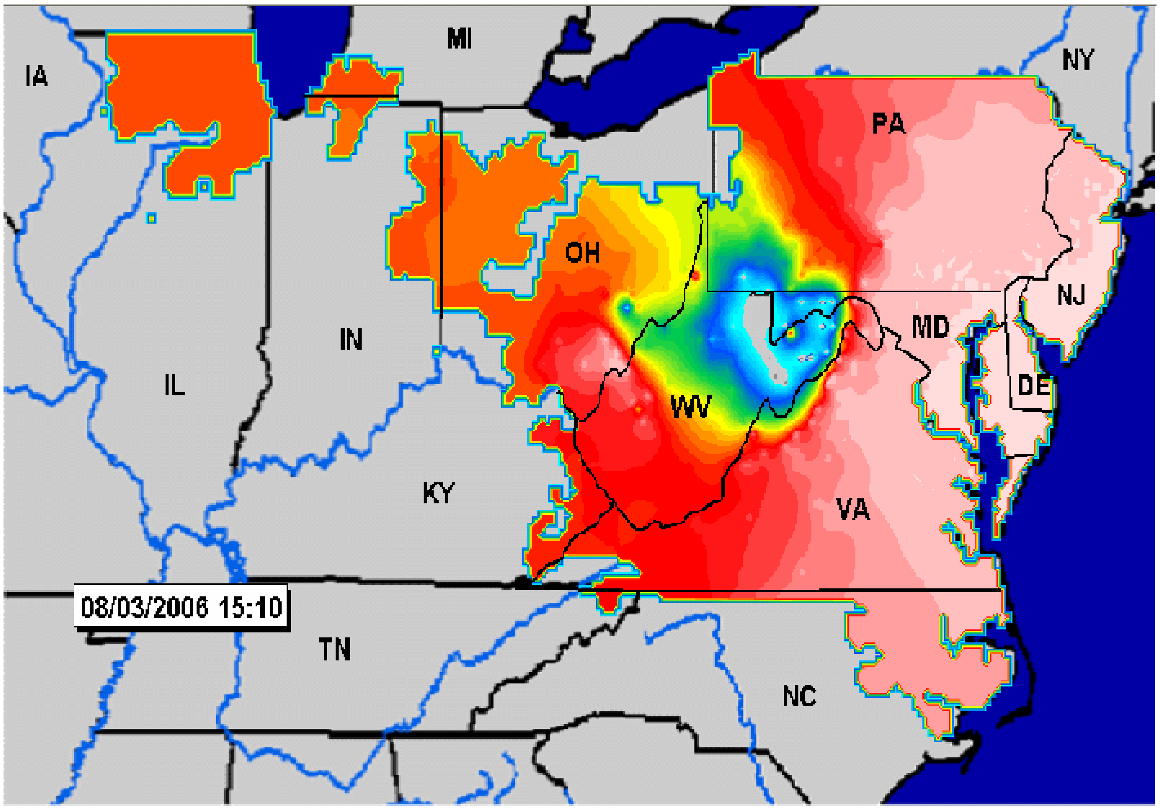
PUBLIC SERVICE COMMISSION OF MARYLAND

ELECTRIC SUPPLY ADEQUACY REPORT OF 2007

In compliance with Section 7-505(e) of
the Public Utility Companies Article

January 2007

PUBLIC SERVICE COMMISSION OF MARYLAND



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I. INTRODUCTION AND EXECUTIVE SUMMARY

Section 7-505(e)(1) of the Public Utility Companies (PUC) Article requires the Public Service Commission of Maryland (PSC or Commission) to "assess the amount of electricity generated in Maryland as well as the amount of electricity imported from other states in order to determine whether a sufficient supply of electricity is available to customers in the State." The report on supply adequacy is to be filed with the General Assembly every two years beginning January 2001 until January 2007. The Electric Supply Adequacy Report of 2007 (Report) is the final report as required by the statute.[1]

This Report covers issues that the Commission considers timely for an understanding of the electric power generation industry in Maryland. The Report initially presents the state of the electric power industry in Maryland. This section includes an overview of net electricity generation and consumption within the State, followed by discussions on transmission and demand side issues. Two significant pieces of environmental legislation passed by the General Assembly and signed by Governor Robert L. Ehrlich, Jr. are also discussed. The Renewable Energy Portfolio Standard legislation (RPS) applies to electricity sales commencing in 2006. The Healthy Air Act (HAA) requires seven Maryland coal plants to reduce emissions over time and the State join the Regional Greenhouse Gas Initiative (RGGI) by June 2007.

The Report also discusses several regional issues that affect Maryland. PJM Interconnection, LLC (PJM), the regional electricity grid operator, expanded to the west and the south and now includes territory as far west as Chicago as well as Virginia and eastern North Carolina. Projected construction of new generation in the region and upgrades and additions to the bulk transmission system should allow PJM system operators to meet established supply reliability criteria. But as this Report will make clear, the margin for error in electricity supply adequacy is getting precariously thin, particularly in areas such as the Baltimore-Washington region, southern Maryland, the Delmarva Peninsula, eastern and central Pennsylvania, New Jersey, and much of Virginia. This Report details several ways that PJM is attempting to address these issues, including a revised capacity structure[2] and Regional Transmission Expansion Planning Protocol (RTEPP). Events such as a prolonged heat wave, unanticipated losses of large generation units or transmission lines, failure of proposed projects to be completed, or severe storms might also result in wholesale price spikes or some localized outages.

Finally, the Report covers several federal and national topics that affect Maryland. The Energy Policy Act of 2005 (EPAct 2005) has major implications for the electricity industry. The North American Electric Reliability Council (NERC) has been selected by the Federal Energy Regulatory Commission (FERC) as the new Electric Reliability Organization (ERO). This organization is charged with developing reliability standards for the electric industry. Also in 2006, the Department of Energy (DOE) released a transmission congestion study that shows that

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1 In accordance with § 2-1246 of the State Government Article (PUC, § 7-505(e)(2)).

2 As reported in the *Electric Supply Adequacy Report of 2005*, the Commission established Case No. 8980 in October 2003 to investigate the best method to maintain electric generating resource adequacy to ensure a continuous, reliable supply of electricity to customers in Maryland. As part of this case, PJM presented for the first time a new capacity construct known as the Reliability Pricing Model (RPM) at a public hearing held on July 8, 2004. In December 2006, FERC conditionally approved RPM, effective June 2007.

the region from New York City to northern Virginia (which includes Maryland) is one of the two areas of the country most in need of new bulk power transmission lines.

Reliability in Maryland is Uncertain

The uncertainty of Maryland's supply adequacy begins with Maryland's status as one of the largest electric energy importing states in the country.[3] Maryland imports over 25% of its electric energy needs. On an absolute basis, Maryland is the fifth largest electric energy importer in the United States. Virginia and New Jersey are in a comparable situation, being respectively the third and fourth largest energy importers in the country. Delaware and the District of Columbia, neighboring jurisdictions, are also large electricity importers, particularly given their relative small size. Thus, not only is Maryland a large importer of electricity, but so are states to the south, east and north of it as well. This makes much of the mid-Atlantic region deficient in generating capacity or, in industry parlance, a "load sink." Of states in the surrounding area, Maryland can import electricity in appreciable amounts only from West Virginia and Pennsylvania, and is competing with Delaware, Virginia, New Jersey, and the District of Columbia for the available exports from those states.

Exacerbating this situation is that Maryland's dependence on out of state electricity supplies will likely increase over the next several years. On the supply side, little new in-state electric generation is scheduled to be built in the next five years. Additionally, some fossil-fired generating capacity may be de-rated or retired in order to comply with both federal and State air emission requirements, including the sulfur dioxide and mercury provisions of Maryland's Healthy Air Act. On the demand side, Maryland's electric utilities and PJM forecast that electricity demand will continue to rise, albeit at a modest pace of between 1% and 2% per year, further increasing Maryland's need for additional electricity supplies.

Maryland's position as a large net importer and the fact many other jurisdictions in PJM are in a similar situation gives the State little margin for error in ensuring electric reliability. Significantly, Maryland has no in-state reserve margin. Existing in-state generating capacity would have to be increased by over 4,000 MW to bring load and electric supply into balance if Maryland was forced to rely on in-state resources alone. De-rating or retiring any existing in-state generation would further increase this need.

Maryland has been relying on the bulk electric transmission grid to make up the difference between available in-State supply and demand. However, Maryland's ability to import additional electricity over that grid, particularly during times of peak demand, is limited at best. This is because the current transmission facilities that allow the importation of electricity into the State is operating at peak capacity during peak load periods. In other words, even though generators in Pennsylvania, West Virginia and states farther west may have excess generation to sell to Maryland, the transmission network is unable to deliver that power during times of peak demand.

[3] Source: Energy Information Administration (EIA). The Commission highlighted this trend in the 2005 Supply Adequacy Report. In 2004, the states with the highest estimated levels of net imports (assuming an average 8% loss factor for comparability) were California, Louisiana, Virginia, New Jersey, Maryland, New York and Ohio. In 2004, the states with the highest net exports were Pennsylvania, West Virginia, Texas, Alabama, and Illinois.

This situation is confirmed by studies from PJM. By 2011, PJM is projecting that reserve margins in the central portion of Maryland and other eastern regions of PJM will be barely adequate to ensure reliability. PJM has ordered that significant new transmission upgrades be made to ensure reliability in eastern PJM, including Maryland, and these upgrades will allow for the most effective use of all PJM generation capacity, both existing and planned. Among other projects, PJM has determined the 500 kV Trans Allegheny Interstate Line (TrAIL) beginning in southwest Pennsylvania and terminating in Loudoun, Virginia is needed by 2011 to ensure electric reliability. Given the length of this project and the significant opposition it has engendered already, the siting and construction of this multi-state line by 2011 will be a significant challenge.

The consequences of this situation are not just reliability-related. As will be discussed in more detail in a section below, transmission "congestion," as the shortage of transmission capacity during peak periods is known, leads to price spikes for spot market electricity purchases during those peak periods. While much of Maryland's electricity needs are covered by bilateral contracts or other hedges that provide some protection from those price spikes, the sellers of power need to take transmission congestion into account in the pricing of their offers.

While congestion in the BGE and Pepco zones merited mention in *the Electric Supply Adequacy Report of 2005*, it has worsened over the last two years. In fact, Maryland offers a first-hand look at the pricing impacts of congestion. Frederick County is a key congestion point on the west-to-east transmission import path. Three years ago, locational marginal prices (LMPs) for electricity in Maryland west of that point averaged $2.90 per megawatt hour (MWh) less than prices in Maryland east of that point. By 2006, that gap had risen to $9.43 per MWh[4]. The gap is likely to continue to increase until additional generation becomes available to serve central and southern Maryland and the Eastern Shore, or additional transmission capacity becomes available to import electricity into those regions.

Price discrepancies also provide a form of early-warning signal that reliability problems are on the horizon. In other words, the economic signals provided by congestion pricing indicate that, unless the trends towards increasing supply/demand imbalance are reversed, the ability of the system to reliably supply electricity during times of peak period will become questionable.

In the long-term, Maryland's electric reliability requires the adoption of energy policies that encourage:

- The construction of generation capacity in-State;[5]
- The siting and building of new transmission facilities that give increased access to out-of-state generation; and,
- Energy conservation and demand management programs that will reduce the need for new electric supplies, and make more efficient use of both existing and planned electric infrastructure.

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4 Source: PJM Interconnection. LMPs for the Allegheny zone in 2003 ($35.78) and 2006 ($48.70) are used as a proxy for electricity prices to the west of Frederick County. A simple average of the annual LMPs for the BGE and Pepco zones in 2003 ($38.68) and 2006 ($58.13) are used as a proxy for points to the east in Maryland.

5 As reported in the 2005 Supply Adequacy Report, development of new generation within the State remains low, with the few new projects using natural gas as fuel, which has seen volatile pricing for several years now.

II. ELECTRICITY INDUSTRY IN MARYLAND

On July 1, 1999, Maryland's Electric Customer Choice and Competition Act of 1999 (Act) went into effect. The Act established the legal framework for the restructuring and provided alterations to the regulation of the electric utility industry in Maryland. The Act restructures "the generation, supply, and pricing of electricity", such that competitive market forces are to be relied upon to encourage the construction of needed facilities.

A. Overview of Electricity Generation and Consumption in Maryland

Electricity generation in Maryland comes primarily from solid fuels (coal and nuclear), a condition that has changed little over the last six years. In 1999, coal supplied 57.4% of the electricity in the State while nuclear provided 25.8%. In 2005, the most recent year that complete information is available, coal generated 55.7% of the electricity in the State while nuclear provided 27.9%. Natural gas, petroleum, hydroelectricity, other gases, and other renewable sources combine for 16.4% of all in-State generation during 2005. Table II.A.1 below summarizes Maryland's in-State fuel mix in gigawatt-hours (GWh) by generating sources for the years 1999, 2004 and 2005:

Table II.A.1: Maryland Electric Power Generation Profile[6]

	1999		2004		2005	
Source	**GWh**	**% Share**	**GWh**	**% Share**	**GWh**	**% Share**
Coal	29,688	57.4%	29,216	56.1%	29,314	55.7%
Petroleum	4,290	8.3%	3,296	6.3%	3,818	7.3%
Natural Gas	2,125	4.1%	1,183	2.3%	1,874	3.6%
Other Gases	60	0.1%	413	0.8%	343	0.6%
Nuclear	13,312	25.8%	14,580	28.0%	14,703	27.9%
Hydroelectric	1,424	2.8%	2,508	4.8%	1,704	3.2%
Other Renewables	786	1.5%	857	1.7%	906	1.7%
Other	0	0.0%	1	0.0%	0	0.0%
Total Generation	**51,685**	**100.0%**	**52,054**	**100.0%**	**52,662**	**100.0%**

Table II.A.2 on the next page shows Maryland's in-State generating capacity profile as of year-end 1999 and 2004. The total of nearly 12,500 megawatts (MW) of installed capacity in Maryland, as of year-end 2004, was an increase of only 6% over the preceding five years. The relative mix of generating capacity has also not significantly changed in the last few years. Coal accounted for nearly 40% of in-State capacity for the years 1999 and 2004. Maryland's nuclear capacity is just below 14% of all of Maryland's generating capacity, a condition that also has not significantly changed. Dual-fired capacity increased its percentage share by almost 10% from 1999 to 2004. This amount is a reflection of the addition of generating units that are capable of burning either petroleum or natural gas. Also, several existing petroleum and natural gas fired units were modified so they are now able to use either fuel.

6 The Energy Information Administration (EIA) is the data source for Tables II.A.1, II.A.2, II.A.3, and II.B.1.

Table II.A.2: Maryland Generating Capacity Profile

	December 31, 1999		December 31, 2004	
Source	**MW**	**% Share**	**MW**	**% Share**
Coal	4,895	41.6%	4,958	39.7%
Petroleum	1,293	11.0%	885	7.1%
Natural Gas	1,398	11.9%	969	7.7%
Other Gases	0	0.0%	152	1.2%
Dual-Fired	1,854	15.7%	3,107	24.9%
Nuclear	1,675	14.2%	1,735	13.9%
Hydroelectric	531	4.5%	566	4.5%
Other Renewables	128	1.1%	127	1.0%
Total Generation	**11,774**	**100.0%**	**12,499**	**100.0%**

Table II.A.3 below summarizes Maryland electricity consumption by customer class for the years 1999, 2004 and 2005 and further compares it to the generation data from Table II.A.1 to show the increase in net imports over a five-year period. Electricity consumption increased by 15.7% between 1999 and 2005. This increase translates into a Maryland annualized compound growth rate of 2.5%, compared to a 1.1% national average for electricity growth. The increases in consumption between 2004 and 2005 occurred even though caps on standard offer service rates were beginning to expire and significant customer classes were starting to experience higher, market-based prices. The table shows that energy use among some customer classifications changed to a significant degree over that period. These changes were due to reclassifications of some customers in 2000, and were not the result of significant changes in actual energy usage rates. Due to the reclassification, commercial use decreased its share of the electricity market from 43.4% in 1999 to 26.2% in 2005, with industrial use increasing by a like amount, 16.8% in 1999 to 31.5% in 2005. Residential share had a slight increase of just over 2%.

