PUBLIC SERVICE COMMISSION
OF MARYLAND

TEN-YEAR PLAN (2004 – 2013) 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

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TABLE OF CONTENTS

LIST OF TABLES

APPENDIX

I. INTRODUCTION

This report constitutes the Maryland Public Service Commission's (Commission or PSC) 2004 Ten-Year Plan 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 Utilities Companies Article (PUC Article), Ann*otated 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 their 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 their local distribution utility. This section also discusses the results of the first auctions pertaining to electric companies that resulted from the Standard Offer Service proceeding (Case No. 8908) and gives an update on the competitive activities of licensed electric and gas suppliers.

Section III presents data on generation activity in Maryland, including exemptions of the Certificate of Public Convenience and Necessity (CPCN) process for on-site generation, a process established under Section 7-207.1 of the PUC Article, which became effective on October 1, 2001.

Section IV provides information on transmission and distribution services in Maryland. Expanding, upgrading, and maintaining transmission lines are critical to the provision of reliable electric service. Discussed here are actions being taken by Maryland utilities in the aftermath of Tropical Storm Isabel and the August 2003 blackout. A summary and update of recent activities at PJM Interconnection, LLC, (PJM)[4] is also included in this section.

Finally, Section V provides a summary of utility efforts since January 1, 2003, to implement conservation programs and to promote and utilize renewable resources and cogeneration. During 2004, the General Assembly passed and Governor Robert L. Ehrlich signed the Renewable Energy Portfolio Standard Legislation (RPS), a significant event that is discussed in this section.

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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 §601 *et seq.*
4. PJM is the regional transmission organization (RTO) for the electric grid in the Mid-Atlantic region and ensures its reliability by coordinating the movement of electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

The Appendix contains a compilation of data provided by Maryland's electric companies. It also includes a list of all licensed electric and natural gas suppliers and brokers in Maryland, Certificate of Public Convenience and Necessity ("CPCN") exemptions since January 2002, and planned transmission enhancements.

II. RETAIL CUSTOMER CHOICE IN MARYLAND

Electric restructuring was initiated in Maryland pursuant to the Electric Customer Choice and Competition Act of 1999. This law established the legal framework for the restructuring and revised regulation of the electric industry in Maryland. The Electric Act deregulated "the generation, supply, and pricing of electricity" 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 electric suppliers, it is helpful to mention natural gas activities also, since many of the electric 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" as well as 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. In the restructured marketplace, if customers choose to remain with their distribution companies, the utilities will continue 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 maintains the potential for significant benefits to electricity customers. Some reasons for moving to a competitive electric market are:

- to put downward pressure on costs, thus providing consumers with the lowest possible electricity prices;
- to allow all customers the opportunity to select their electricity supplier;

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5 As of December 1, 2004, the Commission has issued 32 electric supplier licenses, 18 electric broker licenses, 33 natural gas supplier licenses, and 5 natural gas broker licenses; among these, 15 companies had both electricity and natural gas licenses (see Appendix Table A-8).

6 PUC Article §7-603(b).

- to provide incentives for the creation and development of innovative products and services;
- to 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,
- to attract new business development, retain existing businesses, and enhance overall economic growth.

Electric service is currently available to many classes of Maryland customers via SOS. Among the four major 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 recently approved changes to the appearance of the Electricity and Natural Gas Supplier lists that appear on its website. The revised website allows customers to search for suppliers by service, customer class, and service territory. These searches replace the current static lists that group all electricity and natural gas suppliers together in separate master lists. The Commission recognizes that a supplier's "Actively Seeking" status may change from time to time and wants 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 10, 2004, 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: 1 serving residential load, 13 serving industrial load, 13 serving commercial load, and 4 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 both licensed and prospective Maryland suppliers, Commission Staff, other State agencies, customer groups, and PJM. The conference updated attendees on the status of Electric Choice, gave 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).

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 electric suppliers and electric generation services providers in Maryland pursuant to §7-507 of

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

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 FERC, and any ISO or transmission operator to be used;
- compliance with applicable federal and state environmental laws and regulations that relate to the generation of electricity; and,
- financial integrity and qualification to do business in the State of Maryland.

On July 12, 2002 the Commission published in the *Maryland Register* regulations governing 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 electric suppliers in each of the major distribution utilities in Maryland.

Table 1: Electric Choice Enrollment in Maryland

Number of Customers Served by Electric Suppliers

Utilities	Residential	Small C&I[8]	Mid C&I[9]	Large C&I[10]	ALL C&I	Total
AP	0	0	0	2	2	2
BG&E	33	321	1,857	464	2,642	2,675
Conectiv	193	1,750	194	75	2,019	2,212
Pepco	44,755	4,979	3,498	366	8,843	53,598
Total	44,981	7,050	5,549	907	13,506	58,487

Percentage of Peak Load Obligation Served by Electric Suppliers

Utilities	Residential	Small C&I	Mid C&I	Large C&I	ALL C&I	Total
AP	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
BG&E	0.0%	2.1%	31.4%	90.3%	48.8%	25.6%
Conectiv	0.1%	10.1%	38.4%	91.4%	42.7%	19.2%
Pepco	11.5%	18.9%	34.0%	73.7%	51.1%	32.1%
Total	3.1%	4.7%	30.2%	77.4%	44.4%	23.9%

Source: Maryland Public Service Commission, *Electric Choice Enrollment Monthly Report*, October 2004. The Electric Choice Enrollment Report is updated monthly and can be obtained at: http://www.psc.state.md.us/psc/home.htm.

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 Conectiv and 25 kW for Pepco. These customers are eligible for "Type 1" 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 1 SOS) for each utility but less than 600 kW. These customers are eligible for "Type 2" fixed price utility Standard Offer Service if they do not switch to a supplier.

10 Large C&I customers are commercial or industrial customers with demands equal to or greater than 600 kW, these customers have an option of either "Type 3" fixed price utility Standard Offer Service or hourly priced service (based on PJM hourly LMP) if they do not switch to a supplier.

During 2004, the Commission considered regulations pertaining to consumer protections, including contracting practices, for use where commodity service is provided by a competitive supplier. Proposed Regulations were published in the *Maryland Register* on October 15, 2004, and are subject to a 30-day comment period. The Consumer Protection Regulations, as proposed, represent an attempt to place into regulations requirements previously contained in Commission orders with adjustments, where appropriate, to accommodate development in the supplier markets that has occurred since the issuance of those orders. The Consumer Protection Regulations, as proposed, 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. The Consumer Protection Regulations will not become effective until 2005.

During 2004, the Commission met with representatives of utility companies, their affiliates, and third party energy suppliers that are competitors of utility retail affiliates, 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 markets and to ensure utilities do not subsidize their affiliates. The proposed regulations have been approved by the Commission for publication in the Maryland Register.

C. Standard Offer Service - Case No. 8908

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 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. 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. Limited changes will be made regarding how rate-regulated cooperative utilities provide SOS to their customers.

By Order No. 78710 issued on October 1, 2003, the Commission established the procedures for procuring SOS as Phase II of the proceeding and established the technical details supporting the SOS policy framework. 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 establishes 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. 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 were available for bid.

Listed below is a summary of the initial round 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, 2, and 3 years;
- Type I Non-residential - 1 and 2 years; and,
- Type II and III Non-residential - 1 year.

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

- October 2003**:** The utilities held a joint pre-bid meeting in Baltimore; over 30 interested entities attended;
- November 2003: Commission's 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;
- December 2003: "Dry runs" of the bid-day evaluation process; and,
- February-March 2004: Bids for each tranche; blocks offered were fully subscribed in all four utilities.

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

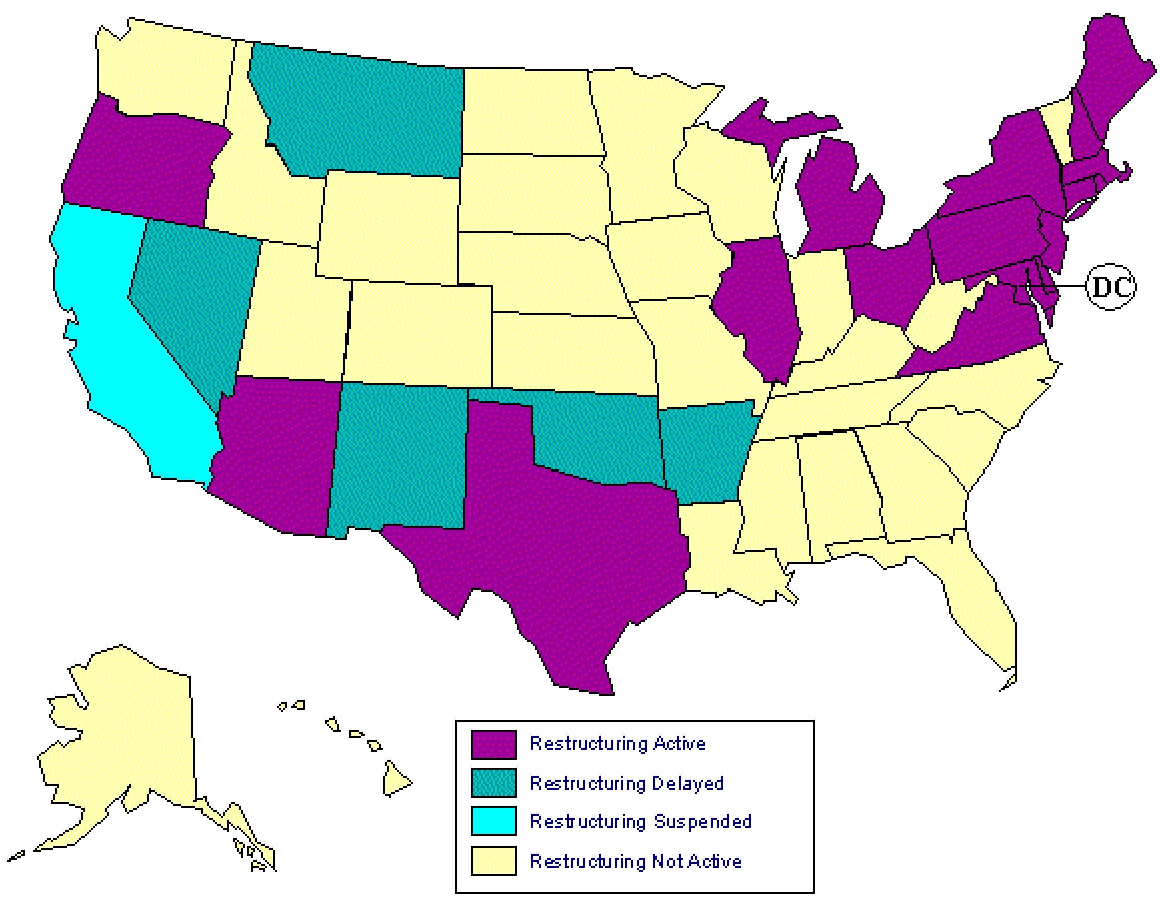
- The utilities conformed to their Bid Plans as required by Commission Orders, and there were appropriate security measures on all bid days.
- Of the 25 bidders in this process, 14 won some portion of the load.
- There was evidence of robust competition in terms of the number of bidders as well as the number of bids received.
- The bid prices reflected general economic conditions.
- On average, the number of megawatts (MW) bidders offered was nearly five times greater than the number of MWs awarded. 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.

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

The second round of SOS bids will be for approximately 3,600 MW, including 290 MW for AP, 1,420 MW for BGE, 510 MW for Conectiv, and 1,380 MW for Pepco. The RFP will again include up to four rounds, scheduled to begin in December 2004 and conclude in March 2005, for supply services to begin June 1, 2005. The joint-utility pre-bid conference was held on October 20, 2004, 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.

D. National Retail Access Activities

Currently, retail electricity access is or will soon be available in 18 states in the nation (including D.C.). 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 Web page, *Status of State Electric Industry Restructuring Activity*, (as of February 2003); <http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html>.

III. ELECTRIC GENERATION ACTIVITY IN MARYLAND

A. Certification of New Electric Plants

During the past two years, the Commission has granted several CPCNs for generating projects in Maryland. The electricity generated by most of these projects will be sold in regional markets. However, the output of some projects will be used entirely on site. Table 2 identifies all generating projects for which the Commission has granted a CPCN and those pending before the Commission. All of the projects listed in this table have plans to interconnect with PJM's regional market.

Table 2: New Generating Resources Planned for Construction in Maryland

Resource Developer And Location	*Capacity (MW)*	*Expected In-Service Date*	*Interconnected with Regional Market*	*CPCN Status*
Clipper Windpower, Garrett County	101	Pending financing	Yes	Granted
Catoctin / EastAlco by Sempra Energy, Frederick County	640	2007	Yes	CN 8997 In Progress
Dans Mountain Wind Force, Allegheny County	50	–	Yes	Pending
Savage Mountain, US Windforce, Allegany and Garrett Counties	40	Pending financing	Yes	Granted
Dickerson Power Plant, Station "H"; Montgomery County	518	Pending financing	Yes	CN 8888 order final Dec 7, 2004
Roth Rock Windpower Project Synergics Wind Energy, Garrett County	40	Pending	Yes	CN 9008 In Progress
Mirant Chalk Point, Prince Georges County	320	–	Yes	CN 8912 Pending

Growth in power plant development has been modest. Many older generating units within PJM can no longer compete with newer more efficient plants. Also, due to the relatively mild weather during the summer of 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. Natural gas has been the fuel of choice for new peakers and mid-merit units. Renewal of federal tax credits has encouraged the development of windfarms in Western Maryland. The RPS Legislation may promote this development further. There have been no new applications for large baseload plants.

PJM analyzed the impact of the retirement of the 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.

B. CPCN Exemptions for On-site Generation

Under PUC Article§7-207.1, which became effective October 1, 2001, 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
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.

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 106 MW (summarized below in Table 3 with details in Appendix Table A-9). 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. 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 3: CPCN Exemptions Since October 2002

PERIOD APPROVED	*NO. OF UNITS*	*TOTAL*
Calendar Year 2002	36	34.5 MW
Calendar Year 2003	12	51.1 MW
Calendar Year 2004	60	53.1 MW
Applications Pending	2	1.1 MW

C. PJM Expansion and State of the Market

PJM's expanding market and geographic footprint help to ensure the availability of more distant resources. During 2004, PJM has expanded into Northern Illinois, Virginia, West Virginia, Western Pennsylvania, and Ohio. 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 recent and near term expansion is listed in the following table:

Table 4: PJM's Expansion Schedule

Utility	States	NERC Region	Integration date
ComEd	Northern Illinois	MAIN	May 1, 2004
AEP & DP&L	Kentucky, West Virginia, Ohio	ECAR	October 1, 2004
Dominion & Virginia Power	Virginia, North Carolina	SERC	January 1, 2005
Duquesne	West Pennsylvania	ECAR	January 1, 2005

With the successful integration of these service territories, PJM plans to reduce the installed reserve margin from 17 percent to 15 percent beginning January 1, 2005.

