PUBLIC SERVICE COMMISSION
OF MARYLAND

TEN-YEAR PLAN
(2005 – 2014)
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

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

[The Commission's Integrated Resource Planning 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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I. INTRODUCTION

This report constitutes the Maryland Public Service Commission's (Commission or PSC) Ten-Year Plan (2005 - 2014) 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 first auctions pertaining to electric companies that resulted from the Standard Offer Service proceedings (Case Nos. 8908 and 9037) and gives an update on the competitive activities of licensed electricity and gas suppliers.

Section III provides information on distribution reliability in Maryland, including utility responses to major storms and blackouts. Topics covered also include the management of distribution outages 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 2005 included the filing 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. In 2005, two new regional organizations were formed: Reliability*First*, to ensure transmission reliability; and the

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1 Section 1-101(h) of the Public Utilities 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.

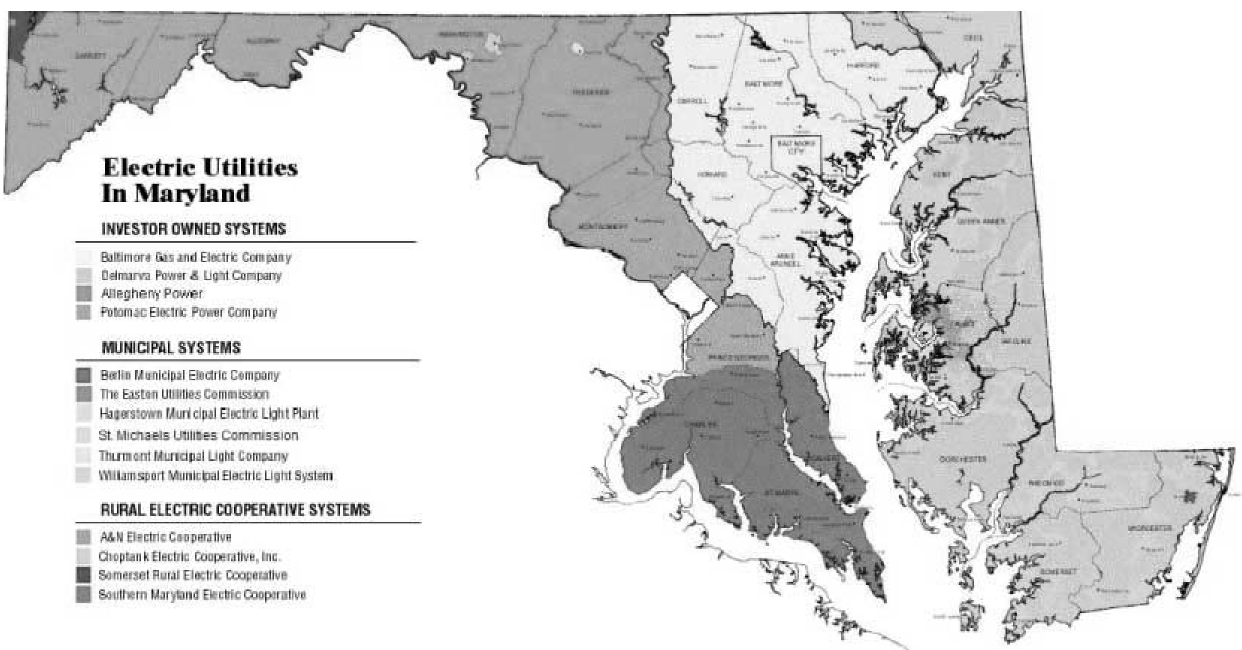
Organization of PJM States, Inc. (OPSI), to foster discussion and cooperation among the utility regulatory commissions and agencies in the PJM region.

Section V provides a summary of utility efforts since January 1, 2005, to implement conservation programs and to promote and utilize renewable resources and cogeneration. Implementation of the Renewable Energy Portfolio Standard Legislation is a significant topic that is discussed in this section.

Section VI presents information on national energy issues that have an impact on Maryland. Important topics this year include the passing of the Energy Policy Act of 2005 (EPAct 2005) by the United State Congress and the impacts of the severe Gulf of Mexico hurricanes on commodity prices and energy infrastructure.

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 electric and natural gas suppliers and brokers in Maryland 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, six municipal systems, and four electric cooperative systems, two of which are rate-regulated.



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]

A. Movement to Retail Electric Choice in Maryland

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 electric 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, 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 electricity 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, 2005, the Commission has issued 37 electricity supplier licenses, 18 electricity broker licenses, 36 natural gas supplier licenses, and 5 natural gas broker licenses; among these, 17 companies had both electricity and natural gas licenses (see Appendix Table A-7).

6 PUC Article §7-603(b).

Electric service is currently available to many classes of Maryland customers via SOS. Among the four large investor owned utilities (IOUs)[7] only residential customers of BGE and 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.

In response to customers' inquiries regarding active licensed electricity suppliers in Maryland, the Commission sent out a notice on June 15, 2004, to all licensed electricity suppliers requesting that they indicate whether they are actively seeking new customers. The Commission approved changes to the appearance of the Electricity and Natural Gas Supplier lists that appear on its website. The revised website now allows customers to search for suppliers by service, customer class, and service territory. These searches replaced the prior static lists that grouped all electricity and natural gas suppliers together in separate master lists. The Commission recognized that a supplier's "Actively Seeking" status may change from time to time and wanted to make the process as interactive and timely as possible. The Commission has received responses from several electricity suppliers indicating that they are actively seeking new customers. As of November 30, 2005, the following list indicates the number of companies in Maryland that have voluntarily registered on the Commission's website as actively soliciting new customers in any service territory: 2 serving residential load, 14 serving industrial load, 16 serving commercial load, and 5 serving other types of load (such as government).

On September 9, 2004, the Commission sponsored its first Electric Supplier Orientation Conference in order to continue to promote retail competition in Maryland. This event attracted nearly one hundred attendees representing more than 40 organizations including licensed and prospective Maryland suppliers, staff from the Commission and other State agencies, PJM, and customer groups. The conference updated attendees on the status of Electric Choice, provided guidance on the steps needed to become a licensed supplier or broker, and informed them about consumer protections and other changes to the Code of Maryland Regulations (COMAR). The Commission is considering holding a second Retail Electric Supplier Conference during 2006.

B. Status of Retail Electric Choice

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.

[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).

On July 12, 2002 the Commission published in the *Maryland Register* regulations governing electric 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 1 below 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. Recent statewide trends continued during 2005. While the percentage of peak load obligation served by electricity suppliers dipped once again for residential customers, this decline was more than offset by more switches away from the utilities to electricity suppliers by mid and large sized customers. Electricity suppliers now serve approximately half of the peak load for all types of commercial and industrial customers and 27% of peak load for all customers.

Table 1: Electric Choice Enrollment in Maryland

Number of Customers Served by Electricity Suppliers

Utilities	Residential	Small C&I[8]	Mid C&I[9]	Large C&I[10]	All C&I	Total
AP	0	41	278	54	373	**373**
BG&E	30	1,058	2,270	574	3,902	**3,932**
Delmarva	155	1,566	204	83	1,853	**2,008**
Pepco	28,470	3,861	3,438	410	7,709	**36,179**
Total	**28,655**	**6,526**	**6,190**	**1,121**	**13,837**	**42,492**

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%	1.1%	22.6%	54.8%	31.2%	**13.7%**
BG&E	0.0%	1.9%	30.6%	92.9%	51.4%	**27.5%**
Delmarva	0.1%	8.2%	32.3%	96.0%	43.2%	**20.4%**
Pepco	7.5%	15.0%	30.1%	87.6%	53.9%	**33.0%**
Total	**1.9%**	**4.1%**	**30.0%**	**88.2%**	**49.9%**	**27.0%**

Source: Public Service Commission of Maryland, *Electric Choice Enrollment Monthly Report*, Month Ending October 2005. 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.

COMAR 20.53, which pertain to consumer protections for residential customers, became fully effective during 2005. The Consumer Protection Regulations contain the requirements of previous Commission orders with adjustments, where appropriate, to accommodate development

8 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 if they do not switch to a supplier.

9 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 No. 9037 to see which customers will be eligible for either Type II-A or Type II-B SOS for the June 1, 2006 to May 31, 2007 period.

10 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.

in the supplier markets that has occurred since the issuance of those orders. The Consumer Protection Regulations address the following issues: privacy policies, non-discrimination requirements, responsibility for enrollment and the problem of unauthorized enrollment, methods of advertising and contracting, minimum contract requirements, billing and payment posting priority, and contract cancellation.

As a complement to COMAR 20.53, the Commission is currently considering two sets of regulations that would pertain to competitive electricity suppliers and competitive gas suppliers and their relationship with non-residential customers. These regulations also address certain supplier-utility coordination issues. Work on the proposed regulations is the ongoing subject of Commission Rulemaking RM 17. The regulations have not yet been approved for publication.

During 2005, the Commission continued to meet with representatives of utilities, their affiliates and third party energy suppliers that are competitors of utility retail affiliates, and the Maryland Office of People's Counsel (OPC) in a series of meetings to draft new regulations to regulate the relationship between utilities and their affiliates. These proposed regulations, which contain a code of conduct for utilities and affiliates, are designed to promote competitive supply markets and to ensure utilities do not subsidize their affiliates. The proposed regulations, which are the ongoing subject of Commission RM 15, have been published in the *Maryland Register*, but not yet finally adopted.

C. Standard Offer Service - Case Nos. 8908/9037, 8985, and 8987

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 the current utility fixed price offers. The fixed price offers have expired with the exception of BGE residential customers, for whom they remain in effect until July 1, 2006, and 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 electric supply to their customers. The Order approved the settlement that establishes the procurement and pricing methodology for this service. SOS is the alternative 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. It 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. 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 electric 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 electric supply to meet their SOS obligations. For the initial SOS procurement to solicit bids to serve load for 2004-2005, the bidding rounds began in February 2004 and concluded in March 2004. Supply services under these contracts began as early as June 1, 2004, and approximately 6,200 megawatts (MW) were available for bid. The contracts for electric supply by type of service were Residential – one, two, and three years; Type I Non-residential – one and two years; and Type II and III Non-residential – one year.

For the second SOS procurement to solicit bids to serve load for 2005-2006, the bidding rounds began in December 2004 and concluded in February 2005. Supply services under these contracts began as early as June 1, 2005, and approximately 3,590 MW were available for bid. Listed below is a summary of the second 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 – 1,055 MW of one-year contracts;
- Type I SOS Non-residential – 730 MW of one-year contracts; and,
- Type II SOS Non-residential – 1,806 MW of one-year contracts.

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

- October 2004**:** The utilities held a joint pre-bid conference in Baltimore; over 30 suppliers attended and/or showed interest in this process;
- November 2004: 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" were also held of the bid-day evaluation process; and,
- December 2004 - February 2005: Bids for each tranche; blocks offered are currently fully subscribed in all four utilities.

The summary results of the second RFP bid process were as follows:[11]

- The utilities conformed to their Bid Plans as required by Commission Orders, and there were appropriate security measures on all bid days.

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

- There were 20 eligible bidders in this process of which 18 suppliers actually submitted bids and eight (8) suppliers won some portion of the load offered this year. Starting June 2005, nine (9) different suppliers will be serving SOS customers.
- There was evidence of robust competition in terms of the number of bidders as well as the number of bids received.
- On average, the number of MWs that bidders offered was over eight times greater than the number of MWs awarded compared to under five times in last year's solicitation. This also demonstrates robust competition in the bidding process. Another indication of robust competition is the fact that there was a wide range of bid prices.
- The bid prices reflected general economic conditions including high and rising prices for the fuels used to produce electricity.

For the third SOS procurement to solicit bids to serve load for 2006-2007, the bidding rounds began in December 2005 and will conclude in February 2006. The RFP will again include up to four rounds for supply services to commence June 1, 2006 (July 1, 2006 for BGE Residential). In addition, there will be another round in June 2006 to procure Type II-A non-summer load. The joint-utility pre-bid conference was held on October 19, 2005, 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 2006-07 procurement of SOS bids will be for approximately 7,540 MW of one-, two- and three-year contracts, including:

- 280 MW for AP, 4,830 MW for BGE, 630 MW for Delmarva and 1,800 MW for Pepco.
- 4,795 MW Residential, 1,225 MW Type I, 475 MW Type II-B and 1,045 MW Type II-A.