Table II.A.3: Maryland Electricity Consumption and Energy Imports

	1999		2004		2005	
Retail Sales	**GWh**	**% Share**	**GWh**	**% Share**	**GWh**	**% Share**
Residential	23,342	39.5%	27,952	41.8%	28,440	41.6%
Commercial	25,662	43.4%	17,264	25.8%	17,932	26.2%
Industrial	9,936	16.8%	21,195	31.7%	21,517	31.5%
Other[7]	146	0.3%	481*	0.7%	477*	0.7%
Total (Actual)	**59,086**	**100.0%**	**66,892**	**100.0%**	**68,366**	**100.0%**
Loss Factor[8]	3,693	6.25%	4,181	6.25%	4,273	6.25%
Total (with Loss)	**62,779**		**71,073**		**72,639**	
Net Generation	51,685	82.3%	52,054	73.2%	52,662	72.5%
Net Imports	**11,094**	**17.7%**	**19,019**	**26.8%**	**19,977**	**27.5%**

7 In 2003, the "Other" section was removed; a new category called "Transportation" was used in 2004 and 2005.

8 The 6.25% loss factor is the 1999-2005 national average for transmission and distribution loss.

Of perhaps greater significance, in 2005 electricity imports amounted to 27.5% of all the electricity consumed in Maryland, about 10% more than the imported 17.7% of the electricity consumed in 1999. Consumption increased 15.7% from 1999 to 2005, while generation only increased by 1.9% during the same period. In effect, nearly all the electricity load growth in Maryland between 1999 and 2005 was met by importing electricity from other states within the PJM region. (See section III-E for the import profiles for the other PJM member states.) This growing dependence on imports means that Maryland has an enormous stake in the reliability of the regional transmission grid and the existence of a robust wholesale power market.

B. Electric Generation Capacity and Output Profile; Potential Changes for Maryland

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

Table II.B.1: Maryland Generating Capacity Profile (as of January 1, 2005)

	Capacity		Vintage of Plants, by % of Fuel Type			
Primary Fuel Type	**Summer (MW)**	**Pct. of Total**	**1-10 years**	**11-20 years**	**21-30 years**	**31+ years**
Coal	4,958.0	39.7%	3.6%	13.0%	13.5%	69.9%
Dual-fired[9]	3,107.2	24.9%	13.8%	24.7%	39.4%	22.1%
Nuclear	1,735.0	13.9%	0.0%	0.0%	100.0%	0.0%
Natural/Other Gases	1,121.1	9.0%	57.2%	0.0%	0.0%	42.8%
Petroleum	885.0	7.0%	1.3%	1.9%	1.4%	95.4%
Hydroelectric	566.0	4.5%	0.0%	0.0%	0.0%	100.0%
Other Renewables	127.0	1.0%	49.4%	5.3%	45.3%	0.0%
TOTAL	**12,499.3**	**100.0%**	**10.6%**	**11.5%**	**29.6%**	**48.3%**

Coal plants[10] represent about 40% of summer peak capacity, but the only units built during the last thirty years were Constellation's two Brandon Shores plants (643 MW each, 1984 and 1991) and the AES Warrior Run plant (180 MW, 1999). The other major coal facilities in Maryland include Morgantown (1,244 MW), Chalk Point (683 MW), Dickerson (546 MW), H.A. Wagner (459 MW) and C.P. Crane (385 MW). Additionally, about 27% of all in-State capacity burns oil either as the primary or the sole fuel source and many of these facilities are aging as well. Overall, only about 22% of the State's generating capacity has been constructed in the past twenty years.

It is possible that some older units that cannot meet stricter environmental standards at the federal or State level may eventually retire. CPCN filings have been made by six of Maryland's coal facilities for various environmental upgrades for compliance with the Maryland

9 The primary fuel type of dual-fired plants: 81.7% petroleum and 18.3% natural gas.

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

Healthy Air Act (HAA). However, some of these units and other older Maryland coal units may have to be retired if the emissions restrictions (including those for carbon dioxide that may be mandated by the Regional Greenhouse Gas Initiative) make these plants uneconomic to operate in the future.

Retirement of older generating units is occurring elsewhere within PJM. In New Jersey, PJM has granted the request of four older facilities to retire in the next two years: 285 MW at Martins Creek in September 2007, 447 MW at B.L. England in December 2007, 453 MW at Sewaren in September 2008, and 383 MW at Hudson in September 2008.

The Maryland generating output profile differs considerably from its capacity profile. In 2005, Maryland plants produced 52,662 gigawatt-hours (GWh) of electricity,[11] generated 55.7% by coal and 27.9% by nuclear plants. Thus, Maryland coal and nuclear facilities generate 83.6% of all electricity, although they represent only 53.6% of capacity. In contrast, oil and gas facilities generated but 10.6% of all electricity in 2005, despite representing 40.9% of in-State capacity.

During the past four years, the Commission has granted several CPCNs for generating projects in Maryland. Below, Table II.B.2 identifies all proposed generating projects for which the Commission has granted a CPCN. No other CPCN applications for new construction are pending. While granting a CPCN is a prerequisite for construction, granting a CPCN does not in and of itself guarantee that construction of new generation will actually take place. None of the facilities listed in Table II.B .2 (with the exception of a tiny amount of landfill gas) is under construction and no firm date to begin construction has been announced. If constructed, the electricity generated by these projects would be available to Maryland and the PJM region.

Table II.B.2: New Generating Resources Planned for Construction in Maryland

Resource Developer And Location	Capacity & Fuel	Requested In-Service Date	Interconnect w/Regional Market?	CPCN Status
Eastern Landfill Gas, LLC, Baltimore Co.	4.2 MW L.F. Gas	In-service Sept. 2006	Yes	Granted 7/19/2005
Clipper Windpower, Inc., Garrett Co.	101 MW Wind	4th Qtr. 2006	Yes	Granted 3/26/2003
Savage Mountain US Wind Force LLC, Allegany and Garrett Cos.	40 MW Wind	4th Qtr. 2007	Yes	Granted 3/20/2003
Sempra Energy, Catoctin Power LLC / Eastalco, Frederick Co.	640 MW Gas	2009	Yes	Granted 4/25/2005
Synergics Wind Energy, Roth Rock Windpower Project, Garrett Co.	40 MW Wind	2008	Yes	H.E. Proposed Order, 10/31/06
INGENCO Wholesale Power, New-land Park Landfill, Wicomico Co.	6.0 MW L.F. Gas	1st Qtr. 2007	Yes	Granted 4/8/2006

[11] Source: EIA. The 52,662 GWh of electricity generated in 2005 consists of the following: coal 55.7%, nuclear 27.9%, petroleum 7.3%, natural gas 3.6%, hydroelectric 3.2%, other renewables 1.7%, and other gases 0.7%.

Growth in power plant development has been modest and has lagged electric load growth in Maryland. The total capacity for the new generating resources planned from the table above is only 831.2 MW, and as stated above no plants of significant size are under construction. Since 2000, only about 700 MW of new generation have been constructed. Natural gas (97%) has been the fuel of choice for these new peaking and mid-merit units. Renewal of federal tax credits has encouraged the planned development of wind farms in Western Maryland. Maryland's Renewable Energy Portfolio Standard and the Energy Policy Act of 2005 may also promote the development of similar facilities. In March 2003, the Commission approved CPCNs for Clipper Windpower, Inc.[12] and Savage Mountain US Windforce LLC[13]. The in-service dates for both of these facilities have been delayed due to ongoing court challenges. On October 31, 2006, a Commission Hearing Examiner (H.E.) issued a proposed order for the Synergics Wind Energy, LLC[14] project. This proposed order has been appealed by several parties and the Commission has not issued a final order. There have been no applications for large baseload power plants.

On October 27, 2005, Constellation Energy announced[15] its intention to apply to the Nuclear Regulatory Commission (NRC) for a combined nuclear construction and operating license. The company mentioned that two of the sites under consideration include its existing Calvert Cliffs Nuclear Power Plant in Southern Maryland and the Nine Mile Point Nuclear Station in upstate New York. In summer 2006, Constellation submitted into a PJM generation queue two potential nuclear power facilities that would be located at Calvert Cliffs. The two proposed units would each have a generating capacity of 1,640 MW (3,280 MW in total) and have projected in-service dates of 2015 and 2016, respectively. Given the lack of nuclear generation built in the United States in recent decades, a firm prediction that new nuclear plants will be built at Calvert Cliffs cannot be made.

C. Historic Electricity Consumption and Demand Forecast in Maryland

The 1999 Act went into effect on July of that year. Using 1999 as the base year and comparing it to 2005 data, total consumption has increased at an annual growth rate of 2.5% while generation has only increased by 1.0% per year. This moderate consumption growth rate combined with little change in generation output has resulted in Maryland electricity imports growing at an annualized rate of 10.3% over this time period. Table II.C.1 on the next page summarizes Maryland's electricity profile.

Current forecasts from PJM and the utilities estimate that electricity retail sales within Maryland will continue to increase, as they have consistently over the past fifteen years.[16]

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

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

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

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

[16] Other forecasts have been made that predict declining or unchanging electricity demand in Maryland for the next 10 to 15 years. If these forecasts are realized, it is likely that electric reliability problems in Maryland

However, planned generation additions with in Maryland will not produce enough supply to satisfy the growth in consumption. The Table II.B.2: *New Generating Resources Planned for Construction in Maryland* lists only 831.2 MW of additional electric capacity in the next few years, but as stated previously, only 1% of the total (10 MW) is under construction or in-service.

Table II.C.1: Maryland Electricity Consumption by Class and Net Generation (GWh)

	Retail Electricity Sales (Consumption)					**Pct.**	**Sales+Loss**	**Net**
Year	**Res.**	**Com.**	**Ind.**	**Trans**[18]	**Total**	**Change**	**Factor**[17]	**Generation**
1990	19,102	11,021	19,308	102	49,533	N/A	52,629	33,162
1995	22,234	23,730	10,057	137	56,158	N/A	59,668	46,366
1999	23,342	25,662	9,936	146	59,086	N/A	62,779	51,686
2000	23,949	26,506	10,066	156	60,677	2.7%	64,469	51,145
2001	24,294	26,995	10,177	174	61,640	1.6%	65,493	49,062
2002	25,489	21,845	20,875	171	68,380	10.9%	72,654	48,279
2003	26,671	16,950	27,176	461	71,258	4.2%	75,712	52,244
2004	27,952	17,264	21,195	481	66,892	-6.1%	71,073	52,053
2005	28,440	17,932	21,517	477	68,366	2.2%	72,639	52,662

Table II.C.2 on the next page includes projected Maryland electricity consumption for the next ten years. Based on forecasts submitted by Maryland's electric utilities, electric energy sales will increase by nearly 17 percent between 2005 and 2016, an average annual growth rate of approximately 1.5 percent (see Table II.C.2, column one). Energy sales, exclusive of losses, are forecast to increase from 68.4 million MWh in 2005 to 79.8 million MWh in 2016. PJM is forecasting similar annual rates of growth in summer peak demand for the entire Mid-Atlantic region, including the LDA zones that cover Maryland, for the 2006 to 2017 time-period.[19]

- PJM Mid-Atlantic Region; 1.5%
- BGE zone (Central Maryland); 1.2%
- DPL zone (Delmarva including Eastern Shore); 1.9%
- PEPCO zone (Central and Southern Maryland); 1.4%
- APS zone (includes Western Maryland); 0.9%

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would be reduced, but not eliminated. Reasons for this conclusion are that consumption would be reduced by only modest amounts, and the risk of generating unit de-rates and retirements still exist. Additionally, even during previous periods of rapid electricity price increases in the 1970's and 1980's or large investments in energy efficiency programs in the 1990's, the demand for electricity in the State actually decreased only on rare occasions. During those periods, the sustainable results from the price increases and energy efficiency investments were a lowering of the rate of increase in demand.

17 "Sales + Loss Factor" is the estimated total including the 6.25% loss factor.

18 Beginning in 2003, the "Other" sector has been eliminated. Data previously assigned to the "Other" sector has been reclassified as follows: Lighting for public buildings, streets, and highways, interdepartmental sales, and other sales to public authorities are now included in the Commercial sector; agricultural and irrigation sales where separately identified are now included in the Industrial sector; and a new sector, Transportation, now includes electrified rail and various urban transit systems (such as automated guideway, trolley, and cable) where the principal propulsive energy source is electricity. Comparisons of data across years should include consideration of these reclassification changes.

19 PJM Load Forecast Report; January 2007; Prepared by PJM Capacity Adequacy Planning Department.

Table II.C.2: Maryland Electricity Consumption Forecast (GWh)

Year	Estimated Total Sales[20]	Sales + Loss Factor[21]	Net Generation[22]	Net Imports[23]	Import Percentage[24]
2006	67,429	71,644	50,908	20,736	28.9%
2007	69,152	73,474	50,908	22,566	30.7%
2008	70,213	74,601	50,908	23,693	31.8%
2009	71,410	75,873	50,908	24,965	32.9%
2010	72,525	77,058	50,908	26,150	33.9%
2011	73,657	78,261	50,908	27,353	35.0%
2012	74,854	79,532	50,908	28,624	36.0%
2013	76,022	80,773	50,908	29,865	37.0%
2014	77,244	82,071	50,908	31,163	38.0%
2015	78,487	83,393	50,908	32,485	39.0%
2016	79,789	84,776	50,908	33,868	40.0%

It should be stated that there is a great deal of uncertainty in forecasting electricity consumption on a long-term basis and that actual demand could vary significantly, particularly in the later years. There are a number of Maryland-specific factors that add to this unpredictability. One factor is the long-term status of the Eastalco smelter outside Frederick, formerly the largest electricity consumer in the State before its closure in 2005. Another is how significant of an impact the Base Realignment and Closure (BRAC) program will have on Maryland's economy and, specifically, the demand for electricity. Finally, the elasticity of consumer response to sharply higher electricity prices, on both a short-term and long-term basis, is very difficult to forecast. As noted in footnote 16, previous history suggests that customers might not reduce demand for electricity as much as one might otherwise expect in the face of higher prices and widespread availability of demand-reduction programs. However, it certainly is possible that these price signals could help trigger a new wave of demand response and energy efficiency programs and cause consumer demand to fall short of levels projected by PJM and the utilities. Given the long lead times required to plan and construct generation and transmission facilities, and Maryland's current shortages of both forms of infrastructure, the State needs to assess the extent to which it can rely on the most optimistic of the load forecasts.

For a longer-term perspective, Chart II.C.1 on the next page combines the historical data from Table II.C.1 and the projected data from Table II.C.2 into a single graphic that shows the trend lines of electricity consumption and net generation for Maryland for the 1999 to 2016 period. The Chart displays an ever widening gap between estimated net consumption and net generation that would need to be filled by net electricity imports from neighboring states. Due to

20 "Estimated Total Sales" is the total that the Commission estimated based upon sales forecast data received from Maryland energy suppliers. Delmarva Power and Light, Potomac Edison, and Somerset did not submit a Maryland specific forecast. Therefore the Commission had to estimate those companies' forecasted demand.

21 "Sales + Loss Factor" is the estimated total including the 6.25% loss factor.

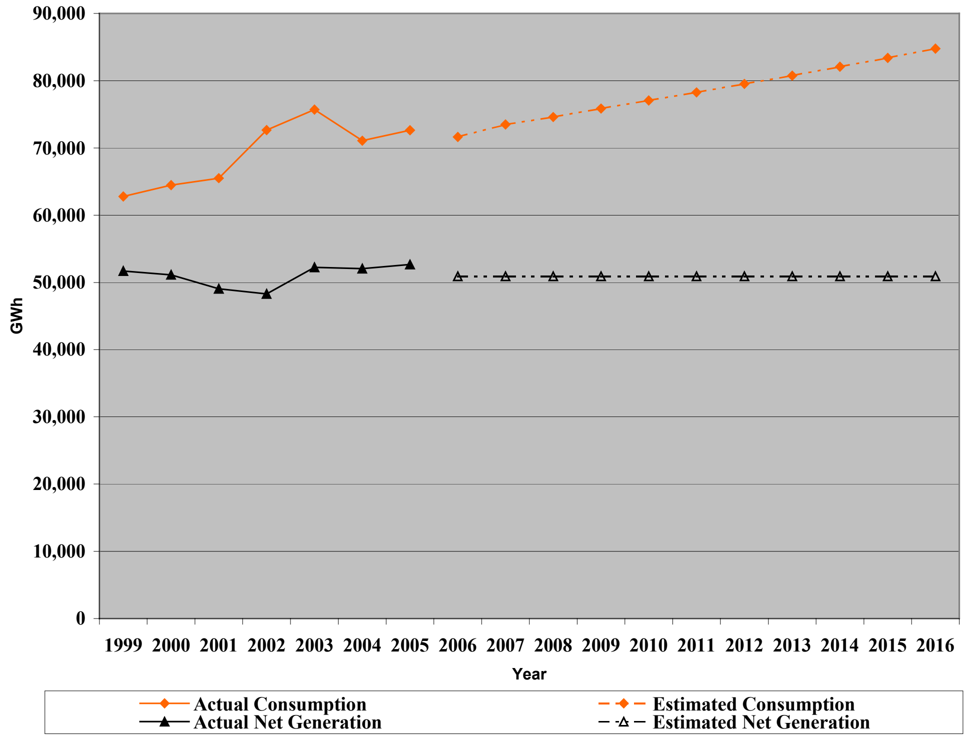
22 "Net Generation" is the average of Maryland's net generation for the years 2000-2005.

23 "Net Imports" is (Sales + Loss Factor) – Net Generation.