PJM issued its 2003 State of the Market Report on January 30, 2004. 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. Long term contracts are preferable to reliance on the energy markets to ensure long-term stability and reliability. To address many of these issues associated with PJM's traditional Installed Capacity (ICAP) market, PJM has introduced the Reliability Pricing Model (RPM). RPM consists of modifications to the capacity market to ensure adequate compensation for generation, which is critical to various PJM regions. RPM is also based on a demand curve, which serves to send price signals for demand side management. (See full discussion of the RPM in Section IV. K below). Retail customers of Load Serving Entities (LSEs) want assurance of continued reliability and reasonably priced generation. Load forecasting methodologies and assumptions are being re-evaluated in PJM working groups called The Reliability Planning Assumptions Working Group and the Reliability Planning Criteria Working Group.

D. Congestion Management

PJM and Conectiv have addressed successfully congestion management issues on the Eastern Shore with hardware upgrades as well as economic measures. In addition, PJM has continued its practice of Post Contingency Congestion Management (PCCM) during the summer of 2004. PCCM reduces the incidence of off-cost operations by increasing the thermal emergency limits of transmission lines. There had been complaints from generators about lost revenue, which may in part be alleviated by RPM. PCCM also raised concerns about reliability, which PJM addressed with its modest implementation of the program. PCCM is used primarily in the summer months. With the application of RPM, PJM has started to examine "sub-zones" like southern Delmarva, which would have separate demand curves and other capacity components. Resource adequacy zones are not expected to have any impact on the pricing of transmission through transmission zones.

IV. TRANSMISSION AND DISTRIBUTION SERVICES

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 and distribution facilities in the State. The MD PSC held its annual Summer Reliability Status Conference on May 10, 2004. During this conference, Maryland's utilities filed comments concerning their ability to meet summer 2004 anticipated electricity demand. PJM also reported on its ability to maintain the grid. Since the summer weather was relatively mild in 2004, there were no major problems in meeting the demand for electricity. The Commission requires that electric distribution companies continue to invest in appropriate mitigation or expansion measures to ensure the reliability of their delivery systems. The Northeast Blackout of August 2003 and Tropical Storm Isabel have forced a re-evaluation of the standards and criteria for assessing reliability in Maryland and throughout the country. See Section IV. (B) of this report for a description of specific measures being taken.

A. The Regional Transmission Expansion Planning Protocol

The PJM Regional Transmission Expansion Planning Protocol (RTEPP) requires that cost responsibility for transmission enhancements be established. There are three types of facility enhancements for which cost assignment must be made:

- Attachment Facilities required solely to interconnect a new generation project;
- Network Facilities that are required to enhance the network solely or in part because of a proposed project; and,
- Network Facilities required to support load growth.

In order to establish a starting point for development of Regional Transmission Expansion Plans and determine cost responsibility for expansion facilities, a "baseline" analysis of system adequacy and security is necessary. The purpose of this analysis is:

- To identify areas where the system, as planned, is not in compliance with the applicable reliability standards (NERC, [13] MAAC, or ECAR reliability standards);
- To bring those areas into compliance, develop and recommend facility expansion plans, including cost estimates and estimated in-service dates; and,
- To establish what will be included as baseline costs in the allocation of the costs of expansion for those generation projects proposing to connect to the PJM system.

1. PJM's Baseline RTEPP

In order to establish a baseline, PJM has defined the five-year period from 2004 through 2008 as the 2003 "baseline" planning period. The existing system plus any planned modifications to the transmission system scheduled to be in service prior to the 2008 summer peak period was chosen as the base system. All new generation and transmission projects in Queues A through I that executed a Facility Study Agreement were also included in this baseline system along with any associated transmission enhancements as identified in the Impact Studies. Any transmission owner identified transmission enhancements independent of those associated with new generation or merchant transmission projects were also included. Only firm transmission service currently committed for the period was represented.

[13] The North American Electric Reliability Council (NERC) promotes the reliability of the electric supply for North America and has ten Regional Reliability Councils, two of which are the Mid-Atlantic Area Council (MAAC) and the East Central Area Reliability Council (ECAR).

The 2003 PJM baseline RTEPP report was first issued on April 5, 2004 and revised on April 30, 2004. Some transmission enhancements required by previous RTEPPs have not yet been put into service. Scheduled transmission enhancements in Maryland that have not been placed into service are summarized in Tables A-10 to A-13 of the Appendix. Supplemental information provided by the transmission owners is discussed below.

2. PJM's Authority From FERC

FERC approved PJM as an Independent System Operator (ISO) in 1997. Since that time PJM has administered its RTEPP as described in Schedule 6 of the Operating Agreement. PJM has subsequently received authority from FERC for procedures and rules for transmission expansions needed to enable the interconnection of new and expanded generation and merchant transmission facilities (1999). Most recently, PJM has amended the RTEPP to include the development of transmission projects to support competition in wholesale electric markets (2003). 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 a Regional Transmission Organization (RTO). PJM is the administrator of the Open Access Transmission Tariff (OATT) as approved by FERC. The OATT is the basis for PJM to collect charges to recover the costs of projects owned, constructed, or financed by the transmission owners. Recently, transmission owners filed new schedules to establish annual carrying charge rates to recover transmission investments made pursuant to the RTEPP.

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.

3. MAAC Reliability Criteria

MAAC is responsible 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.[14]

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 requires that its facilities are capable of surviving the following losses without overloading other equipment:

- The loss of any single facility (MAAC Criteria IIA);

[14] Source: MAAC's Web site at www.maac-rc.org.

- 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).

4. ECAR

While most of Maryland is within the MAAC reliability region, the western portion of the State served by Allegheny Power is within the ECAR region. ECAR's membership includes 29 major electricity suppliers located in nine east-central states serving more than 36 million people.[15] ECAR is similar to MAAC; however, it includes a different contiguous geographical area adjacent to MAAC. ECAR does not use the generator deliverability test that PJM uses in its RTEPP process. Membership in ECAR is voluntary, but ECAR is looking for compliance monitoring and an enforcement process especially now, following the events of the August 14th 2003 Northeast blackout which started in ECAR territory.

5. Southwest PJM – Allegheny, BGE, and PEPCO

For 2005 through 2007, the Southwest PJM system is not in compliance with the PJM CETO/CETL Deliverability test.[16] In 2005, this area may experience voltage drops in excess of defined limits and post-contingency voltages below criteria under certain critical contingencies. The preliminary plan to remedy the voltage fluctuations includes 1000 Mega Volt Amperes Reactives (MVARs)[17] of static and dynamic reactive support installed throughout the region. Approximately one-third of the total reactive support must be installed by the summer of 2005, two-thirds by the summer of 2006, and the remainder by the summer of 2007. BGE and PEPCO are anticipated to share the cost.

Doubs continues to be a focal point for generation and transmission. Although technically in Allegheny's territory, it is adjacent to Pepco and BGE. It is a node for several interstate 500 kV transmission lines: two owned by Allegheny, one by Virginia Power and Light Company ("VEPCO"), and one by BGE. Power flows through Doubs from west to east and Doubs is also a prime site for new generation, since PJM often needs voltage support in this area. The current plan is to replace Doubs 500/230 kV #1 transformer at a cost of $4 million prior to the summer of 2007. Replacement of this transformer will not be necessary if the Catoctin EastAlco power plant is in-service by the summer of 2007.

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15 Source: ECAR's Web site at www.ecar.org.

16 The amount of external capacity resources necessary to maintain the loss of load probability is known as the capacity emergency transfer objective (CETO) and is calculated for each MAAC subsystem. This value is compared to the amount of power imports that can be achieved during capacity emergency conditions, known as the capacity emergency transfer limit (CETL). The tested subarea will have a loss of load probability of no more than 1-day/10 years when CETL exceeds CETO. The CETO/CETL test is commonly referred to as the Deliverability test.

17 MVAR is a measure of reactive power.

6. Central Maryland – BGE

BGE has agreed to complete two capital projects by the summer of 2005 to address an adequacy of supply to load issue in the Baltimore/Washington area. The two projects, including the latest estimated costs, are the installation of:

-Two 230 kV 120 MVAR capacitor banks at the Northwest Substation- $4 million

-One 230 kV breaker at the High Ridge Substation- $362,500

PJM has also identified 500/230 kV transformer tap changes at the Conastone and Waugh Chapel Substations. BGE should not incur any appreciable new Operating and Maintenance (O&M) expenses in order to make these changes.

The Brandon Shores to Riverside 230 kV DCTL is a MAAC facility. For the loss of the Brandon Shores to Riverside DCTL, overloads are projected in the 2005 timeframe on BGE's 115 kV circuits which cross Baltimore (i.e., Westport substation to Green Street substation and Westport substation to the Center Street substation).

A comprehensive analysis showed that the least cost and more timely solution was to remove the possibility of the double circuit transmission line outage and the resulting impact on the downtown circuits. A CPCN is expected for the Brandon Shores to Riverside project in CN9009. BGE also plans to continue with its upgrades to increase the transmission capability on the downtown circuits due to load growth. However, upgrades to the downtown loop will not require a CPCN since these 115 kV lines are underground.

The Graceton-Raphael Rd. 230 kV transmission line was previously identified for upgrade to 800 MW operation. The upgrade was attributable to new generation in the queues. However, due to withdrawals of projects in Southeast Pennsylvania (B48) and Southern Maryland (B15,16), the need for the upgrade has been postponed.

7. Central Maryland – Pepco

By summer of 2006 installation of two new 230 kV circuit breakers at Quince Orchard substation on circuits 23028 and 23029 is recommended at a cost of $3.5 million to resolve reactive problems for N-2 contingencies in the Quince Orchard area. Additionally, Pepco proposes by Summer of 2007 installation of two additional 230 kV circuit breakers at Quince Orchard substation on circuits 23030 and 23031 at a cost of $3.5 million to resolve reactive problems for N-2 contingencies in the Quince Orchard and Bells Mill areas. For summer of 2005, existing operating procedures are being evaluated with respect to the ability to manage any reactive problems that may arise.

The Palmers Corners to Blue Plains project is planned in the event that Mirant decides to retire any or all of the Potomac River generators. Mirant is contractually obligated to give Pepco five years notice prior to retiring the generators. The transmission addition was proposed initially for 2007 as a preparatory contingency plan allowing for Mirant's option to retire the generators. The proposal will be revised, and deferred if appropriate, each year on a five-year rolling basis depending on Mirant's actions.

8. Western Maryland – Allegheny Power

Allegheny Power has listed 10 transmission projects in Western Maryland. The projects are listed at 138 or 230 kV and are for baseline transmission reliability or distribution adequacy. These projects are primarily attributable to load growth in Western Maryland and are not related to any MAAC violations. An order was issued and became final on November 4, 2004 in CN8998 for a CPCN to modify the existing Marlowe-Boonsboro transmission line located in Washington County for eventual service at 230 kV. This line is an extension of the Boonsboro Frostown line that was certificated in 2003. PJM has identified the need for reactive resources at seven locations in Allegheny's Maryland territories. PJM has also identified the need for a spare transformer at Doubs.

9. Eastern Shore – Conectiv

Transmission congestion on the Delmarva Peninsula has continued to decline from 3268 hours in 2001, when there were numerous transmission and generation projects being constructed, to 1040 hours in 2002, and 691hours in 2003. Conectiv lists four projects on the Eastern Shore for Baseline Transmission reliability and distribution adequacy in Maryland, in the period 2005 through 2013. Two of these projects are new 69 kV lines and one is a new 138 kV line. The fourth project is a rebuild of an existing 138 kV line to a higher capacity 138 kV line. In the December 1999 RTEP base plan, PJM required Conectiv to install 50 MVAR per year of transmission capacitors for reactive support (2001-2005) to alleviate CETL voltage violations on the Delmarva Peninsula. The projects and the problems they are intended to address include:

- Severe voltage problems for outage of Red Lion – Cedar Creek 230 kV or Indian River – Milford 230 kV.
- Contingency overload on Mt. Pleasant – Middleton Tap – Townsend 138 kV for outage of Red Lion – Cedar Creek 230 kV.
- Contingency overload on South Harrington – North Seaford – Indian River 138 kV for outage of Indian River – Milford 230 kV.
- Contingency overload on Jones – Cheswold 138 kV for outage of Dover – Milford 230 kV.

10. Eastern Shore – Merchant Transmission

Chesapeake Transmission LLC is proposing a 230-kV transmission line with an estimated capacity of 400 MW. Chesapeake Transmission may start the allocation of the transmission rights during the first half of 2004, and that has been approved by FERC. The project is listed in the PJM Merchant Transmission queues as J02_MTX11 and the feasibility study has been completed.

11. Southern Maryland – SMECO

The Southern Maryland Electric Cooperative (SMECO) has plans for creating a loop on its 230 kV system starting in 2008, 2009, and 2011, respectively. The 230 kV work will include the Calvert Cliffs Switching Station, Calvert Cliffs Tap, Calvert Cliffs, and Hewitt Road

Switching Station. SMECO's territory in Southern Maryland is not part of PJM's RTEPP. The projects are not required to satisfy MAAC requirements since SMECO's lines are not FERC jurisdictional. Although the lines are 230 kV, they are used only by SMECO to serve their primarily radial load. For PJM planning purposes, SMECO is considered a local distribution company and a lumped load on Pepco's network.

B. Tropical Storm Isabel and Storm Related Damages

On September 18-19, 2003, all parts of Maryland were affected by Hurricane/Tropical Storm Isabel (Isabel). At its peak, Isabel left 650,000 of 1.1 million BGE customers without electric power. Isabel also disrupted electric service to nearly a million customers in the combined Pepco and Conectiv service territories, including more than 75 percent of Pepco's customers (Maryland and the District of Columbia) and 35 percent of Conectiv's customers (Delaware, Maryland, Virginia). Other areas were also affected in the storm's aftermath, and both Pepco and Conectiv were confronted with the largest restoration effort in their corporate histories, with more than 5,000 wires down in Pepco's service area requiring 75 miles of cable to be replaced.

