state action and a Reliability Standard;
(5) Regulations pertaining to the funding of the ERO;
(6) Procedures governing an enforcement action by the ERO, a Regional Entity or FERC;
(7) Criteria under which the ERO may enter into an agreement to delegate authority to a Regional Entity for the purpose of proposing Reliability Standards to the ERO and enforcing Reliability Standards;
(8) Regulations governing the issuance of periodic reliability reports by the ERO that assess the reliability and adequacy of the Bulk-Power System in North America; and,
(9) Procedures for the establishment of Regional Advisory Bodies that may provide advice to FERC, the ERO or a Regional Entity on matters of governance, applicable Reliability Standards, the reasonableness of proposed fees within a region, and any other responsibilities requested by the FERC.[51]

Not later than two years after the enactment of Section 1251, by August 8, 2007, FERC (with respect to each electric utility for which it has ratemaking authority) is required to commence consideration, or set a hearing date for consideration, of the standards referred to in Section 1251. By August 8, 2008, FERC (with respect to each electric utility for which it has

[51] See "Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards" Order No. 672, Final Rule in Docket No. RM05-30-000, issued on February 3, 2006, at pp. 1-3.

ratemaking authority) must complete its consideration and make its determination with respect to the standards.

According to Section 1252, not later than one year after enactment of EPAct 2005, FERC shall commence consideration, or set a hearing date for consideration, of the changes referred to in Section 1252. Not later than two year after the enactment of Section 1252, FERC shall complete consideration and make a determination.

In conjunction with the requirement above, Section 1252 mandates additional FERC action. No later than eighteen months after the enactment of Section 1252, FERC shall conduct an investigation in accordance with Section 115(i) of PURPA and issue a decision regarding whether it is appropriate to implement the standards set out in Section 111(d)(14)(A) and (C) of PURPA. These standards direct utilities to offer, and customers to accept, smart meters.

Under EPAct 2005, the Commission shall commence consideration, or set a hearing date for consideration of the changes referred to in Section 1254, not later than one year after the enactment of Section 1254. Not later than two years after the enactment of Section 1254, the Commission shall complete consideration and make a determination.

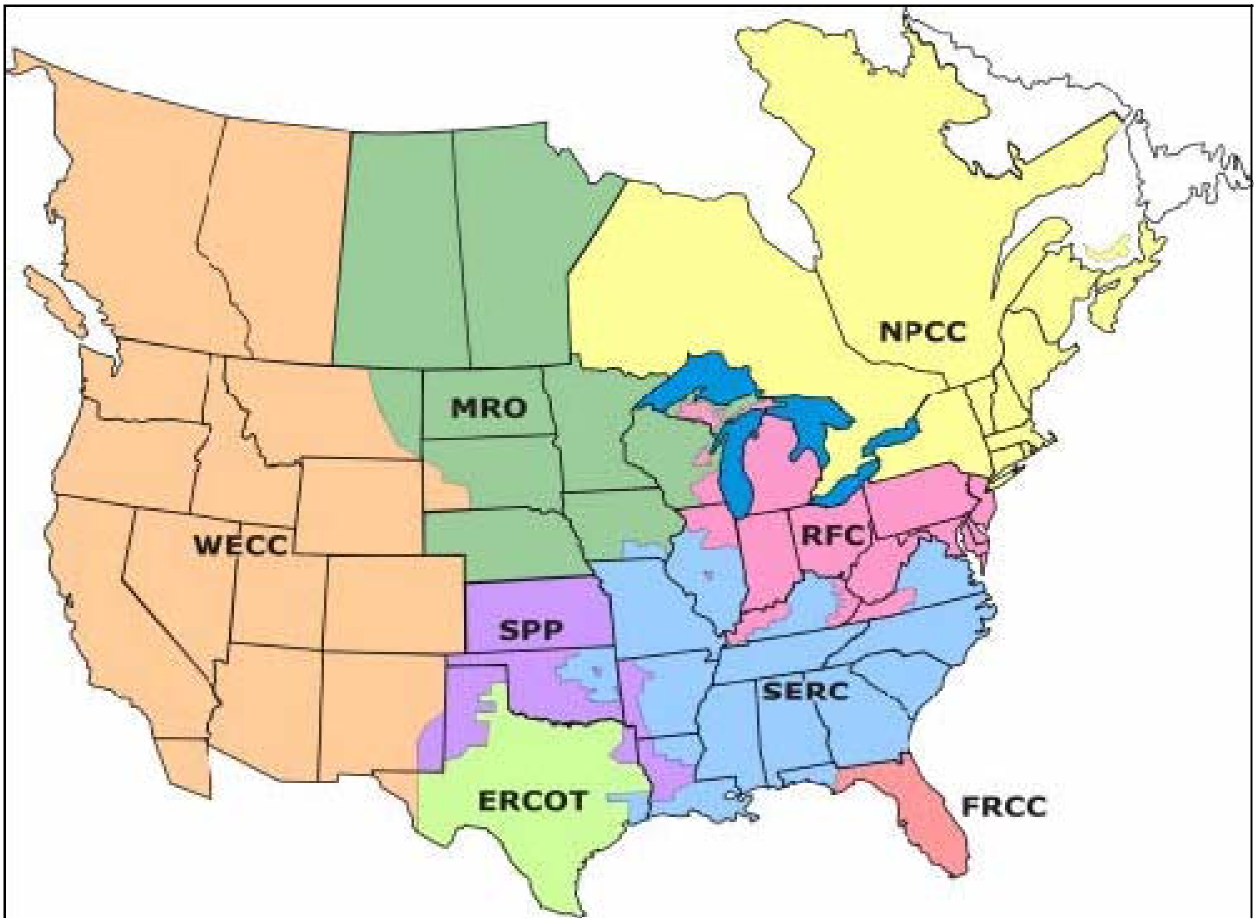
B. Formation of a National Electric Reliability Organization (ERO)

On February 3, 2006, FERC issued Order No. 672, Final Rule to implement the requirements of section 215 of the FPA. Section 215(c) requires FERC to certify a single Electric Reliability Organization that will oversee the reliability of the interconnected North American Bulk-Power Systems. The ERO will develop and enforce the mandatory Reliability Standards, which will apply to all users, owners and operators of the Bulk-Power System. FERC "has the authority to approve all ERO actions, to order the ERO to carry out its responsibilities under these new statutory provisions, and also may independently enforce Reliability Standards."[52]

In Order No. 672, FERC identified the criteria that an applicant must meet to qualify as the single ERO. One applicant, the North American Electric Reliability Council (NERC), submitted its application on April 4, 2006. The NERC proposal included comprehensive plans that discussed in details the transition to and maintenance of NERC as the ERO. Based on FERC's review of NERC's proposal and other public comments submitted by interested parties on NERC's application, FERC found that NERC's proposal met the requirements of Order No. 672 and therefore, certified NERC as the ERO for the United States. In Order No. 672, FERC ordered the ERO to conduct assessments of the adequacy of the Bulk-Power system in North America and to report its findings to FERC, the Secretary of Energy, each Regional Entity (as noted on Map VI-1), and each Regional Advisory Body.

[52] Order No. 672 at p. 8.

Map VI-1: NERC Regional Reliability Councils as of 10/16/2006



NPCC = Northeast Power Coordinating Council; RFC = Reliability*First* Corporation; SERC = SERC Reliability Corporation; FRCC = Florida Reliability Coordinating Council; ERCOT = Electric Reliability Council of Texas, Inc.; SPP = Southwest Power Pool, Inc.; MRO = Midwest Reliability Organization; and WECC = Western Electricity Coordinating Council. Source: NERC 2006 Long-Term Reliability Assessment, p. 5.

C. NERC Reliability Study

On October 2006, NERC issued a study entitled "2006 Long-Term Reliability Assessment: The Reliability of the Bulk Power Systems in North America." The study analyzes the adequacy of electricity supply and the reliability of transmission in North America over the 2006-2015 period. The study notes a series of actions pertaining to bulk power system (transmission, fuel supply, demand response, and delivery of electric generation). Some of the key findings and actions needed[53] are as noted below.

[53] The "Actions Needed" do not represent mandatory requirements, but rather NERC's independent judgment of those steps that will help improve reliability and adequacy of the bulk power systems of North America.

Key Findings:

- Electric capacity margins will decline over the 2006–2015 period in most regions.
- Electric utilities forecast demand to increase over the next ten years by 19 percent (141,000 MW) in the United States and 13 percent (9,500 MW) in Canada, but project committed resources to increase by only 6 percent (57,000 MW) in the U.S. and by 9 percent (9,000 MW) in Canada.
- The lack of adequate transmission emergency transfer capability or transmission service agreements could limit the ability to deliver available resources from areas of surplus to areas of need.
- Long-term electricity supply adequacy requires a broad and balanced portfolio of generation and fuel types, transmission, demand response, renewables, and distributed generation; all supply-side and demand-side options need to be available.
- The adequacy of electricity supplies depends, in part, on the adequacy of fuel supply and delivery systems, not just the installed capacity of generators.
- Gas-fired generating capacity additions are projected to account for almost half of the resource additions over the 2006–2015 period.

Actions Needed:

- Electric utilities[54] need to commit to add sufficient supply-side or demand-side resources, either through markets, bi-lateral contracts, or self supply, to meet minimum regional target levels.
- NERC, in conjunction with regional reliability organizations and electric utilities, will evaluate the implications of the 2006 summer heat wave on future demand forecasts.
- NERC, in conjunction with regional reliability organizations, electric utilities, resource planning authorities, and resource providers, will address the issue of "uncommitted resources" by establishing more specific criteria for counting resources toward supply requirements.
- NERC will expedite the development of its new reliability standard on resource adequacy assessment that will establish parameters for taking into account various factors, such as: fuel deliverability; energy-limited resources; supply/demand uncertainties; environmental requirements; transmission emergency import constraints and objectives; capability to share generation reserves to maintain reliability, etc.
- Electric utilities, resource planning authorities, and resource providers need to evaluate the reliability of fuel supply and delivery systems when determining electricity supply adequacy.
- Entities that purchase fuel for electric generators need to review and strengthen fuel supply and delivery contracts to ensure that fuel disruptions do not limit generator operation during critical electric supply situations.
- Federal, state, and provincial agencies, along with fuel supply and delivery industries, need to evaluate the adequacy of these critical infrastructures for supporting an adequate electricity supply system.