24 "Import Percentage" is Net Imports as a percent of "Sales + Loss Factor".

the lack of scheduled construction of any in-State power plants of significant size, generation output was held constant at recent levels until 2016. However, because of the potential limitations on generation output for Maryland coal facilities due to a combination of the impacts of the Healthy Air Act and federal emissions regulations, it is not unreasonable to assume that the MWh of in-State generation may actually decline over the next ten years. In this event, the projected gap that must be filled by imports from other states would grow ever larger.

Chart II.C.1: Maryland Electricity Consumption and Net Generation, 1999 - 2016

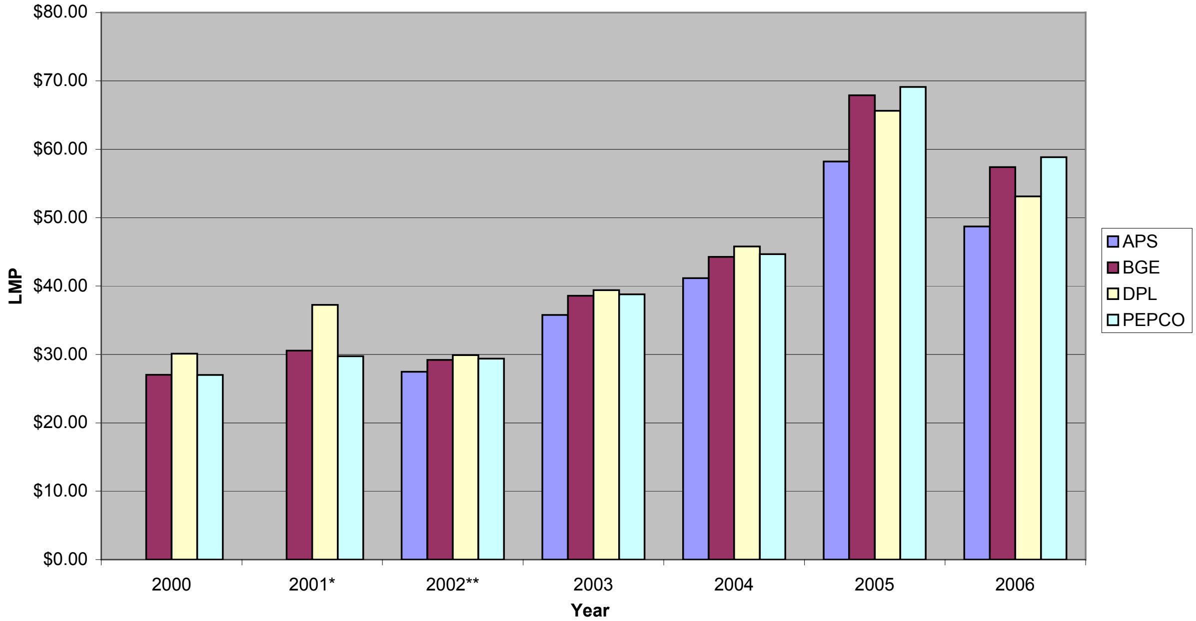


D. Transmission Congestion and High LMPs in Central and Southern Maryland

Transmission congestion occurs when constraints on the transmission system require generation to be dispatched out of merit (price) order. In effect, lower cost power cannot be delivered to where it is needed because of the congestion, so local higher cost power must be used instead. A direct consequence is that higher cost power must be dispatched to meet load requirements, and the consumers will pay higher prices.

Maryland is directly affected by transmission congestion, particularly since it and neighboring states (including the District of Columbia) have to import a large proportion of their energy needs. Evidence of electricity transmission congestion exists in the form of locational marginal prices (LMP). LMP is a pricing approach that shows the impact of congestion by calculating the real time marginal cost of out-of-merit generation, and delivering energy to the location where it is needed. LMPs in Maryland are among the very highest in PJM. While some progress has been made in the last year in reducing both the absolute LMPs and the LMP differential with other states and regions in PJM, Maryland continues to experience significant transmission congestion and high LMPs.

Chart II.D.1: Average Locational Marginal Price



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

Chart II.D.2: Average LMPs for Year 2006

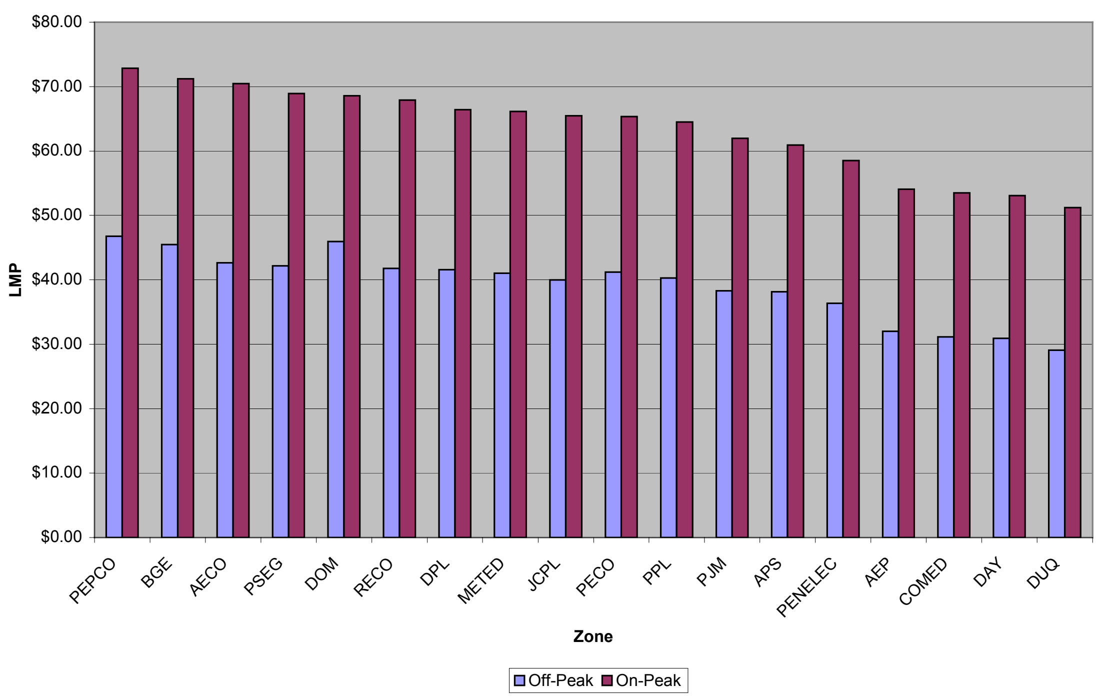
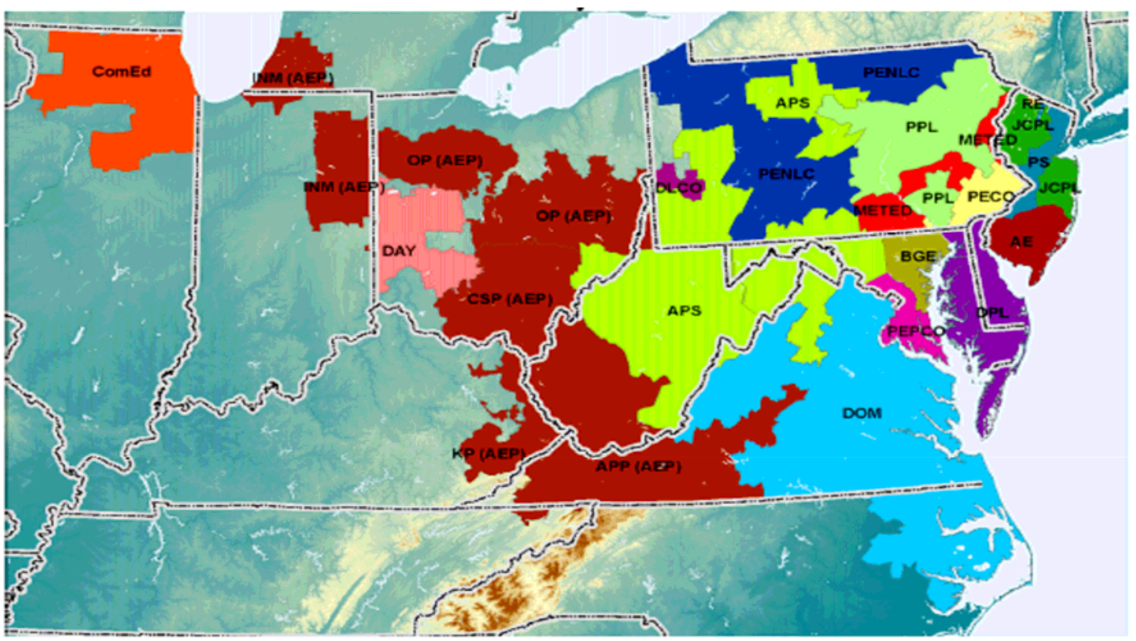


Chart II.D.1 shows the average LMP figures for the PJM zones that provide electricity to the State of Maryland. Western Maryland is covered by the Allegheny Power (APS) zone. Central Maryland includes the Baltimore Gas and Electric (BGE) and Pepco zones. The Delmarva Power and Light (DPL) zone covers the Eastern Shore. When viewing the above chart, one can see that annual average for LMPs found in Maryland had been rising steadily from 2002 to 2005. The data show a decrease for calendar year 2006. Transmission upgrades in PJM coupled with the moderation of fuel prices are the cause for the LMP decline in 2006. From 2005 to 2006, the LMP figures for BGE and Pepco have decreased by 12.86% and 11.84%, respectively. DPL and APS have experienced greater decreases with declines of 16.87% and 13.85%. This is another way of stating the earlier observation that the discrepancy between LMPs in the western part of the State and those in Central and Southern Maryland is growing.

While LMP developments in 2006 are encouraging, Maryland's problem of relatively high LMPs is not solved. Evidence of this can be found in Chart II.D.2. This chart displays the average on peak and off-peak LMP levels for the PJM energy grid. The PJM grid (PJM's footprint by zone can be seen in Map II.D.1 below[25]) is partitioned by the various zones or local deliverability areas (LDAs). The time period for which LMPs were calculated is calendar year 2006.

Map II.D.1: PJM Zones



According to data published on its website,[26] the PJM zones that serve the central Maryland areas have the highest LMPs during both on and off peak periods. On-Peak periods

[25] Source: http://www.pjm.com/documents/maps/pjm-zones.pdf

[26] Monthly LMP data for PJM can be found at: ftp://www.pjm.com/pub/account/lmpmonthly/index.html.

are periods of increased usage and are defined by PJM to be weekdays, except NERC holidays[27] from the hour ending at 8:00 a.m. until the hour ending at 11:00 p.m. Off-peak periods are the periods during which overall demand is decreased. PJM deems these periods to be "all NERC holidays and weekend hours plus weekdays from the hour ending at midnight until the hour ending at 7:00 a.m."

Though the central Maryland zones have the highest LMPs in PJM, it should be noted that the zones associated with states that import large amounts of energy also have high LMPs. The AECO, DOM, PSEG, RECO, DPL, METED, JCPL, and PPL zones are in New Jersey, Virginia, Delaware and eastern Pennsylvania, all of which import large amounts of electricity from western PJM, and are, like Maryland, vulnerable to the price effects of transmission congestion.

E. Natural Gas Pipeline and LNG Terminal Infrastructure in Maryland

Maryland's natural gas pipeline infrastructure is composed of three types of systems: interstate transmission, intrastate transmission, and intrastate distribution. The Commission has jurisdiction over the intrastate facilities while the federal government has jurisdiction over the interstate facilities. Currently there are six interstate transmission companies that operate pipelines and related facilities in Maryland:

- Williams Gas Pipeline
- Eastern Shore Natural Gas
- Colonial Pipeline Company
- Columbia Gas Transmission Company
- Dominion Transmission & Dominion Cove Point LNG, LP
- Duke Energy Gas Transmission

The natural gas distribution infrastructure within Maryland is comprised of eight local distribution companies and one municipality. Table II.E.1 shows the miles of mains and the number of services that each local distribution company has.

Table II.E.1: Miles of Main and Number of Services

Local Distribution Company	Miles of Main	Number of Services
Baltimore Gas & Electric (BGE)	6,746	240,792
Chesapeake Utilities	262	11,912
Columbia Gas of Maryland	622	36,275
Easton Utilities	82	3,583
Elkton Gas	87	4,747
Frederick Gas	477	23,783
PPL Gas Inc.	19	439
Washington Gas	5,114	354,104

27 NERC Holidays are New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

While local distribution companies within Maryland have for the most part been able to expand their systems to meet the growing demand for natural gas, where natural gas is not readily available, piped propane systems have become an alternative. Currently, the State of Maryland has nine jurisdictional operators of piped propane systems, ranging in size between 10 customers, such as a shopping center, to more sizable systems, the largest having 10,265 customers. Eastern Shore Gas has the largest system encompassing the towns of Ocean City, Berlin, Snow Hill, Pocomoke City and their surrounding areas. State regulatory jurisdiction over piped propane covers safety only.

Within Maryland, two companies operate liquefied natural gas facilities: Dominion Transmission (Dominion Cove Point LNG, LP) and BGE. Dominion Transmission's Cove Point facility is located in Calvert County, Maryland. Cove Point is an import terminal used for the storage and dispatch of imported liquefied natural gas (LNG) into major interstate transmission pipelines. Dominion's Cove Point LNG import terminal is under the jurisdiction of the federal government, FERC being the exclusive licensing authority. BGE has two LNG facilities under the jurisdiction of the State. Its Spring Garden facility is a liquefaction/peaking plant located in Baltimore City. The plant takes natural gas off of its system during the warmer months, liquefies it and stores it until it is needed during the winter where it is re-gasified and sent out into its system. BGE's other facility is a satellite plant located in Westminster, Maryland. The satellite plant stores liquefied natural gas from Spring Gardens, delivered by truck, and stores it until it is needed during the winter for peak shaving purposes.

The Cove Point facility is being expanded and upon completion will be the largest LNG terminal in the United States. Dominion Resources received authorization from the FERC to begin construction of the addition on August 18, 2006. Construction began with official ground breaking ceremonies on October 5, 2006. The expansion will increase Cove Point's send-out capacity from 1 billion cubic feet per day to 1.8 BCF and storage capacity will increase from 7.8 BCF to 14.6 BCF. The existing and increased output from the Cove Point facility is destined to service natural gas markets in the Mid-Atlantic and Northeast United States, including Maryland. The project is being built in part because of the lack of firm pipeline capacity to transport natural gas from traditional natural gas producing regions in the Gulf of Mexico, the Gulf Coast, Texas, Oklahoma, and elsewhere in the southwestern United States.

In addition, AES Corporation filed an application with the FERC in January 2007 to build a second LNG facility at the Sparrows Point Industrial Complex. The facility, if built, would have a send-out capacity of 1.5 BCF, with provision for future expansion to increase send-out capacity to 2.25 BCF. As is the case with Cove Point, the need for the project is asserted to be the inability to acquire firm natural gas commitments from traditional domestic supply sources in the southeast and southwestern United States. The Sparrows Point facility would supply natural gas to homes, businesses, utilities, and natural gas fired power plants in the Mid-Atlantic region. The facility would be interconnected with existing natural gas pipelines via a new 85-mile pipeline, to be named Mid-Atlantic Express, LLC. Recently, the Sparrows Point developer announced an intention to construct a 300 MW gas-fired electric generating plant using LNG that has been gasified as the fuel.

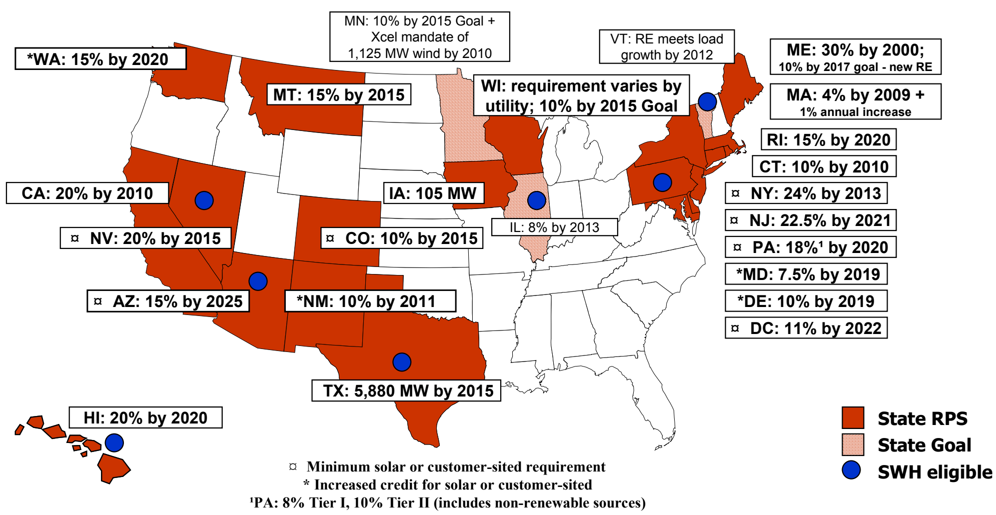
In order to comply with State and federal air emission statutes, increased output from natural gas power plants may be necessary. If so, expansion of existing LNG facilities as is occurring at Cove Point, and construction of new LNG facilities as proposed at Sparrows Point, may be required if natural gas deliveries for all purposes are to be assured.