This event followed closely behind severe thunderstorms occurring from August 26, 2003, through August 28, 2003. The first priority of the utilities providing service to the State must necessarily be the restoration of service as quickly and safely as possible pursuant to Section 20.50.07.05 of the Code of Maryland Regulations ("COMAR"). In addition, the utilities are obligated to provide reports to the Commission regarding a major storm within three weeks of the end of the storm pursuant to COMAR 20.50.07.07.

The Commission instituted Case No. 8977 in order to review the preparedness and performance of utilities in responding to major electric distribution outages resulting Isabel and related events. In addition to the reports relating to restoration of service required by COMAR 20.50.07.05 and .07, the Commission requested that each utility provide the following information: 1) a comparison between the restoration efforts involved in Isabel and Hurricane/Tropical Storm Floyd (September 1999); 2) a report citing specific descriptions of the criteria and methods used to prioritize service restoration; 3) an estimate of the cost of service restoration; and 4) a report regarding coordination with local Emergency Management Agencies prior to and during Isabel. Other parties including Commission Staff, the Maryland Office of People's Counsel, certain state and county governments and private citizens filed comments and appeared at the Commission" legislative-style hearing.

In its Order No. 79159, issued June 4, 2004, the Commission focused on the areas of communication, infrastructure and restoration. Based on the evidence provided in the case, the Commission made the following findings: 1) Maryland utilities have, overall, increased their responsiveness to major storm outages since Floyd in 1999; 2) further improvements are needed in enhancing communications between utilities, local emergency management agencies, media, and customers; 3) utilities may consider taking additional steps with municipal governments to increase private landowner awareness of the risks attendant with off-rights of way tree and vegetation problems that pose risks to utility electrical facilities; and 4) there is no evidence suggesting a need to alter existing policies regarding overhead and underground wiring of the general electric distribution system.

In Order No. 79159, the Commission made the following general recommendations:

- There should be better communications between utilities, local emergency management agencies, media and customers.
- Greater attention to a community-level response should be considered by the utilities as part of the restoration mission and goal.
- Besides existing vegetation management programs, utilities may consider taking additional steps with municipal governments to increase private landowner awareness of the risks attendant with vegetation problems that pose risks to utility electrical facilities.
- No new evidence or industry information has been adduced or presented that would suggest a need to alter the existing policies regarding overhead and underground wiring of the general electric distribution system.

More specific observations fell into three categories: Communications, Infrastructure, and Restorations.

Communications:

- Communications between Maryland's utilities and the Maryland Emergency Management Agency (MEMA) were generally adequate, although Montgomery County had complaints about Pepco. Utilities also directed to meet with local emergency management agencies.
- Utilities and PSC are directed to continue to participate in MEMA storm exercises.
- Pepco and Conectiv, now part of Pepco Holdings Inc. (PHI), had high call volumes and duplicate calls which overloaded Outage Management System (OMS) and resulted in errors. Conectiv and Pepco were directed to provide quarterly status reports on modifications to OMS, including a method to simulate hurricane-level inputs.
- There is no position from the Commission about dry ice but companies need to clearly communicate policy with customers.
- Utilities must begin public education efforts in conjunction with local governments to increase awareness of the risk of planting trees too close to power lines.

Infrastructure

- Basic maintenance tree trimming was adequate. However, there were problems with damage from trees outside the Right of Way (ROW).
- BGE and Pepco were impacted by the high density of trees in the Baltimore-Washington corridor.
- The Commission found no fault with the routine tree trimming practices as related to Isabel outages.
- There was an expression of trust and respect for the Maryland Electric Reliability Tree Trimming (MERTT) Council. Staff and utilities were directed to work through MERTT to develop recommendations as to how to best manage off -ROW trees.

- There was a discussion of whether restructuring of the electric industry has created a disincentive for utilities to maintain systems against storm losses. Goes into expenditures on distribution systems as related in FERC Forms.
- Generally, tree trimming expenses remained relatively level compared to pre-restructuring expenditures.
- Utilities directed to develop procedures to allow for selective undergrounding on a cooperative basis with municipal and county governments, customers, or homeowner groups.

Restoration

- The Commission confirmed previous guidance on restoration priority: Threats to public safety, then hospitals and emergency care facilities, then the largest numbers of customers.
- Utilities directed to develop written description of their life support/vulnerable customer programs and file by August 1. Also directed to provide this description to emergency management, critical care and community service agencies.

C. NERC Implementation of August 14, 2003 Blackout Recommendations

NERC and the Electric Industry have taken significant steps to improve the reliability of the bulk electric system since the blackout of August 14, 2003. The most significant actions taken to date include rectifying the direct causes of the blackout, conducting readiness audits of major systems operators, and revising existing reliability standards. Many stakeholders believe that federal legislation is needed to make the NERC standards mandatory and enforceable. NERC issued a list of the final blackout recommendations July 2004 and provided a status report August 11, 2004. A summary of the recommendations and NERC actions follows:

1. Address the Direct Causes of the Blackout. Issues of tree trimming, communications, and system monitoring, and operator training have been addressed by First Energy, the Midwest ISO, PJM, and NERC.
2. Strengthen the NERC Compliance Enforcement Program. NERC approved a set of revised compliance templates or performance measurements to strengthen and clarify existing reliability standards. Regional reliability councils are required to report violations to NERC within 48 hours. NERC also developed a new operator training template and vegetation management compliance template.
3. Initiate Regular Control Area and Reliability Coordinator Readiness Audits.
   By June 30, 2004, NERC had audited 23 control areas representing the majority of the grid in the US and Canada. NERC will continue with these audits on a three-year cycle.
4. Evaluate Vegetation Management Procedures and Results. NERC is developing a new vegetation management standard. Western Electricity Coordinating Council (WECC) had a successful program following the 1996 blackouts, which reduced the number of vegetation-related outages. This has been adopted by NERC and requires all transmission owners in North America to report all vegetation-related outages.

5. Establish a program to track the implementation of Blackout Recommendations. NERC is working to develop a database to track and report on progress in implementing all applicable blackout recommendations.
6. Improve Operator and Reliability Coordinator Training. NERC now requires all system operators to receive at least five days of training on emergency operations annually. NERC is developing more specific system operator training requirements.
7. Evaluate Reactive Power and Voltage Control Practices. NERC is reviewing the effectiveness of existing standards and their implementation practices. NERC expects to recommend revisions by early 2005. It is important, for instance, that individual generators be rated for reactive capabilities and be compensated when called to produce it.
8. Improve System Protection to Slow or Limit the Spread of Future Cascading Outages. A document on "Recommendations on Loadability Requirements on Transmission Protective Relaying Systems" was approved and is available on NEC's website.
9. Clarify Reliability Coordinator and Control Area Functions, Responsibilities, Capabilities and Authorities. NERC has approved revisions to its Operating Policies.
10. Establish Guidelines for real-time Operating Tools. NERC is evaluating the current systems and tools available for system operators to monitor and study power flows on the grid.
11. Evaluate Lessons Learned. NERC is reviewing the lessons learned from the blackout.
12. Install Additional Time-Synchronized Recording Devices as Needed.
13. Reevaluate System Design, Planning and Operating Criteria
14. Improve System Modeling Data and Data Exchange Practices.
15. Develop Standing Capability to Investigate Future Blackouts
16. Accelerate the Standards Transition
17. Evaluate NERC Actions in the Area of Physical and Cyber Security

D. The NERC Functional Model

Revision of the NERC standards has paralleled the development of the definitive blackout recommendations. The NERC Functional Model has preceded the revised standards, and version v2 of the Functional Model was approved in January 2004. The functional model establishes the Reliability Authority to coordinate global tasks and local tasks. The balancing authority performs the global tasks and the Transmission Operator performs the local tasks. Three authorities must be certified: (1) Reliability Authority (RA), (2) Balancing Authority (BA), and (3) Transmission Operator (TOP). Organizations can also be certified for other functions such as LSE or Generation Owner. Each region must ensure that all areas and functions are covered. Version 0 standards will reference only the Functional Model Authorities. Organizations registering for functions must be certified by Dec 31, 2007.

At the June 14, 2004 Meeting of the Members of NERC, the Members unanimously approved a resolution charging the Regional Managers Committee with examining the future role and responsibilities of the Regional Reliability Councils (RRCs). In 1996, ten (10) RRCs with contiguous geographical boundaries were established: MAAC, ECAR, Northeast Power Coordinating Council (NPCC), Mid-America Interconnected Network (MAIN), Southeastern Electric Reliability Council (SERC), Florida Reliability Coordinating Council (FRCC), Southwest Power Pool (SPP), ERCOT, Mid-Continent Area Power Pool (MAPP), and WECC. The Regional Managers of the eight Eastern Interconnection RRCs were also assigned the task of coordinating an assessment of the existing regional boundaries across the Eastern Interconnections. This is due in part because of the expansion of PJM, and also due to the interdependence of adjacent regions as demonstrated by the blackout of August 14, 2003. Changes have already started. For instance, the Midwest Reliability Organization (MRO) will succeed MAPP, effective January 1, 2005.

The PJM control area boundary is cut by one or more RCCs. The PJM Control area spans all of MAAC, and parts of ECAR, MAIN, and SERC. The boundaries of reliability coordinators like PJM can change due to corporate mergers, regulatory policies or orders, or commercial factors. Boundaries have also changed for other reliability coordinators (MISO, Entergy, Tennessee Valley Authority (TVA)). Regional managers of two RTOs (MISO and PJM) are discussing ways of combining their footprint into a broader RRC, as well as a joint and common market.

The reliability assurance functions and services currently performed by the ten RRCs are divided into five broad categories:

1. Development of Regionally-Specific Reliability Criteria for System Planning and Resource Adequacy, facility ratings, protective relay systems, load shedding & system restoration, disturbance monitoring & analysis.
2. Regional coordination of planning and operations: reliability plan, operator training & tools, market interface, critical infrastructure protection.
3. Assessment of Reliability: Transmission & Resource Adequacy—Seasonal & Long-term, Adequacy of Protective Relay Systems, Management of databases, disturbance analysis.
4. Compliance monitoring and enforcement: NERC & regional compliance programs, readiness audits, compliance audits, recommendation tracking, control area certification.
5. Other services like dispute resolution, operator training and tools, market interface.

Development of future functions and organization is based upon proposed U.S. legislation regarding reliability[18]. Functions performed by the RRCs will be re-evaluated in light of the creation of Independent System Operators/ Regional Transmission Organizations (ISOs/RTOs) to minimize duplication of efforts and clearly delineate responsibilities between RRCs and other organizations. This development is based on five fundamental principles: open and inclusive membership, fair and balanced governance, independence, compliance, and organization boundaries.

[18] The Joint House-Senate Committee Conference Report Proposed Electric Reliability Legislative language (approved by the House 11/18/03), which was used as a reference for establishing fundamental principles for future reliability organizations, for considering future reliability functions and for analyzing alternate models.

E. Revision of Reliability Standards

The Blackout of August 14, 2003 has led to a re-evaluation of the NERC Standards. The NERC Version 0 Reliability Standards have been posted for review and comment. A final posting for voting is planned for Nov 1, 2004, and adoption by the NERC board is expected on Feb 8, 2005. North American Energy Standards Board (NAESB), in cooperation with NERC, is providing business practices. NERC and NAESB are independent standards except for Transmission Loading Relief procedures. NERC and NAESB are cooperating in developing congestion management procedures that divide the reliability requirements and the business practices. Some stakeholders believe that the NAESB business rules should not be included in federal legislation because it would make them difficult to change. PJM for instance changes business rules to accommodate changing situations.

F. Cyber Security

Priority has been placed on the Cyber Security Policy 1200. Information Security Governance is based on the Public Accounting and Investor Protection Act of 2002 (a.k.a., Sarbanes-Oxley) which deals with corporate responsibility for financial reports and management of internal controls. The National Security Summit and ISO17799 have also addressed Cyber Security. Critical Cyber assets include physical assets like communications servers, Supervisory Control and Data Acquisition (SCADA) Systems, and energy management systems. It also includes electronic access, information protection, and recovery plans.

G. Compliance Enforcement and Readiness Audit Programs

NERC sponsored a regulatory webcast briefing on October 28, 2004 with State Commissions and Staff to discuss Compliance Enforcement and Readiness Audit Programs. Legislation is still necessary because voluntary compliance is considered to be insufficient. The NERC Compliance standards apply to any entity responsible for any part of the bulk electric system reliability, i.e., control areas and reliability coordinators. Some entities will be certified as balancing authorities, reliability coordinators, and/or transmission operators. NERC will post annual reports and take corrective actions when non-compliance has been identified. The Compliance audit is in addition to the readiness audit already conducted. As of October 14, 2004, NERC has audited 43 control areas, four reliability coordinators, and one Transmission operator. The remaining audits will be completed by the end of 2006. Areas for improvement have been identified as follows:

1. Training
2. Backup control facilities
3. Documenting authority and responsibilities
4. Real Time Monitoring
5. Reactive Reserve Monitoring
6. Procedure and Policy Updates

H. PJM/MAAC role in NERC Standards Compliance

Revision of the NERC standards has led to a renewed interest in MAAC among the stakeholders and members of PJM. PJM has initiated a MAAC Standards Compliance Task Force (SCTF). MAAC is concerned only with facilities that affect the MAAC Bulk Power System and not facilities affecting the reliability of supply only to local system loads. MAAC is concerned about contingencies in neighboring systems, which might affect the MAAC system. An important part of this program is the NERC Compliance Program. MAAC and each reliability council must report quarterly to NERC all violations of NERC and regional reliability standards. MAAC had no reporting violations for the first and second quarter of 2004.

MAAC has its own process for adopting standards, which may be more prescriptive than the more general NERC standards. Additionally, MAAC staff is developing requirements for Installation of Disturbance Monitoring equipment. It contains triggering and time synchronization requirements for Dynamic Disturbance recorders. The PJM Planning Committee sponsored a working group this year to modify metrics for detecting possible voltage collapse on transmission lines.