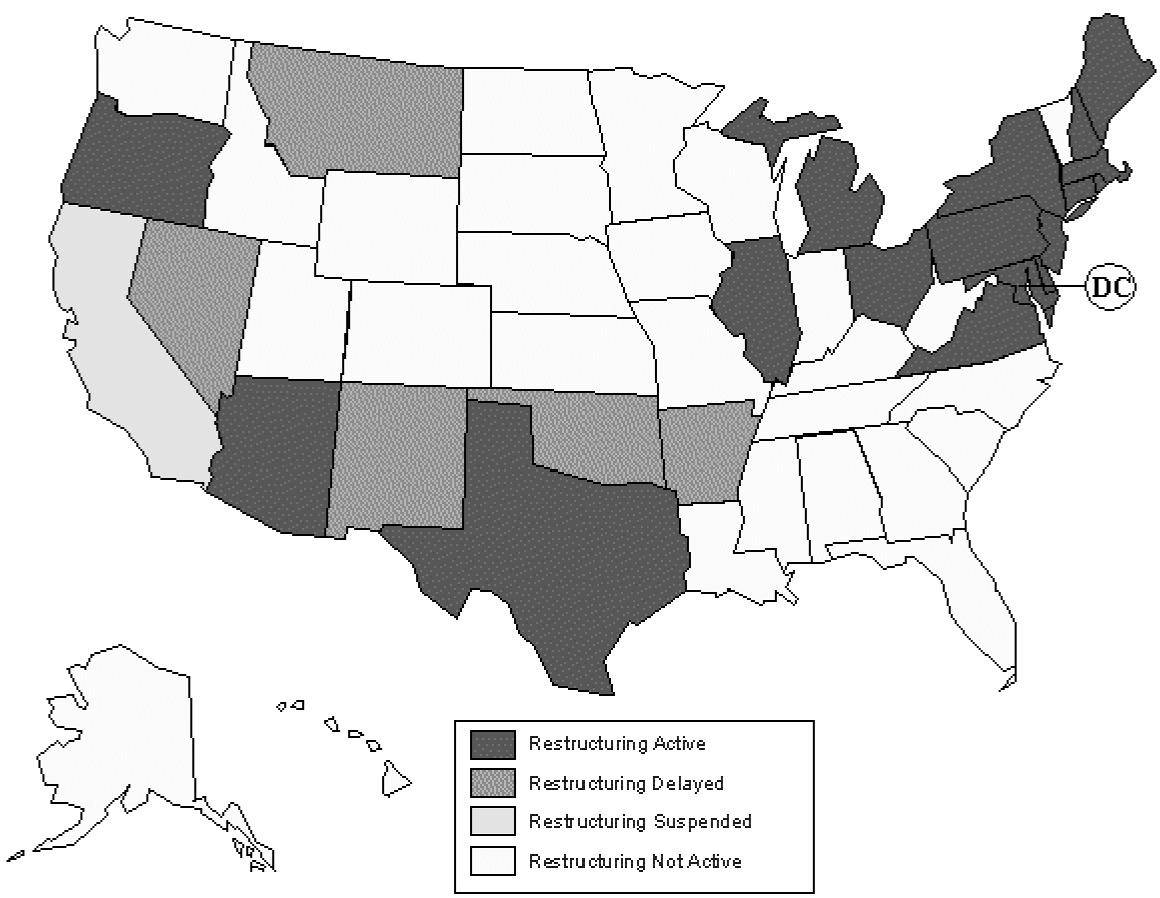
On May 26, 2005, the Commission docketed Case No. 9037*, In the Matter of Default Service for Type II Standard Offer Service Customers*. The Phase I settlement of Case No. 8908 had a provision for the Commission to docket a major policy review proceeding covering this type of SOS service. During June and July 2005, parties filed interventions, settlements or proposals, and direct and rebuttal testimony. Hearings were held on August 2-3, 2005 and initial and reply briefs were filed later in the month. 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 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 that Choptank will provide SOS was extended by five years, beginning on July 1, 2005, and ending on June 30, 2015.

D. National Retail Access Activities

Currently, retail electricity access (electric restructuring) is available in 18 states in the nation (including the District of Columbia). The states offering retail access enacted restructuring legislation or issued regulatory orders to achieve that goal. Five (5) 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 (27) are not 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.[12]



[12] Source: Energy Information Administration website, *Status of State Electric Industry Restructuring Activity*, (as 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, so customers calling in who are affected by a particular ongoing outage may be kept informed.
- Information concerning outages can be extracted from the OMS in near real-time to feed Internet 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 SMECO have implemented an OMS, each with functionality developed generally to the extent described above.

Choptank's OMS is less integrated and automated, but achieves similar functionality using more manual and paper-driven operations than a fully developed, computerized system. The same is true for the outage management processes of Maryland's smaller municipal electric utilities and rural electric cooperatives.

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 due to 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. The Commission recognized this role in Order No. 79159, issued June 4, 2004, following the Isabel storm of 2003. Citing certain shortcomings of utility communication with emergency management officials during the Isabel storm, the Commission ordered each electric utility to hold meetings with emergency management agencies "to discuss how utilities and local emergency management officials can better collaborate during emergency response planning exercises and during storm or disaster restoration." The utilities and the Staff of the Commission's Engineering Division (PSCED) were also directed to meet with the Maryland Emergency Management Agency (MEMA) for a similar collaborative effort.

The meetings were held as directed and led to, or strengthened existing efforts to achieve, the following sampling of benefits:

- A stronger, more cooperative relationship and better communication between utilities and local emergency management agencies of the counties and municipalities served by both;

- Some utilities revised and strengthened their policies and procedures to address the special needs of customers with medical conditions who need priority in service restoration;
- Several utilities maintain internet websites for displaying near real-time outage information and maps; and,
- Inclusion of critical elements of utility electric systems into the Emergency Management Mapping Application, a GIS-based resource used by MEMA and the local emergency management agencies during emergency events.

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.

On 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 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[13] 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 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.

The annual Summer Reliability Conference was held at the Commission on May 9, 2005. Maryland 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 reliably meet the peak summer load demand. No significant shortcomings were encountered in that regard during the 2005 summer. In addition, the utilities gave details of their Demand-Side or Active Load Management programs for load management during periods of high electricity use.

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

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, trees were involved with at least 52% of the almost 1.7 million outages associated with the Isabel storm of 2003 occurring within the service areas of the four large investor-owned utilities.[14]

Several utilities, as well as a report by the Maryland Department of Natural Resources (DNR), noted that most utility problems during Isabel were caused by whole-tree failures with the trees falling from private property.[15] In addition, the DNR report indicated that within Maryland the highest density of trees, including a large percentage of trees with physical defects capable of damaging overhead power lines, occurs in the Baltimore-Washington corridor. This area lies primarily within the service territory of BGE and Pepco, the two utilities operating within Maryland with the highest percentages of tree-related outages during Isabel.[16]

Trees receive much public attention during and immediately following major storms such as Isabel, but large trees cause significant numbers of electric service interruptions throughout any given year. Over the past few years, Allegheny Power has maintained records of electric service outages caused specifically by off right-of-way trees within the AP service territory in Maryland. For 2004, a relatively mild weather year, AP indicates that trees caused about one-fourth of total customer interruptions in its Maryland territory, of which almost 90% were caused by trees growing outside the utility's right-of-way that fell into the power lines.

In Order No. 79159 following Isabel, the Commission recognized the ongoing efforts of the Maryland Electric Reliability Tree Trimming Council (MERTT Council)[17] to deal with the problem of outages caused by privately-owned trees 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 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.

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14 As shown by the Major Storm Reports filed by the utilities after Isabel.

15 Commission Order No. 79159 at page 27, in Case No. 8977.

16 *Ibid.*

17 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.

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." While the other utilities in Maryland may not have at this time as much formal data as AP concerning privately-owned tree risk to overhead lines, all have certainly felt the magnitude of the problem, both during major storms such as Isabel and on an ongoing basis throughout each year.

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. While the MERTT Council and others have worked to spread the word about the "Right Tree, Right Place" concept, the MERTT Council continues to consider how to reconcile the appreciation of an urban tree canopy with the need to protect the power lines.

It is likely that the problems associated with currently existing large trees near power lines will take care of themselves, if they must. 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.

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 electric system projects and programs, ongoing, planned or in development by Maryland's large electric companies, follow.

1. Central Maryland -- BGE

- 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.
- 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.
- Upgrades to the High Ridge substation are being made to address load growth in southern Howard County. Completion is expected in mid-2006.
- Construction of two Otter Point sub-transmission circuits in Harford County to address load growth in the area and enhance reliability. The circuits are expected to be in service by mid-2006.
- Marriott Hill substation transformer upgrade to ensure the load carrying capability to serve southern Anne Arundel County and part of Calvert County. This project is scheduled for completion by the close of 2006.
- Several transmission circuit breaker replacements have been made at the Calvert Cliffs Nuclear Power Plant and the Erdman, Greene Street, and High Ridge substations.
- Installation of transmission capacitors at the Northwest and Waugh Chapel substations--to be completed in 2005 and 2006, respectively.
- 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.

2. Central Maryland -- Pepco

- Pepco has begun installation of automatic circuit re-closing breakers on the least reliable of distribution feeders.
- Construction of the Ammendale Road Area substation and the Darnestown Road Area substation to address load growth in Prince George's County and Montgomery County, respectively.

- Replacement or additions of distribution transformers at the Metzerott Road East, Ritchie, Bells Mill, Gaithersburg, Sligo, Oak Grove, and Quince Orchard substations to address load growth in Prince George's and Montgomery Counties. The projects are scheduled for completion between 2008 and 2011.
- Two high voltage circuit breakers scheduled for installation by mid-2006 at the Quince Orchard substation, with two additional circuit breakers scheduled for installation by summer 2008.
- Extend transmission lines from the Palmers Corner substation to the Blue Plains substation, to benefit southwestern Prince George's County. Completion of the project is scheduled for mid-2007.
- Upgrade high voltage breakers at the Dickerson and Oak Grove substation by June 2006 to provide increased protection against short circuits affecting those substations.
- Installation of high voltage capacitors at the Bells Mill, Quince Orchard, and Norbeck substations by June 2006 to improve voltage and power quality for Maryland areas.

3. Western Maryland -- Allegheny Power

- Construction of McDade substation, 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.
- Install new overhead electric wire on the main line of the Turkey Neck feeder, to provide additional capacity and improved voltage quality to the area around Deep Creek Lake. Project completion is expected to be August 2006.
- Upgrade facilities at the Montgomery substation to provide additional capacity for the Clarksburg, Maryland area, with project completion expected by mid-2006.
- 64 feeder circuits in Maryland are scheduled to receive additional sectionalizing equipment to minimize the number of customers affected by a given outage.
- Construction of a transmission line from the Black Oak substation that will address load growth around Cumberland, with completion expected in 2014.
- Construction of a high voltage switching station and line to the Montgomery substation to address load growth in west-central Maryland, with completion in 2014.
- Conversion of Doubs-Monocacy transmission line to higher voltage to provide better transmission service for west-central Maryland, to be completed in 2007.
- Construction of the Emmitsburg substation and high voltage transmission line to provide additional capacity for serving the area surrounding Emmitsburg, Maryland--planned to be put in service during 2008.

4. Eastern Shore -- Delmarva Power

- Construction of the Jacktown distribution substation, due to be completed in May 2007, is expected to address load growth in the Salisbury area.
- Establishment of the Price substation, to be completed by the close of 2007, is expected to provide load relief around the Centreville area.

- Recently converted approximately 300 kilovolt-amperes (kVA) of electric load from a distribution voltage level of 4kV to 34kV to address the potential for circuit overloading due to demand in Cecil and Harford counties.
- Extension of the number 3486 feeder from the Cecil substation to address load growth in the Elkton area, to be completed by May 2007.
- Capacitors to maintain the proper level of voltage on distribution feeders have recently been installed throughout Cecil and Harford counties.
- Upgrades were completed at the Grasonville and Trappe substations to address potential overloads due to electric load demand in several Eastern Shore counties in Maryland.
- Upgrades were recently made to the Colora transmission line and the North Salisbury to Fruitland transmission line to increase transmission capacity.
- Construction of transmission lines for transmission reliability and distribution adequacy, with expected completion dates:

  Grasonville to Stevensville, December 2006
  Maridel to Ocean City, May 2007
  Easton to Bozman, May 2008
  Piney Grove to Mt. Olive, May 2009
  Ocean Bay to Maridel, May 2010
  Easton to Wye Mills, May 2010
  Vienna to Sharptown, May 2011
  Vienna to Nelson, May 2013

5. Eastern Shore -- Choptank

- The new Oil City substation, supplied at a transmission-level voltage, is expected to be in service in early 2006 to serve electric load in and around Denton. The Oil City substation will feed and is expected to provide more reliable service to Choptank's Hobbs and Hickman distribution substations currently fed by a Delmarva substation.
- Choptank is planning to construct a new Hillsboro substation, to be supplied at a transmission-level voltage, to replace the current substation that is supplied by a Delmarva distribution feeder. Expected to be in service near the end of 2007, the substation will serve load and provide better reliability of service to the Hillsboro and Queen Anne areas.
- Choptank is planning to construct a new substation in the Cambridge area to increase reliability and serve electric load in southern Dorchester County. Plans are to have the substation in service by the end of 2007.
- Construction of a transmission line from the Oil City substation to the Williston substation, to be completed in 2009. The project is expected to improve reliability of service in Caroline County.
- Choptank is currently pursuing a transmission solution to Delmarva Power's reliability and power quality problems at Choptank's Allen substation near Federalsburg, Maryland.
- Construction of a parallel transmission line into the Ocean Pines area is expected to double the available capacity and increase reliability to the Ocean Pines area. The project is planned for completion in 2009.

- Recently completed a multi-year program to inspect every pole in the distribution system for structural integrity.
- Implemented an automated mapping/facilities management system to provide information needed for preventative maintenance, right-of-way clearing and planned equipment replacements.
- Work is continuing on a multi-year project to improve the electrical grounding of substations throughout the distribution system. This effort is expected to reduce damage and outages due to lightning strikes.
- A ten-year program to replace aging re-closing circuit breakers on feeder lines continues, with completion expected in 2009.

6. Southern Maryland -- SMECO

- Scheduled to energize two new distribution feeders by early 2006 to serve new electric load – one feeder will be from the Hollywood substation and one from the St. Charles substation.
- Upgrades have been made to the transmission circuit from the Sunderland substation to the Mount Harmony substation in northern Calvert County.
- Cable replacement has recently been completed on the 6770 circuit, for which a submarine portion across the Patuxent River had failed in early 2005.
- Began phasing in a full-featured computerized OMS in November 2005. Most features of the OMS are expected to be operational in 2006.