54 "Electric utilities" in this context refers to load-serving entities whose responsibility it is to secure energy, transmission, and related interconnected operations services to serve the electrical demand and energy requirements of its end-use customers.

D. Department of Energy (DOE) Transmission Congestion Study

Released in August 2006, the Department of Energy's National Electric Transmission Congestion Study is the first one completed in accordance with Section 1221(a) of the Energy Policy Act of 2005. The report analyzes transmission congestion and recognizes constrained transmission paths found throughout the nation.

Within the study, transmission congestion is said to occur when scheduled or real flows of electricity are restricted below the desired levels. This restriction happens over lines and pieces of equipment and is caused by the capacity of the line or operational restrictions implemented to maintain the reliability and security of the grid. A transmission constraint, as defined by the DOE, is caused by a limitation imposed by a piece of equipment, or an operational restriction.

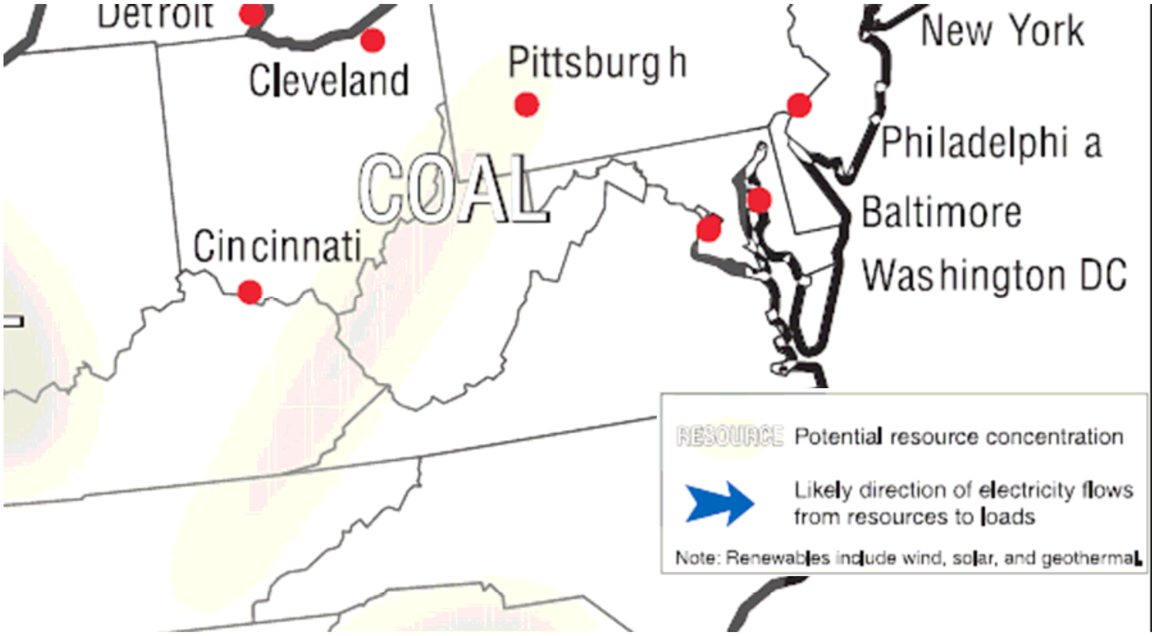
Electricity consumers are impacted by transmission constraints and transmission congestion. The congestion study states that the least expensive energy available to ship across the grid to load centers, is sought after by power purchasers. When the amount of energy that may be transferred from the most cost effective source to a load center is capped, the grid operator re-routes energy from a more expensive source to the load center to meet the load center's demand for energy. When a large portion of the grid is very tightly constrained, a grid operator may be forced to inhibit electricity service to an area of consumers. This restriction is done to maintain the integrity of the grid as a whole.

Through the use of a variety of cost congestion metrics, the Department of Energy created three classifications that aid in identifying areas that merit federal attention. The three classes are Critical Congestion Areas, Congestion Areas of Concern and Conditional Congestion Areas. Critical Congestion Areas are deemed to be regions of the country where the current and/or projected situations will experience the harshest effects of congestion. The two areas identified as being Critical Congestion areas are Southern California and the Atlantic coastal area from metropolitan New York through Northern Virginia.

Congestion Areas of Concern are sections of the nation that have emerging or existent large-scale congestion problems. The DOE deemed that the areas identified by this classification require additional analysis to determine the magnitude of the problem and the possible impacts associated with the proposed congestion remedies. The four identified Congestion Areas of Concern are New England, the Phoenix – Tucson area, the Seattle – Portland area, and the San Francisco Bay area.

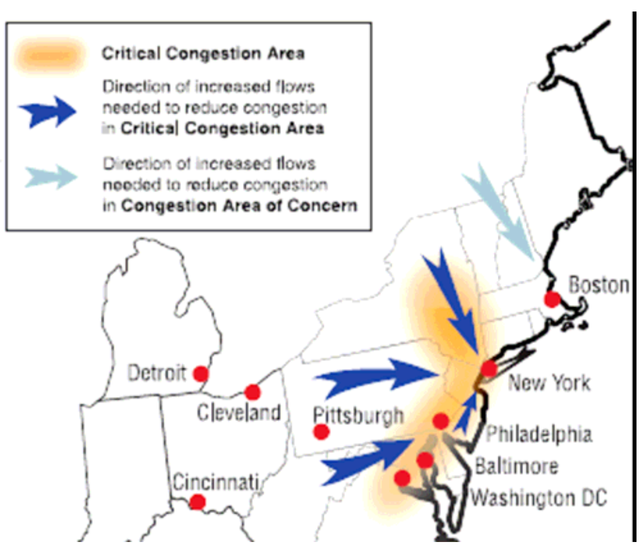
The Conditional Congestion Areas are areas that currently contain some transmission congestion. The DOE has concluded that these areas would experience significant congestion if a significant amount of new generation resources were to be developed without the development of the associated transmission capacity. There are numerous areas that fall under this classification and two of them apply to the PJM system area. The Illinois, Indiana and Upper Appalachia regions both are subject to the congestion potential associated with the development of coal resources. Map VI-2 on the next page shows the local regions affected by this class of congestion.

Map VI-2: Conditional Congestion Area



Of the DOE study's congestion classifications, the Critical Congestion Area identified along the eastern seaboard has the most significant direct impact. This area is identified in Map VI-3 below that is taken from the DOE Study. One can see that this area runs from the New York metropolitan area to the Baltimore - Washington DC metropolitan area.

Map VI-3: Critical Congestion Area



Analyzing the two figures in conjunction sheds light on the situation that Maryland is in. One of the main options to relieve the problem of the transmission congestion in Maryland is to develop the coal resources to the west. If this is to occur then the transmission infrastructure will also need to be upgraded to effectively transport the electricity from the generating sources to the load centers. Transmission planners and electricity supply planners in the Mid-Atlantic region are looking to the west to generate electricity. States such as Indiana, Kentucky, Ohio and West Virginia have both vast coal resources and a willingness to host power plants. These states view power plants as a means of encouraging economic development.

Maryland is directly affected by congestion areas located on the Delmarva Peninsula and the Baltimore – Washington DC 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 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. In an effort to alleviate this congestion problem, several small-scale transmission upgrades have been completed. There is a transmission line being proposed by Pepco Holdings, Inc. would bring new capacity and energy to Delmarva. This line would approach from the south after crossing the Chesapeake Bay.

The Baltimore – Washington DC area is in a situation where the congestion of the electricity transmission grid requires immediate attention. PJM has found that without transmission upgrades, the reliability criteria established for critically important loads, will not be met over the next 15 years.

The DOE study mentions that there is no silver bullet to alleviate these problems. Often times opposition exists towards building new generation or maintaining existing generation in urban areas where there is a demand for grid reliability and local voltage support. Air emissions regulations coupled with a NIMBY (Not In My Back Yard) attitude also serve to hinder the creation of new electricity generation and the upkeep of existing aging generating facilities. Additional transmission capacity is another viable option to pursue in reducing Maryland's congestion. A drawback to new transmission lines is that numerous communities oppose the construction of overhead high-voltage power lines. More aesthetically pleasing underground high-voltage transmission lines are often opposed by utilities and their customers because they are not willing to pay the higher costs incurred from their construction. Demand side measures such as energy efficiency and demand response are mentioned as options to improve the gap between available supply and demand. However these techniques are said to require significant time-consuming expansion in order for the demand-side measures to have an impact on the scale of transmission or power plant generation. Planners in PJM have realized that all of the aforementioned measures need to be pursued in order to guarantee a response that can meet and adapt to future economic and reliability challenges.

E. FERC Staff Report on Demand Response Programs & Advanced Metering

Section 1252(e)(3) of the Energy Policy Act of 2005 requires FERC to prepare a report, by appropriate region, that assesses demands response resources, including those available from all consumer classes, specifically to identify and review the following for the electric power industry:

- Saturation and penetration rate of advanced meters and communication technologies, devices and systems;
- Existing demand response programs and time-based programs;
- The annual resource contribution of demand response;
- The potential for demand response as a quantifiable, reliable resource for regional planning purposes;
- Steps taken to ensure that, in regional transmission planning and operations, demand resources are provided equitable treatment as a quantifiable, reliable resource relative to the resource obligations of any load-serving entity, transmission provider, or transmitting party; and,

- Regulatory barriers to improved customer participation in demand response, peak reduction and critical period pricing programs.

The FERC Staff Report assesses demand response and advanced metering and is based on the results of a voluntary survey sent to approximately 3,400 entities. The demand response results are categorized in the report by NERC region and the advanced metering results are categorized by state. The response rate to the survey was approximately 55%.