PJM/MAAC sponsored a Standards, Compliance and Cyber Security Seminar during July 2004. It was an interactive forum with representation from the various stakeholder sectors: generation, transmission owners, end use customers, operations people, state commissions, and future members of PJM. For 2004, MAAC has a new Compliance Enforcement Program (CEP) and 21 new operating templates. The new templates cover items such as disturbance control, load and generation management, operating limits, electronic tagging of interchange transactions, coordination with other systems, and emergency alerts. MAAC is compliant with all 24 planning measurements and 17 operating templates with the exception of one. Some MAAC criteria need to be clarified. Within MAAC consequential load loss between 1 and 400 MW has been identified for N-1 contingencies, N-2 contingencies, and DCTL outages.

I. Implementation of NERC Standards in Maryland

The MD PSC staff conducted a survey among jurisdictional utilities in Maryland. Transmission owners that are also load serving entities, for example, BGE, Pepco, and Conectiv are complying with the new standards and are actively participating in the development of the standards through MAAC. Portions of Maryland served by Allegheny Power are in the ECAR region of NERC. Allegheny Power has been working with ECAR to comply with the NERC recommendations. No major violations have been found. However, there have been some changes made in relaying and monitoring information. The smaller municipalities and cooperatives do not own transmission and are not directly affected by the NERC standards. However, issues such as vegetation management, communications, and operator training apply to all. Many of the LSEs in PJM actively participated in the development of the standards by filing comments to the proposed templates.

Staff also made a request to PJM asking the RTO to comment on how it implements the NERC Standards in responding to the August 14 Blackout of 2003. On November 29, 2004, PJM provided a detailed response about how it plans to address the "Accelerate the Standards

Transition" recommendation of NERC's blackout report, and how it plans to insure high reliability and quality of service in the PJM area including Maryland. PJM's response to Staff's "Supplemental Data Request for Ten-Year Plan" is attached as Appendix A of this report.

J. Critical Infrastructure

NERC plays a major role in protecting the electric system by serving as the focal point for coordinating information exchange on critical infrastructure issues between the electricity industry and the federal government. Through NERC, government and industry work together to protect the electricity infrastructure from physical and cyber attacks. This coordination ensures that the industry is able to speak with one voice and take action in a consistent and effective manner.

The US Department of Energy (DOE) designated NERC as the electricity sector coordinator for critical infrastructure protection; the National Infrastructure Protection Center (NIPC) asked NERC to be the Information Sharing and Analysis Center for the electricity sector. NERC also works closely with the Department of Homeland Security (DHS) to ensure that the critical infrastructure protection functions so vital to the industry are fully integrated and coordinated with the department. The Electricity Sector Information Sharing and Analysis Center (ESISAC) website posts advisories, alerts, warnings and the current threat alert levels for the Homeland Security Advisory System, DOE, the Nuclear Regulatory Commission, and the electricity sector. NERC has created a compendium of best practices for protecting critical facilities against a spectrum of physical and cyber threats. The Security Guidelines for the Electricity Sector addresses topics including vulnerability and risk assessment, business continuity, physical and cyber security, and protecting sensitive information.

State Public Utility Commissions, both individually and collectively through the National Association of Regulatory Utility Commissioners (NARUC), have a long history of policy formulation and progressive regulatory oversight of the Nation's energy sector. The role of NARUC is being addressed by the Institute of Public Utilities of Michigan State University in a report, which is currently in draft form.[19]

K. Resource Adequacy

In October 2003, the PSC 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.

At a July 8, 2004, hearing held in the matter, PJM presented its new Reliability Pricing Model (RPM) proposal. This model is designed to address transmission system reliability and

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[19] The report is entitled "A Primer on Energy Assurance," prepared by James Blake Atkins and Janice A. Beecher.

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. By notice on October 15, 2003, the MD PSC established a proceeding to review electric generation resource adequacy in Case No. 8980. The Reliability Pricing Model is a major portion of PJM's effort to maintain future adequacy and was introduced during the second half of 2004. Implementation of RPM will be phased in gradually through 2009. Many stakeholders have taken the opportunity to file comments about RPM in Case No. 8980. Generation owners like Mirant, Reliant, and Strategic Energy are actively participating in this process, as well as LSEs such as BGE and SMECO.

The PJM market structure has included a generation capacity market construct as a means to ensure long-term adequacy of supply to ensure 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. Issues include 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.

PJM's RPM proposal is still in its development stage through the PJM stakeholder process. However, the concept behind this approach is that it designed to coordinate the price paid to generation capacity with overall system reliability requirements. This 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. As of this writing, PJM plans to file the RPM at the FERC no later than March 1, 2005.

PJM 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. However, PJM will initially need to hold four consecutive capacity auctions for the 2006-07 to 2009-10 Planning Years, separated by a period ranging from several weeks to a couple of months, in order to effect the transition and set up the initial four-year planning horizon. Most likely, these transitional auctions would commence in the second half of 2005. Additionally, the entire PJM footprint will not be transitioned at once; instead, regions will be layered in over time. PJM currently plans to add the load deliverability zones as follows:

- 2006/2007 Planning Year: PJM Mid-Atlantic Region; PJM Western Region (ComEd, AEP, Dayton P&L, Duquesne and Allegheny Power); PJM Southern Region (Dominion).
- 2007/2008 Planning Year: all 2006-07 regions plus Eastern MAAC (Public Service E&G, Jersey Central P&L, PECO, AE and Delmarva P&L); Southwestern MAAC (BGE and Pepco).
- 2008/2009 Planning Year: all 2006-08 regions plus Central MAAC (PP&L and Med-Ed); Public Service E&G North, DP&L South.

V. ENERGY CONSERVATION, RENEWABLES AND ENVIRONMENTAL ISSUES

A. Statutory Requirements

Section 7-201(b)(2) requires the Commission to evaluate the cost-effectiveness of the investments by electric companies in energy conservation measures and practices 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 requires gas and electric utilities in Maryland to develop and implement energy efficiency and conservation programs, subject to review and approval of 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, 2004, to implement the provisions of Section 7-201. The information presented below in Table 4 are summaries of responses to a data request indicating what efforts were made during 2004 to analyze energy efficiency and conservation programs, including the weatherization of buildings, renewable energy, cogeneration, and widespread promotion of energy conservation programs.

Table 5: Summary Of Conservation, Renewable Resources, And Cogeneration Activities

Distribution Utility	*Summary Of Conservation, Renewable Resources, And Cogeneration Activities*
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 schedule X tariff for small power producers and cogenerators.
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, 2004, 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.
Conectiv/ Delmarva	Since January 1, 2004, Delmarva has neither conducted nor contracted for any analyses to evaluate the cost-effectiveness of the investment in energy conservation measures, practices to reduce electricity demand, and investment in or utilization of renewable resources.
Easton	Easton has no DSM programs in effect at this time. Studies performed in 1998-1999 indicated that the programs in the mid-1990s were no longer in the best interests of its customers. Easton will continue to evaluate new programs.
Hagerstown	The City of Hagerstown does not currently offer any energy conservation measures to its customers. The last energy program, The Residential Retrofit Kit Program ended in 1999.
Pepco	Pepco reports that it continues to monitor and study energy conservation technologies, distributed generation technologies and renewable resources. Pepco reports that no studies concerning the cost-effectiveness of the technologies were conducted since January 1, 2004.
Potomac Edison	Allegheny Power does not contract nor evaluate the cost-effectiveness of the investments in energy conservation measures and practices to reduce electricity demand and in renewable resources. Allegheny Power participates in a working group to address low-income weatherization, which is 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) equipments. 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 the cogeneration or wastes, and there are no cogeneration or waste to energy facilities interconnected with SMECO's electric system at this time.
Thurmont	No analyses have been conducted or contracted for which evaluate the cost-effectiveness of energy conservation measures sponsored by the Thurmont Municipal Light Company since January 1, 2004. No demand-side resources are included in the Town of Thurmont's 2004 Long-Range Plan. Due to a very low customer response rate to a previous DSM program, the Town of Thurmont is cautious in its consideration of any new DSM initiatives.

C. Emissions Disclosures

On September 17, 2003, the Commission docketed Case No. 8973. Comments were requested from all stakeholders regarding the status of emissions disclosure and fuel mix composition associated with generation and delivered electricity in Maryland. The impetus of this proceeding was PJM's introduction of a proposed conceptual design for a new regional Generation Attributes Tracking System (GATS) Phase II. PJM and supporters of GATS II urged the Commission to endorse it for use in ensuring compliance with Maryland's fuel mix and emissions disclosure law. After hearing held December 3, 2003, the Commission issued a Letter Order in this proceeding. The Commission found that GATS I did not produce reliable emissions and fuel mix disclosure labels for use by LSEs in Maryland and vacated its previous directive authorizing its use. Consistent with this finding, the Commission declined to support the use of PJM's proposed GATS II and stated that LSEs may continue to utilize regional average data or provide self-certified company-specific data. In recognition of the recent passage of the RPS law (see discussion below), the Commission encouraged continued efforts by PJM and other stakeholders to develop a uniform emissions tracking system and further noted that development of a regional system may be considered as part of the RPS implementation framework.

D. Renewable Portfolio Standard Legislation

On May 26, 2004, legislation was enacted by the Maryland General Assembly and signed by Governor Robert L. Ehrlich requiring electricity suppliers to meet a Renewable Energy Portfolio Standard ("RPS"). The legislation requires, among other things, that the Maryland Public Service Commission implement a Renewable Portfolio Standard. Implementation of the RPS is required to be accompanied by a system that facilitates trading of Renewable Energy Credits (REC) representing the generation of electricity using renewable resources. The legislation directs the Commission to adopt regulations implementing the legislation no later than July 1, 2005 and the RPS applies to electricity sales commencing in 2006.

A REC is equal to 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 legislation. Generators and suppliers are allowed to trade RECs using a REC registry and trading system that the Commission must establish. A REC has a three-year life during which it may be transferred, sold or otherwise redeemed. The 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 legislation. Compliance fees will be a source of funding for the Maryland Renewable Energy Fund. The Maryland Renewable Energy Fund is designed to promote the development of renewable energy resources in Maryland. The Commission is responsible for creating and administering the overall RPS program; responsibility for developing renewable energy resources has been vested with the Maryland Energy Administration.

The Commission's Technical Staff has prepared a Staff Report on the RPS legislation and relevant implementation issues. Staff recommended a conceptual framework for the RPS program. In addition, Staff set forth eleven threshold policy issues and an administrative issue that it recommended the Commission address at this time. The Commission docketed this matter as Case No. 9019 and is currently considering comments submitted by interested parties and how to proceed in this matter.

APPENDIX
Appendix A
Tables A-1 to A-13

Appendix A

BEFORE THE
MARYLAND PUBLIC SERVICE COMMISSION

RESPONSE OF PJM INTERCONNECTION, LLC
RE: SUPPLEMENTAL DATA REQUEST FOR TEN-YEAR PLAN

November 29, 2004

Response to Staff Supplemental Data Request for Ten-Year Plan

S-1. The August 14 Blackout of 2003 has prompted a review of NERC standards with subsequent recommendations. Attached is a status report on the NERC implementation of these recommendations. Please comment on the role of PJM in this process. Please address each recommendation in the report and provide the following information:

It should be noted at the outset that PJM is actively engaged at all levels of the North American Electric Reliability Council (NERC) organization. PJM is obligated to, and does adhere to NERC reliability standards. NERC membership and participation is voluntary. NERC is comprised of ten Regional Reliability Councils (RRCs), including Mid-Atlantic Area Council (MAAC), East Central Area Reliability Council (ECAR), Mid-America Interconnected Network (MAIN) and Southeastern Electric Reliability Council (SERC). PJM is a member of MAAC, ECAR, MAIN and SERC because it has, or will have, operating and planning responsibilities in each of these four RRCs.

In February 2004, NERC issued an initial blackout report that contained 14 recommendations (and later added three additional recommendations for a total of 17) to address the direct causes of the blackout, strategic initiatives to ensure compliance with reliability standards and track recommendations, and technical initiatives to improve overall electric system reliability and operations.

The 17 recommendations are as follows: (1) Address the Direct Causes of the Blackout; (2) Strengthen the NERC Compliance Enforcement Program; (3) Initiate Regular Control Area and Reliability Coordinator Readiness Audits; (4) Evaluate Vegetation Management Procedures and Results; (5) Establish a Program to Track the Implementation of Blackout Recommendations; (6) Improve Operator and Reliability Coordinator Training; (7) Evaluate Reactive Power and Voltage Control Practices; (8) Improve System Protection to Slow or Limit the Spread of Future Cascading Outages; (9) Clarify Reliability Coordinator and Control Area Functions, Responsibilities, Capabilities and Authorities; (10) Establish Guidelines for Real-Time Operating Tools; (11) Evaluate Lessons Learned; (12) Install Additional Time-Synchronized Recording Devices as Needed; (13) Reevaluate System Design, Planning and Operating Criteria; (14) Improve System Modeling Data and Data Exchange Practices; (15) Develop Standing Capability to Investigate Future Blackouts; (16) Accelerate the Standards Transition; and (17) Evaluate NERC Actions in the Areas of Physical and Cyber Security.

Subsequent to receiving the data request, the Maryland Public Service Commission clarified that PJM should focus on Recommendation No. 16. Thus, while PJM adheres to all 17 NERC recommendations, PJM responds to question S-1 and its sub-parts focusing on the standards as they are primarily addressed in Recommendation No. 16, Accelerate the Standards Transition.

Recommendation 1: Address the Direct Causes of the Blackout; and Recommendation 11: Evaluate Lessons Learned

At the outset, it should be noted that PJM had, prior to the blackout, been moving forward with a Joint Operating Agreement (JOA) with the Midwest Independent System Operator (MISO). The JOA was designed to address many of the issues important to coordinated Regional Transmission Organization (RTO) operation and that were cited in the blackout report, including improved monitoring and communication between the two control areas. The JOA represents an enhancement of communication measures and seams management issues PJM had been addressing with the New York ISO for some time, as reported to FERC. Unfortunately, the JOA was not yet in place as of August 14, 2003 as it was undergoing stakeholder review at that time. After the blackout, the parties met to determine whether additional enhancements to the JOA were needed. MISO and PJM determined that the JOA protocols were fundamentally sound but agreed to further enhancements as a result of the blackout.

In addition to NERCs established procedures and reports on the blackout, PJM also internally evaluated the August 14, 2003 blackout for lessons to learn from the incident.