F. Impacts of the Renewable Energy Portfolio Standard (RPS)

Maryland is one of twenty-four states and the District of Columbia that have implemented a Renewable Portfolio Standard Program. RPS programs typically require either the electricity suppliers in a state or the companies that deliver power to customers in the state to obtain a portion of their electricity from renewable resources. Each state has tailored its version of the RPS to meet specific policy goals, including development of special categories of renewable resources. Map II.F.1[28] displays the various state RPS programs.

PUC Article § 7-701 et seq. (RPS Legislation) describes the RPS for Maryland and how electricity suppliers can satisfy it. The legislation requires that the Commission implement the RPS. Implementation of the RPS is accomplished via a system that facilitates the trading of Renewable Energy Credits[29] (RECs), representing the generation of electricity from qualifying renewable resources. Maryland RECs are defined as coming from Tier 1[30] or Tier 2[31] sources. The RPS began on January 1, 2006, with 2006 being the first compliance year.

Map II.F.1: States with Renewable Portfolio Standards



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28 Source: http://www.dsireusa.org/

29 A REC is equal to the renewable attributes associated with one megawatt-hour of energy generated using specified renewable resources. Each supplier must present, on an annual basis, RECs equal to the percentage specified by the RPS Legislation. Generators and suppliers are allowed to trade RECs using a Commission sanctioned or established REC registry and trading system. A REC has a three-year life during which it may be transferred, sold, or otherwise redeemed.

30 Tier 1 RECs are RECs awarded for electricity generation from the following fuel sources: solar, wind, qualifying biomass, landfill or waste water treatment plant gas, geothermal, ocean, fuel cell that produces electricity from a Tier 1 renewable source, and small hydroelectric (less than 30 MW in rated capacity).

31 Tier 2 RECs are RECs awarded for electricity generation from the following fuel sources: hydroelectric power (rated capacity greater than 30 MW) other than pump storage generation, incineration of poultry litter, and waste-to-energy.

Suppliers that do not meet the annual RPS are required to pay a compliance fee as prescribed in the RPS Legislation. Compliance fees[32] 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, including administering the fund, has been vested with the Maryland Energy Administration (MEA).

Chart II.F.1: MD RPS Certified Rated Capacity by State (as of 12/31/2006)

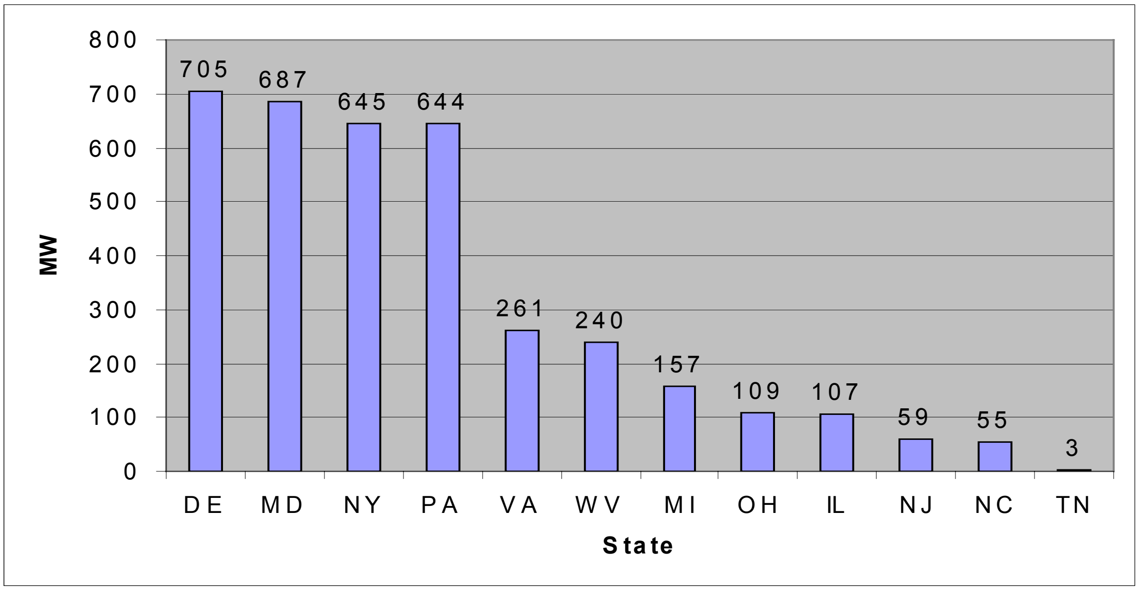

Chart II.F.1 presents the capacity that is currently registered for the RPS program and their geographic locations. While a significant amount of RPS eligible generation is in Maryland, the chart clearly shows that several other states have approximately equal amounts of eligible capacity including Delaware, New York and Pennsylvania. West Virginia, Virginia, Michigan, Ohio, and Illinois also have significant amounts of generation eligible to participate in the Maryland RPS.

Maps II.F.2 and II.F.3 show the approximate location and size of Tier 1 and Tier 2 facilities that may be eligible to participate in the Maryland RPS Program. This information is from a study[33] conducted by the Maryland Power Plant Research Program (PPRP) on the behalf of the Maryland Department of Natural Resources (DNR). The Maryland statute states that to qualify to sell RECs, a facility may be located in states that are both in the PJM RTO or in states adjacent to the states that lie within the PJM RTO. Based upon findings by the Maryland PPRP, for the foreseeable future it appears that the resulting geographic footprint allows for a significant number of existing resources to participate in the Maryland RPS.

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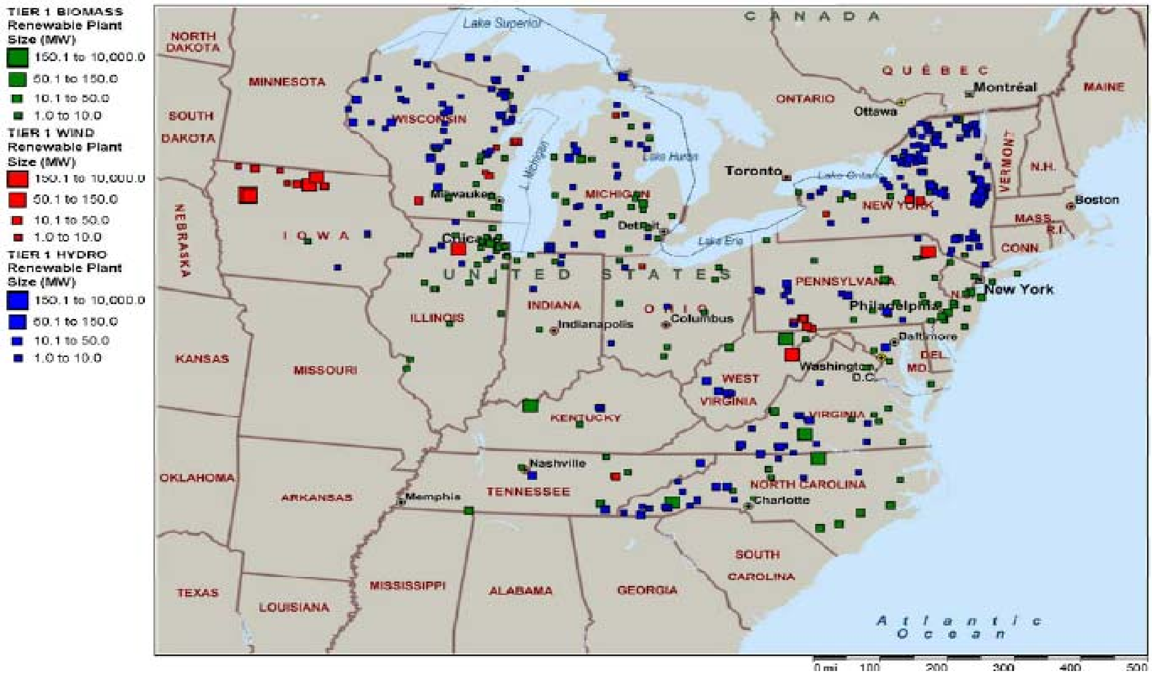
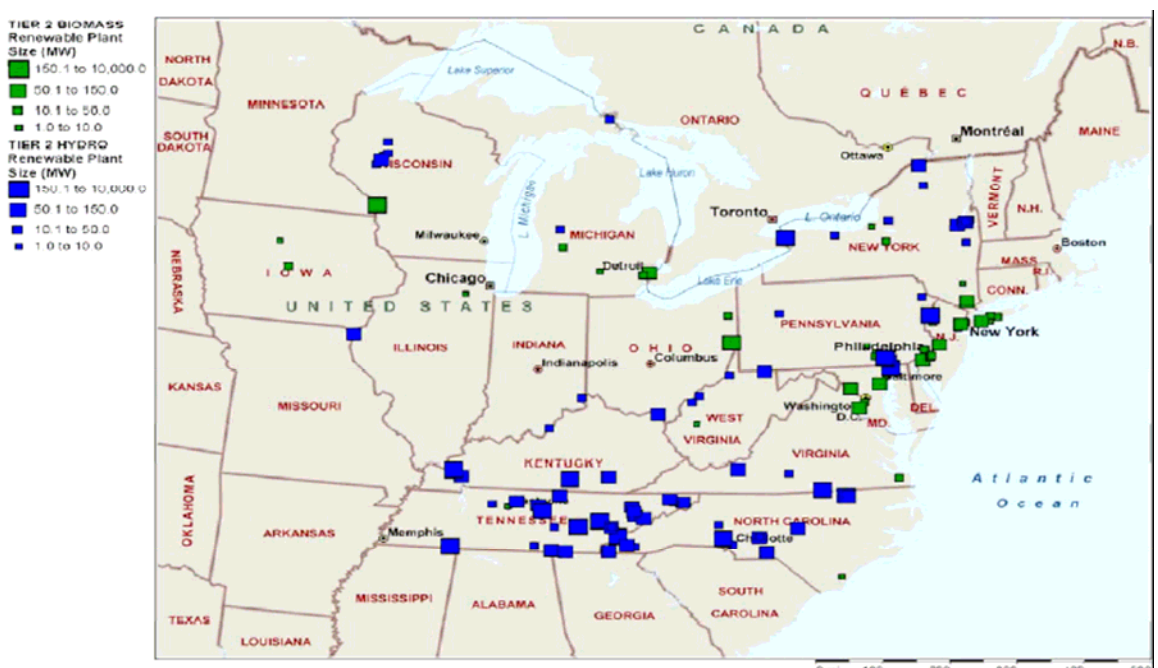
[32] Under § 7-707 of the RPS Statute the compliance fee is 2 cents for each kWh of Tier 1 shortfall and 1.5 cents for each kWh of Tier 2 Shortfall. For a designated industrial process load the compliance fee is 0.8 cents for each kWh of Tier 1 shortfall and no compliance fee for a Tier 2 shortfall.

[33] Source: http://esm.versar.com/pprp/bibliography/PPES_06_01/PPES_06_01.pdf.

Map II.F.2: Potential Tier 1 Renewable Energy Facilities by Technology Type and Size[34]



Map II.F.3: Potential Tier 2 Renewable Energy Facilities by Technology Type and Size[35]



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34 Source: Maryland Power Plant Research Program – Inventory of Renewable Energy Resources Eligible for the Maryland Renewable Energy Portfolio Standard.

35 Source: Maryland Power Plant Research Program – Inventory of Renewable Energy Resources Eligible for the Maryland Renewable Energy Portfolio Standard.

G. Demand Side Management, Demand Response and Distributed Generation

In 1991, the Maryland General Assembly enacted an energy conservation measure that is codified as §7-211 of the PUC Article. This provision required each gas and electric company to develop and implement programs to encourage energy conservation. In response to this mandate and continuing with preexisting initiatives under its existing authority, the Commission directed each affected utility to develop a comprehensive conservation plan. The Commission further directed each utility to engage in a collaborative effort with Staff, the Office of People's Counsel (OPC), and other interested parties to develop its conservation plan. The result of these actions was that each utility implemented conservation and energy efficiency programs.

As noted earlier in this Report, another development in this area was the enactment of the 1999 Act. The 1999 Act established the legal framework for the restructuring of the electric utility industry in Maryland. The 1999 Act also modified PUC Article §7-211 to require that the Commission ensure that electric choice does not adversely impact the continuation of cost-effective energy conservation and efficiency programs. The amended section enumerates various factors the Commission should consider when determining whether a program or service encourages and promotes the efficient use and conservation of energy. Finally, the General Assembly required the Commission to evaluate current and potential Demand-Side Management (DSM) programs to suggest whether these programs are necessary or desirable, and to identify programs that are cost-effective. The Commission also was instructed to recommend the appropriate method of funding for any DSM programs found to be useful and cost-effective.

In 2001, the Commission issued a report on these matters to the General Assembly in consultation with the MEA. The report found generally that DSM programs could be useful tools, providing they met appropriate cost-effectiveness tests. Prior to the 1999 Act, such programs provided benefits including enhanced consumer education and awareness of ways to conserve energy, reduced environmental pollution, improved reliability, and positive effects on individual consumer's economic well-being as well as the State's overall economy. However, the report noted that, going forward, it would be increasingly difficult for DSM programs to be cost-effective given that generation, which has been deregulated, could no longer be considered in part of a traditional avoided cost analysis. The Commission suggested that the most beneficial way to determine whether a DSM program is cost-effective is to determine the overall demand reduction goal and decide whether the goal justifies the effort and attendant costs. The Commission supported the MEA as the appropriate agency to oversee DSM programs and recommended that programs be funded through the general fund or general obligation bonds rather than using public service company rates to recover these costs.

In the Phase II settlement agreement accepted by the Commission in Case No. 8908[36] on September 30, 2003, the parties to the settlement agreement agreed to the establishment of a working group:

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[36] Re *Competitive Selection of Electricity Supplier/Standard Offer Service (SOS)*, 94 Md. PSC, 113, 286 (2003). The PSC 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 expired. The Commission issued orders approving a settlement in two phases on April 29, 2003 (Phase I), and October 1, 2003 (Phase II).

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

On September 13, 2006 the Commission issued a Notice establishing the Demand Response/Distributed Generation (DRDG) Working Group. The Commission directed the DRDG Working Group to discuss and make recommendations to the Commission on existing demand response and distributed generation capabilities in Maryland and to the extent to which additional demand response and distributed generation capabilities can be created in the State. The DRDG Working Group will also review the Mid-Atlantic Distributed Resources Initiative[37] efforts to date and advise the Commission of any MADRI recommendation worthy of implementation in Maryland.

The first meeting of the DRDG Working Group was held on December 13, 2006. The Maryland DRDG background and current status were discussed, as well as DRDG proposals for analysis, implementation or perspectives. Meetings for three identified subteams (Gas DRDG, Conservation, and DG) are scheduled throughout January 2007, and the next general DRDG meeting is planned for February 5, 2007.

H. Impacts of the Healthy Air Act (HAA) on Maryland Coal-fired Generation

House Bill 189 and Senate Bill 154 from the 2006 Session (the Healthy Air Act or HAA) establish a series of emissions limits that seven[38] coal-fired Maryland power plants must achieve to reduce the release of sulfur dioxide (SO_2), oxides of nitrogen (NO_x), and mercury. The legislation also requires that the Governor include the State as a full participant in the Regional Greenhouse Gas Initiative (RGGI) by June 30, 2007. This section focuses on the NO_x, SO_2, mercury, and CO_2 aspects of the legislation. A general description of the RGGI program is included in a later section (section III-I) of this Report.

[37] MADRI was established by "classic" PJM State Commissions, the Department of Energy, and PJM at a meeting in Baltimore, held on June 14-15, 2004. Its goal is "to develop regional policies and market-enabling activities to support distributed generation and demand response in the Mid-Atlantic region." Facilitation support is provided by the Regulatory Assistance Project (RAP) funded by DOE. There has been much participation by a large number of stakeholders, including the Commission, utilities, FERC, service providers, and consumers.

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

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

Many positive things will accrue from the installation of emissions controls to reduce or eliminate specified emissions from coal-fired generating plants in Maryland. It is anticipated that significant improvements in air quality will be realized as the emissions control technologies are installed on Maryland power plants. In all cases, the elimination of most SO_2 from Maryland coal plants should cause a significant reduction of the possibility of acid rain down wind of the power plants. The capture and elimination of most of the NO_x particles from Maryland power plants should reduce the visible plume that sometimes exists under certain weather conditions and reduce the formation of ozone. Particulate emissions and ozone can contribute to certain health problems. Predictions have been made that NOx reductions from the power plants will also reduce nitrogen loadings into the Chesapeake Bay. The elimination of most of the mercury from Maryland coal plant emissions should reduce the amount of waterborne mercury ingested by fish and other marine creatures in our rivers, lakes and the Chesapeake Bay. Certain studies show that reductions in mercury emissions will also lead to improvements in fetal health and the health of small children in particular.