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 the Commission continues its ongoing review of the maintenance and operation of electric utility transmission facilities in the State. The Commission held its annual Summer Reliability Status Conference on May 9, 2005. During this conference, Maryland's utilities filed comments concerning their ability to meet summer 2005 anticipated electricity demand. PJM also reported on its ability to maintain the grid. Although the summer was relatively hot in 2005, after several relatively mild summers, there were no major problems in meeting the demand for electricity. However, the hot summer did contribute to higher spot wholesale electricity prices in the State, in part due to congestion contributed to by under-investment in major backbone transmission projects in PJM.

A. Current Maryland Generation Profile and Recent Unit Retirements

Many older generating units within PJM can no longer compete with newer, more efficient plants. Also, due to the relatively mild weather during the summers of 2003 and 2004, many marginal units did not make enough money to justify maintenance costs. NRG's plant in Vienna, MD, for instance, has commenced seasonal operations, whereby it is only operated during the months when it has historically been dispatched. Table 2 lists the current profile of Maryland-based generating units:

Table 2: 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	872.6	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	125.8	1.0%	49.4%	5.3%	45.3%	0.0%
TOTAL	**12,485.7**	**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[18] 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

[18] Ownership breakdown of Maryland coal facilities: 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.

(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 2003, Maryland plants produced 52,244 gigawatt-hours (GWh) of electricity,[19] generated 57.3% by coal and 26.2% by nuclear plants. Thus, Maryland coal and nuclear facilities generate 83.5% of all electricity, although they represent only 53.6% of capacity. In contrast, oil and gas facilities generate but 9.7% of all electricity, despite representing 40.9% of instate capacity. The State remains a net importer of electricity. In 2003, Maryland retail sales were 71,259 GWh,[20] meaning that 19,014 GWh (26.7%) of electricity were imported from neighboring states over the transmission grid.

During 2003, PJM analyzed the impact of the retirement of Baltimore City's Gould Street generator (104 MW), effective November 1, 2003. There were no identified reliability problems for the winter or summer of 2004. No system reinforcements were identified as a consequence of the retirement. Examination of the unit's impact on PJM energy and ancillary markets indicated no problems. No generating plant retirements in Maryland were announced during 2004 or 2005. Nonetheless, there remains the possibility that some units of the Maryland-based generating fleet could retire on short notice during the next several years, either for economic or environmental reasons. In September 2004, Public Service Electric & Gas (PSEG) announced the retirement for economic reasons of seven older New Jersey-based units, totaling 1,136 MW, with requested December 2004 retirement dates. PJM allowed the Kearny 7 and 8 units (300 MW) to retire in June 2005, but chose to retain the Hudson 1 (383 MW) and the Sewaren 1, 2, 3 and 4 units (453 MW) through the summer of 2008 due to identified reliability issues. The retirement announcements of the PSEG units, following the announced retirements (later withdrawn) by several older Reliant Energy units, have helped spur the debate on the needs for revisions to PJM's capacity markets. More recently, Mirant's Potomac River 482 MW coal-fired facility in Alexandria, Virginia was temporarily shut down on August 24, 2005, following an order by the Virginia Department of Environmental Quality (DEQ). On September 21, 2005, Mirant restarted Unit 1 (up to 88 MW), but no other units are operational as the company seeks a solution to the potential violation of EPA air quality standards. Although the Potomac River situation presents no direct reliability issues for Maryland, the Commission met with members of Mirant's management during the height of the crisis to discuss potential transmission import and economic congestion impacts on the State. Given the age and fuel types of the Maryland fleet, the Commission is monitoring the situation regarding at-risk instate generation.

B. Certification of New Electric Plants

During the past three 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 regions. On the next page, Table 3 identifies all proposed generating projects for which the Commission has granted a CPCN and those pending before it. All of the projects listed in this table have plans to interconnect with PJM's regional market.

[19] Source: EIA. The 52,244 GWh of electricity generated in 2003 consists of the following: coal 57.3%, nuclear 26.2%, petroleum 6.8%, hydroelectric 5.1%, natural gas 2.3%, other renewables 1.7%, and other gases 0.6%.

[20] Source: EIA. The 71,259 GWh of electricity consumed in 2003 consists of the following: residential 37.4% (26,671 GWh), commercial 23.8% (16,950 GWh), industrial 38.1% (27,176 GWh) and other 0.7% (461 GWh).

Table 3: New Generating Resources Planned for Construction in Maryland

Resource Developer And Location	Capacity & Fuel	Expected In-Service Date	Interconnected w/Regional Mkt.	CPCN Status
Mirant Dickerson Power Plant, Station "H", Montgomery Co.	740 MW Gas	Pending financing	Yes	Granted 12/7/2004
Zapco Development Corp., Eastern Sanitary Landfill, Baltimore Co.	4.2 MW L.F. Gas	1st Qtr. 2006	Yes	Granted 7/19/2005
Mirant Chalk Point, Prince George's Co.	340 MW Gas	Pending financing	Yes	Granted 4/1/2005
Clipper Windpower, Inc., Garrett Co.	101 MW Wind	4th Qtr. 2005	Yes	Granted 3/26/2003
Savage Mountain US Wind Force LLC, Allegany and Garrett Cos.	40 MW Wind	4th Qtr. 2005	Yes	Granted 3/20/2003
Sempra Energy, Catoctin Power LLC / Eastalco, Frederick Co.	600 MW Gas	2007/2008	Yes	Granted 4/25/2005
Synergics Wind Energy, Roth Rock Windpower Project, Garrett Co.	40 MW Wind	Pending	Yes	CN 9008 In Progress
INGENCO Wholesale Power, Newland Park Landfill, Wicomico Co.	6.0 MW L.F. Gas	Pending, 1st Qtr. 2006	Yes	CN 9044 In Progress

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. There have been no applications for large baseload plants.

On October 27, 2005, Constellation Energy announced[21] 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; final site selection is expected in early 2006. If approved, any new nuclear units would not be operational until the middle of the next decade.

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:

a. The generating station produces on-site generated electricity;
b. The capacity of the generating station does not exceed 70 megawatts; and

[21] Source: Constellation Energy press release dated October 27, 2005.

c. 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:

a. The generating station does not exceed 25 megawatts;
b. 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
c. 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 292.1 MW. While it appears that most units will be 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. While deployment may occur for a handful of hours during the course of the year, such hours often coincide with "code red" or unhealthy air quality conditions in Maryland.

Table 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	37	67	122.9 MW
Grand Totals*	**130**	**214**	**292.1 MW**
Applications Pending	4	11	18.5 MW

* -- Cumulative totals as of November 30, 2005.

D. PJM Expansion and State of the Market Report

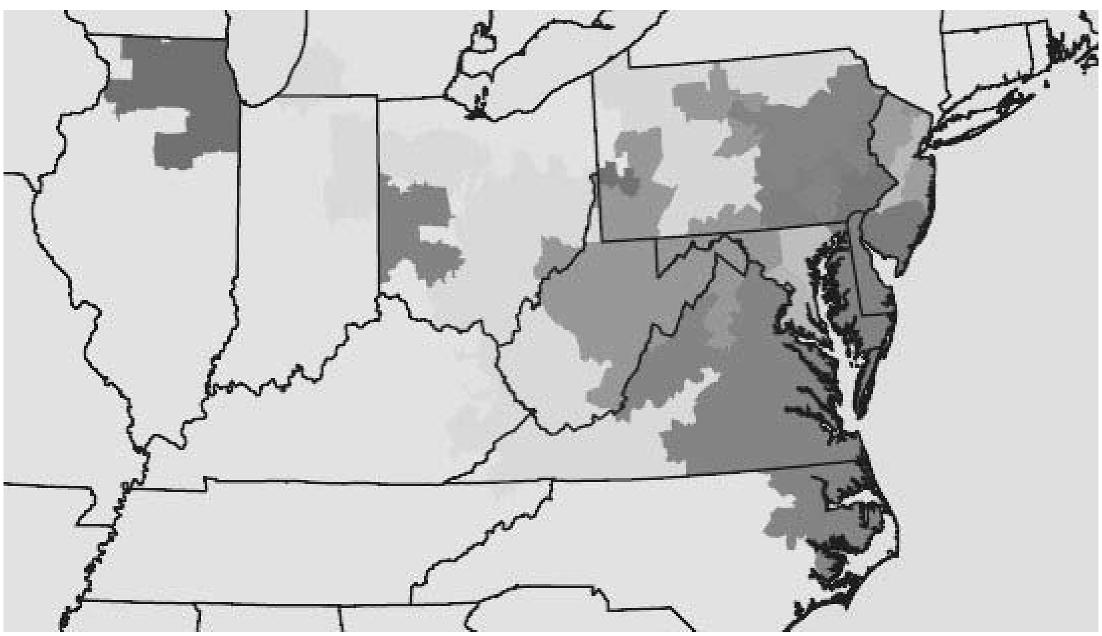
PJM's expanding market and geographic footprint help to ensure the availability of more distant resources. During 2004, PJM added parts of Illinois, Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia, and West Virginia to its footprint. During 2005, PJM incorporated more of

Pennsylvania and Virginia and added parts of North Carolina. The Commission closely monitors generation capacity expansion plans both in the State and the region to assure adequate supplies are available to serve Maryland. PJM's recent major expansion is listed in Table 5 below:

Table 5: PJM's Recent Expansion Integration

Utilities	States	NERC Region	Integration date
Commonwealth Edison	Illinois (Northern)	MAIN	May 1, 2004
American Electric Power Co. (AEP)	Parts of Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia & West Virginia	ECAR	October 1, 2004
Dayton Power & Light	Ohio (Western)	ECAR	October 1, 2004
Duquesne Light	Pennsylvania (Western)	ECAR	January 1, 2005
Dominion	Virginia, North Carolina	SERC	May 1, 2005

With the successful integration of these service territories, PJM reduced the installed reserve margin from 17 percent to 15 percent beginning in 2005. During the one-year period beginning on May 1, 2004, PJM has more than doubled the size of its footprint. The number of customers served has doubled from 25 million to 51 million; peak demand has also doubled from 63,762 MW to over 130,000 MW; and generating capacity has similarly grown from 76,000 MW to almost 164,000 MW. Six new states were added to the footprint, so that PJM (see map below, as of November 2005) now includes all or parts of thirteen states plus the District of Columbia.



PJM's Market Monitoring Unit (MMU) issued its 2004 State of the Market Report on March 8, 2005. In the report, PJM analyzed the health of the capacity and energy markets. Concerns about market power and market mitigation led to studies of market concentration, pivotal suppliers, marginal units, and offer capping. The relevant conclusions from the MMU 2004 State of the Market Report are as follows:

1. During 2004, some geographic areas experienced moderate to high concentration ratios. The Herfindal-Hirschman Index (HHI) results indicated that energy markets in PJM were moderately concentrated in 2004 and there was no evidence of market power.
2. The results of the residual supply indexed (RSIs) showed that PJM markets were competitive in 2003 and 2004, respectively.
3. The MMU concluded that the results of the wholesale energy markets in 2004 were competitive.
4. The results of the price-cost markup index indicated that the energy markets in PJM were competitive in 2004.
5. Generation units with low marginal costs were profitable in 2004.
6. Real-time energy market prices have increased by 10.8% in 2004.
7. Net import reached a peak of 1.8 million MWh in PJM import/export markets.
8. Congestion costs ($808 million in 2004) to total billings increased from 7% (2003) to 9% (2004). Congestion in both BGE and DPL service territories had declined in 2004.
9. The PJM Capacity Market results were competitive during 2004. The ComEd Capacity Market results were reasonably competitive in 2004.
10. "During 2004, the Spinning Reserve Markets in the PJM Mid-Atlantic Region and in the ComEd spinning zone were cleared based on cost-based offers, because these markets were determined to be not structurally competitive." Otherwise, market results suggested that the spinning reserve market was competitive.

Here are some other relevant statistics from the report:

- Following the integration of ComEd, PJM switched from being a net importer to a net exporter of power. Post-integration, the monthly export average was 3.9 million MWh.
- For the twelve months ending September 30, 2004, about 2,300 MW of new generation was added, in comparison to about 5,000 MW in the prior twelve months. About 1,850 MW represented new gas-fired generation, while the remaining 450 MW represented upgrades to existing facilities (including 240 MW of new nuclear generation).
- PJM hourly markets in 2004 had a maximum HHI of 1,634, a minimum HHI of 811, and an average HHI of 1,163, with these HHI's showing moderate concentration.
- For pivotal suppliers, the average RSI was 1.64, showing PJM markets were competitive.
- Net revenues for low marginal cost units (between $10 and $40) have significantly increased, while net revenues for high marginal cost units have plummeted.
- PJM average hourly LMPs were $28.30, $38.27, and $42.40 for 2002, 2003 and 2004, respectively. However, average load-weighted LMP, including fuel costs, was 4.2% lower in 2004 versus 2003. The real-time energy market was competitive in 2004.
- PJM generation capacity by fuel source was the following, as of December 31, 2004: coal 41.3%, gas 29.3%, nuclear 18.2%, oil 7.2%, hydro 3.7%, and solid waste 0.3%.
- Coal (52.1%) and nuclear (36.9%) units generated about 89% of electricity for calendar year 2004. Gas units accounted for 7% of MWhs, while oil, hydro, wind, and solid waste accounted for the remainder.
- Type of fuel used by marginal units in 2004: coal 56%, gas 31% and petroleum 12%.
- Delmarva Peninsula congestion declined 38.7% to 320 hours of constrained operations.