On February 10, 2004, the NERC Board approved a recommendation requiring FirstEnergy, MISO and PJM to develop a remediation plan to address specific deficiencies. PJM was directed to reevaluate and improve its communications protocols and procedures with its neighboring reliability coordinators and control areas. PJM submitted a remediation plan that provided for improved communications with MISO (through the JOA) and with neighboring control areas. PJM took additional steps based on the results of informal reviews. These additional steps included enhancement of an incident response program; assignment of an operations engineer/power dispatcher as the Reliability Coordinator and acceleration of the incorporation of the reliability coordinator areas into the PJM Energy Management System Model; acceleration of the installation of visualization tools in the PJM control rooms that increased the visibility of neighboring systems; and further coordination of planning with MISO and neighboring regions.

NERC approved PJM's remediation plan on improved communications protocols and procedures with its neighboring reliability coordinators and control areas subject to the following conditions:

1. PJM shall be subject to a follow-up audit of the implementation of its plan within two months after PJM integrates Commonwealth Edison into its market. *(This condition was later waived because there were no concerns with the smooth integration of Commonwealth Edison into PJM.)*

2. PJM shall certify to NERC that it has fully implemented its plan to respond to the corrective actions required in the board's February 10, 2004 resolution not later than June 30, 2004. *(PJM provided formal certification to NERC on the completion of this plan of which the*

major item was the implementation of the MISO-PJM Joint Operating Agreement providing for the RTOs to operate to the more conservative limit observed by either of them when there are differing analytical results.)

3. PJM shall report to the Operating Committee on its meetings with each neighboring reliability coordinator and control area prior to the summer season to discuss communication protocols and expected summer conditions, not later than June 30, 2004. *(PJM provided formal certification to NERC on the completion of these discussions.)*

Recommendation 2: Strengthen the NERC Compliance Enforcement Program

The NERC Compliance Enforcement Program (CEP) was established to manage and enforce compliance with NERC reliability standards. CEP provides direct input in the development of a reliability standard, in particular the measures and compliance administration portions of the standard. Field testing is also managed and coordinated by CEP.[20]

PJM adheres to NERC reliability standards, including the revised compliance templates (performance measurements) that were integrated into the 2004 CEP. Through its membership, PJM assisted NERC in development of the compliance templates that are the foundation for the CEP. PJM also assisted NERC in the development of guidelines for reporting and disclosing violations of each of the NERC reliability standards.

Each of the ten member RRCs has as one of its functions the monitoring and reporting on compliance by all its members to NERC Reliability Standards. Historically, MAAC performed this monitoring and compliance/enforcement task. Since PJM's market integration projects (Allegheny Power in April 2002, Commonwealth Edison in May 2004, and American Electric Power and Dayton Power & Light in October 2004) have been implemented, ECAR and MAIN now also monitor the compliance of PJM to NERC Standards. Each RRC has its own process for monitoring and reporting on each of the standards to which PJM must comply. Each RRC also has an annual plan for monitoring, assessing, and compliance reporting to appropriate organizations and implementing actions for non-compliance.[21] Should there be events of non-compliance, the RRC will cite the violation and direct the non-complying entity to provide a remediation plan to correct the deficiency. Should the infraction become chronic, or if it is of a significant impact to the interconnected grid, letters of notification will be provided to appropriate regulatory agencies with jurisdiction over the violator.

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[20] NERC Reliability Standards Process Manual, Version 2.1. (March 11, 2003)

[21] e.g., see: www.maac-rc.com

Recommendation 3: Initiate Regular Control Area and Reliability Coordinator Readiness Audits

PJM has undergone numerous audits by NERC and industry investigative teams over the past two years as the PJM market integration projects have been implemented. Additionally, PJM was recently audited by an independent team of industry, Federal Energy Regulatory Commission (FERC) and NERC personnel in a NERC Control Area Readiness Audit. This audit found PJM to be fully qualified and capable of reliably and effectively operating the bulk electric power system in PJM's entire territory[22].

Further, MAAC and the other RRCs continually monitor PJM's compliance with the existing Operating Policies and Planning Standards, and will continue to do so when Version 0 Reliability Standards become effective as discussed below.

Recommendation 4: Evaluate Vegetation Management Procedures and Results

Although transmission owners are responsible for following NERC's Vegetation Management Procedures, PJM has put in place mechanisms for consolidating transmission owners' responses for vegetation management and reporting on their behalf to appropriate organizations. The PJM Performance Department reviews operational information daily including vegetation outages reported in the PJM eDART system and provides all vegetation related tripping incidents within the PJM control area to each reliability region organization (RRO, another acronym for RRC). The Performance Department summarizes and reviews all vegetation related tripping monthly with the PJM System Operations Subcommittee and also provides a monthly report to each RRO.

Each transmission owner with facilities within the PJM control area provides a monthly report to their RRO, identifying any vegetation outages, confirming that no outages occurred, or reporting violations of the vegetation management reporting standard. Each RRO reports to NERC any violations in accordance with established procedures.

On an annual basis, each transmission owner operating within the PJM control area provides to its RRO its detailed vegetation management plan for the upcoming year and demonstrates how it has performed its vegetation management program for the current year.

Recommendation 5: Establish a Program to Track the Implementation of Blackout Recommendations; Recommendation 15: Develop Standing Capability to Investigate Future Blackouts

Regions shall report quarterly to NERC on the status of follow-up actions to address recommendations, lessons learned, and areas noted for improvement. NERC staff reports both NERC activities and a summary of regional activities to the NERC board.

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[22] See: http://www.nerc.com/pub/sys/all_updl/rap/audits/Final_PJM_Audit_Report.pdf.

With respect to recommendations resulting from reviews of the August 14, 2003 Blackout, MAAC has implemented a tracking system and report[23] which notes the initiatives and status of the recommendations from NERC, U.S.-Canada Task Force and MAAC Outage Review Team. There are dozens of undertakings, many already completed, to assure the continued reliable operation and planning of the bulk power system in PJM. Each recommendation has a responsible party assigned to assure timely completion. Reports on the status of the activities initiated to address these recommendations are regularly provided to MAAC committees and PJM's Operating Committee, Planning Committee, Reliability Committee and Members Committee, depending upon which committee has oversight over the particular area being addressed.

Recommendation 6: Improve Operator and Reliability Coordinator Training

PJM has always had a thorough training program for system operators. As a specific response to the NERC report, PJM tracked and reported on the training each individual participated in to ensure that they all complied with the initial five days of training officially devoted to emergency procedures that were required under the newly developed NERC training template.

PJM, in fact, is a NERC-certified training facility. The PJM System Operator Certification Program certifies PJM Generation and Transmission Operators using complex simulations on the Dispatcher Training System, a duplicate of the real-time energy management system. NERC and PJM System Operator Certifications are also required of all PJM System Operator personnel. PJM's member Transmission Operators and Generation Operators are also required to be PJM-Certified.

Initial and on-going training is required of all system operators. One week out of every six weeks is a required training week for each PJM system operator. Additionally, annually PJM requires system operators to participate in a four week training course that is a lecture series taught in a classroom environment. The generation Market Operations Center (MOC) operator orientation class, System Dynamics for System Operators, and Annual PJM System Operator Seminar each run for one week; to comprise this program PJM requires all systems operators to be certified.

Additional training opportunities are provided in the following areas: Emergency Operations Preparedness Drills (emergency procedures drill and system restoration drill), twice a year; PJM-MISO drills; and various on-line technical training is available twenty-four hours a day, 365 days a year.

Recommendation 7: Evaluate Reactive Power and Voltage Control Practices

NERC's technical committees are reviewing effectiveness of the existing standards on reactive power and voltage control and how they are being implemented in practice among the ten NERC RRCs. Revisions and improvements to the standards are expected to be recommended in early 2005.

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[23] See: http://www.pjm.com/committees/reliability/reliability.html.

Voltage control and reactive power coordination are essential elements to promoting reliability. PJM has had for many years an alert system that identifies when the system loads are heavy and bulk power voltage levels are, on an anticipated or actual basis, at or approaching undesirable low levels. These procedures consist of the following:

- Low Voltage Alert - heighten awareness, increase planning, analysis, and preparation efforts when heavy loads and low voltages are anticipated in upcoming operating periods

- Heavy Load Voltage Schedule Warning – issued to request members to prepare for maximum support of voltages on the bulk power system.

- Heavy Load Voltage Schedule Action - issued to members at peak load periods via the ALL-CALL system to request maximum support of voltages on the bulk power system and increase reactive reserves on the 500kV system.

PJM's long standing emergency procedures include steps, if necessary, for voltage based load shedding. PJM's voltage criteria were enhanced following the low voltages observed in July 1999. In addition, PJM has a reporting process for load incidents. PJM has procedures in place to plan, operate and review voltage control and reactive power practices. These procedures are contained in PJM's Transmission Operations Manual.[24] PJM frequently updates procedures, manuals and communications and protocols involving voltage control and reactive power. In addition, PJM provides training on reactive power and voltage control.

PJM's JOA provides for voltage control and reactive power coordination. PJM, and its JOA partner, MISO, maintain a wide area view of interconnection conditions by enhancing their coordination of voltage and reactive levels throughout RTO footprints. Through the sharing of data with other neighboring Reliability Coordinators for their analysis and coordinated operations, PJM and MISO ensure the maintenance of sufficient reactive reserves to respond to scenarios of high load periods, loss of critical reactive resources, and unusually high transfers. Under the JOA, each RTO coordinates with the owners of the transmission facilities subject to its control and the control areas as necessary and feasible to supply its own reactive load and losses at all load levels.

Voltage schedule coordination is the responsibility of each RTO. The voltage schedule is determined based on conditions in the proximity of generating stations and Extra High Voltage (EHV) (defined as 230 kV facilities and above) stations with voltage regulating capabilities. Each RTO coordinates data exchange, operational procedures and actual operations information with owners of transmission facilities and Control Areas to determine adequate and reliable voltage schedules considering actual and post-contingency conditions. Each RTO also establishes voltage limits at critical locations

[24] See: Section 3 of the PJM Manual entitled "Transmission Operations Manual" (m03) located at http://www.pjm.com/contributions/pjm-manuals/pdf/m03v13.pdf . (From the PJM homepage, select "Documents" and then "Manuals.")

within its own system and exchanges this information with the other RTOs. Finally, each RTO maintains awareness of the voltage limits in the other Party's area and awareness of outages and potential contingencies that could result in violation of those voltage limits.

Recommendation 8: Improve System Protection to Slow or Limit the Spread of Future Cascading Outages; Recommendation 10: Establishing Guidelines for Real-time Operating Tools; Recommendation 12: Install Additional Time-Synchronized Recording Devices as Needed

NERC has formed a team of technical experts to evaluate improvements in system protection (relay) systems to slow or limit the spread of outages. PJM is in compliance with the Recommendations on Loadability Requirements on Transmission Protective Relaying Systems.

Processes and protocols are in place at PJM today to prepare for and react to "maximum credible events", including catastrophes and "acts of God." System planners routinely anticipate scenarios and design the system to isolate foreseeable problems and prevent cascading outages – as the PJM system did on August 14th – through the use of protective equipment such as the system's emergency relay devices. PJM's protective relays operated as designed during the August 14, 2003 Blackout, thus contributing to halt the cascading blackout. Protecting both transmission and generation equipment during an outage through the use of protective devices is essential because it ensures a faster recovery time as well as limiting the extent of the initial impact to the system. Therefore, ensuring that relay standards and maintenance practices are in place is crucial.

PJM electrical engineers design systems for "normal contingencies", and redundant, independent protection systems are deployed in accordance with good engineering practice. System resiliency is tested by postulating "extreme contingencies", and by modeling in near-real time what actions systems and system operators can take to mitigate the effects of those contingencies.

Normal operations routinely accommodate a single contingency event to occur without triggering a system overload. PJM employs emergency operator procedures to manage system operations in order to avoid contingency events from occurring. PJM may initiate conservative operations, including preventative shutdown of designated systems, to offset load and maintain system balance, and the reduction of power transfers into, across or through the PJM control area among other actions. In short, PJM has the authority and responsibility to declare an emergency and to direct the appropriate response, and PJM market participants accept PJM's emergency protocols when they sign PJM's agreements.

At PJM, contingency assessment takes place within the context of PJM's management of its overall market. PJM gathers real time information from its members every two to ten seconds. That information is taken into account by PJM's state estimator every thirty seconds, yielding a system solution – a snapshot of the system providing line flows and voltage levels at each system locus – that becomes the starting point of the contingency analysis applications which are run once per minute. The contingency analysis considers approximately two thousand transmission line losses and hundreds of generator loss events every minute.

Based on that contingency analysis, if a problem is noted, system operators "bind" the problem, and economic dispatch algorithms calculate Locational Marginal Pricing (LMP) bus prices on a five minute cycle that result in a redispatch of generation to alleviate overloads. Generation redispatch to mitigate potential system disturbances is for the most part automatic in PJM: calculated dispatch prices sent to individual units or market operations centers to indicate at what level they should operate, and most units are automatically controlled to render recommended levels of operation. Thus, LMP provides the signal to the generator which assures continued reliable operation of the grid for actual as well as postulated system conditions.

Recommendation 9: Clarify Reliability Coordinator and Control Area Functions, Responsibilities, Capabilities and Authorities

As part of PJM's responsibility to provide short-term reliability, PJM serves as the NERC Reliability Coordinator for the PJM/PJM West region. Additionally, pursuant to agreements, and with NERC approval, PJM assumed the role of Reliability Coordinator for the American Electric Power, Duquesne Light, Commonwealth Edison, and Dayton Power and Light electrical systems.

The role of Reliability Coordinator at PJM has been assigned to a staff member not involved in real-time operations. This change assures that personnel have the proper wide-area view and the opportunity to analyze the operating situation across a major portion of the Eastern Interconnection. The Eastern Interconnection grid, which includes Maryland, is comprised of a collection of highly integrated and interdependent local systems. Since coordination of the interconnected grid is vital to enhanced reliability, PJM, in addition to its JOA with MISO, has begun putting in place data exchange agreements (similar to the PJM-MISO JOA) with neighboring control areas to increase the level of coordination and data sharing between neighboring systems.

The PJM-MISO JOA and similar data exchange agreements detail monitoring measures and specific actions that each entity would take on its own system to clear congestion or reliability problems occurring on the other's system. The agreements establish procedures for coordinated management of congestion across system boundaries. The agreements also integrate and support NERC's short term recommendations to its Control Areas and Reliability Coordinators to take near-term actions to assure reliable operations, by addressing emergency action planning, emergency training, management of voltage and reactive supply, reliability communications, and protocols in the event of failure of system monitoring and control functions. The agreements also provide each region with tools to help evaluate current and projected system conditions over the broader region and to take actions to mitigate conditions that could lead to interruption of electricity service.