The technologies required to eliminate the majority of NO_x, SO_2 and mercury require the installation of large, expensive equipment on existing power plants. The size of the additional equipment is such that the footprint of each power plant must increase by a significant amount and additional transportation facilities must be made available to import and export the materials required for operation of the capture and sequestration process. The size and costs of the equipment needed to control SO_2 and mercury are particularly large. In fact, the size requirements alone raise questions as to whether all of Maryland's coal-fired generating stations will have the physical room to install the necessary equipment. Unless new technology requiring less space becomes available, or Maryland alters the HAA's requirements for at least one of the stations, at least one station is at serious risk of closure due to the HAA.[39] As also noted earlier,

[39] Constellation's Charles P. Crane station has insufficient space for the "scrubber" technology necessary to meet the mercury control provisions of the HAA. While scrubbers are used primarily for SO_2 control, they are a component of mercury control technology as well. The HAA allows Constellation to average its SO_2 emissions across all of its in-State generating plants. Thus, Constellation can overcontrol its SO_2 emissions at its other plants and not worry about the lack of space for the scrubbers at Crane. However, the HAA's mercury provisions are plant specific, so Constellation cannot overcontrol mercury at other facilities and undercontrol it at Crane. Scrubbers are a necessary component, at least as of this writing, for the control of mercury to the

the continued operation under the HAA's provisions of Allegheny Energy's R. Paul Smith Station also has some questions.

The cost of NO_x, SO_2 and mercury mitigation for the coal-fired Maryland power plants that have the available property is estimated to be in the range of $2 to $3 billion in capital improvements and in excess of $500 million per year in additional operating costs. It is anticipated that most or all of these costs ultimately will be passed on to consumers in the generation price of electricity via the PJM wholesale energy or capacity markets. The Commission provided substantial analysis of this factor's potential impacts on Maryland consumers in its legislative comments on SB 154 and HB 189, and will not repeat them here. Absent plant closures, though, the HAA should not affect the reliability of electric supply.

Table II.H.1: New Environmental Upgrades Planned for Existing Generation Plants

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

degree specified by the HAA. This appears to leave three options for Crane: (1) it will close; (2) the State will have to amend the HAA to permit Crane's continued operation; or (3) federal authorities could require Constellation to continue to operate Crane despite its non-compliance with the HAA due to the capacity shortfalls in Central Maryland. If the latter option is used, customers in the PJM zone in which the plant is located likely will incur the costs of operation, including environmental controls.

Sections 7-205 and 7-206 of the PUC Article require persons modifying generating stations under certain circumstances to obtain a certificate of public convenience and necessity from the Commission. Please see Table II.H.1 above for more information on the CPCNs filed by affected Maryland coal plants to comply with the HAA.

As noted above, the HAA will lead to owners of at least two Maryland coal-fired power plants to consider whether it is possible, or worthwhile, to install the necessary equipment. Any existing Maryland coal plants that may have to be retired will exacerbate the existing reliability challenges and increase the possibility of supplies during peak periods not being able to meet the demand for electricity. The consequences could include periods of voltage reductions and/or rolling outages during peak load periods to keep the system from collapsing.

III. PJM / REGIONAL ISSUES AND EVENTS

A. Overview of PJM and the Formation of OPSI

In the 1999 Act, Maryland (as in many other states) relinquished much of its jurisdiction over generation activities. However, the Commission still has jurisdiction over the retail (or distribution) function of electric companies. Absent regulation of generation,[40] in order to ensure that all aspects of electricity supply and distribution work appropriately, there needs to be a functional wholesale electric market.

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

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

As listed in the *2005 State of the Market Report*, PJM now operates a centrally dispatched competitive wholesale electricity market with about 390 market buyers, sellers and traders of electricity in region that is comprised of more than 51 million people. The PJM footprint includes all or parts of 14 political jurisdictions including Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. Currently PJM's electricity market has a generating capacity of about 165,000 MW, and in 2006 peak demand was nearly 145,000 MW.

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

- PJM operations;

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

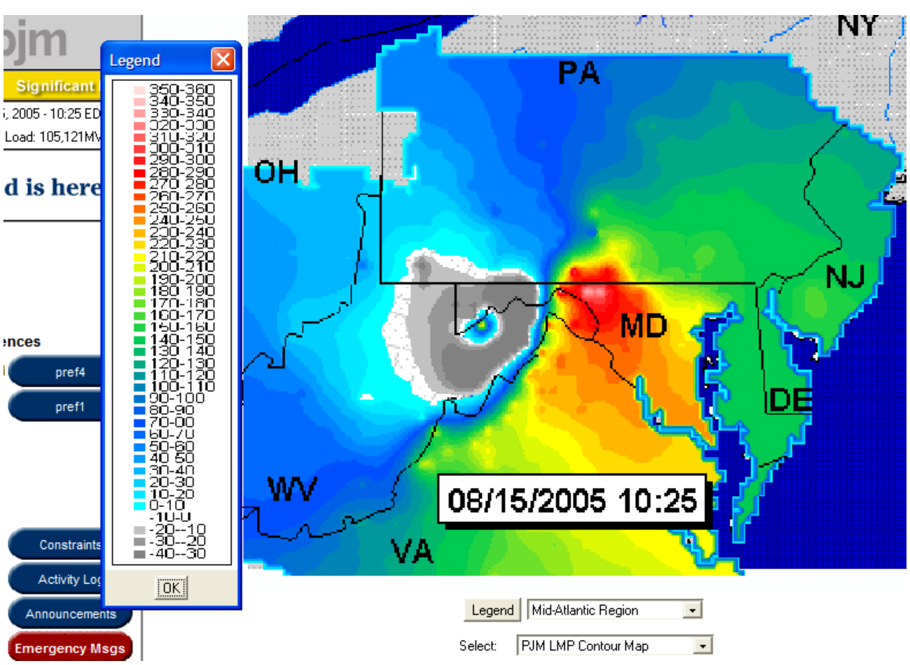
- The electric generation and transmission system serving the PJM States;
- FERC matters; and,
- The jurisdiction and role of the PJM States to regulate and promote the electric utilities and systems within their respective boundaries.

Each state commission will have a member on the OPSI Board of Directors, and the OPSI executive committee consisting of the president, vice-president, secretary, and treasurer will set general policy direction. The Maryland Commission has been an active participant in OPSI. Other significant information concerning OPSI is that it is a voluntary organization, addresses regional issues directly related to PJM, and OPSI positions do not bind individual commissions and are not official actions of any member state.

B. PJM Summer Peak Events of 2005 and 2006

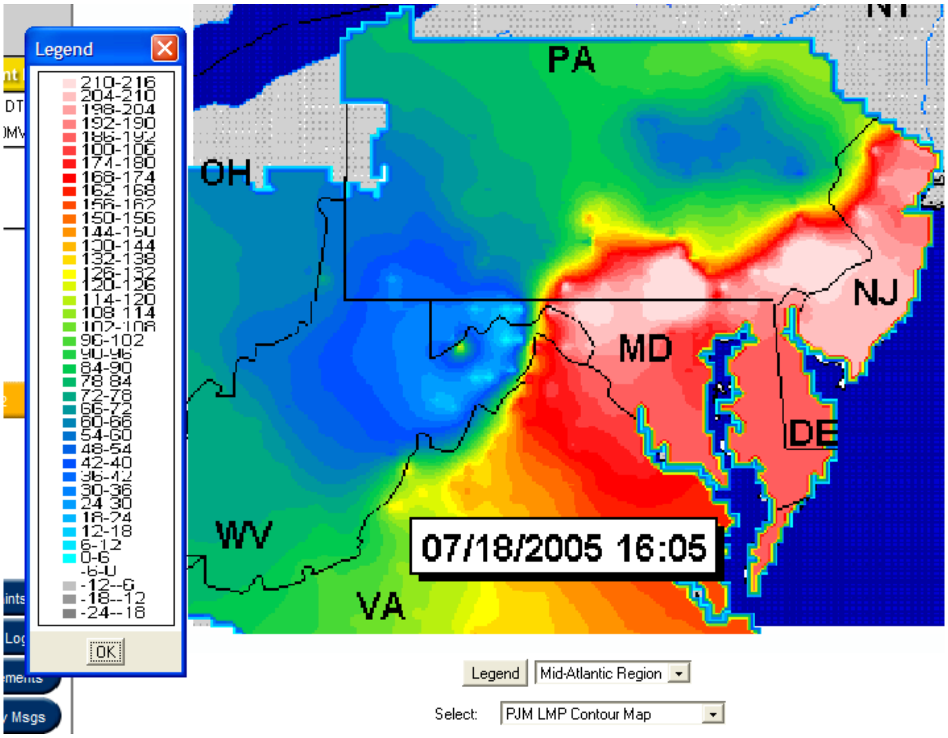
This section includes LMP contour maps as displayed on PJM's *eData* site during the summers of 2005 and 2006. The first map shows August 15, 2005, at 10:25 in the morning and indicates a load of about 105,000 MW. This pattern was typical of normal days in the 2005 summer where congestion was present – the highest LMPs in all of PJM, which on this day were approximately $300 per MWh, formed a bulls-eye centered near Frederick County, Maryland. Thus, the BGE and Pepco territories had higher spot wholesale prices than the transmission-constrained Delmarva Peninsula and northern New Jersey. LMPs in those regions were between $150 per MWh and $200 per MWh (still higher than most of PJM, however). Further, notice that there is also a circular region in Western Maryland and eastern West Virginia that actually has negative LMPs, due to the west to east transmission constraints that prevent sufficient low-cost power from crossing the Allegheny Mountains. This map clearly shows that within a range of less than fifty miles, LMPs can range from over $300 per MWh to negative values.

Map III.B.1: LMP Contour Map – August 15, 2005 at 10:25 AM



The second map shows one of the hottest days of the year, July 18, 2005, at 4:05 pm when peak load had just exceeded 130,000 MW. On this day, the congestion and high LMPs stretch from Northern Virginia, through Central Maryland and the Delmarva Peninsula, and into Southeastern Pennsylvania and all of New Jersey. Once again, LMPs are much lower just west of the Allegheny Mountains – on this day, LMPs vary between about $170-230 per MWh on the high side and $0-40 per MWh on the low side, a less extreme range of LMPs than on the lower demand day.

Map III.B.2: LMP Contour Map – July 18, 2005 at 4:05 PM

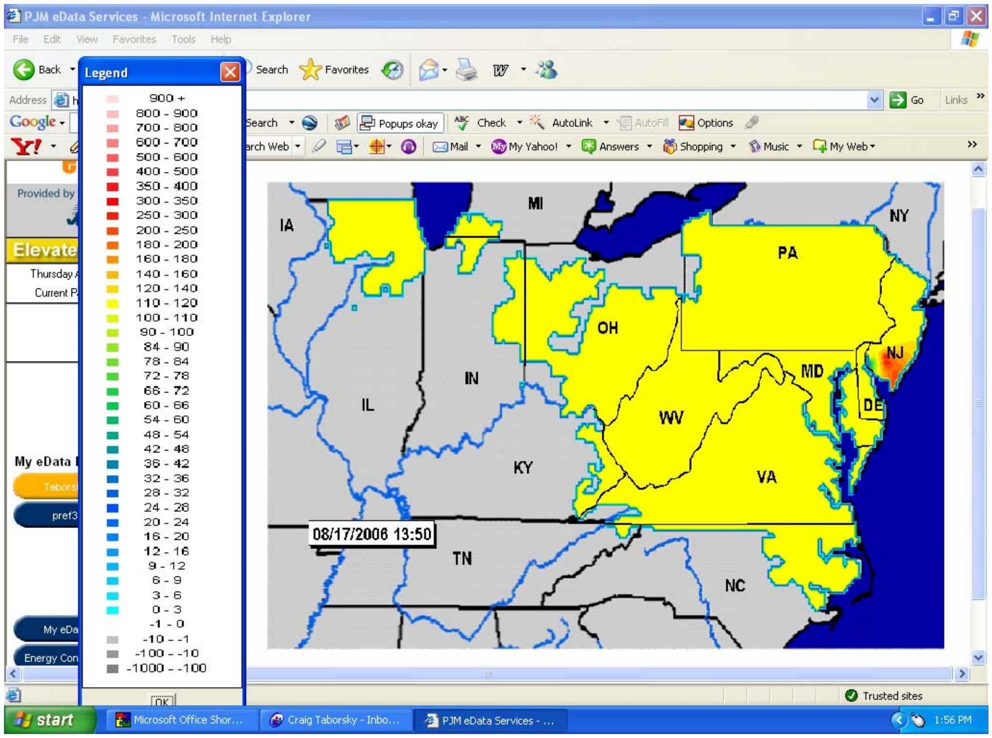


Over the course of 2006, PJM had summer peak events that were comparable to events that occurred in 2005. Map III.B.3 is an LMP contour map of the RJM RTO on August 17, 2006 at 1:50 PM. According to data found on PJM's website,[41] during this time period the load was around 105,000 MW. The load demand is comparable to the previously displayed (Map III.B.1) LMP contour map for August 15, 2005.

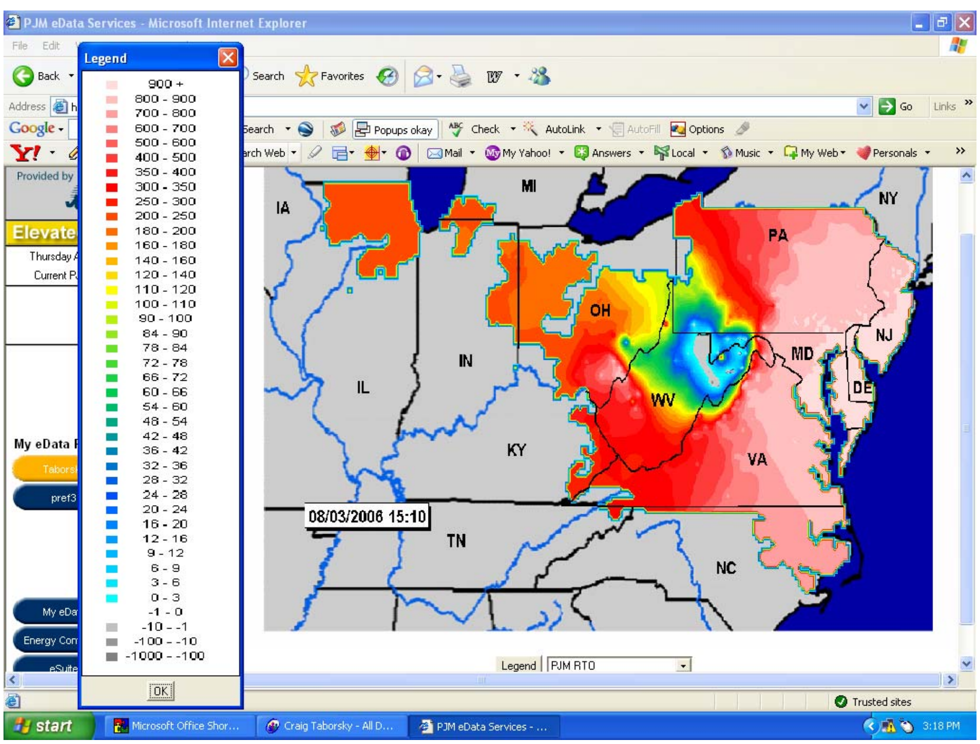
While the load demand and time of occurrence are close, a contrast can be seen between the variations in LMPs throughout the PJM RTO. Congestion exists where there are disparities in the LMPs. Except for a portion of southern New Jersey, LMP prices are even throughout most of the PJM area on the LMP contour map for August 17, 2006. This is indicative of properly dispersed electricity resources and a more capable transmission grid. Few transmission inefficiencies exist to provide a gap in the magnitude of the LMPs.

[41] Source: http://www.pjm.com/markets/jsp/loadhryr.jsp.

Map III.B.3: LMP Contour Map – August 17, 2006 at 1:50 PM



Map III.B.4: LMP Contour Map – August 3, 2006 at 3:10 PM



Transmission upgrades implemented between the summers of 2005 and 2006 have helped to reduce the LMP disparities seen in 2005. However there is still a need for additional transmission upgrades. During peak periods, substantial variances in the LMP levels still exist. The LMP Contour Map shown on the previous page occurred on August 3, 2006 at 3:10 PM. Based upon load data from the PJM website,[42] the hourly load for PJM at 3:00 PM on August 3, 2006 was around 135,000 MW. The time and load demand are comparable to the LMP contour map provided for July 18, 2005, at 4:05 PM (Map III.B.2). When comparing the peak events from July 18, 2005 and August 3, 2006, one can see that there is still a lack of adequate transmission capacity to move the surplus of generation from the Allegheny Mountain Region to other areas of PJM. There appears to be a need for added transmission or generation to meet the peak needs of the eastern portion of the PJM area.