E. Transmission Congestion in Maryland

During the summer of 2005, the Commission monitored the locational marginal prices (LMPs)[22] being experienced in Maryland. As a result, the Commission has determined that the LMPs for central Maryland appear to be higher than for any other region in the PJM system. The Eastern Shore has only marginally lower LMPs. The LMPs for both are significantly higher than average LMP for the entire PJM system and the regions to the west, served by Allegheny Power Systems (APS) and American Electric Power (AEP).

Included are two charts (see next page) comparing the LMPs for BGE and Pepco (serving central Maryland), and Delmarva Power & Light (serving the Delmarva Peninsula, including the Eastern Shore), with the PJM system as a whole and the APS and AEP systems. The charts compare the LMPs by hour, and are weighted to include all days of the month. The results for June, August, and September are nearly identical to July's.

Note that the difference among the LMPs is relatively narrow in the nighttime and early morning hours. But as load builds during the day, the LMP differential widens substantially. The explanation for this is that during the off-peak hours, there is relatively little congestion in PJM, but during the daytime when usage builds, eastern PJM tries to import more energy from the west. At this point, congestion increases, and the differentials among LMPs increase.

In effect, the PJM transmission system cannot support the energy imports that eastern PJM, and central and eastern Maryland in particular, desire to receive. This results in the out of merit dispatch of generation, with oil and natural gas fired units operated at increased levels despite their high fuel costs.

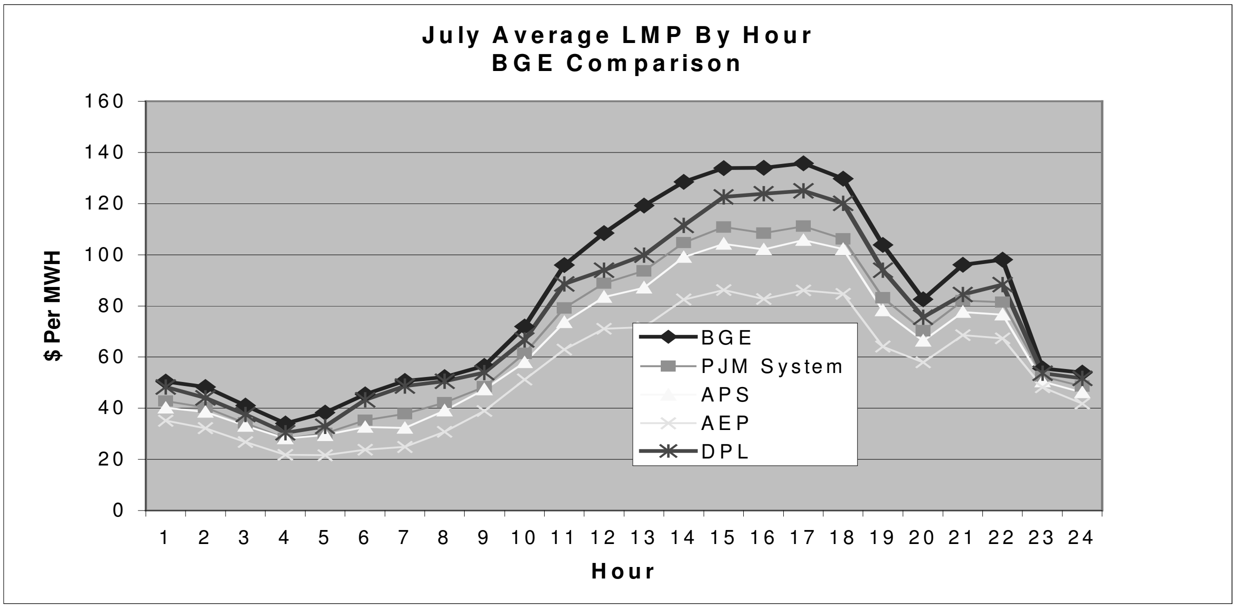
Maryland is vulnerable to a further widening in this LMP gap. Factors that could adversely affect the differential include:

- The shutdown of the Potomac River Station has decreased the capability to import energy into Maryland by over 100 MW.
- Further reduction in the level of generating capacity that serves Maryland would result in increased operation of expensive oil and natural gas fired generation, and a lower capability to import lower cost coal-based energy.
- The cost of oil and natural gas has risen substantially since the end of summer. If these price increases were sustained, Maryland's LMPs would increase further, as would the differential with many other load deliverability areas (LDAs) in PJM. Several other LDAs are served on the margin by coal-fired generation; for Maryland, the marginal capacity is oil and natural gas fired units.

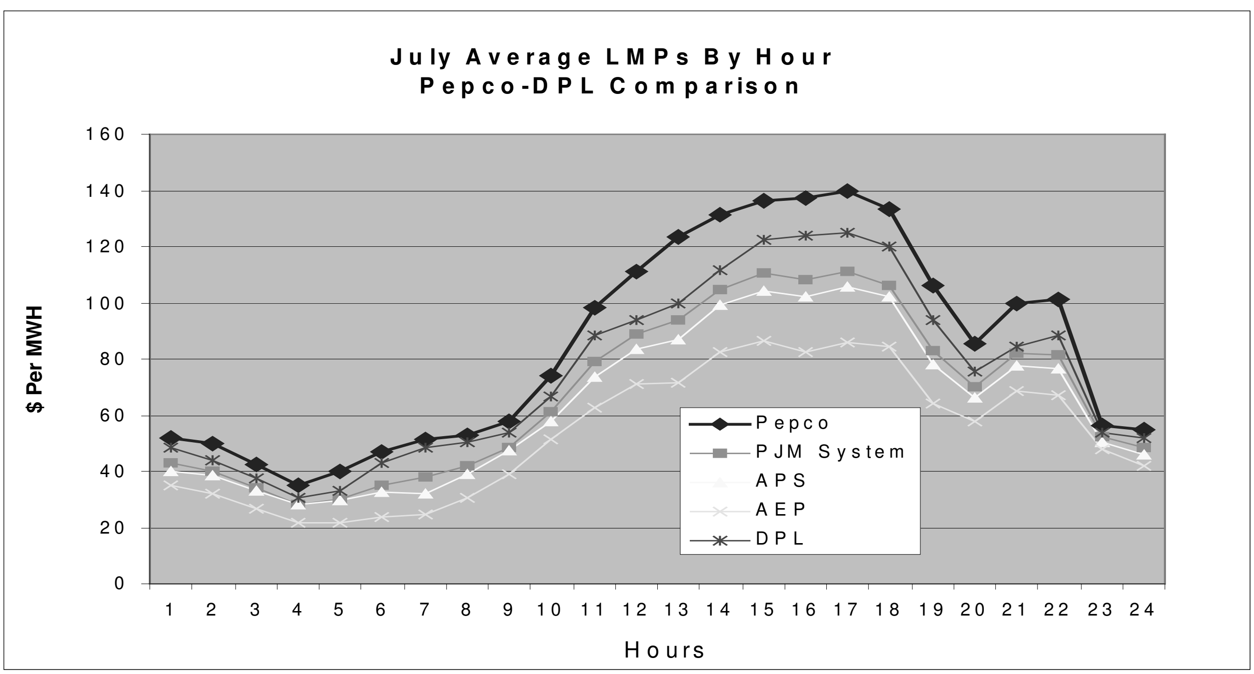
A near-term effect of these higher LMPs is that both spot and contract electricity prices will increase in Maryland. In addition, the higher LMPs appear to support the need for both

[22] Locational marginal pricing is the cost of providing the last incremental amount of electricity required to meet electrical demand and ensure reliability at any point of time. LMP includes the cost of producing the electricity and delivering to where it is needed. LMPs may vary significantly among locations, even among locations in proximity to one another. Transmission constraints can result in load pockets, and severely limit the pocket's ability to access lower cost generation resources elsewhere.

more cost-effective generation in Maryland and increased transmission facilities to import more cost-effective energy from outside the state.



The PJM 2004 State of the Market Report identified restrictions along the Bedington-Black Oak 500 kV transmission line as a leading cause for congestion in central and eastern Maryland. Other facilities that contribute to congestion in Maryland include the Doubs Substation, Wylie Ridge substation, Doubs-Mt. Storm 500 kV circuit, Hatfield-Black Oak 500 kV circuit, and Fort Martin–Pruntytown 500 kV circuit. PJM has included the Bedington-Black Oak transmission line in the economic planning review process.



PJM is proposing some interim solutions for the constraints. PJM expects to implement the following changes by the end of 2007:

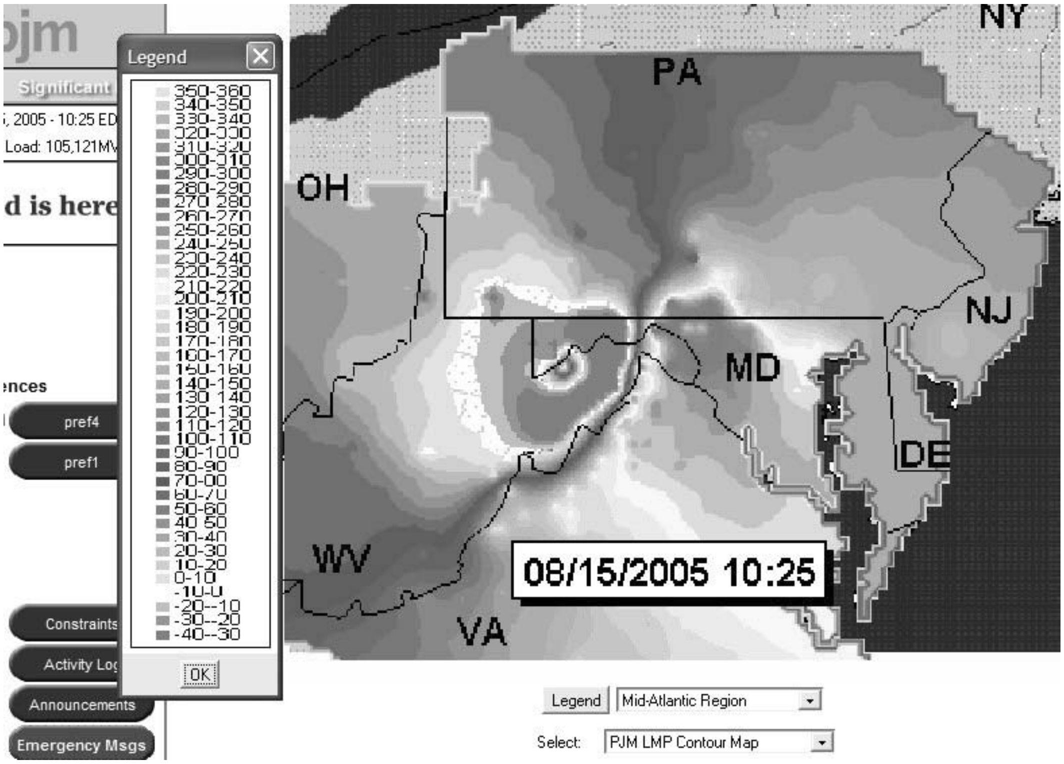
- One of the four 500 kV transformers at Doubs has been a limiting factor for power flows through Doubs. This transformer is scheduled to be replaced during the fall of 2005.
- A Static VAR Compensator (SVC) will be installed on the Bedington-Black Oak Line during the 2007-2008 timeframe. This will help to mitigate the voltage limit.
- No specific upgrade has been proposed for the thermal limit on the Pruntytown-Mount Storm 500 kV transmission line, but analysis is continuing.
- The Doubs - Mount Storm 500 kV transmission line reaches its sag limit when heavily loaded. This is scheduled to be adjusted in the fall of 2005.

The upgrades listed above are expected to improve transfer limits. However, most engineers concede that congestion between western PJM and central and eastern Maryland will continue until a new transmission line is built or substantial base load generation is installed.

PJM has initiated an evaluation of Long Term Transmission Planning which would be required for a new line due to the long lead-time needed for such a large project. The kick-off meeting was July 25, 2005. The Long Term Transmission Planning initiative will extend the Regional Transmission Planning Process (RTEP) out to ten years instead of five. PJM has also launched a proposal for new lines through the constrained area called Project Mountaineer.

A new transmission line for the area would be a long-term project. Therefore, it is important to support PJM's efforts for expanding the planning horizon. It is also important to review any short-term fixes that are available. The Commission will continue to monitor the observed congestion between western PJM and Maryland, and participate in the efforts being made by PJM to alleviate the problems.

The next page shows two typical LMP maps as displayed on PJM's *eData* site during the summer of 2005. The first map shows August 15, 2005, at 10:25 in the morning and indicates a load of about 105,000 MW. This pattern was typical of normal days in the summer where congestion was present – the highest LMPs in all of PJM have a bulls-eye centered near Frederick County, Maryland, on this day being approximately $300/MWh. Thus, Central Maryland's BGE and Pepco territories have higher spot wholesale prices than the transmission-constrained Delmarva Peninsula and Northern New Jersey regions, where LMPs range between $150-200/MWh (still higher than most of PJM, however). Further, notice that there is also a circular region in Western Maryland and Eastern West Virginia that actually has negative LMPs, due to the west to east transmission constraints that prevent sufficient low-cost power from crossing the Allegheny Mountains. This map clearly shows that within a range of less than fifty miles, LMPs can range from over $300/MWh to negative values. The second map shows one of the hottest days of the year, July 18, 2005, at 4:05pm when peak load had just exceeded 130,000 MW (one of the top three demand days in PJM history). On this day, the congestion and high LMPs stretch from Northern Virginia, through Central Maryland and the Delmarva Peninsula, and into Southeastern Pennsylvania and all of New Jersey. Once again, LMPs are much lower just west of the Allegheny Mountains – on this day, LMPs vary between about $170-230/MWh on the high side and $0-40/MWh on the low side, a less extreme range of LMPs than on the lower demand day.