The survey results showed that the national penetration rate for advanced metering is 6%. Demand response programs in the Report included both incentive-based rates and time-based rates. The results show that 37,500 MW of demand response is included in existing programs and that demand response capability represents between 3% and 7% of peak demand in most regions.

FERC Staff identified several actions and steps that could be taken to enable greater use of demand resources in regional transmission planning and operations procedures, including:

- Assure that planning and operational requirements are specified in terms of functional needs;
- Accommodate the inherent characteristics for demand response resources;
- Allow appropriately designed demand response resources to provide all ancillary services;
- Allow for the consideration of demand response alternatives to all transmission enhancement proposals.;
- When appropriate, treat demand response as a permanent solution; and,
- Develop better demand response forecasting tools for system operators.

FERC Staff identified several regulatory barriers to improved customer participation in demand response, peak reductions and critical peak pricing programs, including:

- 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 for specific state-level barriers to greater demand response;
- Specific retail and wholesale rules that limit demand response;
- Barriers to providing demand response services to third parties;
- Insufficient market transparency and access to data; and,
- Better coordination of federal-state jurisdiction affecting demand response.

FERC Staff concluded that demand response has an important role to play in both the wholesale and retail markets. The potential immediate reduction in peak electric demand that can be achieved from existing demand response resources is between three and seven percent of peak electric demand in most regions. However, the technologies needed to support significant deployment of electric demand response resources have little market penetration.

Based on the conclusions, FERC Staff recommended that FERC:

- Explore how to better accommodate demand response in wholesale markets;
- Explore how to coordinate with utilities, state commissions and other interested parties on demand response in wholesale and retail markets; and,
- Consider specific proposals for compatible regulatory approaches, including how to eliminate regulatory barriers to improved participation in demand response, peak reduction and critical peak pricing programs.

F. Impacts of Volatile Commodity Prices on Wholesale Electricity Markets

On May 18, 2006, FERC held a technical conference to discuss the *Summer Energy Market Assessment 2006* report.[55] Record high storage levels and strong early injections, along with a gradual recovery in the Gulf following Hurricanes Katrina and Rita in 2005, helped to moderate natural gas futures from the high levels reached in the fall of 2005. However, concerns over high oil prices and the potential for additional hurricane activity in the Gulf of Mexico tended to exert upward pressure on prices. Due to widening price differentials, there was some fuel switching from residual fuel oil to natural gas for electric generation. Coal stockpiles remained below five-year averages due to railroad disruptions and strong coal demand.

On October 19, 2006, FERC held a technical conference to discuss the *Winter 2006-07 Energy Market Assessment* report. The general conclusion of FERC Staff was that current conditions for natural gas indicated that the system has significant flexibility to deal with most challenges that might arise through the winter. In addition, there would be enough natural gas in storage, as well as sufficient pipeline capacity, to meet needs for winter 2006-2007. The report noted the energy prospects for this winter look as good as they have for some time. Spot prices were at their lowest levels since last year's hurricanes; these low spot prices reflect large storage inventories among a set of fuels, particularly natural gas. The National Oceanic & Atmospheric Administration (NOAA) predictions for winter weather are mild. These positive conclusions exist despite increased gas use during the summer due to heat and fuel switching away from oil.

Recent natural gas prices are low as compared to last year. A short-lived peak of over $8.50/MMBtu occurred in early August during a widespread summer heat wave characterized by increases in natural gas use for electric generation. Natural gas reached a four-year low in the first week of October when it dropped to $3.66/MMBtu. This low price was strongly attributed to high storage levels. These high levels of storage began with the low withdrawals last winter due to record mild weather. The early 2006 surplus was sustained despite a summer when natural gas was used in unprecedented amounts to generate electricity during several geographically dispersed heat waves. Natural gas has been an attractive alternative versus competing fuels, not necessarily coal, but certainly with oil. Swap markets indicate rising gas prices relative to oil, meaning the market does not believe the cheap gas to oil relationship will hold into the winter. Weather is likely to be the most important factor in this price relationship.

An attempt to assess market expectations for the winter of 2006-2007 using future prices reveals that the recent moderation in prices extends into the winter. Through early 2005 and into

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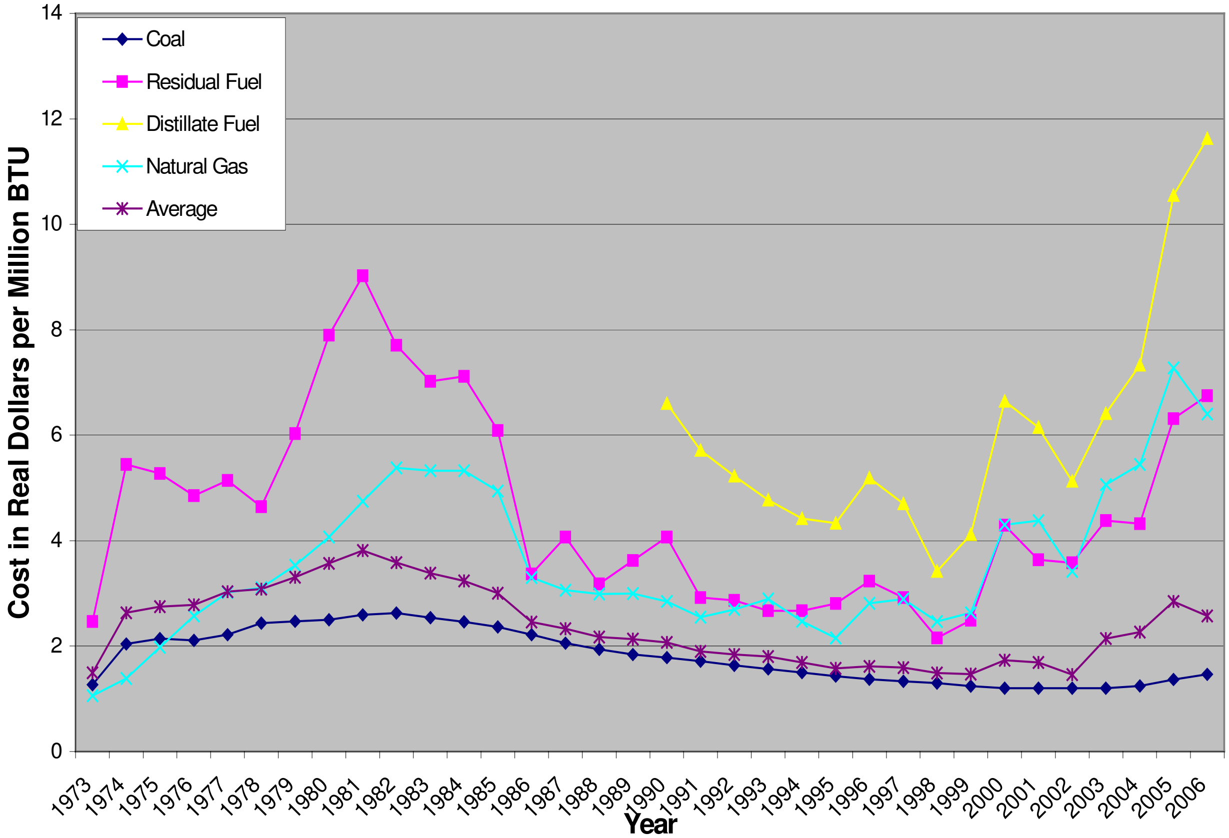
[55] The information provided in this description was largely obtained from FERC. For more information you can visit the FERC website at http://www.ferc.gov/.

the hurricanes, prices almost doubled from a little over \$6.00/MMBtu to over \$10.00/MMBtu. More recently prices have fallen significantly, briefly dropping to under \$7.00/MMBtu in October before rising recently to around \$8.00/MMBtu. Distribution companies use a combination of gas in storage that is injected during the summer and gas purchased under longer-term contracts. This natural hedge protects reliability and moderates retail price volatility. Price volatility remains a major challenge to electricity market, which depends on natural gas as fuel of choice for electric generation. A graphical representation of the impact of natural gas price volatility over several decades is presented below.

Chart VI-1: Yearly Avg Cost by Fuel



*2006 spans 1/1/06 - 6/30/06

APPENDIX
Tables A-1 to A-12

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, 2005)												
	System-Wide						Maryland					
Utility/Co.	**Residential**	**Comm.**	**Industrial**	**Other**	**Sales for Resale**	**Total**	**Residential**	**Comm.**	**Industrial**	**Other**	**Sales for Resale**	**Total**
A&N	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0
Berlin	1,727	279	89	20	0	2,115	1,727	279	89	20	0	2,115
BGE	1,084,087	114,695	4,970	0	0	1,203,752	1,084,087	114,695	4,970	0	0	1,203,752
Choptank	41,925	3,888	17	262	0	46,092	41,925	3,888	17	262	0	46,092
DPL	449,063	59,806	583	679	0	510,131	170,436	25,252	276	278	0	196,242
Easton	8,107	2,038	0	123	0	10,268	8,107	2,038	0	123	0	10,268
Hagerstown	15,010	2,180	132	4	0	17,326	15,010	2,180	132	0	0	17,322
PE/AP	399,865	53,825	6,046	717	6	460,459	211,427	26,036	2,791	344	3	240,601
Pepco	674,046	72,977	12	138	1	747,174	465,722	46,289	11	107	0	512,129
SMECO	126,824	12,073	4	193	0	139,094	126,824	12,073	4	193	0	139,094
Somerset	11,834	1,052	7	0	0	12,893	750	32	4	0	0	786
Thurmont	2,471	326	9	44	0	2,850	2,471	326	9	44	0	2,850
Williamsport	869	60	37	35	0	1,001	869	60	37	35	0	1,001
Total	2,815,828	323,199	11,906	2,215	7	3,153,155	2,129,355	233,148	8,340	1,406	3	2,372,252