PJM's 2006 peak load of approximately 144,800 MW occurred on August 2, 2006. PJM was able to meet this peak load with economic generation and load management in the Mid-Atlantic Region. PJM did not have to load maximum emergency generation nor did PJM require a voltage reduction as was required in the Mid-Atlantic/Dominion regions to serve the somewhat lower peak load experienced a year earlier on July 27, 2005.

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

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

[42] Source: http://www.pjm.com/markets/jsp/loadhryr.jsp.

- Also on the Eastern Shore, the 69 kV circuit between Edgewood-North Salisbury 69 kV was upgraded to provide a higher facility rating. PJM performed an evaluation of expected congestion savings for this project and found a net present value of approximately $1.5 million from 2006 through 2016.

Overall, the generation and transmission upgrades that have been implemented have been beneficial to Maryland and other portions of eastern PJM. The closing of the Eastalco facility in Frederick County, which removed 300 MW of demand from the system, is also a reason for the improved reliability and reduced LMP spreads. In sum, the load demand threshold that results in transmission congestion appears to have increased from 2005 to 2006, but summer peak events still occur and drive congestion throughout PJM. More transmission upgrades or new electricity generation in eastern PJM will need to be introduced in order to meet the growing load demand in the areas that require electricity imports.

C. Installed Reserve Margin and Load Response Programs

As part of the planning process, PJM forecasts the Installed Reserve Margin throughout the RTO. As well, PJM has designed load response programs in order to compensate customers who voluntarily curtail consumption during emergencies. Both processes are described below.

Installed Reserve Margin (IRM)

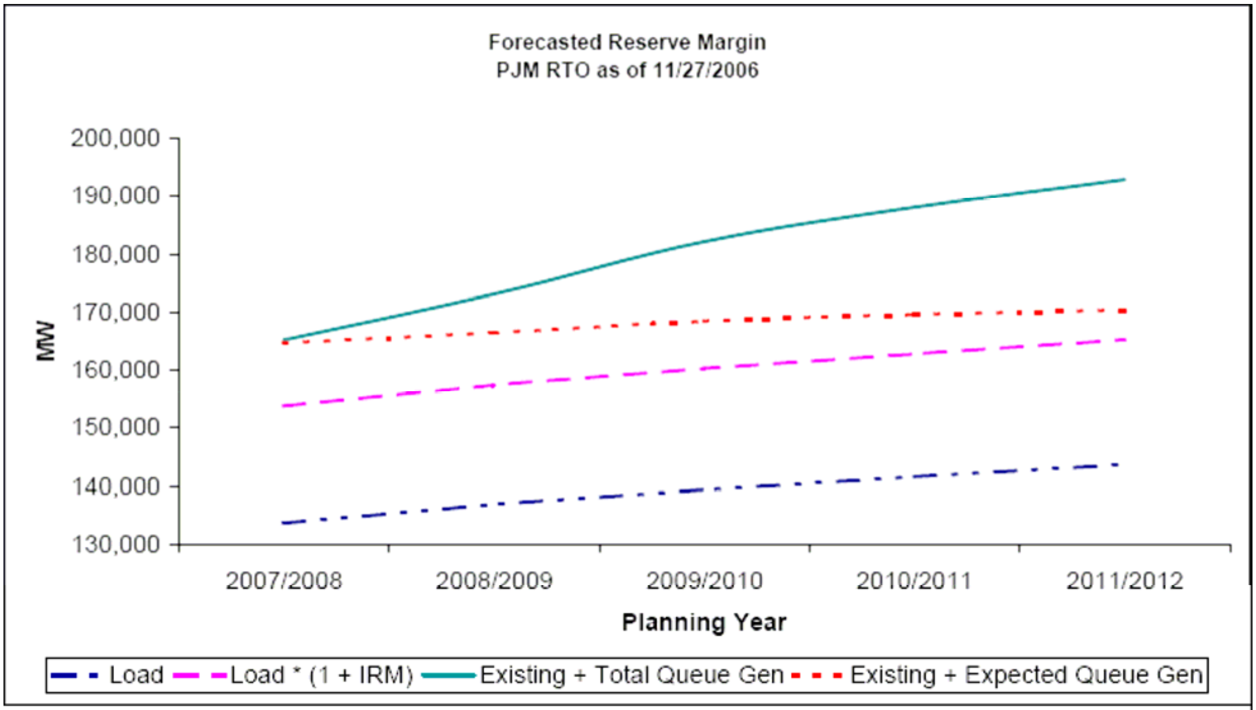
In order to ensure adequate generating resources, PJM requires an installed obligation reserve for the summer peaks. The installed obligation reserve recognizes that some generating resources may be unavailable during the peak. Only Installed Capacity (ICAP) is used to determine if the IRM requirement will be met.

For the 2001/02 and 2002/03 PJM Planning Years, the IRM for PJM East was 19.0% (PJM West had separate IRM levels in 2002/03). Following the integration of PJM West, all of PJM had a 17.0% reserve margin for the 2003/04 Planning Year. During the significant expansion of PJM for the 2004/05 Planning Year, the reserve margins varied by region and time period. The IRM for PJM Mid-Atlantic and the Allegheny Power (APS) zone was reduced to 16.0%, while the integrated AEP and Dayton zones entered on October 1, 2004 with a 15.0% IRM. With Dominion and Duquesne now fully integrated into PJM on January 1, 2005, the PJM-wide IRM was unified at 15.0%.

The following chart and table show the five-year forecasted reserve margin for PJM beginning with the 2007-2008 planning year.[43] While IRM is forecast to be sufficient through the five-year planning period, it is projected to decline from 23.2% to 18.6% in the 2011-2012 planning year. Also, most of the generating resources in PJM are in the western part of the system, with several states or jurisdictions in eastern PJM having negative reserve margins, including Maryland. Thus the reserve margins shown in the table are only adequate if there are sufficient transmission facilities to move available capacity in western PJM to the east. In its most recent planning reports, PJM has stated that in order to ensure reliability in eastern PJM

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

new transmission facilities are required, including the Allegheny Power-Dom inion Resources TrAIL 500 kV line terminating in Loudoun County, Virginia.



Source: PJM Interconnection, LLC

PJM RTO - 11/27/2006

	A	B	C	D	E	F	G	H	I
Planning Year	Forecasted Summer Peak Net Internal Demand	Forecasted Peak Net Internal Demand + Reserve Requirement	Existing Installed Capacity as of 11/27/06	Total Inter-connection Queue Generation by June 1st	Expected Inter-connection Generation Additions by June 1st	Announced Retirements	Existing + Total Inter-connection Queue Generation	Existing + Expected New Generation Additions	Summer Peak Forecasted Reserve Margin %
2007/2008	133,686	153,739	164,906	1,043	499	732	165,217	164,672	23.2%
2008/2009	136,901	157,436	164,906	8,960	2,895	1,080	173,097	166,487	21.6%
2009/2010	139,369	160,274	164,906	8,976	1,957	0	182,073	168,444	20.9%
2010/2011	141,567	162,802	164,906	5,999	1,162	0	188,072	169,606	19.8%
2011/2012	143,714	165,271	164,906	4,780	794	0	192,852	170,400	18.6%

Column A: PJM Total Demand - Active Load Management. Forecast is calculated as a diversified sum of zonal forecasts.

Column B: Column A multiplied by the Reserve Requirement of 1.15

Column C: Installed Capacity of 11/27/2006. This number represents "iron-in-the-ground" inside of the PJM electrical territory. This number excludes external sales/purchases and does not necessarily represent generation controlled by PJM

Column D: Represents the Queue Generation from June 1st of the first year listed to May 31st of the second year listed.

Column E: Queue Generation * Commercial Probability (by project status)

Column F: Announced Future Generator Retirements

Column G: Existing Installed Capacity + Total Queue Generation - Announced Retirements

Column H: Existing Installed Capacity + Expected Queue Generation - Announced Retirements

Column I: [Column H/Column A] - 1

* Each planning year row represents a snapshot of the system as of the first day of the planning year (June 1st)

Load Response Programs

PJM has designed load response programs to ensure that customers who voluntarily curtail their consumption during emergencies and high prices are compensated. The programs provide incentives to customers who take a proactive approach of ensuring reliability of the regional electricity grid. If a customer consumes less than usual, then there is that much more capacity on the grid to deliver to another area to alleviate possible congestion and keep prices low throughout the region. PJM contends that consumers who act in this manner deserve to receive the benefit that their actions facilitate.

There can also be distributed resource participants in these programs, such as on-site generators and load restrainers. On-site generators have the capability to be connected to the grid. Exporters to the grid are eligible to participate in this program if they possess interconnection agreements and comply with the requirements of PJM's Open Access Transmission Tariff agreement. Load curtailers can participate to the extent that their reduction is quantifiable through an approved meter on an electric distribution company (EDC) account.

PJM membership is necessary to participate in these programs but in certain instances a member can act as a third party for a non-member. Payments for curtailment are made only to those who are signatories to the PJM Operating Agreement. To participate in these programs there is also the requirement that load shedders must have metering equipment that provides for hourly kWh values. These should not be estimates but actual usage measurements, and meet EDC requirements. These programs offer the most cost-effective way to ensure that electricity is available during scarce times. Coupled with an appropriate siting policy, these types of programs can provide incentives to end users to utilize power efficiently and to generation and transmission owners to construct where the increased load and capacity will be most beneficial.

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

The PJM market structure has included a generation capacity market construct as a means to ensure long-term adequacy of supply and adequate availability of generation to meet demand. The current generation capacity product is constructed as a single product, which is applicable across the entire PJM market footprint and across all operational conditions.

In the Commission's opinion, the current PJM capacity market structure could be improved to correct for the following issues:

- Inconsistency between the capacity market ground rules and the transmission 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,
- Significant price volatility, which could leave the capacity market vulnerable to market power.

On August 31, 2005, PJM filed its RPM proposal with the FERC for approval to "address current serious inadequacies" in existing capacity rules. In this filing, PJM proposed to replace its current capacity construct with RPM on June 1, 2006, and requested that FERC issue its final order on the filing no later than January 31, 2006.

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

In an order issued April 20, 2006, FERC found PJM's existing capacity market to be unjust and unreasonable and established further proceedings to determine a just and reasonable replacement for the existing market structure. FERC also encouraged the parties to the case to continue to seek a negotiated resolution.

Over the balance of 2006, FERC managed settlement discussions between all the affected parties including PJM, state commissions, and PJM members, under the auspices of Administrative Law Judge Lawrence Brenner:

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

Changes to the reliability pricing model that occurred during settlement discussion included: (1) addition of explicit performance metric for generators to deliver energy during peak period hours; (2) a revised demand curve with generally lower capacity reference prices; (3) addition of a fixed resource requirement (opt-out) alternative; (4) inclusion of various market power mitigation provisions; (5) addition of cost of new entry reference price adjustment based on empirical data from actual capacity market activity; and (6) additional integration with the PJM RTEPP. On December 21, 2006, FERC approved, with conditions, the RPM settlement agreement.

When fully transitioned, PJM plans to hold a centralized auction three years in advance of a given June 1 to May 31 planning year, with several incremental auctions held to fine-tune the process. PJM proposed to hold four consecutive capacity auctions for the 2007/2008 to 2010/2011 Planning Years, each auction separated by a period of several weeks, in order to effect the transition and set up the initial three-year planning horizon. These transitional auctions are scheduled to commence in the first half of 2007. Additionally, the entire PJM footprint would not be transitioned at once; instead, regions will be layered in over time. PJM filed plans to add the LDAs as follows:

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

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

On November 8, 2006, PJM held its first RPM Stakeholder Implementation meeting, during which a Settlement Agreement Overview and RPM Implementation timetable were presented. Additional RPM Stakeholder Implementation meetings were scheduled for December 18, 2006, and January 10, 2007. PJM is expected to conduct its initial series of capacity auctions in the spring of 2007 in order for RPM to be in place for the 2007/2008 Planning Year that commences on June 1, 2007.

E. Electricity Sources and Sinks in Eastern PJM

States that consume more electricity than they generate are classified as net importers of electricity, or sinks. As mentioned earlier in this report, Maryland is a large importer of electricity. The 2005 Maryland energy profile shows that it imports almost 30% of its total statewide consumption. Many of the Northeastern PJM states, similar to Maryland, are also net importers of electricity. For example, the District of Columbia (D.C.) imports 98.1% of its electricity retail sales. Therefore, D.C. is almost completely reliant on exports from other states in the PJM system to supply their electricity.

Delaware, Virginia, Maryland, and New Jersey have similar electricity import profiles. Table III.E.1 shown below lists those states within PJM that import more than 20% of their total consumption (In the three tables below, consumption is referred to as Retail Sales):

Table III.E.1: State Electricity Imports for Year 2005

State	Retail Sales	Sales + Losses	Net Generation	Imports	Pct. Imported
District of Columbia (D.C.)	11,881	12,624	235	12,389	98.1%
Delaware	12,069	12,823	8,129	4,694	36.6%
Virginia	108,590	115,377	78,879	36,498	31.6%
Maryland	68,366	72,639	52,662	19,977	27.5%
New Jersey	75,978	80,727	59,252	21,475	26.6%

Source: EIA. All energy figures are in MWhs.

In addition to those states that import, there are some states that neither import nor export a significant amount of electricity. These states only contribute, or receive, a marginal amount of electricity into, or out of, the PJM system. Both New York and Ohio receive less than 9% of their retail sales from a generating source outside of their state. Kentucky generates enough electricity to meet its demand and export a small percentage of its generation to other states. Table III.E.2 below lists those states within or bordering PJM that do not import or export significant amounts of electricity:

Table III.E.2: Neutral Electricity Import/Export States for Year 2005

State	Retail Sales	Sales + Losses	Net Generation	Imports	Pct. Imported
New York[44]	150,246	159,636	146,613	13,023	8.2%
Ohio	159,654	169,632	157,732	11,900	7.0%
Kentucky	89,313	94,895	97,672	-2,777	-2.9%*

Source: EIA. All energy figures are in MWhs. * Negative imports mean the state exports electricity.

Finally, there are three states, within the PJM system that are sources, or export a large percentage of the electricity that they produce. Pennsylvania, West Virginia and Illinois export their excess electricity to those states that do not generate enough electricity to meet their demand. West Virginia, for example, generates over three times the amount of electricity that it consumes. Similarly, Pennsylvania exports nearly 40% of all the electricity it produces. Nationally, West Virginia and Pennsylvania are the two largest electricity-exporting states in the country. Table III.E.3 below lists those three states within PJM that export a significant amount of electricity:

Table III.E.3: State Electricity Exports for Year 2005

State	Retail Sales	Sales + Losses	Net Generation	Imports	Pct. Exported
West Virginia	30,135	32,018	93,212	-61,194	191.1%
Pennsylvania	147,917	157,162	218,130	-60,968	38.8%
Illinois	144,554	153,589	194,390	-40,801	26.6%

Source: EIA. All energy figures are in MWhs.

The tables above illustrate a clear picture and a consistent theme within the PJM system: the energy needs of several states in eastern PJM are supported by the exports from West Virginia, Pennsylvania and Illinois. However, Illinois is also a MISO state, so it is more difficult to determine how much of its generation is divided between the PJM and MISO RTOs. This further highlights the need for an adequate, reliable, and efficient transmission grid. The importing states, in effect, compete with each other for the imported electricity. Through its regional planning process, PJM recognized this trend and is working with its membership to ensure the transmission infrastructure is added to facilitate this electricity trade.

F. PJM's Generation Profile and Potential Generation Additions

PJM has grouped generation interconnection requests into queues based on the date the request was made. Table III.F.1 shows both actual and proposed generation additions. Due to transmission system upgrade requirements or business or siting-related issues, a developer may withdraw several projects in the queues. Changes to construction schedules may also result in changes to the in-service dates.

[44] The New York Independent System Operator (NYISO) is a single state ISO that contains all of New York state.