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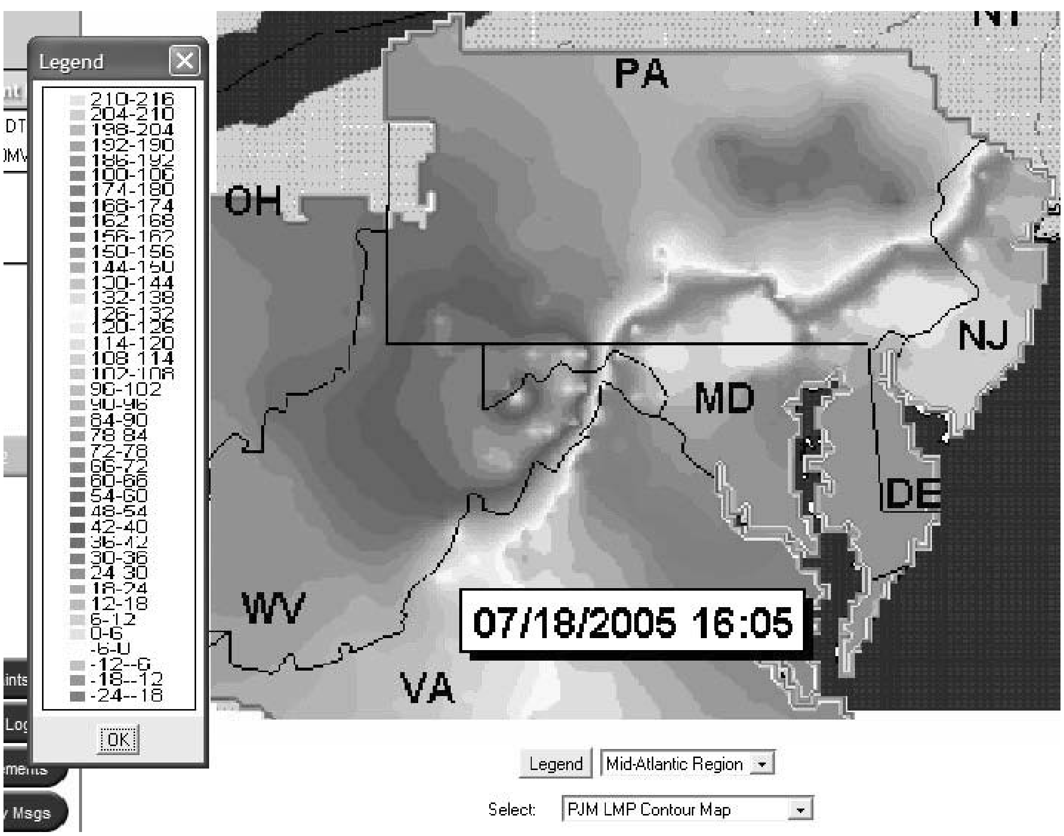

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PJM LMP Contour Map

F. The Regional Transmission Expansion Planning Protocol (RTEP)

Planning the enhancement and expansion of transmission capability on a regional basis is one of the primary functions of an RTO like PJM. PJM implements this function pursuant to the Regional Transmission Expansion Planning Protocol (RTEP) set forth in Schedule 6 of the PJM Operating Agreement. A key part of this regional planning protocol is the evaluation of both generation interconnection and merchant transmission interconnection requests, the procedures for which are codified under Part IV of the PJM Open Access Transmission Tariff (OATT).

PJM annually develops an RTEP 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 of an RTEP, 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 which become part of the RTEP Report.

As a regional planning effort, RTEP determines the best way to integrate projects to provide for the operational, economic and reliability requirements of the grid. The RTEP 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 ten years. The Reliability Planning Process Working Group (RPPWG) was started this year to revise RTEP for a ten 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
- Proposed merchant transmission projects

The Transmission Expansion Advisory Committee (TEAC) is the primary forum for stakeholders to discuss the results of RTEP. It has met several times this year, most recently November 15, 2005.

<u>Baseline Reliability Assessment</u>

PJM establishes a baseline for a five-year period 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' (MAAC, ECAR, MAIN or 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 RTEP 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 RTEP, 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. For instance the Edgewood-North Salisbury 69 kV circuit is limited by a disconnect switch. PJM completed a cost/benefit study to upgrade the circuit by simulating congestion from 2006 through 2016, and found that the benefit is over 35 times more than the cost. Therefore, PJM is recommending the upgrade with 100% of the cost allocated to Delmarva.

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 the seams is expected to reduce congestion on an inter-RTO basis and enhance the physical and economic efficiencies of congestion management.

RTEP October 2005 Plan Summary

PJM's most recent RTEP Plan recommends the following transmission enhancements to meet the needs described above, over the 2005 through 2010 time frame:

Baseline Network Upgrades:	$ 863 Million
Merchant Transmission & Generation Network Upgrades:	$ 551 Million
Total RTEP Transmission Enhancements:	$1414 Million

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 over 17,000 MW of new generation, representing over 139 projects. 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;
- members' plans for capacity additions, including new generation and merchant transmission interconnection requests;
- transmission owner plans to develop transmission;
- interregional transmission development plans; and,
- long-term firm transmission service requests.

How Do RTEP-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. As part of the RTEP, PJM maintains a well-defined interconnection process that identifies the transmission upgrades required to connect generation and merchant transmission projects and contains specified financial and construction-related milestone obligations. Market participants may propose projects intended to relieve costly and persistent congestion. The RTEP process establishes the market window. If no projects are proposed, 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 Rights of Way (ROW) or modifications to existing facilities. Due to the long lead-time for this process, PJM is revising its planning horizon from five to ten or more years.

PJM's RTEP process attracts investment in power plants built at no risk to ratepayers. Although merchant transmission projects have been slow to develop, they offer the promise of long-term transmission solutions for delivering distant energy resources. A number of factors account for PJM's successful RTEP 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.
- 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 in 1997. Since that time, PJM has administered its RTEP as described in Schedule 6 of the Operating Agreement. PJM has subsequently received authority from FERC for procedures and rules for transmission expansions needed to enable the interconnection of new and expanded generation and merchant transmission facilities (1999). Most recently, PJM has amended the RTEP to include the development of transmission projects to support competition in wholesale electric markets (2003). 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 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 RTEP.

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 integrated planning 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 ten Regional Reliability Councils. PJM uses the Mid-Atlantic Area Council (MAAC) reliability criteria. NERC has undertaken a massive revision of its standards following the Northeast Blackout of 2003.

EPAct 2005 requires the formation of an Electric Reliability Organization (ERO) similar to NERC with mandatory and enforceable standards. FERC is now conducting technical conferences to address issues associated with this Notice of Proposed Rulemaking in Docket No. RM05-30-000. The Rulemaking concerns the certification of the ERO and procedures for the establishment, approval, and enforcement of Electric Reliability Standards.

MAAC sets standards for the Mid-Atlantic region, including all or parts of the states of Pennsylvania, New Jersey, Delaware, Maryland, Virginia, and the District of Columbia. The purpose of MAAC is to ensure the adequacy, reliability and security of the bulk electric supply systems of the region through coordinated operations and planning of their generation and transmission facilities. Due to the expanding footprint of PJM, the boundaries of the NERC reliability councils are changing. Starting January 1, 2006, companies doing business in PJM's territory will comply with standards adopted by the new regional council known as Reliability*First* (see Section IV.G).

MAAC has oversight of all facilities at a voltage level of 230 kV and above that are specified on the MAAC facilities list as provided by the transmission owning companies geographically within the MAAC territory. MAAC criteria require that its facilities are capable of surviving the following losses without overloading other equipment:

- The loss of any single facility (MAAC Criteria IIA);
- The loss of any second facility after readjustment of the system (MAAC Criteria IIB); and,
- The loss of any double circuit tower line (DCTL) or faulted circuit breaker (MAAC Criteria IIC).

PJM Transmission Projects Affecting Maryland

The results of PJM's most recent baseline analysis and RTEP are summarized below. Tables A-8 to A-11 of the Appendix summarize scheduled transmission enhancements in Maryland as reported by the transmission owners. PJM's RTEP includes the transmission enhancements required for Sempra to interconnect 640 MW of generation at the Eastalco 230 kV bus with an in-service date of 2008. It does not include any loss of load at Eastalco[23]. 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

[23] On November 23, 2005, Alcoa Inc. filed an 8-K with the SEC, in which the company committed to a plan to curtail production at the Eastalco aluminum smelter located in Frederick, MD on December 19, 2005.

new 230 kV circuits between Palmers Corner and Blue Plains and contributions to the dynamic reactive device at Black Oak.

RTEP Baseline Updates

- In 2009, the Bedington 500/138 kV transformer #2 is overloaded at 107% of emergency rating for the outage of Bedington – Doubs 500 kV. The recommended solution is to install a fourth Bedington 500/138 kV transformer. The cost is estimated at $7 million with a May 2009 in-service date.
- In 2009, the Burtonsville – Sandy Springs 230 kV circuit is overloaded at 105% for the outage of Burtonsville – High Ridge 230 kV. The recommended solution is to upgrade the strain bus and replace two 230 kV disconnect switches at a cost estimate of $400,000. The projected in-service date is May 2009.
- In 2009, the Doubs – Aqueduct 230 kV circuit is overloaded at 110% of emergency rating for the outage of Doubs – Dickerson 230 kV. Also in 2009, the Doubs – Dickerson 230 kV circuit is overloaded at 110% of emergency rating for the outage of Doubs – Aqueduct 230 kV. The proposed solution for these two overloads is to reconductor the Doubs – Aqueduct 230 kV and the Doubs – Dickerson 230 kV circuits. Allegheny Power is presently reviewing the cost and conductor type to complete the reconductoring.
- In 2009, the Black Oak 500/138 kV transformer is overloaded for the outage of Hatfield – Black Oak 500 kV. Allegheny Power has proposed an operating procedure to eliminate the overload. PJM is working with Allegheny Power to determine if this adequately addresses the overload.

PJM Western 500 kV Interface

The Black Oak – Bedington 500 kV transmission line has been implicated as a bottleneck contributing to congestion in central Maryland. PJM's Economic Planning process has resulted in projects to address the thermal and reactive limits on this line.

- The existing thermal limit is increased by about 17% through replacement of wavetraps. There is a Merchant Transmission project (M05) to replace these wavetraps.
- To address the reactive (voltage) limit, there is a reliability upgrade to install a -100 / +525 MVAR[24] dynamic reactive device at Black Oak 500 kV prior to June 2008. Prior studies have determined that the device will reduce but not eliminate the congestion on Black Oak – Bedington 500 kV. The closure of Potomac River generating units increased the size of the dynamic reactive device from –100/+350 MVAR to –100/+525 MVAR.
- Sempra's new generation at Eastalco reduces congestion on the Black Oak–Bedington 500 kV line by up to 40%. However, this effect cannot be included in the baseline because the generator has not yet executed an Interconnection Service Agreement.

Studies are presently underway to assess appropriate means to mitigate congestion on the Western interface. The Black Oak – Bedington line is just one link in a larger network of lines

[24] MVAR is a measure of reactive power.

that carry power primarily from west to east. Changes in any one line will affect flows on other lines. The PJM Western Interface includes Keystone-Juniata, Conemaugh-Juniata, Conemaugh-Hunterstown, and Doubs-Brighton. Additionally, Dominion is upgrading the Mt. Storm-Doubs line prior to June 1, 2006. Also, Allegheny Power will be replacing a 500 kV transformer at Doubs by June 1, 2006, with costs attributable to BGE, Pepco, and Delmarva. In previous years, similar measures were used to effectively address congestion problems on the Delmarva Peninsula. Capacitors, transformer and line adjustments have been used successfully to mitigate congestion problems. However, for the sake of long term reliability, new lines are needed.

PJM is addressing problems at more distant facilities, which affect power flow in Maryland. Merchants or other utilities may resolve the problems with charges attributable to Load Serving Entities (LSEs) in Maryland.

Southwestern MAAC Operational Performance

In order to maintain the operational performance of the southwestern region, PJM has prescribed the components listed below. Although they may not be physically located in Maryland, the units affect power flow in Maryland. The costs for the upgrades have accordingly been apportioned to the load being served. Furthermore, the acceleration of baseline transmission or generation projects may eliminate the need for the following projects:

- Install a 150 MVAR capacitor at Loudoun 500 kV. The cost is estimated at $1.5 million with a June 2006 in-service date.
- Install a 150 MVAR capacitor at Asburn 230 kV. The cost is estimated at $1.0 million with a June 2006 in-service date.
- Install a 150 MVAR capacitor at Dranesville 230 kV. The cost is estimated at $1.0 million with a June 2006 in-service date.
- Install a 33 MVAR capacitor at Possum Pt. 115 kV. The cost is estimated at $600,000 with a June 2006 in-service date.
- Install a 500/230 kV transformer at Clifton to reduce the loading on the existing Loudoun 500/230 kV transformers. A 150 MVAR capacitor is also being installed at Clifton 500 kV. The cost is estimated at $7.0 million with a June 2006 in-service date.
- Accelerate the upgrade to Mt. Storm – Doubs 500 kV to be completed prior to June 2006.
- Accelerate the 360 MVAR Waugh Chapel 500 kV capacitor to be installed prior to June 2006.
- Increase the size of the Black Oak dynamic reactive device from -100/+350 MVAR to -100/+525 MVAR.