Table A-3: Sales by Customer Class (GWh) (as of December 31, 2005)												
	System-Wide						Maryland					
Utility/Co.	**Residential**	**Commercial**	**Industrial**	**Other**	**Sales for Resale**	**Total**	**Residential**	**Commercial**	**Industrial**	**Other**	**Sales for Resale**	**Total**
A&N	N/A	N/A	N/A	N/A	N/A	0.00	N/A	N/A	N/A	N/A	N/A	N/A
Berlin	22.59	3.12	14.55	0.36	0.00	40.61	22.59	3.12	14.55	0.36	0.00	40.61
BGE	13,762.00	15,814.00	3,736.00	0.00	0.00	33,312.00	13,762.00	15,814.00	3,736.00	0.00	0.00	33,312.00
Choptank	610.00	177.00	83.00	0.50	0.00	870.50	610.00	177.00	83.00	0.50	0.00	870.50
DPL	5,669.00	5,495.00	3,112.00	51.00	0.00	14,327.00	2,373.00	1,802.00	514.00	12.00	0.00	4,701.00
Easton	110.00	147.00	0.00	13.00	0.00	270.00	110.00	147.00	0.00	13.00	0.00	270.00
Hagerstown	156.70	66.60	131.30	7.40	0.00	362.00	156.70	66.60	131.30	7.40	0.00	362.00
PE/AP	6,122.00	3,377.00	6,377.00	24.00	772.00	16,672.00	3,267.00	1,984.00	4,483.00	12.00	486.00	10,232.00
Pepco	8,024.00	18,120.00	736.00	708.00	5.00	27,593.00	6,085.00	8,916.00	479.00	291.00	0.00	15,771.00
SMECO	2,123.00	1,073.00	196.00	4.00	0.00	3,396.00	2,123.00	1,073.00	196.00	4.00	0.00	3,396.00
Somerset	114.00	37.00	12.00	0.00	0.00	163.00	6.50	0.30	0.40	0.00	0.00	7.20
Thurmont	41.55	16.95	27.99	0.82	0.00	87.31	41.55	16.95	27.99	0.82	0.00	87.31
Williamsport	10.28	1.38	7.84	0.86	0.00	20.36	10.28	1.38	7.84	0.86	0.00	20.36
Total	36,765.12	44,328.05	14,433.68	809.94	777.00	97,113.78	28,567.62	30,001.35	9,673.08	341.94	486.00	69,069.98

Table A-4: Typical Utility Bills in Maryland, Winter 2006									
	Energy Use (kWh) Demand (kW) per month			Typical Bill ($)			Revenue: $/kWh		
Utility/Co	Res.	Comm.	Ind.	Res.	Comm.	Ind.	Res.	Comm.	Ind.
A&N	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Berlin	1000	10000	200000	$158.99	$1,745.14	$27,120.02	$0.15899	$0.17451	$0.13560
BGE	750	12500	200000	$58.60	$1,161.93	$19,026.87	$0.07813	$0.09295	$0.09513
Choptank	1000	12500	200000	$115.93	$1,336.29	$19,243.05	$0.11593	$0.10690	$0.09622
DPL	750	3500	200000	$99.54	$539.96	$23,457.85	$0.13272	$0.15427	$0.11729
Easton	750	12500	N/A	$103.81	$1,839.08	N/A	$0.13841	$0.14713	N/A
Hagerstown	750	12500	200000	$71.75	$193.39	$14,849.15	$0.09566	$0.12893	$0.07424
PE/AP	1640	5100	21650	$111.65	$437.42	$1,810.26	$0.06808	$0.08577	$0.08361
Pepco	750	12500	200000	$96.33	$1,540.97	$22,770.81	$0.12840	$0.12330	$0.11390
SMECO	750	12500	200000	$85.40	$1,298.72	$18,037.94	$0.11390	$0.10390	$0.09020
Somerset	869	2300	11175	$82.55	$205.43	$882.83	$0.75000	$0.11500	$0.07900
Thurmont	750	12500	200000	$68.14	$1,083.34	$15,001.36	$0.08973	$0.08440	$0.07398
Williamsport	750	12500	200000	$71.10	$1,213.11	$17,744.77	$0.09355	$0.09464	$0.08776

Table A-5 (a): System-Wide Peak Demand Forecast, 2006-2020 (Net of DSM Programs; MW)

Year	A&N	BGE	Berlin	Choptank	DPL	Easton	Hagers-town	PE/AP	Pepco	Somerset	SMECO	Thurmont	Williams-port
2006	N/A	7,212	10.30	228	4,260	63.60	76.60	2,842	6,753	48.30	797	20.83	4.64
2007	N/A	7,291	10.51	254	4,374	65.10	78.90	2,897	6,886	49.60	785	21.14	4.71
2008	N/A	7,448	10.72	263	4,488	66.50	81.30	2,945	7,020	51.00	808	21.46	4.78
2009	N/A	7,536	10.93	278	4,603	68.00	83.70	3,004	7,157	52.20	831	21.78	4.85
2010	N/A	7,622	11.15	289	4,717	69.40	86.20	3,051	7,296	53.50	853	22.11	4.92
2011	N/A	7,703	11.38	299	4,831	70.90	88.80	3,113	7,439	54.80	875	22.44	5.00
2012	N/A	7,755	11.60	310	4,946	72.30	91.50	3,172	7,585	56.20	897	22.78	5.07
2013	N/A	7,874	11.83	321	4,059	73.80	94.20	3,231	7,733	57.70	919	23.12	5.15
2014	N/A	7,954	12.07	333	5,174	75.20	97.00	3,296	7,885	59.30	941	23.47	5.23
2015	N/A	8,029	12.31	345	5,290	76.60	99.90	3,359	8,039	60.90	961	23.82	5.30
2016	N/A	8,081	12.56	358	5,411	78.10	102.90	3,427	8,195	62.50	982	24.18	5.38
2017	N/A	8,198	12.81	373	N/A	79.50	106.00	3,491	N/A	64.20	1,004	24.54	5.46
2018	N/A	8,284	13.07	389	N/A	81.00	109.20	3,559	N/A	65.90	1,023	24.91	5.55
2019	N/A	8,369	13.33	405	N/A	82.40	112.50	3,630	N/A	67.70	1,044	25.28	5.63
2020	N/A	8,454	13.59	423	N/A	83.90	115.90	3,699	N/A	69.50	1,063	25.66	5.71

Table A-5 (b):
Maryland Peak Demand Forecast, 2006-2020 (Net of DSM Programs; MW)

Year	A&N	BGE	Berlin	Choptank	DPL	Easton	Hagers-town	PE/AP	Pepco	Somerset	SMECO	Thurmont	Williams-port
2006	N/A	7,212	10.30	228	N/A	63.60	76.60	N/A	N/A	N/A	797	20.83	4.64
2007	N/A	7,291	10.51	254	N/A	65.10	78.90	N/A	N/A	N/A	785	21.14	4.71
2008	N/A	7,448	10.72	263	N/A	66.50	81.30	N/A	N/A	N/A	808	21.46	4.78
2009	N/A	7,536	10.93	278	N/A	68.00	83.70	N/A	N/A	N/A	831	21.78	4.85
2010	N/A	7,622	11.15	289	N/A	69.40	86.20	N/A	N/A	N/A	853	22.11	4.92
2011	N/A	7,703	11.38	299	N/A	70.90	88.80	N/A	N/A	N/A	875	22.44	5.00
2012	N/A	7,755	11.60	310	N/A	72.30	91.50	N/A	N/A	N/A	897	22.78	5.07
2013	N/A	7,874	11.83	321	N/A	73.80	94.20	N/A	N/A	N/A	919	23.12	5.15
2014	N/A	7,954	12.07	333	N/A	75.20	97.00	N/A	N/A	N/A	941	23.47	5.23
2015	N/A	8,029	12.31	345	N/A	76.60	99.90	N/A	N/A	N/A	961	23.82	5.30
2016	N/A	8,081	12.56	358	N/A	78.10	102.90	N/A	N/A	N/A	982	24.18	5.38
2017	N/A	8,198	12.81	373	N/A	79.50	106.00	N/A	N/A	N/A	1,004	24.54	5.46
2018	N/A	8,284	13.07	389	N/A	81.00	109.20	N/A	N/A	N/A	1,023	24.91	5.55
2019	N/A	8,369	13.33	405	N/A	82.40	112.50	N/A	N/A	N/A	1,044	25.28	5.63
2020	N/A	8,454	13.59	423	N/A	83.90	115.90	N/A	N/A	N/A	1,063	25.66	5.71

Table A-6 (a): System-Wide Energy Sales Forecast, 2006-2020 (Net of DSM Programs; GWh)													
Year	**A&N**	**Berlin**	**BGE**	**Choptank**	**DPL**	**Easton**	**Hagers-town**	**PE/AP**	**Pepco**	**Somerset**	**SMECO**	**Thurmont**	**William-sport**
2006	N/A	41.42	32,484	988	14,218	305	352.80	14,401	27,639	191	3,485	88.62	20.67
2007	N/A	42.25	33,309	1,149	14,529	313	363.40	14,763	28,137	196	3,583	89.95	20.98
2008	N/A	43.09	33,585	1,203	14,850	319	374.30	15,094	28,645	201	3,687	91.30	21.29
2009	N/A	43.96	34,027	1,259	15,180	326	385.50	15,360	29,162	206	3,791	92.67	21.61
2010	N/A	44.84	34,411	1,319	15,520	333	397.10	15,568	29,689	211	3,893	94.06	21.93
2011	N/A	45.73	34,770	1,381	15,868	340	409.00	15,829	30,226	216	3,994	95.47	22.26
2012	N/A	46.65	35,145	1,444	16,223	347	421.30	16,154	30,772	221	4,094	96.90	22.60
2013	N/A	47.58	35,520	1,508	16,586	354	433.90	16,423	31,328	227	4,190	98.36	22.94
2014	N/A	48.53	35,895	1,575	16,958	361	446.90	16,764	31,894	233	4,283	99.83	23.28
2015	N/A	49.50	36,270	1,646	17,338	368	460.30	17,114	32,470	240	4,378	101.33	23.63
2016	N/A	50.49	36,645	1,719	17,726	375	474.10	17,544	33,057	246	4,471	102.85	23.98
2017	N/A	51.50	37,020	1,807	N/A	382	488.30	17,857	N/A	253	4,561	104.39	24.34
2018	N/A	52.53	37,395	1,896	N/A	389	502.90	18,265	N/A	259	4,650	105.96	24.71
2019	N/A	53.58	37,770	1,991	N/A	396	518.00	18,675	N/A	266	4,732	107.55	25.08
2020	N/A	54.65	38,145	2,090	N/A	403	533.50	19,158	N/A	273	4,815	109.16	25.46