Table III.F.1: Actual and Proposed Generation (MW) Additions in PJM (As of October 30, 2006)

Queue (Dates)	Total Requested	Currently In-Service	Under Construction	Under Study
A (4/1/1997-4/15/1999)	26,554	8,364	0	0
B (4/16/1999-11/30/1999)	20,474	4,568	24	0
C (12/1/1999-3/31/2000)	4,614	463	0	47
D (4/1/2000-7/31/2000)	8,309	666	40	0
E (8/1/2000-11/30/2000)	18,432	795	0	0
F (12/1/2000-1/31/2001)	3,145	52	0	0
G (2/1/2001-7/31/2001)	23,574	337	1,274	670
H (8/1/2001-1/31/2002)	9,125	155	548	0
I (2/1/2002-7/31/2002)	5,019	80	0	76
J (8/1/2002-1/31/2003)	876	10	159	0
K (2/1/2003-7/31/2003)	2,709	121	505	15
L (8/1/2003-1/31/2004)	4,268	44	666	0
M (2/1/2004-7/31/2004)	4,595	88	973	472
N (8/1/2004-1/31/2005)	9,757	1,779	297	2,413
O (2/1/2005-7/31/2005)	7,887	242	82	4,224
P (8/1/2005-1/31/2006)	8,947	113	294	6,417
Q (2/1/2006-7/31/2006)	15,744	0	5	14,642
R (8/25/2006-11/30/2006)	8,814	0	0	8,814
Total MW	**182,843**	**17,877**	**4,867**	**37,790**

Source: http://www.pjm.com/planning/project-queues/queues.html as of October 30, 2006.

Of the 182,843 M W requested only 17,877 MW (9.8%) are currently in-service, while 4,864 MW (2.7%) are under construction, and 37,790 MW (20.7%) are still under study. Only 33.1% of the total requested generation additions have been, or will, be added to the PJM system. This 33.1% is itself an optim istic forecast because it assum es all the generati on units currently under study are built and that all the units currently under construction are completed.

Although new generation should be sufficient to meet established reliability criteria within the region, the Comm ission is concerned a bout the lack of fuel diversity exhibited by generation additions. Com bustion turbine capacity in eastern PJM is exp ected to r emain the predominant source of near generation for the next fi ve years at least. Na tural gas prices have of course risen sh arply in recen t years and rem ain volatile (see Section IV.E). This trend toward reliance on natural gas as a fuel resource m ust be closely monitored. It is to b e noted that in th e PJM region, many projects have been withdrawn due to profit forecasts, general financial market instability, and more recently due to the much higher fuel costs for gas-fired plants making them less economic to operate.

In Maryland, approximately 4,688 MW of new generation has been proposed in the PJM Queues for the three-year period from 2004 through 2006. The m ain fuels of the proposed additions are nuclear (71%) and natural gas (28%). However, the two 1640 MW nuclear plants have in service dates of 2015 and 2016, and if for some reason they are withdrawn from the queues then natural gas would account for 92% of the proposed additional generation.

G. The Regional Transmission Expansion Planning Protocol (RTEPP)

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

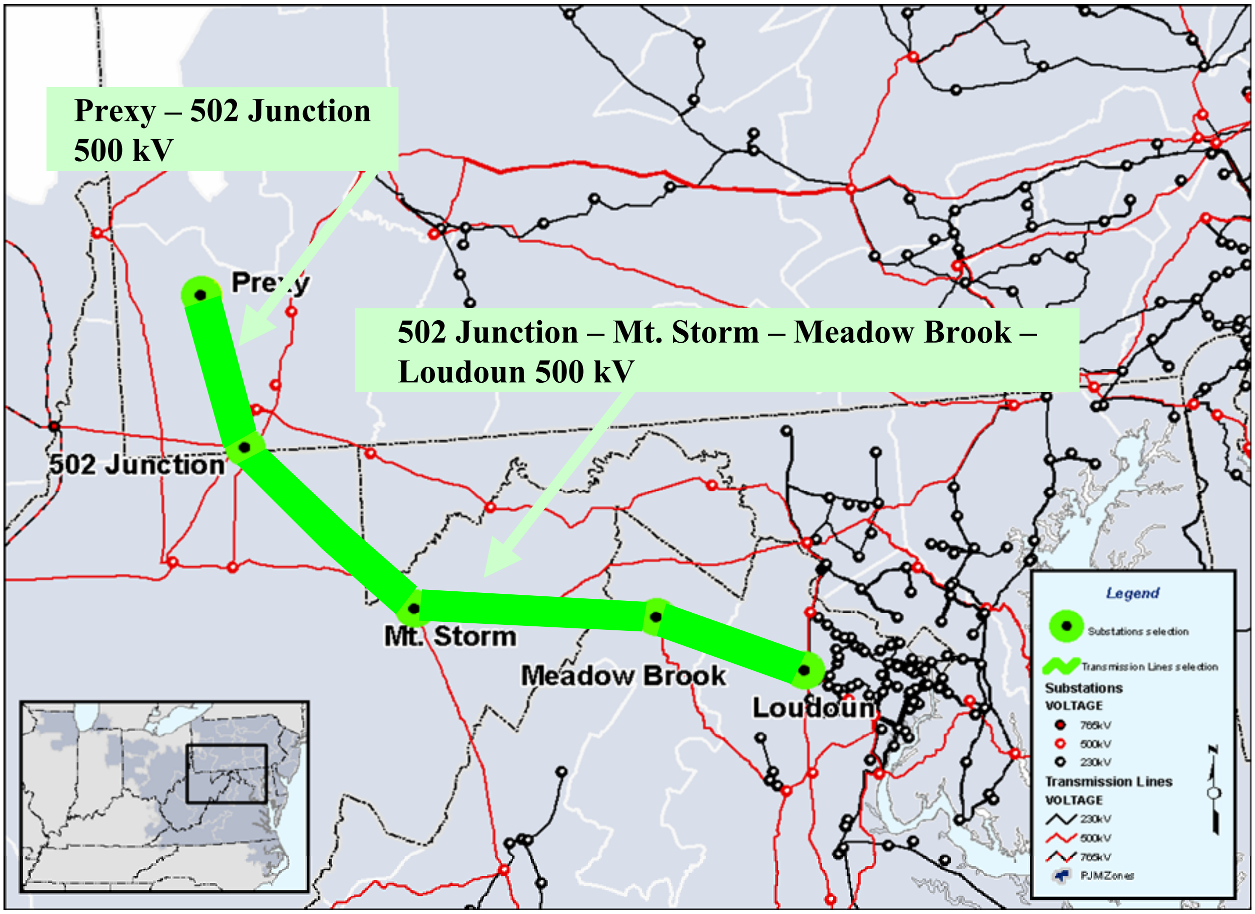
PJM's most recent Regional Transmission Expansion Plan was presented at the May 23, 2006, Transmission Expansion Advisory Committee (TEAC) meeting, and was approved by PJM's Board of Governors a month later on June 23, 2006. The RTEP authorized construction of $1.3 billion in electric transmission upgrades,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

The principal reason for the Trans-Allegheny Interstate Line (TrAIL), as it is called, is that it addresses imminent reliability problems within the PJM electric transmission system. According to PJM, the line is needed by June 2011 to avoid reliability problems that might result in service disruptions. Specific benefits of the line contained in materials provided by PJM, Allegheny and Dominion include:

- Improving system reliability; TrAIL will ensure electric reliability in the Mid-Atlantic region, of which Maryland is a part. The economic and social costs of disruptions in electric service can of course be enormous.
- Meeting the growing demand for electricity. The Mid-Atlantic is the fastest growing region in the PJM footprint, and already is in many respects capacity deficient. As described earlier, Maryland imports over 25 percent of its energy needs and this percentage will grow as the Maryland economy expands while output from existing generating plants may be reduced to comply with environmental regulations.
- Increasing west-to-east transfer capability, making cost-effective generation available to more consumers. PJM estimates that the TrAIL project will increase west to east power transfer capabilities by about 5,300 MW, and thus reduce congestion. Maryland would realize a significant portion of the resulting economic benefits.

The RTEP also covers generation projects within PJM's footprint, which are discussed at TEAC meetings. As described earlier, the system enhancements planned by PJM have accommodated 18,717 MW of new generation, representing over 140 projects, with nearly 3,800 MW of generation under construction. These generation additions enhance system reliability, supply adequacy and competitive markets for PJM's market participants and the customers they serve. Importantly, the generation additions represent various fuel types, including natural gas, wind, and coal.

Map III.G.1: TrAIL



H. Reliability Standards

EPAct 2005 requires the formation of an electric reliability organization (ERO) with mandatory and enforceable standards. FERC was authorized by EPAct to designate an organization to serve as the ERO. The North American Electric Reliability Council (NERC) submitted an application and qualifications to be the ERO to FERC. On July 20, 2006, FERC approved NERC's application.

NERC up to then had been a power industry organization that developed electric reliability standards for the United States and Canada. Due to regional differences in the United States and Canada, NERC standards are customized through regional reliability councils. These organizations are responsible for overseeing the implementation of standards that ensure the reliability and security of the bulk electric supply system.

As part of the development of larger and more integrated wholesale power markets, new reliability councils were formed, including one covering the most of the PJM and the Midwest Independent System Operator (MISO) footprints, Reliability*First* Corporation (RFC). There are presently eight regional reliability councils (see Map IV.B.1, on page 45). Beginning January 1, 2006, RFC became responsible for setting reliability standards for most of PJM and all of MISO.

RFC does not set reliability standards for that portion of PJM that is in Virginia and North Carolina. Southeast Electric Reliability Council (SERC) sets reliability standards for those two states, and most of the rest of the Southeast United States.

The "2006 Long-Term Reliability Assessment, The Reliability of Bulk Power Systems in North America" prepared by NERC includes regional self-assessments, including one for RFC. Concerning the adequacy of resources the RFC self-assessment states, "Summer reserve margins in RFC range from a high of 23.0 percent in 2006, declining to 11.1 percent in 2015. These reserve margins are based on forecast net internal demand and potential capacity resources." Confirming the fragile nature of the reliability outlook in RFC (and in consequence PJM) the self-assessment further states:

> The amount of potential capacity resources is sufficient through 2012. Starting in 2013, additional capacity resources are needed to maintain a 15 percent reserve margin. The amount of needed capacity resources ranges from 1,600 MW in 2013 to 8,400 MW in 2015. These reserve margins include over 19,800 MW of projected capacity additions and existing capacity that is currently categorized as undeliverable. If the proposed capacity projects are not completed as scheduled and the transmission system is incapable of fully delivering all existing capacity, a reduction of the entire 19,800 MW of capacity resources would reduce the reserve margin to in 2015 to 1.9 percent.[45]

I. The Regional Greenhouse Gas Initiative (RGGI)

In April 2003, New York Governor George E. Pataki initiated the Regional Greenhouse Gas Initiative (RGGI, pronounced "Reggie") process by sending a letter to the governors of the Northeast and Mid-Atlantic States.[46] He invited them to pursue "a course of cooperation" and work together "to develop a strategy that will help the region lead the nation in the effort to fight global climate change." Many scientists believe carbon dioxide (CO_2) emissions to be a major contributor to the climate change phenomenon known as global warming.

Since 2003, state representatives have been working to develop the program, which relies on a flexible, market-based approach to curb power plant emissions, while also promoting greater energy efficiency and energy independence. The program's main goal is to develop a multi-state cap-and-trade program covering greenhouse gas (GHG) emissions. The initiative will initially be aimed at developing a program to reduce CO_2 emissions from power plants in participating states, while maintaining energy affordability and reliability and accommodating, where feasible, the diversity in policies and programs in individual states. After the cap-and-trade program for power plants is implemented, the states may consider expanding the program to other kinds of sources.

Seven Northeast and Mid-Atlantic states are currently participating in RGGI. Each has agreed to implement a cap-and-trade program whose goal is to reduce CO_2 emissions. This is

45 "2006 Long-Term Reliability Assessment," North American Electric Reliability Council, October 2006, p. 83.
46 The information provided in this description was largely obtained from the RGGI website. For additional information on the RGGI program, see the RGGI website at www.rggi.org.

the first mandatory cap-and-trade program for CO_2 emissions in the history of the United States. The states who are currently full participants in RGGI are Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York and Vermont.

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

Maryland's HAA requires Maryland to become a full participant in RGGI by June 30, 2007.[47] Current developments indicate that Maryland may be a full participant at an earlier date. By design, the RGGI program will be expandable and flexible, permitting other states to join in the initiative when they deem it appropriate. States and other political jurisdictions currently in observer roles to the RGGI process are: the District of Columbia, Massachusetts, Pennsylvania, Rhode Island, the Eastern Canadian Provinces, and New Brunswick. Under RGGI, the participating states will launch a regional cap-and-trade system that utilizes emissions credits or allowances to limit the total amount of CO_2 emissions. Beginning in 2009, emissions of CO_2 from power plants in the region would be capped at current levels —approximately 121 million tons annually[48] — with this cap remaining in place until 2015. The initial base annual emissions budget for the 2009-2014 periods is as follows:

Table III.I.1: Annual Emissions Budget (2009 –2014)

State	Carbon Dioxide Allowances (2009 – 2014)
Connecticut	10,695,036 tons
Delaware	7,559,787 tons
Maine	5,948,902 tons
New Hampshire	8,620,460 tons
New Jersey	22,892,730 tons
New York	64,310,805 tons
Vermont	1,225,830 tons
Total	121,257,573 tons

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

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

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

One of the RGGI issues that should be noted is that, currently, the CO_2 emissions totals are for in-state power generation only. Maryland is an importer of power from out-of-state sources and CO_2 totals do not provide an adjustment for power generated from outside the State. Of the states committed to being part of RGGI, Maryland shares its status of being a significant importer with New Jersey and, to a lesser extent, with Delaware. RGGI has not yet dealt with imports issue probably because most of the current RGGI states do not rely on imports for a significant portion of their requirements. The imports issue creates a level of vulnerability for Maryland and could become problematic if it is not addressed.

The number of allowances granted to RGGI states is the product of negotiation. To date, the negotiations have used as a starting point the emissions from in-state generation only, as noted above. If after Maryland joins RGGI it becomes required to obtain CO_2 emissions allowances covering their imports, and is not granted an increase in those allowances, the State will be thousands if not millions of allowances short of its needs, at a large cost to consumers. The Commission has been and continues to recommend that the State negotiate a going-in level of allowances sufficient to cover not just in-State generation but also the substantial portion of electricity supply that the State currently imports.

Currently, the RGGI Imports and Leakage Group is addressing the imports issue. RGGI staff proposals are circulating that would allow allowances for generation imported from outside of a state, but the final determinations on this issue have not been made.

As to the rest of the RGGI program, after determining the states' starting points they would then begin reducing emissions incrementally over a four-year period to achieve a 10 percent reduction by 2019. Compared to the emissions increases the region would see from the sector without the program, RGGI will result in an approximate 35 percent reduction by 2020.

Under the cap-and-trade program, the states will issue one allowance, or permit, for each ton of CO_2 emissions allowed by the cap. Each plant will be required to have enough allowances to cover its reported emissions. The plants may buy or sell allowances, but an individual plant's emissions cannot exceed the amount of allowances it possesses. The total amount of the allowances will be equal to the emissions cap for the seven-state region. Electric generating units with a capacity of 25 MW or more will be included under RGGI. The RGGI states have agreed that at least 25 percent of a state's allowances to be dedicated to strategic energy or consumer benefit purposes, such as energy efficiency, new clean energy technologies and ratepayer rebates. A power plant also could purchase these allowances for its own use. The funds generated from these sales are to be used for beneficial energy programs.

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

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

IV. FEDERAL / NATIONAL ISSUES AND EVENTS

During 2005, the United States Congress passed and President George W. Bush signed the Energy Policy Act of 2005 (EPAct 2005). EPAct 2005 is likely to have significant impacts on electricity issues facing Maryland well into the future.

A. Overview of the Energy Policy Act of 2005 (EPAct 2005)

Passed by Congress in 2005 in an effort to increase both energy supply and efficiency, the Energy Policy Act of 2005 is comprised of a number of provisions that affect the cost and supply of energy in Maryland. EPAct 2005 also encourages state commissions to conduct several studies and analyses.

First, mergers and acquisitions are likely to be affected by EPAct 2005's repeal of the Public Utility Holding Company Act (PUHCA). Gone is the Securities and Exchange Commission's (SEC) traditional role in reviewing merger proposals and the stipulation that utility combinations must be between continuous or interconnected companies. The approval authority of proposed mergers and acquisition activity falls upon FERC and state regulatory agencies. There are no pending utility mergers in Maryland.

Transmission Infrastructure Provisions

EPAct 2005 added a new Section 219 to the Federal Power Act. According to the FERC's most recent ruling on providing transmission investment incentives,[49] Section 219 was enacted because of a long decline in transmission investment that is threatening reliability and causing billion of dollars in congestion costs. The DOE National Electric Transmission Congestion Study (covered fully later in this section) confirmed that eastern PJM is one of the most congested regions in the United States. To reverse this historical trend, Section 219 directs the FERC to "establish by rule, incentive-based (including performance-based) rate treatments" that: "promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance and operation of all facilities for the transmission of electric energy in interstate commerce…" FERC's final rule fulfilled that command by providing a range of rate treatments that remove impediments to new investment or otherwise attract that investment. The incentives provided by FERC in its final order should encourage investment in bulk transmission facilities in PJM, including those that would directly affect reliability and congestion relief in Maryland.