G. Formation of ReliabilityFirst

As part of the development of larger and more integrated wholesale power markets, and the related restructuring of electricity organizations that manage and monitor those markets, new reliability councils are being formed, including one covering the PJM and Midwest Independent System Operator (MISO) footprints. Consolidation of regional reliability councils is taking place with the objective of a more consistent application of electric system rules and procedures.

On November 1, 2005, the nation's newest regional reliability council was formed, named Reliability*First*. Reliability*First* was organized to develop regional standards for reliable planning and operation of the regional electric power system and provide non-discriminatory compliance monitoring and enforcement of both NERC and Reliability*First* standards.

The NERC Members and Board of Trustees have approved Reliability*First* to begin full operations on January 1, 2006. NERC found that Reliability*First*, which was incorporated June 15, 2005, meets all the requirements of a regional reliability entity necessary to ensure reliability among its members, including PJM. Reliability*First* will monitor compliance to technical standards for electric companies, independent power producers, load entities, electric transmission companies, and others that contribute to or manage power on the electric grid.

The portions of the network that will be covered by Reliability*First* are in the East Central Area Reliability Council (ECAR), Mid-America Interconnected Network (MAIN), and the Mid-Atlantic Area Council (MAAC). These councils will turn over regional reliability responsibilities when Reliability*First* becomes operational, and will wind down other operations in early 2006.

Reliability*First* covers the region that spans thirteen states and the District of Columbia, encompassing primarily the Mid-Atlantic and central areas of the United States. The portion of the electric grid covered by Reliability*First* represents nearly 40% of the eastern interconnection electric network.

H. The Regional Planning Process Working Group (RPPWG) and Project Mountaineer

One of the outgrowths of the Reliability Pricing Model development effort and associated discussions was an acknowledgement on PJM's part for a need to develop and put in place a long-term planning process that explicitly takes into consideration the potential benefits of large transmission projects. Up until now, the PJM planning process essentially looked out no more than five years into the future. This effectively eliminated consideration of large transmission projects that may take ten or more years to plan and build.

In a May 31, 2005, letter to the PJM membership, Phil Harris, the President and CEO of PJM wrote:

> The Regional Transmission Expansion Process (RTEP) currently uses a five-year planning horizon. It has become apparent that that the level and nature of transmission investment required for the region requires a longer time period. The Board is directing PJM to work with the Membership to develop protocols for establishing a ten-year planning process by year-end.
>
> The Board is concerned that PJM's current methodology for economic planning may not be achieving the desired outcomes of ensuring adequate transmission investment to support robust competitive markets. The Board is directing PJM to review its current economic planning process and work with the Members to

identify appropriate changes. To the extent feasible, PJM will undertake this analysis in conjunction with the development of the longer term planning process.

In response, PJM has formed the Regional Planning Process Working Group (RPPWG). In addition PJM put forward a concept that eventually may result in bulk transmission investments that better connect the eastern, southern, and western elements of PJM. The concept has been named “Project Mountaineer.”

The mission of the RPPWG is to determine how to change the RTEP to expand the planning horizon and to develop the transmission resources necessary to support competitive wholesale markets. A proposal for implementing the long term planning horizon and for developing the metrics to implement construction of transmission to support competitive wholesale markets is being discussed at this time.

The RPPWG has met regularly throughout the second half of 2005, and will continue to meet in 2006 to develop and refine the proposal and seek approval from the appropriate PJM committees and board. The Commission actively supported the formation of RPPWG and has been directly engaged in the activities of the RPPWG. Thus far, significant progress has been made, including the adoption by PJM of the long-term planning component that addresses reliability.

The purpose of the Project Mountaineer stakeholder group is to establish the processes required to identify, considering the needs and concerns of all interested stakeholders, the specific transmission facilities that will comprise a large bulk power transmission facility that would improve the interconnection between the PJM east, south, and west regions. The Project Mountaineer Working Group will also develop the protocols for how such a large project would be implemented.

The Project Mountaineer stakeholder group is proceeding in parallel with the RPPWG. The activities of the two groups are meant to complement one another, with the Project Mountaineer stakeholder group providing input to the RPPWG on how the planning process and metrics to measure benefits and costs should be designed. Among the stakeholder group’s responsibilities:

- Develop a process to identify the parties responsible for the construction of proposed transmission facilities;
- Develop a process to identify cost responsibility for and/or opportunities for investment in proposed transmission facilities;
- Identify and develop a process to consider regulatory, environmental, and siting issues related to proposed transmission facilities; and,
- Provide feedback to the RPPWG to assist in developing the long-term transmission model.

The Commission has also been an active participant in the Project Mountaineer Working Group. It is anticipated that as the RPPWG begins to develop specific planning process elements, the Project Mountaineer stakeholder group will become more active.

I. 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 four 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 two 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 New Jersey, load will increase by 1,950 MW between 2005 and 2010. Conversely, only 51 MW of capacity were added in 2003 and 2004, and only 1,340 MW are under construction.
- Load is forecast to grow at a rate of 2.7 percent per year and increase by 573 MW in Delmarva over the next five years, but only 60 MW were added in 2004 and only 150 MW are being studied for potential interconnection.
- In the Baltimore-Washington area, only 77 MW were added in 2004 and none is being studied for potential interconnection. The load growth rate for Delmarva and Baltimore-Washington is expected to be the highest in PJM. In 2005, peak demand in the Baltimore-Washington region exceeded 13,800 MW, with over 1,500 MW potentially added by 2010.

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 model 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."

As filed, PJM's proposal plans a transitional phase to move from the current capacity construct to the RPM. When fully transitioned, PJM plans to hold a centralized auction four 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 2006/2007 to 2009/2010 Planning Years, each auction separated by a period of several weeks, in order to effect the transition and set up the initial four-year planning horizon. These transitional auctions were scheduled to commence in the first half of 2006. 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:

- 2006/2007 Planning Year: PJM Mid-Atlantic Area Council (MAAC) 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).
- 2007/2008 Planning Year: the MAAC region plus the APS zone; an area consisting of the zones of ComEd, AEP, Dayton, Dominion, and Duquesne; the eastern MAAC 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 southwestern MAAC region consisting of the zones of Pepco and BGE.
- 2008/2009 Planning Year and beyond: A full complement of local deliverability areas corresponding to the areas tested in the RTEP process. LDAs will be the MAAC 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 MAAC region; the southwestern MAAC region; the western MAAC 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, 2005, PJM filed with the FERC its Answer to Comments and Protests. In this filing, PJM proposed several changes to the transition auctions and the phase-in of LDAs. Now, PJM proposes to implement RPM on June 1, 2007 (a one-year delay) and to eliminate the first transitional auction, effectively combining the first two transitional auctions and beginning with the 2007/2008 Planning Year LDAs noted above. On December 8, 2005, FERC issued a notice that it will hold a technical conference on PJM's RPM filing on February 3, 2006.

J. Formation of the Organization of PJM States, Inc. (OPSI)

In May 2005, the Organization of PJM States, Inc. (OPSI) was formed, of which the Maryland Public Service Commission is a member. OPSI is a non-profit, 501(c)(4) Delaware corporation. OPSI's members include all fourteen state regulatory commissions (inclusive of the District of Columbia Public Service Commission) within the PJM footprint. OPSI provides a means for the PJM States to act in concert with one another, when it is deemed to be in the common interest of their affected publics. According to its articles of incorporation, OPSI will undertake such activities as data collection and dissemination, market monitoring, issue analysis, policy formation, advice and consultation, decision-making and advocacy related to:

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

Each state commission will have a member on the OPSI Board of Directors, and the OPSI executive committee consisting of the president, vice-president, secretary, and treasurer will set general policy direction. Maryland Commissioner Allen Freifeld is presently serving as the Treasurer of OPSI.

Other significant information concerning OPSI is that it is a voluntary organization, addresses regional issues directly related to PJM, and OPSI positions do not bind individual commissions and are not official actions of any member state. It is anticipated that OPSI's budget will be less than $500 thousand and that it will be funded by a PJM tariff. PJM has filed the tariff with FERC, and FERC has received and reviewed comments on the application. On December 15, 2005, FERC approved the tariff and it will take affect in 2006.

OPSI has had several board meetings since its inception, and held its first annual meeting and strategic retreat on September 15 and 16, 2005. Both commissioners and commission staff representing each OPSI member were in attendance. Several working groups were formed during the meeting including those related to: (1) PJM's Reliability Pricing Model; (2) Regional Transmission Planning; (3) market monitoring and market mitigation; and (4) governance issues concerning the relationship and deliberations between OPSI and PJM.

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, 2005, to implement the provisions of Section 7-201 of the PUC Article. The information presented below in Table 6 are summaries of responses to a data request indicating what efforts were made during 2005 to analyze energy efficiency and conservation programs, including the weatherization of buildings, renewable energy, cogeneration, and widespread promotion of energy conservation programs.

Table 6: Summary of Conservation, Renewable Resources, and Cogeneration Activities

Distribution Utility	*Summary Of Conservation, Renewable Resources, And Cogeneration Activities Since January 1, 2005*
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, Rider 6 WH Switch, and Rider 24 Load Response Program to customers under Schedules G, GS, and GL or P.

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 PV-Net Metering residential customer. The system is reportedly a 2.2 kW system. SMECO owns and operates a 308-watt PV power system for a remote, radio controlled, motor operated switch on a 66,000-volt transmission line in Barstow, Maryland. 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.

In 2004, the Commission docketed Case No. 9019, *In the Matter of the Commission's Inquiry into the Implementation of the Renewable Energy Portfolio Standard*, for the purpose of considering comments from interested parties regarding certain policy and administrative issues pertaining to implementation of the RPS Legislation. In December 2004, the Commission issued a letter of advice to Commission Staff regarding how to proceed in this matter.

With Case No. 9019 as a foundation, Staff convened the RPS Working Group composed of utilities, electricity suppliers, renewable energy providers, environmentalists, industry specialists, OPC, and other interested parties. Beginning with a proposed set of regulations drafted to comply with the RPS Legislation and the Commission's direction regarding the issues in Case No. 9019, the RPS Working Group offered comments and alternative language on successive drafts of proposed regulations pertaining to the RPS Legislation.

On April 13, 2005, the Commission received Staff's recommended proposed RPS regulations and opened Rulemaking 12. The Commission received comments and reply comments on the proposed regulations. The Commission held three Open Meetings on the RPS Regulations for the purpose of addressing outstanding issues raised by the parties. On May 25, 2005, the Commission voted to publish what subsequently became Section 20.61 of the COMAR. The proposed regulations were published August 3, 2005 in the *Maryland Register*. The Proposed Regulations were adopted as published on a temporary emergency basis effective July 1, 2005. After additional comments and an Open Meeting, COMAR 20.61 was finally adopted and became effective November 24, 2005.

With regulations in place, the full implementation of the RPS Program has begun. Staff created the necessary forms to begin program administration. The forms are currently available online. Applications are now being received from RPS program participants. An integral part of the RPS program is the Generation Attributes Tracking System (GATS). This is in keeping with PUC Article § 7-708(a)(2) which requires the Commission to use a trading system that is consistent with and operates in conjunction with a trading system developed by PJM Interconnection, Inc. GATS is a new system designed and operated by PJM Environmental Information Services, Inc. (PJM-EIS) to create, record, and track RECs. GATS will monitor the generation of participating units and create RECs monthly based on actual output. A GATS certificate from a Commission-certified renewable energy facility will be identified as a Maryland-eligible Tier 1 or Tier 2 REC. The first compliance reports will be due in 2007 for the calendar year 2006.

As required by the RPS Enabling Legislation (ch 488 Acts 2004), Staff has formed a Technical Advisor Group (TAG) to develop recommendations on siting and operational and monitoring criteria for wind-powered electricity generating facilities relating to avian and bat issues. This eight-member team will provide a recommendation to the Commission at the conclusion of its work. The General Assembly has made certain suggestions regarding avian and bat issues that is would like the group to consider specifically.

D. Regional Power Plant Emissions Initiatives

The Regional Greenhouse Gas Initiative (RGGI, pronounced "ReGGIe") is a cooperative effort of nine Northeast and Mid-Atlantic states to discuss the design of a regional cap-and-trade program, initially covering carbon dioxide (CO_2) from power plants in the region.[25] RGGI was founded after New York Governor George E. Pataki sent letters to eleven governors from Maine to Maryland in April 2003. By July 2003, he had received positive responses from eight[26] governors who supported his effort to develop a regional cap-and-trade system within two years. After discussions got underway, representatives from some eastern Canadian provinces began observing the process; representatives from Maryland, Pennsylvania, and the District of Columbia observe as well.

Before RGGI was formed, many of the Northeast and Mid-Atlantic states were already in various stages of studying or implementing programs to reduce greenhouse gas (GHG) emissions. For example, in April 2000, New Jersey adopted a statewide goal of reducing GHG's to 3.5% below 1990 levels, by 2005. In August 2001, the New England governors and eastern Canadian premiers issued a Climate Change Action Plan, which calls for GHG reductions to 10% below 1990 levels by 2020. New York has adopted a similar plan, with goals of a 5% reduction by 2010 and 10% reduction by 2020. One goal of RGGI is to develop a "model rule" for adoption in each state, as well as to create a flexible, market-based GHG program that can serve as the model for a federal GHG program. A current proposal, not yet adopted by any state, would establish a two-phase cap to stabilize GHG's through 2015 and achieve 10% reductions by 2020.