Table A-6 (b): Maryland Energy Sales Forecast, 2006-2020 (Net of DSM Programs; GWh)													
Year	**A&N**	**Berlin**	**BGE**	**Choptank**	**DPL**	**Easton**	**Hagers-town**	**PE/AP**	**Pepco**	**Somerset**	**SMECO**	**Thurmont**	**William-sport**
2006	N/A	41.42	32,484	988	N/A	305	353	N/A	N/A	N/A	3,485	88.62	20.67
2007	N/A	42.25	33,309	1,149	N/A	313	363	N/A	N/A	N/A	3,583	89.95	20.98
2008	N/A	43.09	33,585	1,203	N/A	319	374	N/A	N/A	N/A	3,687	91.30	21.29
2009	N/A	43.96	34,027	1,259	N/A	326	386	N/A	N/A	N/A	3,791	92.67	21.61
2010	N/A	44.84	34,411	1,319	N/A	333	397	N/A	N/A	N/A	3,893	94.06	21.93
2011	N/A	45.73	34,770	1,381	N/A	340	409	N/A	N/A	N/A	3,994	95.47	22.26
2012	N/A	46.65	35,145	1,444	N/A	347	421	N/A	N/A	N/A	4,094	96.90	22.60
2013	N/A	47.58	35,520	1,508	N/A	354	434	N/A	N/A	N/A	4,190	98.36	22.94
2014	N/A	48.53	35,895	1,575	N/A	361	447	N/A	N/A	N/A	4,283	99.83	23.28
2015	N/A	49.50	36,270	1,646	N/A	368	460	N/A	N/A	N/A	4,378	101.33	23.63
2016	N/A	50.49	36,645	1,719	N/A	375	474	N/A	N/A	N/A	4,471	102.85	23.98
2017	N/A	51.50	37,020	1,807	N/A	382	488	N/A	N/A	N/A	4,561	104.39	24.34
2018	N/A	52.53	37,395	1,896	N/A	389	503	N/A	N/A	N/A	4,650	105.96	24.71
2019	N/A	53.58	37,770	1,991	N/A	396	518	N/A	N/A	N/A	4,732	107.55	25.08
2020	N/A	54.65	38,145	2,090	N/A	403	534	N/A	N/A	N/A	4,815	109.16	25.46

Table A-7: List of Currently Licensed Electric and Natural Gas Suppliers and Brokers/Aggregators
(As of November 30, 2006)

Company	Electric Supplier License #	Electric Broker License #	N. Gas Supplier License #	N. Gas Broker License #
[1] ACN Energy, Inc.			IR-352	
[2] Affiliated Power Purchasers, Inc.		IR-279		
[3] Allegheny Energy Supply Company, LLC	IR-229			
[4] America PowerNet Management	IR-604			
[5] AOBA Alliance, Inc.		IR-267		IR-375
[6] Ashland Energy Services			IR-332	
[7] Association and Agency Consortium for Energy, LLC		IR-268		
[8] BGE Home Products and Services	IR-228		IR-311	
[9] Blue Star Energy Services	IR-757			
[10] BOC Energy Services	IR-753			
[11] Bollinger Energy Corporation		IR-265	IR-322	
[12] BP Energy Company			IR-676	
[13] BTU Energy				IR-864
[14] Co-eXprise, Inc.	IR-879		IR-879	
[15] Colonial Energy, Inc.			IR-606	
[16] Commerce Energy, Inc.	IR-639		IR-737	
[17] Compass Energy Services			IR-652	
[18] Competitive Energy	IR-895		IR-895	
[19] Conoco, Inc.			IR-378	
[20] Constellation Energy Projects & Services Group	IR-239			
[21] Consolidation Edison Solutions	IR-603			
[22] Constellation New Energy, Inc.	IR-500		IR-522	
[23] Constellation New Energy – Gas Division, LLC		IR-655		
[24] Coral Energy Gas Sales, Inc.			IR-360	
[25] CQI Associates, LLC		IR-575		
[26] Cypress Natural Gas			IR-674	
[27] Delta Energy, LLC			IR-645	
[28] Direct Energy Services	IR-719		IR-791	
[29] Dominion Retail, Inc.	IR-252		IR-345	
[30] Downes Associates, Inc.		IR-523		

Table A-7: List of Currently Licensed Electric and Natural Gas Suppliers and Brokers/Aggregators
(As of November 30, 2006)

[31] DTE Energy Trading, Inc.	IR-686			
[32] Eastern Shore of MD Educational Consortium Energy Trust		IR-342		
[33] Econnergy Energy Company	IR-340		IR-334	
[34] Energy Options, LLC		IR-568		
[35] Energy Services Management, LLC		IR-236		IR-312
[36] Energy Services Provider Group, LLC		IR-518		IR-519
[37] EnergyWindow, Inc.		IR-274		
[38] Enron Energy Marketing Corp.			IR-370	
[39] Enspire Energy			IR-814	
[40] Essential.com, Inc.	IR-259			
[41] FirstEnergy Solutions Corp.	IR-225			
[42] Glacial Energy, Inc.	IR-888			
[43] Hess Corporation	IR-219		IR-323	
[44] Hess Energy, Inc.			IR-337	
[45] HIS Power & Water, LLC	IR-271			
[46] Horizon Power & Light	IR-704			
[47] Houston Energy Services Company, LLC.			IR-403	
[48] Liberty Power Corporation	IR-607			
[49] Liberty Power, Maryland	IR-793			
[50] Marathon Oil Company			IR-364	
[51] Market Direct d/b/a MD Energy		IR-614		
[52] MeadWestvaco Energy Services, LLC	IR-669			
[53] Metromedia Energy, Inc.			IR-355	
[54] Metromedia Power, Inc.				IR-867
[55] Mid Atlantic Renewables	IR-856			
[56] Mid-Atlantic Aggregation Group Independent Consortium, LLC		IR-234		
[57] Mirant Americas Energy Marketing, LP.	IR-297			
[58] Mirant Americas Retail Energy Marketing, LP.	IR-480			
[59] Mona Building Technologies, LLC		IR-257		
[60] MxEnergy.com, Inc.			IR-327	
[61] National Energy Consortium		IR-928		IR-928
[62] Ohms Energy Company, LLC	IR-679			

Table A-7: List of Currently Licensed Electric and Natural Gas Suppliers and Brokers/Aggregators
(As of November 30, 2006)

[63] Pepco Energy Services, Inc. d/b/a Conectiv Energy Services	IR-222		IR-316	
[64] Pivotal Utility, Inc.			IR-376	
[65] PPL EnergyPlus, LLC	IR-230			
[66] Premier Energy Group		IR-942		IR-943
[67] Premier Power Solutions		IR-894		
[68] QVINTA, Inc.		IR-557		IR-530
[69] Richards Energy Group, Inc.		IR-818		
[70] Reliant Energy Solutions East, LLC	IR-525			
[71] Select Energy, Inc.	IR-275		IR-331	
[72] Sempra Energy Solutions	IR-442		IR-464	
[73] SmartEnergy.com, Inc.	IR-270			
[74] Smith Energy		IR-626		
[75] South River Consulting		IR-863		
[76] Sprague Energy Corp.				IR-339
[77] Stand Energy Corp.			IR-623	
[78] Statoil Natural Gas, LLC			IR-561	
[79] Strategic Energy, LLC	IR-437			
[80] South Jersey Energy Co.	IR-740			
[81] SUEZ Energy Resources	IR-605			
[82] The New Power Company IBM Global Services	IR-336			
[83] Tiger Natural Gas			IR-351	
[84] TransAlta Energy Marketing, Inc.			IR-474	
[85] Trigen-Baltimore Energy Corporation		IR-258		
[86] UGI Energy Services, Inc.	IR-237		IR-319	
[87] UtiliTech, Inc.		IR-915		IR-915
[88] Utility Resource Solutions			IR-613	
[89] VA Power Energy Mkting d/b/a Dominion Sales & Mkting, Inc.			IR-689	
[90] Washington Gas Energy Services, Inc.	IR-227		IR-324	
[91] World Energy Solutions, Inc.		IR-619		
[92] WPS Energy Services	IR-951			

No. of Suppliers/Brokers: ➡Electric Suppliers = 28; Electric Brokers = 17; Natural Gas Suppliers = 23; Natural Gas Brokers = 3, Electric & Natural Gas Suppliers = 14; Electric & Natural Gas Brokers = 7; Natural Gas Supplier & Electric Broker = 1; ➡ Total = 93.