Recommendation 13: Reevaluate System Design, Planning and Operating Criteria

NERC is working, by means of a technical group, with the regions to reevaluate existing criteria and practices. The technical group will determine whether there are additional standards or enhancements to existing standards that would further promote reliability. This project will not be completed until February 2006. PJM is assisting in this project by means of its membership in four of the regional members of NERC: MAAC, MAIN, ECAR and SERC.

The NERC Operating Reliability Subcommittee has established a Real-time Tools Best Practices Task Force (RTBPTF) to identify the best practices currently employed for building and maintaining real-time network models and for performing state estimation and real-time contingency analysis. The ultimate goal of the task force will be to recommend specific, auditable requirements for inclusion in new reliability standards for real-time network modeling and network analysis tools. An interim goal will be to develop guidelines for minimally acceptable capabilities for these critical reliability tools. PJM's Energy Management System (EMS) already includes the latest advanced applications to fully monitor, assess and respond to bulk power system conditions.

System design and planning criteria review is just getting organized in the NERC organization, and PJM will be participating in this effort.

Recommendation 14: Improve System Modeling Data and Data Exchange Practices

The NERC Planning Committee (PC) at its March 2004 meeting approved the Multiregional Modeling Working Group's (MMWG) participation in an assignment, in conjunction with the PC's Transmission Issues Subcommittee (TIS), from the "August 14, 2003 Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts" document approved by the NERC Board of Trustees on February 10, 2004. This blackout recommendations document includes 14 high-level recommendations and a number of associated underlying recommendations, which all together total 30 recommendations. Of the 30 recommendations, the PC (and its subgroups) are involved with 14 of them — four in a primary role and ten in a secondary role. The assignment for which the MMWG and TIS have responsibility on behalf of the PC, but secondary to the RRCs, is Recommendation No. 14.

Recommendation No. 14 calls on the Regional Reliability Councils, within one year (by February 2005), to establish and begin implementing criteria and procedures for validating data used in power flow models and dynamic simulations by benchmarking model data with actual system performance. Validated modeling data is also to be exchanged on an interregional basis as needed for reliable system planning and operation. This model validation initiative is underway in MAAC under the auspices of the PC.

Recommendation 16: Accelerate the Standards Transition

NERC is accelerating the approval of new reliability standards that will translate the existing NERC operating policies and planning standards, along with the new compliance templates and several new standards into an integrated and comprehensive set of measurable reliability standards. NERC's single set of reliability standards, known as Version 0 standards, will replace the three existing documents by which it currently measures performance reliability: operating policies, planning standards and compliance templates. These reliability standards will address planning and operations, and will include compliance measures for each standard. [25]

The current Version 0 standards are based largely upon the NERC Functional Model, which defines the functions that need to be performed to ensure the bulk electric system operates reliably. PJM has been actively involved in stakeholder discussions concerning the function model and its certification efforts.

Prior to the August 14, 2003 blackout, NERC began developing a set of industry reliability standards by which it could measure performance in lieu of the existing policies and standards. These post-Version 0 standards, some of which were under development prior to the blackout but were put on hold during the Version 0 development, are sometimes called "Version 1" standards.[26]

Following the 2003 blackout, the industry recognized that the existing policies and standards lacked clarity and were not definitive regarding who was responsible for specific actions. Consequently, the U.S.-Canada Blackout Report both recommended that NERC step-up the Version 0 standards development process. Since then, NERC has introduced a Plan for Accelerating the Adoption of Reliability Standards by February 2005.[27]

PJM has been involved, through the NERC stakeholder process, in the development of both the Version 1 standards and Version 0 standards from the beginning of the process. In both standards processes, PJM is represented by PJM employees in the Stakeholders Committee, the Registered Ballot Body and various subcommittees, working groups and task forces. As a member of four of NERC's RRC members, PJM may initiate new or revised standards and may comment on proposed standards through the standard authorization process. As a member of the ballot body, PJM will actively vote on the Version 0 standards, scheduled for December 2004. Through the standard authorization review process, PJM has actively filed comments on all drafts of the Version 0 standards.

PJM supports the need for clear and precise reliability standards for the industry. While it is important that such standards be approved, there should not be a rush to approve these standards without a thorough technical review by those who must implement and abide by them. PJM supports the current draft of Version 0 Reliability Standards.

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25 See www.nerc.com/standards.
26 Id.
27 Id.

The Version 0 standards underwent a rigorous revision process, resulting in Drafts 1 and 2 and, currently before NERC members, Draft 3. Draft 3 of the Version 0 standards is currently before the industry members, and will be voted on in December 2004. There are 40 Version 0 Operating Standards (260 pages) and 50 Version 0 Planning Standards (171 pages). A single ballot is to be conducted to vote for the entire package. If they pass, Version 0 standards will be before the NERC Board in February 2005, for Board endorsement. If endorsed, Version 0 standards will be effective April 1, 2005, and the existing NERC operating policies, planning standards and compliance templates will be retired. It is expected thereafter that Version 0 standards will continue to be enhanced and massaged by the industry, and will be modified to include the relevant provisions of the Version 1 standards that were under development prior to the August 2003 blackout.

PJM is ready to implement and comply with all Version 0 standards. By virtue of the PJM Operating Agreement, all Members are bound to also comply – a clear benefit of an RTO since RTOs reach non-jurisdictional entities. PJM will monitor and continue participating in the drafting and review of Version 1 standards. PJM is already in compliance with the standards contemplated in Version 0, as they are generally translations from existing requirements in NERC's Operating Policies and Planning Standards. While there are no substantial changes in Version 0, PJM's footprint is expanding and PJM will expand its monitoring function in order to provide MAAC, ECAR and MAIN with the information necessary for those organizations to assess compliance to Version 0 Standards. PJM is mandated through the PJM Operating Agreement to meet the new standards as well as any existing ones. There will be more reporting and revised reporting procedures under the new standards.

In addition, a greater coordination effort with adjacent RRCs is necessary due to PJM market integration. This coordination process was begun two years ago and is aimed at assuring the accurate, timely and non-duplicative reporting and assessment of PJM across all three RRCs.

Recommendation 17: Evaluate NERC Actions in the Areas of Physical and Cyber Security

NERC approved a one-year extension of the existing Urgent Action Cyber Security Standard until August 2005, when it will be superseded by Cyber Security Standard 1300, currently under development. PJM is, through the NERC standards development processes described above, actively participating in the development of Security Standard 1300.

Security Standard 1300 will apply to reliability, balancing, interchange, service providers, transmission owners and operators, generation owners and operators and load serving entities. Thus it will apply to those PJM members who own and operate critical physical or cyber assets.

PJM is committed to cyber security. PJM has assigned a senior management member to be responsible for and manage PJM's cyber security program. PJM's cyber security program has identified and documented critical cyber assets, including physical assets and energy management systems networks. PJM has established and maintains an information technology security plan, and enforces access authorization and authentication. PJM's systems are protected by firewalls, intrusion detection and vulnerability assessments software. PJM constantly monitors security activity and tests its systems for weaknesses. In addition, PJM has established a recovery plan that identifies an action plan and procedures to use to recover critical cyber assets. PJM performs an annual drill on recovery plans.

PJM's security policies, procedures and guidelines also provide for security awareness, monitoring and incident handling training. PJM employees are educated in detecting, reporting and responding to security incidents, and are informed of the proper procedures to disclose such incidents to authorities. PJM maintains a document that identifies the date of completion of training for each of its employees.

PJM periodically assesses its security program, and enhances and modifies it as needed. PJM also has a business continuity/disaster recovery plan.

S-2. The seriousness of the 2003 Blackout has caused a re-evaluation of standards and practices at all levels. In general, what is PJM doing to prevent such an event?

At the outset, it should be noted that PJM's size, the operation of its relays and sound system planning all helped to stem the spread of the August 14, 2003 blackout beyond the limited areas of PJM affected (northern New Jersey and Erie-West area). This is not to say that any system is immune from major outages. However, within PJM, each of the above factors worked to stabilize the PJM system and prevent the August 14 events from further impacting the PJM system.

While no system can guarantee 100% reliability, PJM, as a FERC approved RTO, is committed to being the industry leader in reliable operations and efficient wholesale power markets. PJM performs an array of functions, including long-term resource adequacy planning, real time operations and generation dispatch, market monitoring, and administration of a variety of markets across a broad footprint that includes all or parts of the District of Columbia, Maryland, Pennsylvania, New Jersey, Delaware, Virginia, Ohio, West Virginia, Indiana, Illinois, Kentucky, Tennessee, and Michigan.[28] PJM continually reviews, and when necessary, enhances it rules and operating procedures and systems. PJM's functions to ensure both short term and long term reliability further include coordinating information and operations with other RTO's, and continued participation in the development of NERC reliability standards.

<u>Resource Adequacy Planning</u>

PJM ensures long-term resource adequacy planning and regional transmission planning. PJM has historically included a resource adequacy construct as a means to ensure long-

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[28] Pending regulatory approval, by the start of 2005, PJM will integrate Dominion Power and Duquesne Power & Light into PJM.

term adequacy of generation supply to meet future demand. The existence of a resource adequacy construct is driven by the fact that electric energy is an essential commodity and it is simply unacceptable to have shortages. The blackout that occurred in August 2003 dramatically illustrated the tremendous negative impact that a failure of electric supply has on social welfare and on the economy in general. The development of voluntary demand response initiatives over the long run holds great promise for providing customers "self-help" means to address price spikes and scarcity of supply; however these developments will take additional time to fully mature. Therefore, the justifiable social requirement for high reliability standards coupled with the fact that electric energy cannot easily be stored for later use during times of excess supply clearly indicates that a mechanism to ensure supply adequacy is required.

The current resource adequacy is a short-term construct. It does not require any long-term forward commitment of resources to meet the region's capacity requirement, nor even a requirement for load serving entities (LSEs) to commit resources for entire seasonal intervals. Based on past experience, the capacity credit market clearing prices are low when supply is abundant, but rather quickly rise to the level of the Capacity Deficiency Rate when the demand is greater than the supply. This type of pricing behavior tends to result in contradictory investment signals which can lead to unpredictable behaviors and fails to provide a consistent, long-term price signal to enable developers to secure the financing necessary to build additional capacity.

Trends revealed in PJM's reliability planning analysis demonstrate the need for a prompt change in PJM's approach to ensuring long-term reliability. Stakeholders have raised concerns about whether the current resource adequacy construct provides sufficient incentives to ensure long term investment in resources needed to meet growing customer demand for electricity. Additionally, the independent PJM Market Monitor has raised concerns about the competitiveness of the existing capacity markets.

While various stakeholder groups have attempted to address these concerns over the last few years and have made incremental improvements in the structure, PJM Staff remains concerned that the current capacity construct is a short-term construct that does not require a long-term commitment by resources or send a forward price signal to ensure system reliability over the long-term. PJM Staff maintains that PJM must ensure that it has an integrated approach to assuring long-term reliability and competitively priced delivered energy, and PJM must ensure that any new resource adequacy construct that is adopted is compatible and integrates with PJM's Regional Transmission Expansion Planning Process, encourages load management, has a deliverability component, supports retail access programs, includes a market-based price discovery mechanism, accommodates bilateral contracts and self-supply, and includes appropriate market mitigation.

In response to these concerns, PJM Staff developed a Reliability Pricing Model (RPM) proposal that is currently before the Maryland Public Service Commission, *In the Matter of the Inquiry into Electric Generating Resource Adequacy*; Case No. 8980. (See Comments of PJM filed Nov. 1, 2004). While the proposed RPM is still under development in PJM's open stakeholder process, the RPM model is a robust model that integrates planning, operations, and markets to create a holistic approach to ensuring long-term resource adequacy in PJM. PJM is working to finalize this proposal by the end of 2004 and plans to present it for endorsement in the PJM Members Committee with the intent to file the proposal at FERC in the first quarter of 2005.

Market Integrations

On May 1, 2004, the Commonwealth Edison transmission system in northern Illinois was integrated into PJM and its wholesale markets. On October 1, 2004, American Electric Power and Dayton Power & Light integrated into PJM. Planned integrations include Dominion and Duquesne Light on January 1, 2005.
Market integration benefits include enhanced reliability through: more robust markets; centralized dispatch; and comprehensive regional transmission expansion planning. An additional benefit is that the market is facilitated by more efficient dispatch of a large generation fleet, taking advantage of diverse weather variations and time zone effects. Market integration increases coordination of the grid, which increases reliability and helps prevent future blackouts. Further, the PJM market is designed so that market participants are incented to take actions which promote reliability. PJM is currently the world's largest grid operator.

Regional Transmission Expansion Planning Process

This year, 2004, the PJM Board of Managers approved an additional $87 million in grid upgrades under its Regional Transmission Expansion Plan (RTEP), for a total of nearly $862 million since PJM's first RTEP was approved in 2000. PJM's RTEP is the first region-wide process that systematically and objectively evaluates grid upgrades and generation interconnections, involves stakeholders and provides a mechanism to mandate necessary grid improvements. The upgrades provide for the interconnection of additional generation and keep the system in compliance with reliability standards. PJM has the authority to require transmission upgrades to be made to maintain reliability standards. The RTEP process provides a methodology for: coordinating planning across multiple transmission systems; evaluating alternative solutions including transmission, generation and load options; reflecting broad stakeholder input to the process; incorporating the impacts of operating concerns and congestion, and resolution of seams issues. Assuring adequacy of the transmission grid for the long term is a major factor in preventing future blackouts.

System Operations Enhancements

In March of 2004, a new two-story array of video cubes was installed in the PJM control room to replace the old, static mapboard. The video wall displays data in a larger format than possible on a computer screen. It allows simultaneous display of multiple conditions and information from the entire grid down to the bus level. It shows trends in conditions and sets the priority of alarms.

In December of 2003, the state estimator was updated. The new state estimator provides the widest picture of the status of the North American grid. It can model conditions on the grid from Minnesota to the Atlantic and from Tennessee and the Carolinas to New England. It looks into neighboring systems because conditions there can affect reliability here. It feeds data into systems that run "what-if scenarios" to determine how the grid would be affected if certain facilities unexpectedly tripped. Tens of thousands of data values are input into the PJM EMS every few seconds in order to provide accurate and up-to-the-second information regarding the status of the electric power grid to the state estimator.