Issues involving a regional GHG cap-and-trade system include the impacts on electricity prices, fuel diversity, and reliability, as well as how to deal with "leakage" effects when some states participate and others do not. Obviously, power plant emissions do not recognize state boundaries, so it may be difficult to maintain a level playing field among generators when only some states participate. This is not an issue in the New England and New York ISO's, but only two states in the PJM footprint (Delaware and New Jersey) are currently participating. In order to comply with GHG reductions, there is a bias towards replacing coal-fired generation with new natural gas plants. New England now is highly dependent upon gas-fired generation, which may become problematic given the recent price spikes for this commodity (see Section VI.B) and the potential reliability issues for transporting enough gas from the Gulf pipelines into this region. It is possible that RGGI could spur renewed interest in nuclear generation, given the issues with price and availability for natural gas.

On November 17, 2005, Governor Robert L. Ehrlich, Jr. announced tighter rules aimed at reducing the emissions from the State's six largest coal plants, called the Maryland Clean Power Rule. All of these plants are owned by either Constellation Energy Group or Mirant Corp, and are located in Anne Arundel, Baltimore, Charles, Montgomery, and Prince George's Counties. Under the new rules, these plants must reduce nitrogen oxides (NO_X) by 69%, sulfur dioxide (SO_2) by 85% and mercury by 70%, by 2010 – five years quicker than under federal standards.

25 Source: Regional Greenhouse Gas Initiative website at http://www.rggi.org.
26 Participating RGGI states include: Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont.

The Governor stated that "It will ensure Maryland meets the new federal air quality standards for ozone and fine particles by the Clean Air Act deadline of 2010." These plants would comply with emissions standards by adding local pollution controls rather than via a cap-and-trade program.

E. Mid-Atlantic Distributed Resources Initiative (MADRI)

The Mid-Atlantic Distributed Resources Initiative (MADRI) was established by "classic" PJM State Commissions, the Department of Energy (DOE), and PJM at a meeting in Baltimore, held on June 14-15, 2004. Its goal is "to develop regional policies and market-enabling activities to support distributed generation and demand response in the Mid-Atlantic region". Facilitation support is provided by the Regulatory Assistance Project funded by DOE. 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.
- 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.
- Developing Model Small Generation interconnection standards, which has been a highly contentious process between utilities and small generation (particularly solar) providers. While near completion, the final result will not be a "consensus" regulation or tariff.
- 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. This topic is still under discussion and development.
- 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.

MADRI may be a significant resource for a number of areas for EPAct 2005, described in detail in Section VI.A, as well as for electric rate case hearings.

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. In late August and late September, respectively, Hurricanes Katrina and Rita caused major disruptions to the energy infrastructure in the Gulf of Mexico, primarily in Louisiana and Texas. Both of these events are 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. Repeal of the Public Utility Holding Company Act (PUHCA)

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 currently under consideration including between Exelon-PSEG, and Duke-Cinergy.

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. Energy Project Siting and Infrastructure Development

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. Cinergy, 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 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). The Commission is given the authority to implement any of these standards in 16 U.S.C. §2621(c).

Not later than two years after the enactment of Section 1251, by August 8, 2007, the Commission (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, the Commission (with respect to each electric utility for which it has 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, the Commission 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, the Commission shall complete consideration and make a determination.

In conjunction with the requirement above, Section 1252 mandates additional Commission action. No later than eighteen months after the enactment of Section 1252, the Commission 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. Impacts of the Gulf Hurricanes on Commodity Prices and Infrastructure

On October 12, 2005, FERC held a technical conference to discuss the development of natural gas infrastructure and the status of Gulf Coast facilities damaged by Hurricanes Katrina and Rita. In restructured electricity markets, natural gas prices are now a crucial factor as they are setting the umbrella for higher electricity prices in hours when gas-fired plants set the LMPs. Particularly in the New England states, a sufficient supply of natural gas is critical in order to ensure system reliability during the winter months. Thus, the post-hurricane condition of gas infrastructure, including rigs, refineries, storage facilities and pipelines will be critical. The general conclusion of the presenters was that there would be enough natural gas in storage, as well as sufficient pipeline capacity, to meet needs for winter 2005-2006.

At this technical conference, the FERC's Office of Market Oversight and Investigations (OMOI) presented its Staff Report[27] on the impacts of Katrina and Rita on commodity prices, including electricity. OMOI Staff noted that:

> The Gulf storms exacerbated already tight supply and demand conditions, increasing prices for fuels in the United States further after steady upward pressure on prices throughout the summer of 2005. Most of this was due to increased electric generation demand for natural gas caused by years of investment in gas-fired generation and a significantly warmer-than-average summer. Supply showed some weakness despite increasing numbers of active drilling rigs. The result was broadly higher energy prices.

Measured in national average cooling degree-days (CDDs), the three summer months were 26% hotter than in 2004, which was close to average. Starting in June, increased air conditioning demand increased the use of gas-fired electric generation. While year-to-date net generation for gas-fired generators was essentially flat with 2004 as of the end of May, it was 7.1% higher by the end of July, driven by a 25% greater year-over-year increase in consumption by gas-fired generators in July 2005 alone. At Henry Hub, average natural gas prices rose from \$7.39/MMBtu (April 5-9) to \$9.81/MMBtu (August 22-27) just before the hurricanes, before rising to \$14.10/MMBtu (September 26-30) in their immediate aftermath. Immediately after Rita, prices peaked at \$15.22/MMBtu before Henry Hub was out-of-service until October 4, 2005, removing a key national benchmark for gas prices during an important period. Moderate weather in the northeastern United States during the first half of November helped lower prices, which traded below \$10.00/MMBtu at Henry Hub during part of the month. By early December, however, spot and future gas prices were again approaching record highs due to cold weather.

Similarly, electricity prices have been significantly higher in 2005, as compared to 2004. Through early September, year-to-date prices in PJM averaged \$64/MWh versus \$50/MWh (+28%), with similar increases in other parts of the country. CDDs were 39% above average in the Mid-Atlantic and 42% above average in the Northeast. As a result, generation in June, July, and August far outpaced recent history, and peak demand set many new records (including PJM, which reached 130,754 MW peak demand on July 18 and a record 135,000 MW on July 26). Rising fuel prices, particularly for natural gas, contributed to higher electricity prices. This was especially true in eastern regions because they have substantial gas- and oil-fired generation and higher locational fuel premiums. Winter power prices may be much higher than last year, as forward power prices for the winter hit historic highs in the aftermath of the hurricanes. The price impacts are likely to be greater in the Northeast than in PJM, as the spread between the two regions for some winter forward contracts tripled from about \$24 to \$75. If the upcoming winter is significantly colder than normal, the likelihood of severe price spikes is much greater in New England than in New York, and even less so in PJM, given its dependence on coal and nuclear fuel sources (see Section IV.D).

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[27] OMOI October 12, 2005, Staff report entitled *Gulf Coast Storms Exacerbate Tight Natural Gas Supplies; Already High Prices Driven Higher*.

APPENDIX
Tables A-1 to A-11

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, 2004)												
	System-Wide						Maryland					
Utility	**Residential**	**Commercial**	**Industrial**	**Other**	**Sales for Resale**	**Total**	**Residential**	**Commercial**	**Industrial**	**Other**	**Sales for Resale**	**Total**
A&N	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Berlin	1,628	285	87	17	0	2,017	1,628	285	87	17	0	2,017
BGE	1,072,090	113,608	4,774	0	0	1,190,472	1,072,090	113,608	4,774	0	0	1,190,472
Choptank	40,996	3,723	16	279	0	45,094	40,996	3,723	16	279	0	45,094
DPL	441,609	58,580	589	643	2	501,423	167,470	24,658	276	267	0	192,671
Easton	7,993	2,010	0	121	0	10,124	7,993	2,010	0	121	0	10,124
Hagerstown	14,869	2,158	135	4	0	17,166	14,869	2,158	135	4	0	17,166
PE/AP	388,578	52,484	5,954	691	6	447,713	206,335	25,543	2,762	342	3	234,985
Pepco	660,883	71,317	11	134	0	732,345	458,912	45,089	10	102	0	504,113
SMECO	123,353	11,798	4	180	0	135,535	123,353	11,798	4	180	0	135,535
Somerset	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Thurmont	2,470	325	9	47	0	2,851	2,470	325	9	47	0	2,851
Williamsport	821	59	35	33	0	948	821	59	35	33	0	948
Total	**2,755,290**	**316,347**	**11,614**	**2,149**	**8**	**3,085,688**	**2,096,937**	**229,256**	**8,108**	**1,392**	**3**	**2,335,976**

Table A-3: Sales by Customer Class (GWh) (as of December 31, 2004)												
	System-Wide						Maryland					
Utility	**Resi-dential**	**Com-mercial**	**Indus-trial**	**Other**	**Sales for Resale**	**Total**	**Resi-dential**	**Com-mercial**	**Indus-trial**	**Other**	**Sales for Resale**	**Total**
A&N	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
BGE	13,313	15,052	3,991	0	0	32,356	13,313	15,052	3,991	0	0	32,356
Berlin	20	3	14	0	0	37	20	3	14	0	0	37
Choptank	575	169	75	1	0	820	575	169	75	1	0	820
DPL	5,363	5,238	3,251	51	1	13,904	2,212	1,710	529	12	0	4,463
Easton	104	146	0.0	12	0	262	104	146	0.0	12	0	262
Hagers-town	149	63	129	7	0	348	149	63	129	7	0	348
PE/AP	5,922	3,199	6,475	24	746	16,366	3,244	1,879	4,624	12	471	10,230
Pepco	8,135	17,334	748	680	5	26,902	6,301	8,435	466	281	0	15,483
SMECO	2,034	1,041	194	6	0	3,274	2,034	1,041	194	6	0	3,274
Somerset	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Thurmont	40	16	27	1	0	84	40	16	27	1	0	84
Williams-port	9	2	7	1	0	19	9	2	7	1	0	19
Total	**35,664**	**42,263**	**14 ,911**	**783**	**752**	**94,372**	**28,001**	**28,516**	**10,056**	**333**	**471**	**67,376**

Table A-4: Typical Utility Bills in Maryland, Winter 2005						
	Typical Bill ($)			Revenue: cents/kWh		
	Residential	**Commercial**	**Industrial**	**Residential**	**Commercial**	**Industrial**
A&N	N/A	N/A	N/A	N/A	N/A	N/A
BGE	$58.62	$1,085.40	$16,185.40	$0.07816	$0.08683	$0.0809
Berlin	$140.66	$1,569.59	$23,220.01	$0.140660	$0.156959	$0.116100
Choptank	$88.45	$1,400.97	$20,526.01	$0.117933	$0.112080	$0.102630
DPL	$70.96	$415.90	$15,005.65	$0.094613	$0.118829	$0.075028
Easton	$73.47	$1,308.04	N/A	$0.09796	$0.10464	N/A
Hagerstown	$47.75	$862.95	$10,152.81	$0.0636	$0.0690	$0.0576
Allegheny Power	$107.55	$495.85	$3,057.55	$0.06722	$0.07629	$0.07457
Pepco	$66.22	$1,030.01	$12,716.55	$0.0883	$0.0824	$0.0636
Somerset	N/A	N/A	N/A	N/A	N/A	N/A
SMECO	$59.05	$861.13	$12,354.06	$0.0787	$0.0689	$0.0618
Thurmont	$54.46	$843.95	$11,345.56	$0.07149	$0.06617	$0.05575
Williamsport	$60.79	$136.22	$823.29	$0.055	$0.054	$0.055

Table A-5: Peak Demand Forecast , 2005-2019 (Net of DSM Programs; MW)													
Year	**A&N**	**BGE**	**Berlin**	**Choptank**	**DPL**	**Easton**	**Hagers-town**	**PE/AP**	**Pepco**	**Somerset**	**SMECO**	**Thurmont**	**Williams-port**
2005	N/A	6,940	9.71	211.0	4,028	61.2	79.83	3,022	5,796	N/A	770	21.60	4.600
2006	N/A	7,016	9.90	218.2	4,143	62.6	82.23	3,070	5.904	N/A	767	21.92	4.600
2007	N/A	7,109	10.10	227.4	4,257	64.1	84.70	3,131	6,015	N/A	788	22.25	4.610
2008	N/A	7,213	10.30	241.7	4,372	65.5	87.24	3,187	6,128	N/A	811	22.59	4.610
2009	N/A	7,311	10.51	252.6	4,487	66.9	89.86	3,238	6,244	N/A	831	22.92	4.620
2010	N/A	7,406	10.72	262.3	4,601	68.3	92.58	3,293	6,362	N/A	852	23.27	4.620
2011	N/A	7,505	10.93	272.3	4,716	69.7	95.36	3,353	6,483	N/A	871	23.62	4.630
2012	N/A	7,608	11.15	283.2	4,831	71.2	98.22	3,407	6,606	N/A	891	23.97	4.630
2013	N/A	7,709	11.38	294.6	4,945	72.6	101.17	3,469	6,731	N/A	909	24.33	4.640
2014	N/A	7,807	11.60	306.6	5,060	74.0	104.21	3,532	6,859	N/A	927	24.70	4.640
2015	N/A	N/A	11.83	319.3	5,177	75.4	107.33	3,596	6,989	N/A	945	25.07	4.650
2016	N/A	N/A	12.07	332.5	5,297	76.9	110.55	3,659	7,121	N/A	962	25.44	4.650
2017	N/A	N/A	12.31	346.6	5,419	78.3	113.87	3,722	7,256	N/A	980	25.82	4.650
2018	N/A	N/A	12.56	361.3	5,544	79.7	117.28	3,787	7,394	N/A	996	26.21	4.660
2019	N/A	N/A	12.81	377.1	5,673	81.1	120.80	3,853	7,534	N/A	1,013	26.60	4.660