Table A-8:
Transmission Enhancements by Service Area

									From Location		To Location	
Transmission Owner	#	Voltage (kV)	Length (Miles)	No. of circuits	Start Date	End	In-Service Date	Purpose	County	Terminal	County	Terminal
(PE)/Allegheny Power (AP)	1	230	0.1	1	2006	N/A	2006	BTR	N/A	Doubs	N/A	Lime Kiln (Section 207)
(PE)/Allegheny Power (AP)	2	138	0.1	2	2006	N/A	2006	GI	N/A	Kelso Gap (new)	N/A	Oak Park - Elk Garden
(PE)/Allegheny Power (AP)	3	230	0.1	1	2006	N/A	2006	BTR	N/A	Lime Kiln	N/A	Monocacy
(PE)/Allegheny Power (AP)	4	230	0.1	1	2006	N/A	2006	BTR	N/A	Lime Kiln	N/A	Montgomery
(PE)/Allegheny Power (AP)	5	230	0.1	1	2007	N/A	2007	BTR	N/A	Doubs	N/A	Lime Kiln (Section DLF1)
(PE)/Allegheny Power (AP)	6	230	0.1	1	2007	N/A	2007	BTR	N/A	Lime Kiln	N/A	McCain
(PE)/Allegheny Power (AP)	7	138	0.1	2	2007	N/A	2007	DA	N/A	McDade (new)	N/A	Halfway - Paramount No. 1
(PE)/Allegheny Power (AP)	8	138	0.1	2	2007	N/A	2007	DA	N/A	Paramount No. 1 (new)	N/A	McDade - Reid
(PE)/Allegheny Power (AP)	9	138	0.1	2	2007	N/A	2007	GI	N/A	Savage Mountain (new)	N/A	Garrett - Carlos Junction
(PE)/Allegheny Power (AP)	10	230	0.1	1	2007	N/A	2008	BTR	N/A	Frederick "A"	N/A	Monocacy
(PE)/Allegheny Power (AP)	11	138	5	1	2009	N/A	2009	DA	N/A	Clear Spring	N/A	Nipetown - Reid
(PE)/Allegheny Power (AP)	12	230	0.1	2	2009	N/A	2009	DA	N/A	Jefferson No. 1 (new)	N/A	Doubs - Monocacy
(PE)/Allegheny Power (AP)	13	230	0.1	2	2008	N/A	2009	DA	N/A	South Frederick No. 1 (new)	N/A	Monocacy - Lime Kiln
(PE)/Allegheny Power (AP)	14	230	0.6	2	2009	N/A	2010	DA	N/A	Ridgeville	N/A	Mt. Airy - Damascus
(PE)/Allegheny Power (AP)	15	230	2.1	2	2009	N/A	2010	DA	N/A	Urbana	N/A	Lime Kiln - Montgomery
(PE)/Allegheny Power (AP)	16	138	8	1	2010	N/A	2011	DA	N/A	Emmitsburg	N/A	Catoctin
(PE)/Allegheny Power (AP)	17	138	0.1	2	2010	N/A	2011	DA	N/A	Fairplay (new)	N/A	Marlowe - Boonsboro
(PE)/Allegheny Power (AP)	18	138	0.5	1	2014	N/A	2014	BTR	N/A	Black Oak	N/A	Cumberland
(PE)/Allegheny Power (AP)	19	230	7.8	1	2016	N/A	2016	BTR	N/A	Montgomery	N/A	Bucklodge (new)
BGE	1	230		1	Jul-06	Dec-06	N/A	BTR	N/A	Brandon Shores	N/A	Riverside
BGE	2	115		1	Jul-06	Dec-06	N/A	DA	N/A	Westport	N/A	Paca
BGE	3	115	4.7	1	Mar-07	May-07	N/A	DA	N/A	Westport	N/A	Center
BGE	4	115	1.44	1	Jan-06	May-07	N/A	OTH	N/A	Paca	N/A	Center
BGE	5	115	3.66	1	Mar-08	Jun-08	N/A	DA	N/A	Westport	N/A	Paca
BGE	6	115	3.4	2	Jan-07	Dec-08	N/A	TCA	N/A	Northwest	N/A	Finksburg
DPL	1	69	2.73	1	Jan-06	May-07	N/A	BTR	Maridel	N/A	Ocean City	N/A
DPL	2	69	5.32	1	Sep-04	Dec-07	N/A	DA	Grasonville	N/A	Stevensville	N/A
DPL	3	69	9	1	Sep-06	Dec-07	N/A	DA	Todd	N/A	Allen	N/A
DPL	4	69	11.13	1	Sep-07	May-08	N/A	DA	Easton	N/A	Bozman	N/A
DPL	5	69	2.5	1	Jan-09	May-10	N/A	BTR	Berlin	N/A	Worcester	N/A
DPL	6	138	12.98	1	Jan-10	May-11	N/A	BTR	Easton	N/A	Wye Mills	N/A
DPL	7	69	4.42	1	Jan-10	May-11	N/A	BTR	Vienna	N/A	Sharptown	N/A
DPL	8	69	4.6	1	Jan-11	May-12	N/A	BTR	Piney Grove	N/A	Mt. Olive	N/A
DPL	9	138	13.73	1	Sep-11	May-13	N/A	BTR	Vienna	N/A	Nelson	N/A
DPL	10	138	24	1	Jan-11	May-13	N/A	BTR	Church	N/A	Wye Mills	N/A
DPL	11	69	2.61	1	Jan-12	May-13	N/A	BTR	Ocean Bay	N/A	Maridel	N/A
DPL	12	500	43	1	Jan-10	Dec-14	N/A	MAPP	Calvert Cliffs	N/A	Vienna	N/A
DPL	13	230	28.28	1	Jan-10	Dec-14	N/A	MAPP	Vienna	N/A	Steele	N/A
DPL	14	230	18.7	1	Jan-10	Dec-14	N/A	MAPP	Vienna	N/A	Loretto	N/A
DPL	15	230	9.51	1	Jan-10	Dec-14	N/A	MAPP	Loretto	N/A	Piney Grove	N/A
DPL	16	500	35	1	Jan-10	Dec-14	N/A	MAPP	Vienna	N/A	Indian River	N/A
PEPCO	1	230	5	2	Jan-09	Jun-11	N/A	BTR	Palmers Corner	N/A	Blue Plains	N/A
PEPCO	2	230	5.34	1	Jan-11	Jun-13	N/A	BTR	Ritchie	N/A	Benning	N/A
PEPCO	3	500	33	1	Jan-10	Jan-14	N/A	MAPP	Possum Point	N/A	Burches Hill	N/A
PEPCO	4	500	19	1	Jan-10	Jan-14	N/A	MAPP	Burches Hill	N/A	Chalk Point	N/A
PEPCO	5	500	20	1	Jan-10	Jan-14	N/A	MAPP	Chalk Point	N/A	Calvert Cliffs	N/A
SMECO	1	230	26	2	2013	2014	N/A	DA	Calvert	Holland Cliff Sw. St.	Calvert	So. Calvert Sw. St.
SMECO	2	230	10.5	2	2015	2016	N/A	BTR	Calvert	So. Calvert Sw. St.	St. Mary's	Hewitt Road Sw. St.

Codes for Purpose:
BTR: Baseline Transmission Reliability
GI: Accomodation for Generator Interconnection
DA: Distribution Adequacy
TCA: Transmission Customer Adequacy
OTH: Other

Table A-9:
Renewable Generating Energy Projects Providing Capacity and Energy to Maryland Customers
(As of December 31, 2005)

Company	Name	Site Location	QF Status (Yes or No)	Fuel	Net Capacity (MW)	2005 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	Hydro, runoff from a water treatment plant	N/A	642
BGE	BRESCO (Baltimore Refuse Energy Systems Co.	Baltimore, MD	Yes	Refuse with Natural Gas	57	293103
Choptank	None	None	None	None	None	None
DPL	Amercian Hydro Power	Bay View, MD	Yes	Hydro	0.39	
DPL	Eastern Correctional Institute	Somerset county, MD	Yes	Wood Chips	4.4	
Easton Utilities	None	None	None	None	None	None
Hagerstown Light Department	None	None	None	None	None	None
PEPCO	Panda Brandywine L.P.[1]	Brandywine, Md	Yes	Natural Gas / Oil	230	575675
PEPCO	PG County Detention Center[1]	Upper Marlboro, MD	Yes	Landfill Methane Gas	2.55	6777
PEPCO	PG County Brown Station Rd. Landfill	Upper Marlboro, MD	Yes	Landfill Methane Gas	3.5	14818
Potomac Edison (PE) / Allegheny Power (AP)	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

[1]Agreement transferred to Mirant Corporation under back-to-back arrangements per Purchase Power Agreement (PPA) dated 12/19/2000. Not for serving load.

Table A-10
Power Purchase Agreements
(As of December 31, 2005)

Company	Name	Site Location	QF Status (Yes or No)	Fuel	Net Capacity (MW)	2005 Net Generation (MWh)
(PE)/Allegheny Power (AP)	None	None	None	None	None	None
BGE	Alternative Energy Associates (AEA)/Brighton Dam	Laurel, MD	Yes	Hydro, runoff from a water treatment plant	N/A	642
BGE	BRESCO (Baltimore Refuse Energy Systems Co.	Baltimore, MD	Yes	Refuse with Natural Gas	57	293103
Berlin	None	None	None	None	None	None
Choptank	None	None	None	None	None	None
DPL	Amercian Hydro Power	Bay View, MD	Yes	Hydro	0.39	
DPL	Eastern Correctional Institute	Somerset county, MD	Yes	Wood Chips	4.4	
DPL	Conectiv Energy Supply	System	No	System		9260316
DPL	Wholesale Suppliers	System	No	System		4063233
Easton Utilities	None	None	None	None	None	None
Hagerstown Light Department	None	None	None	None	None	None
PEPCO	Panda Brandywine L.P.[1]	Brandywine, Md	Yes	Natural Gas / Oil	230	575675
PEPCO	PG County Detention Center[1]	Upper Marlboro, MD	Yes	Landfill Methane Gas	2.55	6777
PEPCO	PG County Brown Station Rd. Landfill	Upper Marlboro, MD	Yes	Landfill Methane Gas	3.5	14818
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

[1]Agreement transferred to Mirant Corporation under back-to-back arrangements per Purchase Power Agreement (PPA) dated 12/19/2000. Not for serving load.