By June 2004, the new unit commitment software was installed and in operation. This new computer program more precisely schedules which units should be ready to run and when they need to be ready. Thus, more accurate scheduling will save an estimated $56 million annually. It is the first such program using mixed-integer programming techniques, providing a more robust solution than the techniques in general industry use.

<u>Coordinated Operations across Broad Regions</u>

It has become increasingly clear that the traditional system of multiple control areas with voluntary coordination agreements and planning undertaken by each utility individually simply is a sub-optimal means to enhance future reliability. The number of players and the new uses of the grid require a large regional coordinated approach. Thus, PJM has been working on such an approach as evidenced by the PJM-MISO JOA and control area data exchange agreements referenced in response to S-1, above.

In addition, on May 24, 2004, the Tennessee Valley Authority, MISO and PJM executed a Data Exchange Agreement. This Agreement strengthens coordination of regional transmission operations. It provides protocols and procedures to exchange grid operational data among the three regional operators. All together the regional operators cover 43 percent of the Eastern Interconnection. This data exchange program will further enhance the modeling and monitoring capabilities of all three organizations, increasing their ability to observe, recognize and solve operational problems.

<u>Continued Participation in NERC's Standards Development</u>

As discussed in response to S-1 above, PJM is actively engaged at all levels of the NERC organization, and adheres to NERC reliability standards. PJM is mandated to meet the new NERC standards as well as any existing ones. Through PJM's membership in MAAC, ECAR, MAIN and SERC, PJM is represented by PJM employees' participation in the various subcommittees, working groups and task forces. Through the established NERC processes, PJM will monitor and continue participating in the Version 0 standards process, as well as drafting and review of Version 1 standards.

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)/Conectiv	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, 2003)												
	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
Berlin	1,537	278	60	17	1	1,893	1,537	278	60	17	1	1,893
BGE	1,061,748	112,095	4,851	0	0	1,178,694	1,061,748	112,095	4,851	0	0	1,178,694
Choptank	39,966	3,639	16	283	0	43,904	39,966	3,639	16	283	0	43,904
DPL	434,144	57,352	601	628	0	492,725	164,015	24,080	279	266	0	188,640
Easton	7,615	1,956	0	120	0	9,691	7,615	1,956	0	120	0	9,691
Hagers-town	14,716	2,157	136	4	0	17,013	14,716	2,157	136	4	0	17,013
PE/AP	378,566	51,169	5,846	680	6	436,267	201,650	24,987	2,722	346	3	229,708
Pepco	652,149	71,230	0	138	1	723,518	452,934	44,977	0	106	0	498,017
SMECO	119,861	11,323	4	161	0	131,349	119,861	11,323	4	161	0	131,349
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	2,423	318	11	46	0	2,769	2,423	318	11	46	0	2,798
Williams-port	821	59	35	33	0	948	821	59	35	33	0	948
Total	**2,713,546**	**311,576**	**11,560**	**2,110**	**8**	**3,038,771**	**2,067,286**	**225,869**	**8,114**	**1,382**	**4**	**2,302,655**

Table A-3: Sales by Customer Class (GWh) (as of December 31, 2003)												
	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	12,754	14,897	4,358	0	0	32,009	12,754	14,897	4,358	0	0	32,009
Berlin	20	3	22	0	0	45	20	3	22	0	0	45
Choptank	554	159	75	1	0	789	554	159	75	1	0	789
DPL	5,177	4,992	4,325	49	0	14,543	2,137	1,617	512	11	0	4,277
Easton	101	147	0.0	12	0	260	101	147	0	12	0	260
Hagers-town	145	61	130	7	0	343	145	61	130	7	0	343
PE/AP	5,593	3,082	6,367	24	729	15,795	3,010	1,828	4,566	12	419	9,835
Pepco	7,710	17,611	0	668	5	25,994	5,956	8,801	0	285	0	15,042
SMECO	1,917	985	192	6	0	3,100	1,917	985	192	6	0	3,100
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	39	16	27	1	0	83	39	16	27	1	0	83
Williams-port	9	2	7	1	0	19	9	2	7	1	0	19
Total	**34,019**	**41,955**	**15,503**	**769**	**734**	**92,980**	**26,642**	**28,516**	**9,889**	**336**	**419**	**65,802**

Table A-4: Typical Utility Bills in Maryland, Winter 2003						
	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	$72.10	$1,252.91	$17,978.62	$0.0961	$0.1002	$0.0899
Berlin	$89.00	$1,601.43	$18,385.40	$0.117401	$0.12589	$0.09048
Choptank	$74.12	$1,183.53	$16,776.42	$0.09883	$0.09468	$0.08388
DPL/Conectiv	$69.62	$343.69	$12,910.21	$0.092827	$0.098197	$0.064551
Easton	$75.23	$1,329.43	N/A	$0.10031	$0.10635	N/A
Hagerstown	$47.75	$862.95	$10,152.81	$0.0636	$0.0690	$0.0576
Allegheny Power	$130.51	$417.39	$2,226.84	$0.06869	$0.06522	$0.05264
PEPCO	$62.82	$907.22	$12,716.55	$0.0838	$0.0726	$0.0636
Somerset	N/A	N/A	N/A	N/A	N/A	N/A
SMECO	$53.48	$720.17	$10,892	$0.0713	$0.0514	$0.0545
Thurmont	$54.22	$839.82	$11,279.56	$0.07117	$0.06584	$0.05542
Williamsport	$60.79	$136.22	$823.29	$0.055	$0.054	$0.055

Table A-5: Energy Input by Utility (GWh) (as of December 31, 2003)								
Utility	**Fossil**	**Hydro**	**Nuclear**	**Cogeneration**	**Other**	**Net Interchange**	**Purchases**	**Total**
A&N	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
BGE[29]	0	0	0	0	0	0	0	33,745
Berlin	4	0	0	0	0	0	45	49
Choptank	0	0	0	0.1	0	0	846	846
DPL/Conectiv	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Easton	49	0	0	0	0	223	0	272
Hagerstown	0	0	0	0	0	0	362	356
Allegheny Power	0	0	0	1,450	0	-1,450	10,385	10,385
PEPCO	0	0	0	592	0	0	27,375	27,967
Somerset	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SMECO	0	0	0	0	0	0	3,254	3,254
Thurmont	0	0	0	0	0	0	86	86
Williamsport	0	0	0	0	0	0	20	20

[29] BGE purchases all of its generation from the wholesale market through full-requirements service agreements.

Table A-6: Peak Demand Forecast , 2004-2018 (Net of DSM Programs; MW)													
Year	**A&N**	**BGE**	**Berlin**	**DPL**	**Chop-tank**	**Easton**	**Hagers-town**	**PE/AP**	**PEPCO**	**Som-erset**	**SMECO**	**Thur-mont**	**Williams-port**
2004	N/A	6,904	9.90	3,915	198.0	61.3	77.51	2,955	5,927	N/A	724	20.07	4.600
2005	N/A	7,019	9.70	4,024	202.6	62.8	79.83	3,002	6,030	N/A	750	20.37	4.600
2006	N/A	7,129	9.84	4,137	207.3	64.4	82.23	3,041	6,134	N/A	775	20.67	4.600
2007	N/A	7,239	9.99	4,252	216.7	65.9	84.70	3,076	6,240	N/A	799	20.98	4.610
2008	N/A	7,347	10.14	4,372	226.5	67.4	87.24	3,106	6,348	N/A	824	21.30	4.610
2009	N/A	7,452	10.29	4,495	236.8	69.0	89.86	3,137	6,458	N/A	845	21.62	4.620
2010	N/A	7,558	10.45	4,620	247.7	70.5	92.58	3,170	6,570	N/A	867	21.94	4.620
2011	N/A	7,665	10.60	4,748	259.3	72.0	95.36	3,208	6,684	N/A	888	22.27	4.630
2012	N/A	7,783	10.76	4,879	271.4	73.6	98.22	3,243	6,799	N/A	909	22.60	4.630
2013	N/A	7,897	10.92	5,013	284.1	75.1	101.17	3,286	6,916	N/A	929	22.94	4.640
2014	N/A	N/A	11.09	5,150	297.6	76.6	104.21	3,326	7,034	N/A	950	23.29	4.640
2015	N/A	N/A	11.25	N/A	311.8	78.2	107.33	3,364	7,154	N/A	971	23.64	4.650
2016	N/A	N/A	11.42	N/A	326.7	79.7	110.55	3,411	7,277	N/A	991	23.99	4.650
2017	N/A	N/A	11.60	N/A	342.5	81.2	113.87	3,463	7,401	N/A	1011	24.35	4.650
2018	N/A	N/A	11.77	N/A	359.1	82.8	117.28	3,517	7,527	N/A	1030	24.72	4.660

Table A-7: Energy Sales Forecast, 2004-2018 (Net of DSM Programs; GWh)													
Year	**A&N**	**BGE**	**Berlin**	**DPL**	**Chop-tank**	**Easton**	**Hagers-town**	**PE/AP**	**PEPCO**	**Somerset**	**SMECO**	**Thur-mont**	**Williams-port**
2004	N/A	33,720	37.08	18,486	826.6	294	354.0	16,198	26,981	N/A	3,108	82.89	17.0
2005	N/A	34,204	36.65	18,905	866.8	301	364.6	16,364	27,485	N/A	3,214	84.13	17.0
2006	N/A	34,651	37.20	19,329	909.3	309	375.6	16,623	28,075	N/A	3,314	85.40	17.0
2007	N/A	35,094	37.76	19,767	955.1	316	386.9	16,816	28,677	N/A	3,412	86.68	17.1
2008	N/A	35,532	38.33	20,217	1,003.2	324	398.5	17,066	29,279	N/A	3,508	87.98	17.1
2009	N/A	35,981	38.90	20,705	1,053.7	331	410.4	17,008	29,894	N/A	3,597	89.30	17.1
2010	N/A	36,436	39.48	21,157	1,106.8	338	422.7	17,105	30,522	N/A	3,679	90.64	17.1
2011	N/A	36,896	40.08	21,609	1,163.3	346	435.4	17,285	31,163	N/A	3,760	92.00	17.2
2012	N/A	37,363	40.68	21,937	1,222.8	353	448.5	17,541	31,817	N/A	3,841	93.38	17.2
2013	N/A	37,835	41.29	22,265	1,285.1	361	461.9	17,730	32,485	N/A	3,919	94.78	17.2
2014	N/A	N/A	41.91	22,593	1,351.1	368	475.8	17,913	33,167	N/A	3,997	96.20	17.2
2015	N/A	N/A	42.54	N/A	1,420.5	375	490.1	18,122	33,864	N/A	4,074	97.64	17.3
2016	N/A	N/A	43.17	N/A	1,493.6	383	504.8	18,462	34,575	N/A	4,151	99.11	17.3
2017	N/A	N/A	43.82	N/A	1,570.6	390	519.9	18,708	35,301		4,229	100.59	17.3
2018	N/A	N/A	44.48	N/A	1,652.0	397	535.5	19,031	36,042	N/A	4,304	102.10	17.3

Table A-8:
List of Currently Licensed Electric and Natural Gas Suppliers and Brokers/Aggregators
(as of 12-1-04)

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] Bollinger Energy Corporation		IR-265	IR-322	
[11] BP Energy Company			IR-676	
[12] Colonial Energy, Inc.			IR-606	
[13] Commonwealth Energy Corporation	IR-639			
[14] Compass Energy Services			IR-652	
[15] Conoco, Inc.			IR-378	
[16] Constellation Energy Source, Inc.	IR-239			
[17] Consolidation Edison Solutions	IR-603			
[18] Constellation New Energy, Inc.	IR-500		IR-522	
[19] Constellation New Energy – Gas Division, LLC		IR-655		
[20] Coral Energy Gas Sales, Inc.			IR-360	
[21] CQI Associates, LLC		IR-575		
[22] Cypress Natural Gas			IR-674	
[23] Delta Energy, LLC			IR-645	
[24] Dominion Retail, Inc.	IR-252		IR-345	
[25] Downes Associates, Inc.		IR-523		
[26] Eastern Shore of Maryland Educational Consortium Energy Trust d/b/a ESMEC Energy Trust		IR-342		

Table A-8: (continued)
List of Currently Licensed Electric and Natural Gas Suppliers and Brokers/Aggregators
(as of 12-1-04)

Company	Electric Supplier License #	Electric Broker License #	N. Gas Supplier License #	N. Gas Broker License #
[27] Econnergy Energy Company	IR-340		IR-334	
[28] Energy America, LLC	IR-276		IR-317	
[29] Energy Options, LLC		IR-568		
[30] Energy Services Management, LLC d/b/a Maryland Energy Consortium		IR-236		IR-312
[31] Energy Services Provider Group, LLC		IR-518		IR-519
[32] EnergyWindow, Inc.		IR-274		
[33] Enron Energy Marketing Corp.			IR-370	
[34] Entex Gas Resources Crop.			IR-350	
[35] Essential.com, Inc.	IR-259			
[36] FirstEnergy Solutions Corp.	IR-225			
[37] Hess Energy, Inc.			IR-337	
[38] HIS Power & Water, LLC	IR-271			
[39] Houston Energy Services Company, LLC.			IR-403	
[40] ISG Sparrows Point	IR-592			
[41] Liberty Power Corporation	IR-607			
[42] Marathon Oil Company			IR-364	
[43] Market Direct d/b/a MD Energy		IR-614		
[44] MeadWestvaco Energy Services, LLC	IR-669			
[45] Metromedia Energy, Inc.			IR-355	
[46] Mid-Atlantic Aggregation Group Independent Consortium, LLC d/b/a MAAGIC		IR-234		
[47] Mirant Americas Energy Marketing, LP.	IR-297			
[48] Mirant Americas Retail Energy Marketing, LP.	IR-480			
[49] Mona Building Technologies, LLC		IR-257		
[50] MxEnergy.com, Inc.			IR-327	

Table A-8: (continued)
List of Currently Licensed Electric and Natural Gas Suppliers and Brokers/Aggregators
(as of 12-1-04)