Table A-6: Energy Sales Forecast, 2005-2019 (Net of DSM Programs; GWh)													
Year	**A&N**	**BGE**	**Berlin**	**Choptank**	**DPL**	**Easton**	**Hagers-town**	**PE/AP**	**Pepco**	**Somerset**	**SMECO**	**Thurmont**	**Williams-port**
2005	N/A	33,635	37.82	855.4	14,050	294	364.6	16,827	27,074	N/A	3,319	85.11	17.0
2006	N/A	34,105	38.57	895.6	14,360	301	375.6	17,205	27,562	N/A	3,409	86.39	17.0
2007	N/A	34,638	39.35	945.7	14,679	308	386.9	17,559	28,062	N/A	3,509	87.69	17.1
2008	N/A	35,206	40.13	999.4	15,059	314	398.5	17,933	28,647	N/A	3,608	89.00	17.1
2009	N/A	35,734	40.94	1,057.7	15,354	321	410.4	17,947	29,071	N/A	3,697	90.34	17.1
2010	N/A	36,295	41.76	1,109.6	15,704	328	422.7	18,172	29,501	N/A	3,785	91.69	17.1
2011	N/A	36,864	42.59	1,163.0	16,064	335	435.4	18,397	29,938	N/A	3,869	93.07	17.2
2012	N/A	37,441	43.44	1,221.6	16,435	342	448.5	18,740	30,381	N/A	3,948	94.46	17.2
2013	N/A	37,030	44.31	1,282.8	16,817	349	461.9	19,028	30,831	N/A	4,022	95.88	17.2
2014	N/A	38,626	45.20	1,347.4	17,211	355	475.8	19,380	31,287	N/A	4,096	97.32	17.2
2015	N/A	N/A	46.10	1,415.3	17,619	362	490.1	19,739	31,750	N/A	4,167	98.78	17.3
2016	N/A	N/A	47.02	1,486.3	18,024	369	504.8	20,158	32,220	N/A	4,242	100.26	17.3
2017	N/A	N/A	47.96	1,561.6	18,439	376	519.9	20,451	32,697	N/A	4,311	101.76	17.3
2018	N/A	N/A	48.92	1,604.6	18,863	383	535.5	20,821	33,181	N/A	4,379	103.29	17.3
2019	N/A	N/A	49.90	1,725.3	19,297	389	551.6	21,204	33,672	N/A	4,441	104.84	17.3

Table A-7:
List of Currently Licensed Electric and Natural Gas Suppliers and Brokers/Aggregators
(As of November 30, 2005)

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] Amerada Hess Corporation	IR-219		IR-323	
[5] America PowerNet Management	IR-604			
[6] AOBA Alliance, Inc.		IR-267		IR-375
[7] Ashland Energy Services			IR-332	
[8] Association and Agency Consortium for Energy, LLC		IR-268		
[9] BGE Home Products and Services d/b/a BGE Commercial Building Systems	IR-228		IR-311	
[10] Blue Star Energy Services	IR-757			
[11] BOC Energy Services	IR-753			
[12] Bollinger Energy Corporation		IR-265	IR-322	
[13] BP Energy Company			IR-676	
[14] Colonial Energy, Inc.			IR-606	
[15] Commerce Energy, Inc.	IR-639		IR-737	
[16] Compass Energy Services			IR-652	
[17] Conoco, Inc.			IR-378	
[18] Constellation Energy Source, Inc.	IR-239			
[19] Consolidation Edison Solutions	IR-603			
[20] Constellation New Energy, Inc.	IR-500		IR-522	
[21] Constellation New Energy – Gas Division, LLC		IR-655		
[22] Coral Energy Gas Sales, Inc.			IR-360	
[23] CQI Associates, LLC		IR-575		
[24] Cypress Natural Gas			IR-674	
[25] Delta Energy, LLC			IR-645	
[26] Direct Energy	IR-719			
[27] Dominion Retail, Inc.	IR-252		IR-345	
[28] Downes Associates, Inc.		IR-523		

Table A-7: (continued)
List of Currently Licensed Electric and Natural Gas Suppliers and Brokers/Aggregators
(As of November 30, 2005)

Company	Electric Supplier License #	Electric Broker License #	N. Gas Supplier License #	N. Gas Broker License #
[29] Eastern Shore of Maryland Educational Consortium Energy Trust d/b/a ESMEC Energy Trust		IR-342		
[30] Econnergy Energy Company	IR-340		IR-334	
[31] Energy America, LLC	IR-276		IR-317	
[32] Energy Options, LLC		IR-568		
[33] Energy Services Management, LLC d/b/a Maryland Energy Consortium		IR-236		IR-312
[34] Energy Services Provider Group, LLC		IR-518		IR-519
[35] EnergyWindow, Inc.		IR-274		
[36] Enron Energy Marketing Corp.			IR-370	
[37] Entex Gas Resources Crop.			IR-350	
[38] Essential.com, Inc.	IR-259			
[39] FirstEnergy Solutions Corp.	IR-225			
[40] Hess Energy, Inc.			IR-337	
[41] HIS Power & Water, LLC	IR-271			
[42] Horizon Power & Light	IR-704			
[43] Houston Energy Services Company, LLC.			IR-403	
[44] ISG Sparrows Point	IR-592			
[45] Liberty Power Corporation	IR-607			
[46] Liberty Power, Maryland	IR-793			
[47] Marathon Oil Company			IR-364	
[48] Market Direct d/b/a MD Energy		IR-614		
[49] MeadWestvaco Energy Services, LLC	IR-669			
[50] Metromedia Energy, Inc.			IR-355	
[51] Mid-Atlantic Aggregation Group Independent Consortium, LLC d/b/a MAAGIC		IR-234		
[52] Mirant Americas Energy Marketing, LP.	IR-297			

Table A-7: (continued)
List of Currently Licensed Electric and Natural Gas Suppliers and Brokers/Aggregators
(As of November 30, 2005)

Company	Electric Supplier License #	Electric Broker License #	N. Gas Supplier License #	N. Gas Broker License #
[53] Mirant Americas Retail Energy Marketing, LP.	IR-480			
[54] Mona Building Technologies, LLC		IR-257		
[55] MxEnergy.com, Inc.			IR-327	
[56] Ohms Energy Company, LLC	IR-679			
[57] Pepco Energy Services, Inc. d/b/a Conectiv Energy Services	IR-222		IR-316	
[58] Pivotal Utility, Inc.			IR-376	
[59] PPL EnergyPlus, LLC	IR-230			
[60] QVINTA, Inc.		IR-557		IR-530
[61] Reliant Energy Solutions East, LLC	IR-525			
[62] Select Energy, Inc.	IR-275		IR-331	
[63] Sempra Energy Solutions	IR-442		IR-464	
[64] SmartEnergy.com, Inc.	IR-270			
[65] Smith Energy		IR-626		
[66] Sprague Energy Corp.				IR-339
[67] Stand Energy			IR-623	
[68] Statoil Natural Gas, LLC			IR-561	
[69] Strategic Energy, LLC	IR-437			
[70] South Jersey Energy Co.	IR-740			
[71] SUEZ Energy	IR-605			
[72] The New Power Company IBM Global Services	IR-336			
[73] Tiger Natural Gas			IR-351	
[74] Total Gas & Electric, Inc.			IR-348	
[75] TransAlta Energy Marketing, Inc.			IR-474	
[76] Trigen-Baltimore Energy Corporation		IR-258		
[77] UGI Energy Services, Inc.	IR-237		IR-319	
[78] Utility Resource Solutions			IR-613	
[79] Washington Gas Energy Services, Inc.	IR-227		IR-324	

No. of Suppliers/Brokers: ➡Electric Suppliers = 25; Electric Brokers = 13; Natural Gas Suppliers = 23; Natural Gas Brokers = 1 ; Electric & Natural Gas Suppliers = 12; Electric & Natural Gas Brokers = 4; Natural Gas Supplier & Electric Broker = 1; ➡ Total = 79.

Table A-8:
Transmission Enhancements in Allegheny Power's Service Area

Transmission Owner	#	Project	Voltage (kV)	Length (miles)	No. of circuits	Start Date	In-service date	Purpose
Allegheny	1	New Line from Kelso Gap to Oak Park – Elk Garden	138	0.1	2	2005	2005	GI
Allegheny	2	Boonsboro to Marlowe	230	12.4	1	2005	2005	BTR
Allegheny	3	New line from Paramount No. 1 to Halfway-Reid	138	0.1	2	2005	2006	DA
Allegheny	4	Upgrade Urbana from 34.5 kV for 230 kV connection with Lime Kiln-Montgomery	230	2.1	2	2005	2006	DA
Allegheny	5	New Line from Fairplay to Marlowe- Boonsboro	138	0.1	2	2010	2011	DA
Allegheny	6	Upgrade Ridgeville substation from 34.5 kV for connection with Mt. Airy-Damascus Transmission Line	230	0.6	2	2007	2008	DA
Allegheny	7	New South Frederick No.1 connection to Monacacy-Lime Kiln	230	0.1	2	2008	2009	DA
Allegheny	8	Upgrade Emmitsburg 34.5 kV substation to connect to Catoctin at 138 kV	138	8	1	2007	2008	DA
Allegheny	9	New Jefferson No.1 substation to connect to the Doubs-Monacacy Transmission Line	230	0.1	2	2008	2009	DA

Table A-8 (continued)

Transmission Enhancements in Allegheny Power's Service Area

Transmission Owner	#	Project	Voltage (kV)	Length (miles)	No. of circuits	Start Date	In-service date	Purpose
Allegheny	10	Upgrade Clear Spring 34.5 kV to connect with Nipetown –Reid Transmission line -138 kV	138	5	1	2009	2009	DA
Allegheny	11	From Doubs to Lime Kiln (Section 207)	230	0.1	1	2005	2006	BTR
Allegheny	12	From Doubs to Lime Kiln (Section DLF2)	230	0.1	1	2006	2006	BTR
Allegheny	13	From Lime Kiln to McCain	230	0.1	1	2006	2006	BTR
Allegheny	14	From Lime Kiln to Monocacy	230	0.1	1	2005	2006	BTR
Allegheny	15	From Lime Kiln to Montgomery	230	0.1	1	2005	2006	BTR
Allegheny	16	From Frederick to Monocacy	230	0.1	1	2007	2007	BTR
Allegheny	17	From Black Oak to Cumberland	138	0.5	1	2014	2014	BTR
Allegheny	18	New Line from Montgomery to Bucklodge	230	7.8	1	2014	2014	BTR

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

Table A-9:
Transmission Enhancements in Baltimore Gas & Electric Company's Service Area

Transmission Owner	#	Project	Voltage (kV)	Length (miles)	No. of circuits	Start Date	In-ser-vice date	Purpose
BGE	1	Baltimore City – Westport Paca in Baltimore City	115	4	2	Jan-04	Jun-08	BTR, DA
BGE	2	Baltimore County to Northwest in Finksburg Baltimore City	115	3.3	1	Jan-07	Dec-08	DA
BGE	3	Westport to Center Street in Baltimore City	115	1.95	1	Jan-04	May-07	BTR
BGE	4	Westport to Wilkens in Baltimore City	115	2.05	2	Jan-07	Jun-10	DA
BGE	5	Brandon Shores in Anne Arundel County to Hawkins Point in Baltimore City	230	2.49	1	Mar-06	Jun-07	BTR
BGE	6	Sollers Point to Riverside in Baltimore County	230	0.49	1	Mar-06	Jun-07	BTR

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

Table A-10:
Transmission Enhancements in Delmarva Power & Light's Service Area

Transmission Owner	#	Project	Voltage (kV)	Length (miles)	No. of circuits	Start Date	In-ser-vice date	Purpose
DPL	1	Rebuild Vienna in Dorchester County to Nelson in Sussex County	138	13.73	1	9-2011	5-2013	BTR
DPL	2	Existing Line Church to Wye Mills in Easton	138	12.98	1	1-2009	5-2010	BTR
DPL	3	2nd line from Grasonville to Stevensville in Queen Annes County	69	5.32	1	9-2004	12-2006	DA
DPL	4	2nd line from Easton to Bozman County	69	11.13	1	9-2007	5-2008	DA
DPL	5	Existing line from Vienna to Sharptown	69	4.42	1	1-2010	5-2011	BTR
DPL	6	Existing line from Piney Grove to Mt. Olive	69	4.60	1	1-2008	5-2009	BTR
DPL	7	Existing line from Todd to Allen	69	9.00	1	1-2009	5-2010	DA
DPL	8	Existing line from Ocean Bay to Maridel	69	2.61	1	1-2009	5-2010	BTR
DPL	9	Existing line from Maridel to Ocean City	69	2.73	1	1-2006	5-2007	BTR

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

Table A-11:
Transmission Enhancements in SMECO's Service Area

Transmission Owner	#	Project	Voltage (kV)	Length (miles)	No. of circuits	Start Date	In-service date	Purpose
SMECO	1	Hollard Cliff to Calvert Cliffs Tap in Calvert County (CPCN required)	230	20.0	2	2015	2016	DA
SMECO	2	Calvert Cliffs Tap to Calvert Cliffs Switching Station in Calvert County (CPCN required)	230	1.1	2	2016	2017	DA
SMECO	3	Calvert Cliffs Switching Station to Hewitt Road Switching Station in St. Mary's County (CPCN required)	230	12.7	2	2018	2019	DA

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