Table A - 11: Transmission cost Allocations for PJM RTEP

UpgradeID	Description	In Service Date	CostEstimate	APS	BGE	PEPCO	DPL	Maryland %	Maryland $	TransmissionOwner	State	UpgradeType
				Cost Allocation								
b0024	Construct new 230 kV circuit between Cardiff and Oyster Creek	6/29/2005 0:00	$58						N/A	AE	NJ	Transmission
b0039.2	PEPCO Reactive Upgrades	5/31/2005 0:00	$3						N/A	PEPCO	MD	Substation
b0039.5	Install Waugh Chapel 230kV 360MVAR capacitor bank	6/29/2006 0:00	$2						N/A	BGE	MD	Substation
b0040	Replace Doubs 500/230 kv transformer #1	12/31/2005 0:00	$4						N/A	AP	MD	Transformer
b0052.1	Add a second 10.2 MVAR at Montgomery 34.5 KV for a total of 20.4 MVAr (eff.)	6/15/2006 0:00	$0						N/A	AP	MD	Substation
b0052.2	5.1 MVAR cap at Boonsboro 34.5 KV	9/16/2004 0:00	$0						N/A	AP	MD	Substation
b0052.3	Add a second 10.2 MVAR cap at Mt. Airy 34.5 KV for a total of 20.4 MVAr (eff.)	10/27/2004 0:00	$0						N/A	AP	MD	Substation
b0052.4	Increase the 8.2 MVAr capacitor to 10.2 MVAR (eff.) at Antietam 34.5 KV	11/1/2004 0:00	$0						N/A	AP	MD	Substation
b0052.5	Install 10.2 MVAR (effective) 34.5 kV Capacitor at McCain Substation	2/2/2005 0:00	$0						N/A	AP	MD	Substation
b0053	Add a second 10.2 MVAr capacitor for a total of 20.4 MVAR (eff.) at Davis Mill 34.5 KV	8/3/2005 0:00	$0						N/A	AP	MD	Substation
b0054	Add 22 MVAR of capacitance at Ringgold 138 KV for a total of 66 MVAr (eff.)	6/30/2005 0:00	$0						N/A	AP	MD	Substation
b0085	Install third Branchburg 500/230 kV transformer	4/24/2005 0:00	$15					0%	$0.00	PSEG	NJ	Transformer
b0090	Add 150 MVAR capacitor at Camden 230 kV	7/14/2005 0:00	$1					0%	$0.00	PSEG	NJ	Substation
b0091	Replace Wavetrap on Doubs - Montgomery Tap 230 kV	5/6/2005 0:00	$0						N/A	AP	WV	Substation
b0115	Install 5% series reactor at Hyatt Station and install 29 MVAR capacitor at Trent 138 kV Station	7/12/2005 0:00	$1						N/A	AEP	OH	Substation
b0125	Add Special Protection Scheme at Bridgewater to automatically open 230 kV breaker for outage of Branchburg – Deans 500 kV and Deans 500/230 kV #1 transformer	7/29/2005 0:00	$0					0%	$0.00	PSEG	NJ	Substation
b0126	Replace wavetrap on Branchburg – Flagtown 230 kV	5/24/2005 0:00	$1					0%	$0.00	PSEG	NJ	Substation
b0129	Replace wavetrap on Flagtown – Somerville 230 kV C-2203 line	5/25/2006 0:00	$1					0%	$0.00	PSEG	NJ	Substation
b0130	Replace all de-rated Branchburg 500/230 kV transformers	5/19/2006 0:00	$20				2%	2%	$0.40	PSEG	NJ	Transformer
b0144.1	Build new Red Lion – Milford – Indian River 230 kV circuit	6/20/2006 0:00	$45				100%	100%	$44.91	DPL	DE	Transmission
b0144.2	Indian River Sub - 230kV Terminal Position	6/20/2006 0:00	$7				100%	100%	$7.47	DPL	DE	Substation
b0144.3	Red Lion Sub - 230kV Terminal Position	11/15/2005 0:00	$1				100%	100%	$0.97	DPL	DE	Substation
b0144.4	Milford Sub - (2) 230kV Terminal Positions	12/23/2005 0:00	$2				100%	100%	$2.10	DPL	DE	Substation
b0144.5	Indian River - 138kV Transmission Line for AT-20	5/26/2006 0:00	$0				100%	100%	$0.12	DPL	DE	Transmission
b0144.6	Indian River - 138 & 69kV Transmission Ckts. Undergrounding	4/18/2006 0:00	$4				100%	100%	$3.65	DPL	DE	Transmission
b0146.1	Replace Quince Orchard 230kV circuit breaker for line 23029	5/19/2006 0:00	$2						N/A	PEPCO	MD	Breaker
b0148	Re-rate Glasgow - Mt. Pleasant 138 kV and North Seaford - S. Harrington 138 kV	8/23/2004 0:00					100%	100%	$0.00	DPL	DE	Transmission
b0149	Complete structure work to increase rating of Cheswald - Jones REA 138 kV	12/14/2004 0:00					100%	100%	$0.00	DPL	DE/MD	Transmission
b0152.1	Add 1-230 kV breakers at High Ridge	6/1/2005 0:00	$1						N/A	BGE	MD	Breaker
b0152.2	Install 230kV breaker at High Ridge for line 2338	5/15/2006 0:00	$1						N/A	BGE	MD	Breaker
b0217	Upgrade Mt. Storm - Doubs 500kV	6/3/2006 0:00	$2	3%	15%	17%	5%	40%	$0.68	Dominion	WV/VA/MD	Transmission
b0220	Upgrade coolers on Wylie Ridge 500/345kV #7	4/18/2006 0:00	$0	0%	0%	11%	0%	11%	$0.04	AP	WV	Transformer
b0221	Replace disconnect switch on Edgewood - N. Salisbury 69kV	3/29/2006 0:00	$0	0%	0%	0%	100%	100%	$0.02	DPL	MD	Substation
b0222	Install 150 MVAR capacitor at Loudoun 500kV	5/31/2006 0:00	$2	0%	18%	19%	5%	42%	$0.63	Dominion	VA	Substation
b0223	Install 150 MVAR capacitor at Ashburn 230kV	5/31/2006 0:00	$1	0%	18%	19%	5%	42%	$0.42	Dominion	VA	Substation
b0224	Install 150 MVAR capacitor at Dranesville 230kV	5/31/2006 0:00	$1	0%	18%	19%	5%	42%	$0.42	Dominion	VA	Substation
b0225	Install 33 MVAR capacitor at Possum Point 115kV	5/31/2006 0:00	$1	0%	22%	23%	0%	45%	$0.27	Dominion	VA	Substation
b0226	Install 500/230kV transformer at Clifton and Clifton 230kV 150 MVAR capacitor	6/26/2006 0:00	$7	0%	9%	13%	2%	24%	$1.68	Dominion	VA	Transformer
b0240	Open the Black Oak #3 500/138kV transformer for the loss of Hatfield - Black Oak 542 500kV line	1/13/2006 0:00	$0	100%	0%	0%	0%	100%	$0.00	AP	WV	Transformer
b0249	Install 28 MVAR of 69kV bus capacitors at Bells Mill	12/2/2005 0:00	$1						N/A	PEPCO	MD	Substation
b0341	Install Breaker at Northern Neck 115 kV	4/10/2006 0:00	$1					0%	$0.00	Dominion	VA	Breaker
b0383	Wye Mills AT-1 and AT-2 138/69kV Replacements	6/6/2006 0:00	$2						N/A	DPL	DE	Transformer
b0384	Replace Indian River AT-20 (400 MVA)	6/12/2006 0:00	$4						N/A	DPL	DE	Transmission
b0390	Rehoboth/Lewes (6751-1 & 6751-2) upgrade	5/25/2006 0:00	$2						N/A	DPL	DE	Transmission
								Total	$63.78			

Table A - 12: Transmission Cost Allocations for PJM RTEP for Maryland Utilities									
UpgradeID	**Description**	**Cost ($ Millions)**	**IS Date**	**APS**	**BGE**	**PEPCO**	**DPL**	**Maryland %**	**Maryland $M**
b0217	Upgrade Mt. Storm - Doubs 500kV	$1.70	6/3/2006	3%	15%	17%	5%	40%	$0.68
b0383	Wye Mills AT-1 and AT-2 138/69kV Replacements	$2.29	6/6/2006						N/A
b0384	Replace Indian River AT-20 (400 MVA)	$3.74	6/12/2006						N/A
b0052.1	Add a second 10.2 MVAR at Montgomery 34.5 KV for a total of 20.4 MVAr (eff.)	$0.34	6/15/2006						N/A
b0144.1	Build new Red Lion – Milford – Indian River 230 kV circuit	$44.91	6/20/2006				100%	100%	$44.91
b0144.2	Indian River Sub - 230kV Terminal Position	$7.47	6/20/2006				100%	100%	$7.47
b0226	Install 500/230kV transformer at Clifton and Clifton 230kV 150 MVAR capacitor	$7.01	6/26/2006	0%	9%	13%	2%	24%	$1.68
b0039.5	Install Waugh Chapel 230kV 360MVAR capacitor bank	$1.70	6/29/2006						N/A
	Total Allocation For Planning Year Beginning June 1, 2006								**$54.74**
b0218	Install third Wylie Ridge 500/345kV transformer	$12.00	6/1/2007	3%	9%	8%	7%	27%	$3.24
	Total Allocation For Planning Year Beginning June 1, 2007								**$3.24**
b0230	Install fourth Meadowbrook 500/138 kV	$7.00	5/1/2008	60%	6%	6%	3%	75%	$5.25
b0244	Install a 4th Waugh Chapel 500/230kV transformer, terminate the transformer in a new 500 kV bay and operate the existing in-service spare transformer on standby	$26.30	5/31/2008		66%	34%		100%	$26.30
b0296	Rehoboth/Cedar Neck Tap (6733-2) upgrade	$1.70	5/31/2008				100%	100%	$1.70
b0169	Build a new 230 kV section from Branchburg – Flagtown and move the Flagtwon - Somerville 230 kV circuit to the new section	$10.00	6/1/2008				3%	3%	$0.30
b0171.1	Replace two 500 kV circuit breakers and two wave traps at Elroy substation to increase rating of Elroy - Hosensack 500 kV	$2.20	6/1/2008				11%	11%	$0.24
b0206	Install 161Mvar capacitor at Planebrook 230kV substation	$2.00	6/1/2008				18%	18%	$0.36
b0207	Install 161Mvar capacitor at Newlinville 230kV substation	$2.00	6/1/2008				18%	18%	$0.36
b0208	Install 161Mvar capacitor Heaton 230kV substation	$2.00	6/1/2008				18%	18%	$0.36
b0215	Install 230kV series reactor and 2- 100MVAR PLC switched capacitors at Hunterstown	$13.00	6/1/2008		6%	3%	8%	17%	$2.21
b0216	Install -100/+525 MVAR SVC at Black Oak	$35.00	6/1/2008	1%	15%	17%	4%	37%	$12.95
b0227	Install 500/230kV transformer at Bristers; build new 230kV Bristers - Gainesville circuit, upgrade two Loudoun - Brambleton circuits	$20.10	5/1/2009	3%	17%	19%	6%	45%	$9.05
b0229	Install fourth Bedington 500/138 kV	$7.00	5/1/2009	13%	13%	16%	3%	45%	$3.15
b0288	Brighton Substation - Add 2nd 1000 MVA 500/230kV transformer, 2 500kV circuit breakers and miscellaneous bus work	$21.00	5/31/2009		45%	55%		100%	$21.00
b0295	Raise conductor temperature of North Seaford - Pine Street - Dupont Seaford	$0.30	5/31/2009				100%	100%	$0.30