Company	Electric Supplier License #	Electric Broker License #	N. Gas Supplier License #	N. Gas Broker License #
[51] Ohms Energy Company, LLC	IR-679			
[52] Pepco Energy Services, Inc. d/b/a Conectiv Energy Services	IR-222		IR-316	
[53] PPL EnergyPlus, LLC	IR-230			
[54] QVINTA, Inc.		IR-557		IR-530
[55] Reliant Energy Solutions East, LLC	IR-525			
[56] Select Energy, Inc.	IR-275		IR-331	
[57] Sempra Energy Solutions	IR-442		IR-464	
[58] SmartEnergy.com, Inc.	IR-270			
[59] Smith Energy		IR-626		
[60] Sprague Energy Corp.				IR-339
[61] Stand Energy			IR-623	
[62] Statoil Natural Gas, LLC			IR-561	
[63] Strategic Energy, LLC	IR-437			
[64] The New Power Company IBM Global Services	IR-336			
[65] Tiger Natural Gas			IR-351	
[66] Total Gas & Electric, Inc.			IR-348	
[67] Tractebel Energy Services, Inc.	IR-605			
[68] TransAlta Energy Marketing, Inc.	IR-474		IR-474	
[69] Trigen-Baltimore Energy Corporation		IR-258		
[70] UGI Energy Services, Inc.	IR-237		IR-319	
[71] Utility Resource Solutions			IR-613	
[72] Washington Gas Energy Services, Inc.	IR-227		IR-324	

SUMMARY (as of 12-1-04)

No. of Suppliers/Brokers

Electric Supplier Licenses = 32 **Electric Broker Licenses = 18** **Natural Gas Supplier Licenses = 34**
Natural Gas Broker Licenses = 5 **Companies Serving Both Electric & Natural Gas = 15.**

Table A-9:
CPCN Exemptions from January, 2002-November , 2004

NAME	*NO. OF UNITS*	*TOTAL kWs*	*LOCATION*	*DATE APPROVED*
Amerada Hess Corp.	1	500	6200 Pennington Ave., Baltimore	8/25/04
APC Realty & Equip. Co. d/b/a Sprint	1	600	7267 Park Circle Dr., Hanover	3/12/03
APC Realty & Equip. Co. d/b/a Sprint	1	600	12001 Indian Creek Ct., Beltsville	5/28/03
AT&T	1	1,000	9000 Mendenhall Ct., Columbia	2/12/03
Bethesda Triangle	1	1825	4835 Cordell Ave., Bethesda	8/04
Capstone Development Corporation	1	20	4310 Knox Rd., Bldg. 4(B), Univ. of MD, College Park	6/9/04
Capstone Development Corporation	2	40	6903 Prienkert Dr., Bldgs. 5&6, Univ. of Md, College Pk.	6/16/04
Center for Advancement of Genomics	1	2,000	5 Research Pl., Rockville	6/4/03
Comcast Cablevision of Baltimore County	1	400	8031 Corporate Dr., Baltimore	1/16/02
Corporate Realty Management	1	500	7323 Aviation Blvd., Linthicum Park	9/1/04
Dept. of the Air Force-Andrews AFB	1	900	Bldg. 1204, Andrews AFB	2/02
Dept. of the Air Force-Andrews AFB	1	900	3479 Fetchet Ave., Andrews AFB	3/8/02
Dept. of the Air Force-Andrews AFB	1	800	Bldg. 1535, Andrews AFB	6/16/04
Dept. of the Army-Aberdeen Proving Ground	2	1,300	2201 Aberdeen Blvd., Aberdeen	7/31/02
Dept. of the Army-Aberdeen Proving Ground	8	1,800	Colleran Rd., Bldg. 345, Aberdeen	11/12/03
Dept. of the Army-Adelphi Laboratory	1	600	2800 Powder Mill Road, Adelphi	5/12/04
Dept. of the Army-Fort Detrick	8	3638	Beasley Dr., Doughten St., Ditto Ave., & Porter St., Fort Detrick	9/8/04
Dept. of the Navy	1	8,000	8901 Wisconsin Ave., Bldg. 16, National Naval Medical Ctr., Bethesda	8/13/03
Digene Corporation	1	1500	1201 Clopper Rd., Gaithersburg	6/9/04
Discovery Communication	1	2000	8040 Kennett St., Silver Spring	12/31/03
Fannie Mae	10	20,000	MXD Office Park, Urbana	9/3/03
General Services Administration	1	2,000	10901 New Hampshire Ave., Silver Spring	2/18/03
General Services Administration	1	6,000	10901 New Hampshire Ave., Silver Spring	2/18/03
H. B. Mellott Estate	1	1200	13645 Rockdale Rd., Clear Spring	10/6/04
H. B. Mellott Estate	1	600	10102 Mapleville Rd., Hagerstown	10/6/04
Honeyland 108, LLC	2	2,000	9140 Old Annapolis Rd., Columbia	9/17/03
Human Genome Sciences, Inc.	3	1500	14200 Shady Grove Rd., Rockville	8/28/02

Table A-9: (continued)
CPCN Exemptions January, 2002-November, 2004

Human Genome Sciences, Inc.	1	1,250	9800 Medical Center Dr., Rockville	2/12/03
Human Genome Sciences, Inc.	3	2250	9912 Belward Campus Dr., Rockville	3/3/04
IBM	2	5000	800 N. Frederick Ave., Gaithersburg	10/7/04
John Hopkins University	1	1,000	733 S. Broadway St., Baltimore	1/22/03
John Hopkins University	1	900	11100 John Hopkins Rd., Dist. Utilities Bldg., Laurel	5/28/03
John Hopkins University	2	3650	724 N. Wolfe St., Phipps 550, Baltimore	3/3/04
John Hopkins University	1	750	11100 John Hopkins Rd., Bldg. 36, Laurel	5/26/04
Lockheed Martin Global	4	2,380	22300 Comsat Dr., Clarksburg	2/13/02
Lopke Quarries	1	1,067	New Windsor, MD	11/4/04
Md. Economic Development Corporation	1	500	8080 Greenmeade Dr., College Park	8/04
Medimmume, Inc.	1	1,500	Quince Orchard Dr., Gaithersburg	1/15/03
Montgomery County Dept. of Public Works & Transportation	1	1,000	16630 Crabs Branch Way, Rockville	7/7/04
Morgan Stanley Mgmt. Serv., Inc.	1	750	901 S. Bond St., Baltimore	8/6/03
Mountainside Teleport Co.	2	1,500	17633 Technology Blvd.	3/12/03
Mushroom Canning Co.	1	225	902 Woods Rd., Cambridge	2/12/03
Nasdaq Stock Market, Inc.	1	2,000	9513 Key West Ave., Rockville	1/11/02
NASD	1	900	15201 Diamondback Dr., Rockville	1/04
National Institutes of Health	2	2,000	9000 Rockville Pike, Bethesda	10/2/02
National Institutes of Health	3	5100	9000 Rockville Pike, Bldg. 36, Bethesda	2/04
National Institutes of Health	1	750	9000 Rockville Pike, Bldg. 38, Bethesda	2/04
National Institutes of Health	1	2,000	9000 Rockville Pike, Bldg. 38, Bethesda	12/1/04
Northrup Grumman Corp.	1	250	7323 Aviation Blvd	9/4/02
Northrup Grumman Corp.	1	2000	7323 Aviation Blvd	8/23/04
Northwest Hospital Center	2	2000	5401 Old Court Road, Randallstown	8/23/04
Patuxent River Naval Air Station	1	2,000	22445 Peary Rd., Patuxent	7/04
Parrot Material Co.	1	600	611 Hoods Mill Road, Woodbine	3/3/04
PerdueFarms, Inc.	1	2000	6906 Zion Church Rd., Salisbury	11/4/04
Qiagen Sciences, Inc.	1	1,000	19300 Germantown Rd., Germantown	1/22/03
Recovery Point System	1	2000	20441 Century Blvd., Germantown	6/3/04
SAIC	1	600	7116 Geoffrey Way, Frederick	6/23/04
SAIC	1	500	430 Miller Dr., Fort Detrick, Frederick	8/18/04
SBC Telecom, Inc.	1	1,500	7150 Standard Dr., Hanover	1/8/03

Table A-9: (continued)
CPCN Exemptions January, 2002-November, 2004

Social Security Administration	3	3,600	6201 Security Blvd., Baltimore	8/28/02
Sprint Communications	2	1,500	6050 Race Rd., Elkridge	4/23/03
The Baltimore Sun	2	2,000	501 N. Calvert St., Baltimore	5/8/02
The Baltimore Sun	2	4,000	300 E. Cromwell St., Baltimore	5/8/02
The JBG Companies	1	1,750	12735 Twinbrook Pkwy., Rockville	8/20/03
The JBG Companies	1	2,000	5625 Fishers Ln., Rockville	8/20/03
Univ. of MD Biotechnology Institute	1	1,200	9600 Gudelsky Dr., Rockville	11/26/03
Verizon, Inc.	1	1,000	1801 E. Fayette St., Baltimore	7/31/02
Verizon, Inc	1	750	6315 Greenbelt Rd., College Park	7/31/02
Verizon, Inc.	1	750	5711 York Rd., Baltimore	7/31/02
Verizon, Inc.	1	1,000	309 Carroll Ave., Laurel	7/31/02
Verizon, Inc.	1	1,000	490 Fleet St., Rockville	7/31/02
Verizon, Inc.	1	750	19420 Walter Johnson Dr., Germantown	7/31/02
Verizon, Inc.	1	800	1801 McCormick Rd., Largo	7/31/02
Verizon, Inc.	1	750	3701 Koppers St., Baltimore	7/31/02
Verizon MD, Inc.	1	800	214 E. 31st St., Baltimore	10/2/02
Verizon MD, Inc.	1	1,000	4533 Stanford St., Bethesda	11/03
Verizon MD, Inc.	1	1,000	400 Reisterstown Rd., Baltimore	11/03
Verizon MD, Inc.	4	8,000	323 N. Charles & 320 St. Paul Pl.	11/03
Verizon MD, Inc.	2	3,000	6961 Tudsbury Dr., Windsor Mill	7/7/04
Verizon MD, Inc.	1	500	8900 Riggs Rd., Hyattsville	8/4/04
Verizon MD, Inc.	1	600	1400 Philadelphia Rd., Edgewood	8/4/04
Verizon, MD, Inc.	1	500	14200 Old Marlboro Pike, Upper Marlboro	8/4/04
Verizon MD, Inc.	1	1000	128 E. Church St., Salisbury	8/4/04
Verizon MD, Inc.	1	600	6601 Windsor Mill Rd., Woodlawn	8/4/04
Walter Reed Army Medical Center	1	250	Brookville Rd. and Stephen Sitter Ave., Silver Spring	6/4/03
Washington Metropolitan Area Transit Authority	1	450	9450 Lottsford Rd., Largo	3/29/04
Washington Metropolitan Area Transit Authority	1	230	701 Harry Truman Dr., Largo	3/29/04
Washington Surburban Sanity Com.	1	1,050	6600 Crane Hgwy., Upper Marlboro	4/9/03
Worldcom, Inc.	2	2,000	2606 Carsins Run Rd., Aberdeen	8/28/02

Table A-9: (continued)
CPCN Exemptions January, 2002-November, 2004

NAME	*NO. OF UNITS*	*TOTAL kWs*	*LOCATION*	*DATE APPROVED*
Johns Hopkins-APL	1	600	11100 Johns Hopkins Rd., Bldg. 29, Laurel, MD	Application Pending
T-Mobile	1	500	12050 Baltimore Ave., Beltsville, MD	Application Pending

Table A-10:
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	Rebuild Boonsboro-Frostown line to connect to Doubs-Ringold 230 kV circuit	230	3.3	1	2003	2004*	BTR
Allegheny	2	Boonsboro to Marlowe	138	12.4	1	2004	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 Lappans No. 1 to Marlowe-Boonsboro	138	0.1	2	2008	2009	DA
Allegheny	6	Upgrade Ridgeville substation from 34.5 kV for connection with Mt. Airy-Damascus Transmission Line	230	0.6	2	2006	2007	DA
Allegheny	7	New South Frederick No.1 connection to Monacacy-Lime Kiln	230	0.1	2	2006	2007	DA
Allegheny	8	Upgrade Emmitsburg 34.5 kV substation to connect to Catoctin at 138 kV	138	8	1	2011	2012	DA
Allegheny	9	New Jefferson No.1 substation to connect to the Doubs-Monacacy Transmission Line	230	0.1	2	2010	2010	DA

Table A-10 (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 substation to connect with Nipetown-Reid Transmission line at 138 kV	138	5	1	2009	2009	DA

*: Project Completed July, 2004.

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 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	Gunpowder in Baltimore County to Joppatowne in Harford County	115	9.9	2	Jan-03	Mar-04	OTH
BGE	2	Westport to Paca in Baltimore City	115	4	1	Jan-04	Jun-08	BTR, DA
BGE	3	Mt. Washington to Coldspring in Baltimore City	115	2.18	2	Jan-01	Sep-04	OTH
BGE	4	Joppatowne to Edgewood in Harford County	115	1.98	2	Jun-02	Jul-04	BTR
BGE	5	Westport to Center Street in Baltimore City	115	1.95	1	Jan-04	Jun-07	BTR
BGE	6	Westport to Wilkens in Baltimore City	115	2.05	2	Jan-07	Jun-10	DA
BGE	7	Brandon Shores in Anne Arundel County to Hawkins Point in Baltimore City	230	2.49	1	Jan-07	Jun-07	BTR
BGE	8	Sollers Point to Riverside in Baltimore County	230	0.49	1	Jan-07	Jun-07	BTR
BGE	9	Green Street Station to Monument Street in Baltimore City	115	2	2	Jan-11	Jun-13	BTR

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

Table A-12:
Transmission Enhancements in Conectiv's Service Area

Transmission Owner	#	Project	Voltage (kV)	Length (miles)	No. of circuits	Start Date	In-ser-vice date	Purpose
Conectiv	1	Rebuild Vienna in Dorchester County to Nelson in Sussex County	138	13.7	1	2010	2013	BTR
Conectiv	2	New Line Church to Wye Mills in Queen Annes County	138	25.9	1	2005	2008	BTR
Conectiv	3	2nd line from Grasonville to Stevensville in Queen Annes County	69	5.5	1	2004	2005	DA
Conectiv	4	2nd line from Easton to Bozman in Talbot County	69	11.1	1	2007	2008	DA

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

Table A-13:
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	2008	2009	DA
SMECO	2	Calvert Cliffs Tap to Calvert Cliffs Switching Station in Calvert County (CPCN required)	230	1.1	2	2009	2010	DA
SMECO	3	Calvert Cliffs Switching Station to Hewitt Road Switching Station in St. Mary's County (CPCN required)	230	12.7	2	2011	2012	DA

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