Table A - 12: Transmission Cost Allocations for PJM RTEP for Maryland Utilities (continued)

UpgradeID	Description	Cost ($ Millions)	IS Date	APS	BGE	PEPCO	DPL	Maryland %	Maryland $M
b0298	Replace both Conastone 500/230kV transformers with larger transformers	$42.50	5/31/2009		66%	34%		100%	$42.50
b0307	Reconductor Endless Caverns - Mt. Jackson 115 kV	$2.00	5/31/2009	19%	14%	16%	5%	54%	$1.08
Total Allocation For Planning Year Beginning June 1, 2008									**$127.11**
b0238	Reconductor Doubs - Dickerson and Doubs - Aqueduct 1200MVA	$9.60	6/1/2009		19%	31%	4%	54%	$5.18
b0241.3	Red Lion Sub - 500/230kV work	$12.63	6/1/2009				100%	100%	$12.63
b0245	Replacement of the existing 954 ACSR conductor on the Bedington - Nipetown 138kV line with high temperature / low sag conductor	$0.43	6/1/2009	24%	20%	24%		68%	$0.29
b0246	Rebuild of the Double Tollgate - Old Chapel 138kV line with 954 ACSR conductor	$1.95	6/1/2009	9%	15%	17%	6%	47%	$0.92
b0251	Install 100 MVAR of 230 kV capacitors at Bells Mill	$3.90	6/1/2009			100%		100%	$3.90
b0252	Install 100 MVAR of 230 kV capacitors at Bells Mill	$3.00	6/1/2009			100%		100%	$3.00
b0260	Replace Red Lion 230/138kV transformer	$5.50	6/1/2009				100%	100%	$5.50
b0261	Replace 1200 Amp disconnect switch on the Red Lion - Reybold 138kV circuit	$0.08	6/1/2009				100%	100%	$0.08
b0262	Reconductor 0.5 miles of Christiana - Edge Moor 138kV	$0.80	6/1/2009				100%	100%	$0.80
b0282	Install 46MVAR capacitors on the DPL distribution system	$1.20	6/1/2009				100%	100%	$1.20
b0284.1	Build 500 dV substation in PN - Tap the Keystone - Juniata and Conemaugh - Juniata 500kV, connect the circuits with a breaker and half scheme, and install new 400 MVAR capacitor.	$25.00	6/1/2009				12%	12%	$3.00
b0287	Install 600 MVAR Dynamic Reactive Device in the Whitpain 500kV vicinity	$27.00	6/1/2009				18%	18%	$4.86
b0291	Replace 1600A disconnect switch at Harmony 230 kV and for the Harmony - Edgemoor 230kV circuit, increase the operating temperature of the conductor	$0.85	6/1/2009				100%	100%	$0.85
b0228	Upgrade Burtonsville - Sandy Springs 230kV curcuit	$0.40	5/1/2010		60%			60%	$0.24
b0369	Install 100 MVAR Dynamic Reactive Device at Airydale 500dV substation	$8.00	5/1/2010		7%	4%	8%	19%	$1.52
b0312	Reconductor Gallows to Ox 230 kV	$3.00	5/31/2010	4%	5%	6%	3%	18%	$0.54
b0263	Replace 1200 Amp wavetrap at Indian River on the Indian River - Frankford 138kV line	$0.20	6/1/2010				100%	100%	$0.20
b0269	Install a new 500/230kV substation in PECO, and tap the high side on the Elroy - Whitpain 500kV and the low side on the North Wales - Perkiomen 230kV circuit	$25.50	6/1/2010				13%	13%	$3.32
b0269.1	Add a new 230kV circuit between Whitpain and Heaton substations	$21.65	6/1/2010				13%	13%	$2.81
b0269.2	Reconductor the Whitpan 1 - Plymtg 1 230kV circuit	$1.50	6/1/2010				13%	13%	$0.20
b0269.3	Convert the Heaton bus to a ring bus	$4.10	6/1/2010				13%	13%	$0.53
b0294.4	Reconductor the Heaton - Warminster 230kV circuit	$2.50	6/1/2010				13%	13%	$0.33
b0269.5	Reconductor Warminster - Buckingham 230kV circuit	$1.75	6/1/2010				13%	13%	$0.23

Table A - 12: Transmission Cost Allocations for PJM RTEP for Maryland Utilities (continued)									
UpgradeID	Description	Cost ($ Millions)	IS Date	APS	BGE	PEPCO	DPL	Maryland %	Maryland $M
b0272.1	Replace line trap and disconnect switch at Keeney 500kV Substation - 5025 Line Terminal Upgrade	$0.21	6/1/2010				34%	34%	$0.07
b0272.2	Replace a wave trap and potential transformer at Rock Spring 500kV substation - 5025 Line Terminal Upgrade	$0.20	6/1/2010				34%	34%	$0.07
b0290	Install 400MVAR capacitor in the Branchburg 500kV vicinity	$9.00	6/1/2010				18%	18%	$1.62
b0320	Create a new 230kV station that splits the 2nd Milford to Indian River 230kV line. Add a 230/69kV transformer and run a new 69kV line down to Harbeson 69kV.	$12.80	6/1/2010				100%	100%	$12.80
b0321	Install a new Prexy 500kV substation and Prexy to 502 Junction 500kV circuit	$120.00	6/1/2010	100%				100%	$120.00
b0327	Build 2nd Harrisonburg - Valley 230kV	$5.00	6/1/2010	20%	8%	8%	3%	39%	$1.95
b0366	Install 4th ritchie 230/69kV transformer	$11.50	5/1/2011			100%		100%	$11.50
b0367.1	Reconductor circuit 23035 for Dickerson-Quince Orchard 230kV	$3.75	5/1/2011		21%	33%	5%	59%	$2.21
b0367.2	Reconductor circuit 23033 for Dickerson-Quince Orchard 230kV	$3.75	5/1/2011		19%	30%	6%	55%	$2.06
b0370	Install 500 MVAR Dynamic Reactive Device at Airydale 500kV substation	$22.00	5/1/2011		7%	4%	8%	19%	$4.18
b0268	Reconductor the 8 mile Gilbert - Glen Gardner 230kV circuit	$7.00	6/1/2011				1%	1%	$0.07
b0319	Add a second 1000 MVA Burches Hill 500/230kV transformer	$31.60	6/1/2011		26%	74%		100%	$31.60
b0322	Convert Lime Kiln substation to 230kV operation	$4.20	6/1/2011	100%				100%	$4.20
b0323	Replace the North Shenandoah 138/115kV transformer	$2.00	6/1/2011	29%	13%	14%	5%	61%	$1.22
b0328.1	Build new Meadowbrook - Loudoun 500kV circuit (30 or 50 miles)	$130.00	6/1/2011		19%	21%	6%	46%	$59.80
b0328.2	Build new Meadowbrook - Loudoun 500kV circuit (20 or 50 miles)	$90.00	6/1/2011		19%	21%	6%	46%	$41.40
b0328.3	Upgrade Mt. Storm 500kV substation	$10.00	6/1/2011		19%	21%	6%	46%	$4.60
b0328.4	Upgrade Loudoun 500kV substation	$10.00	6/1/2011		19%	21%	6%	46%	$4.60
b0338	Replace Gordonsville 230/115kV transformer for larger one	$3.00	6/1/2011	3%	11%	12%	4%	30%	$0.90
b0343	Replace Doubs 500/230kV transformer #2	$5.20	6/1/2011		19%	23%	6%	48%	$2.50
b0344	Replace Doubs 500/230kV transformer #3	$5.20	6/1/2011		19%	23%	6%	48%	$2.50
b0345	Replace Doubs 500/230kV transformer #4	$5.30	6/1/2011		19%	23%	6%	48%	$2.54
b0347.1	Build new Mt. Torm - 502 Junction 500kV circuit	$288.00	6/1/2011		19%	21%	6%	46%	$132.48
b0347.2	Build new Mt. Storm - Meadowbrook 500kV circuit	$252.00	6/1/2011		19%	21%	6%	46%	$115.92
b0347.3	Build new 502 Junction 500kV substation	$50.00	6/1/2011		19%	21%	6%	46%	$23.00
b0347.4	Upgrade Meadowbrook 500kV substation	$20.00	6/1/2011		19%	21%	6%	46%	$9.20
b0348	Upgrade Stonewall - Inwood 138kV with 954 ACSR conductor	$1.60	6/1/2011	16%	16%	17%	6%	55%	$0.88
b0373	Convert Doubs - Monocacy 138kV facilities to 230kV operation	$9.40	6/1/2011	88%				88%	$8.27
b0375	Install 0.5% reactor at Dickerson on the Pleasant View - Dickerson 230kV circuit	$5.00	6/1/2011		19%	26%	6%	51%	$2.55
b0376	Install 300MVAR capacitor at Conemaugh 500kV substation	$2.00	6/1/2011		8%	5%	9%	22%	$0.44