Energy Supply Provisions

Energy project siting and infrastructure development is encouraged by EPAct 2005. Of significance to Maryland, FERC has jurisdiction for siting and licensing the construction and operation of liquefied natural gas facilities. Maryland is home to the nation's largest LNG terminal, Dominion's Cove Point facility, and AES Corporation has announced plans to build another LNG facility at Sparrows Point.

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[49] Promoting Transmission Investment through Pricing Reform, Final Rule; Order on Rehearing, December 22, 2006, Federal Energy Regulatory Commission Docket No. RM06-4-001; Order No. 679-A.

Nuclear power is another energy source that is encouraged by the EPAct 2005. The first six nuclear power plants that are licensed and built are eligible for production tax credits (1.8 cents per kWh) for the first eight years of their operation. Financing costs for the first six plants that come about from unnecessary delays caused by the licensing process and not the owner will also be reimbursed. Combined with the Nuclear Regulatory Commission's (NRC) early site permitting and combined construction and operating licensing process, growing demand for electricity, and increased concern over the environmental impact of air emissions, building new nuclear power plants is now more possible than it has been since the events at Three Mile Island. Constellation Energy, through its Unistar subsidiary, has shown strong interest in building additional nuclear units at its Calvert Cliffs site, and these units could be eligible for the financial incentives provided in the EPAct 2005. Finally, the EPAct 2005 also has provisions that provide a renewed commitment for the research and development of next-generation nuclear facilities.

EPAct 2005 permits the United States Department of Energy to assign transmission corridors of "national interest." The intent is to identify geographic regions where transmission upgrades are necessary to ensure reliability and reduce congestion. If DOE makes a National Interest Electric Transmission Corridors (NIETC) designation, affected states must act within a year of receiving a complete transmission siting application, or FERC could accept jurisdiction over siting proposed transmission facilities. These NIETCs and their relevance to the State of Maryland are further explained in IV.D. EPAct 2005 also promotes reliability by requiring common nationwide standards for electric reliability, and the creation of a national organization that will monitor the status of the grid.

Renewable energy production is encouraged by EPAct 2005. Tax credits associated with the development of renewable energy facilities are available to facilities that are on-line by the end of 2007. These benefits include tax credits (1.8 cents per kWh) for many renewable energy options for nine years.

The first coal gasification and other clean-coal projects could be completed with the aid of the incentives provided by the EPAct 2005. Appreciable amounts of direct grants, loan guarantees and accelerated depreciation, divided among different technologies, aid in making this option a reality. While coal gasification combined cycle power plants may not be built in Maryland, utilities which are in the PJM footprint, including AEP, are proposing to build coal gasification combined cycle (CGCC) facilities in eastern Ohio and West Virginia. Duke Energy, in Ohio and Indiana, is also proposing to build CGCC power plants. Some of the power from these facilities could be delivered to Maryland if sufficient transmission capacity is built.

<u>Energy Efficiency Provisions</u>

Subtitle E of Title XII (Electricity) of EPAct 2005 is of specific concern to Maryland utility regulators. Subtitle E incorporates amendments to the Public Utility Regulatory Policy Act of 1978 (PURPA). Sections 1251, 1252 and 1254 of EPAct 2005 add net metering, fuel sources, fossil fuel generation efficiency, time-based metering and interconnection standards to 16 U.S.C. §2621(d). Within the deadlines discussed below, 16 U.S.C. §2621(a) requires the Commission to consider and determine whether it is appropriate to implement the standards in 16

U.S.C. §2621(d)(11-15) to carry out the purpose of Title 16 of the U.S. Code. The procedural requirements for consideration and determination are set forth in 16 U.S.C. §2621(b).

The Commission is given the authority to implement any of these standards in 16 U.S.C. §2621(c). Not later than two years after the enactment of Section 1251 (or, by August 8, 2007), the Commission, with respect to each electric utility for which it has ratemaking authority, is required to commence consideration, or set a hearing date for consideration, of the standards referred to in Section 1251. By August 8, 2008, the Commission must complete its consideration and make its determination with respect to the standards.

According to Sections 1252 and 1254, not later than one year after enactment of EPAct 2005, the Commission shall commence consideration, or set a hearing date for consideration, of the changes referred to in Sections 1252 and 1254. Not later than two years after enactment the Commission shall complete its consideration and make a determination.

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

In response to Section 1254 of EPAct 2005, which focuses on establishing small generator interconnection standards, and the recommendations of the Mid-Atlantic Distributed Resources Initiative (MADRI), the Commission established[50] a Demand Response and Distributed Generation Working Group (DRDG). After the DRDG was created intervention petitions, notices of appearance and comments were provided by a number of persons and entities.[51]

The comments were generally supportive of the Commission adopting an interconnection standard consistent with the intent of Section 1254 of EPAct 2005. Many of the remarks also encourage the Commission to launch a working group that addresses technical and policy issues involved in developing interconnection standards. The comments also suggested that the Commission find an appropriate balance between the synergies that could result from the interconnection of distributed generation and the reliability and safety of the distribution system.

The Commission accepted the aforementioned recommendations and instituted the Small Generator Interconnection Standards Working Group[52] (SGIS). The working group is set to develop a report for the Commission that will outline policy choices or consensus proposals. Another function of the report is to provide specific provisions for interconnection standards that

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50 Working group was established on September 13, 2006. See Case Nos. 8908 and 9059.

51 Comments were provided by: Potomac Electric Power Company and Delmarva Power & Light Company; the Office of People's Counsel; Baltimore Gas and Electric Company; The Potomac Edison Company d/b/a Allegheny Power; the Commission's Technical Staff; The E Cubed Company, LLC; SunEdison, LLC, the Maryland-DC-Virginia Solar Energy Industries Association, and the Solar Energy Industries Association; Choptank Electric Cooperative, Inc.; Southern Maryland Electric Cooperative, Inc.; the Maryland Energy Administration - Power Plant Research Program; Constellation NewEnergy, Inc; and Eastalco Aluminum Co.

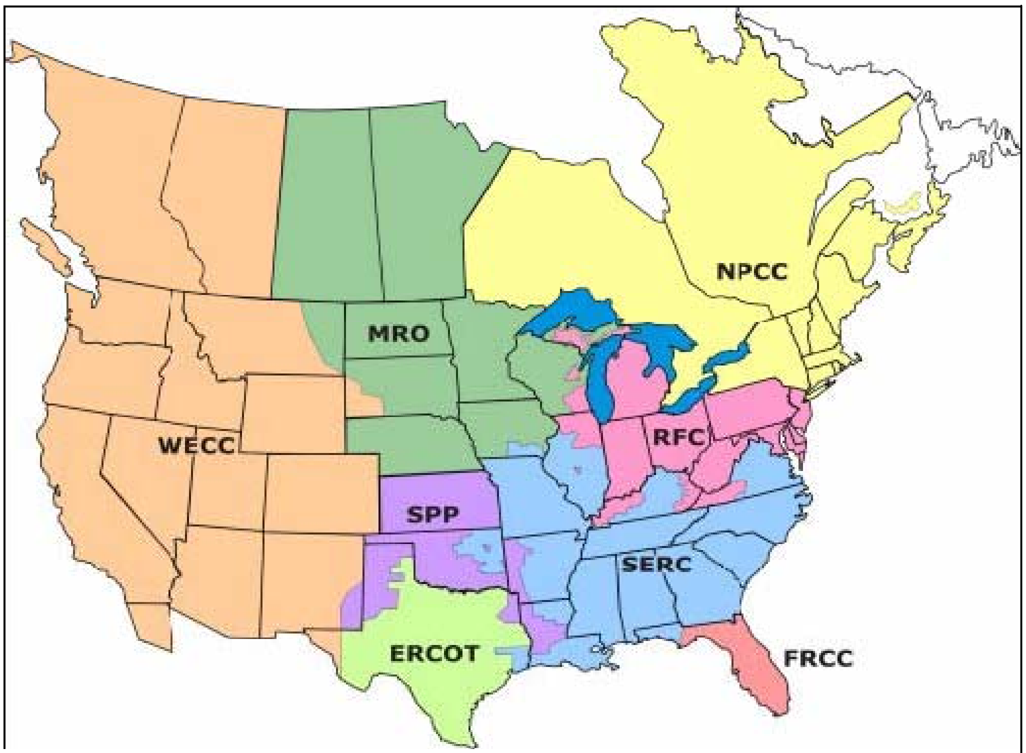
52 Case No. 9060, October 17, 2006.

are consistent with those alternatives or recommendations that could be adopted by the Commission.

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

On February 3, 2006, FERC issued Order No. 672, its Final Rule to implement the requirements of section 215 of the FPA. Section 215(c) requires FERC to certify a single Electric Reliability Organization that will oversee the reliability of the interconnected North American Bulk-Power Systems. The ERO will develop and enforce the mandatory Reliability Standards, which will apply to all users, owners and operators of the Bulk-Power System. FERC "has the authority to approve all ERO actions, to order the ERO to carry out its responsibilities under these new statutory provisions, and also may independently enforce Reliability Standards."[53]

Map IV.B.1: NERC Regional Reliability as of 10/16/2006



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

In Order No. 672, FERC identified the criteria that an applicant must meet to qualify as the single ERO. One applicant, the North American Electric Reliability Council (NERC), submitted its application on April 4, 2006. The NERC proposal included comprehensive plans that discussed in details the transition to and maintenance of NERC as the ERO. Based on

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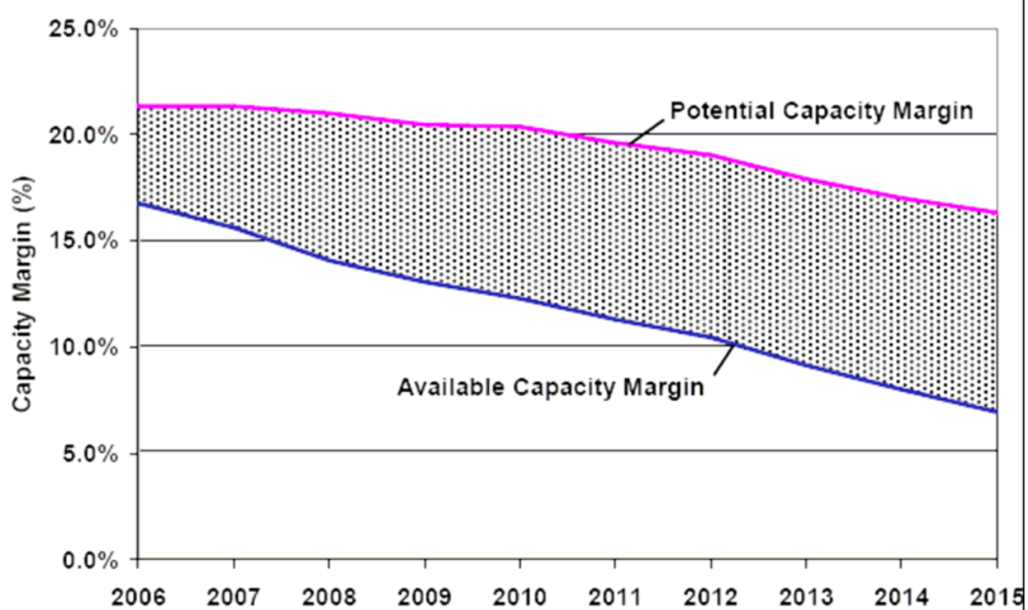
[53] Order No. 672 at p. 8.

FERC's review of NERC's proposal and other public comments submitted by interested parties on NERC's application, FERC found that NERC's proposal met the requirements of Order No. 672 and therefore, certified NERC as the ERO for the United States. In Order No. 672, FERC ordered the ERO to conduct assessments of the adequacy of the Bulk-Power system in North America and to report its findings to FERC, the Secretary of Energy, each Regional Entity (as noted the map), and each Regional Advisory Body.

C. NERC Reliability Study

In October 2006, NERC issued a study entitled "2006 Long-Term Reliability Assessment: The Reliability of the Bulk Power Systems in North America." The study analyzes the adequacy of electricity supply and the reliability of transmission in North America over the 2006-2015 periods. The study notes a series of actions pertaining to bulk power system (transmission, fuel supply, demand response, and delivery of electric generation). Of significance, NERC predicts that available capacity margins will decline throughout the United States over the 2006-2015 period (see Chart IV.C.1), dropping below 10 percent on or about year 2012. Available capacity margins are calculated as the difference between committed capacity and peak demand, with committed capacity defined as generating capacity either existing, under construction, or planned that will be available, deliverable and committed to serve demand. Potential capacity margin includes the above and uncommitted capacity resources, which are planned and existing capacity that cannot be counted as firm capacity due to either transmission constraints, or is in a preliminary planning phase.

Chart IV.C.1: Available Versus Potential Capacity Margins for the United States



Other key findings and actions needed[54] are noted below, and are generally consistent with the findings this report states to exist in Maryland and the eastern half of PJM generally.

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

Key Findings:

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

Actions Needed:

- Electric utilities[55] need to commit to add sufficient supply-side or demand-side resources, either through markets, bilateral contracts, or self-supply, to meet minimum regional target levels.
- NERC, in conjunction with regional reliability organizations and electric utilities, will evaluate the implications of the 2006 summer heat wave on future demand forecasts.
- NERC, in conjunction with regional reliability organizations, electric utilities, resource planning authorities, and resource providers, will address the issue of "uncommitted resources" by establishing more specific criteria for counting resources toward supply requirements.
- NERC will expedite the development of its new reliability standard on resource adequacy assessment that will establish parameters for taking into account various factors, such as: fuel deliverability; energy-limited resources; supply/demand uncertainties; environmental requirements; transmission emergency import constraints and objectives; capability to share generation reserves to maintain reliability, etc.
- Electric utilities, resource planning authorities, and resource providers need to evaluate the reliability of fuel supply and delivery systems when determining electricity supply adequacy.
- Entities that purchase fuel for electric generators need to review and strengthen fuel supply and delivery contracts to ensure that fuel disruptions do not limit generator operation during critical electric supply situations.
- Federal, state, and provincial agencies, along with fuel supply and delivery industries, need to evaluate the adequacy of these critical infrastructures for supporting an adequate electricity supply system.

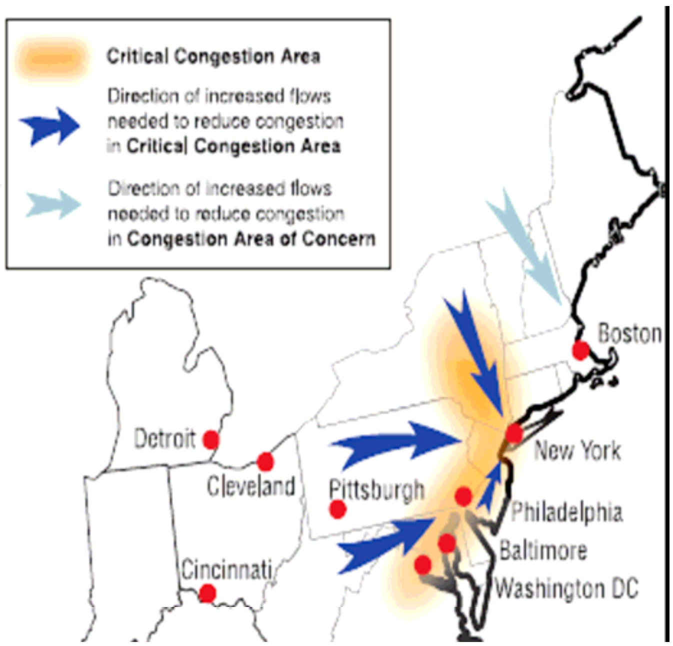
[55] "Electric utilities" in this context refer to load serving entities whose responsibility it is to secure energy, transmission, and related inter-market operations to serve the electrical demand and energy requirements of its end-use customers.

D. Department of Energy (DOE) Transmission Congestion Study

In August 2006, the United States Department of Energy (DOE) released the National Electric Transmission Congestion Study (NETCS). This study is a response to Section 1221(a) of the Energy Policy Act of 2005. According to Section 1221(a), the Secretary of Energy is directed to conduct a national study of transmission congestion within the electricity grid. Subsequent studies are to be done every three years. A required study result was that the Secretary designates areas that are National Interest Electric Transmission Corridors (NIETCs). These NIETC areas are to be "any geographic areas experiencing electric energy transmission capacity constraints or congestion that adversely affects customers."

Through the use of a variety of cost congestion metrics, the Department of Energy created three classifications that aid in identifying areas that merit federal attention. The three classes are Critical Congestion Areas, Congestion Areas of Concern and Conditional Congestion Areas. "Critical Congestion Areas" are deemed to be regions of the country where the current and/or projected situations will yield harsh congestion effects. Two regions were identified as being "Critical Congestion Areas," Southern California and the Atlantic coastal area from metropolitan New York City and its environs through Northern Virginia (see map). The latter Critical Congestion Area is of particular concern to Maryland as the State comprises a major portion of this congested area.

Map IV.D.1: Critical Congestion Area

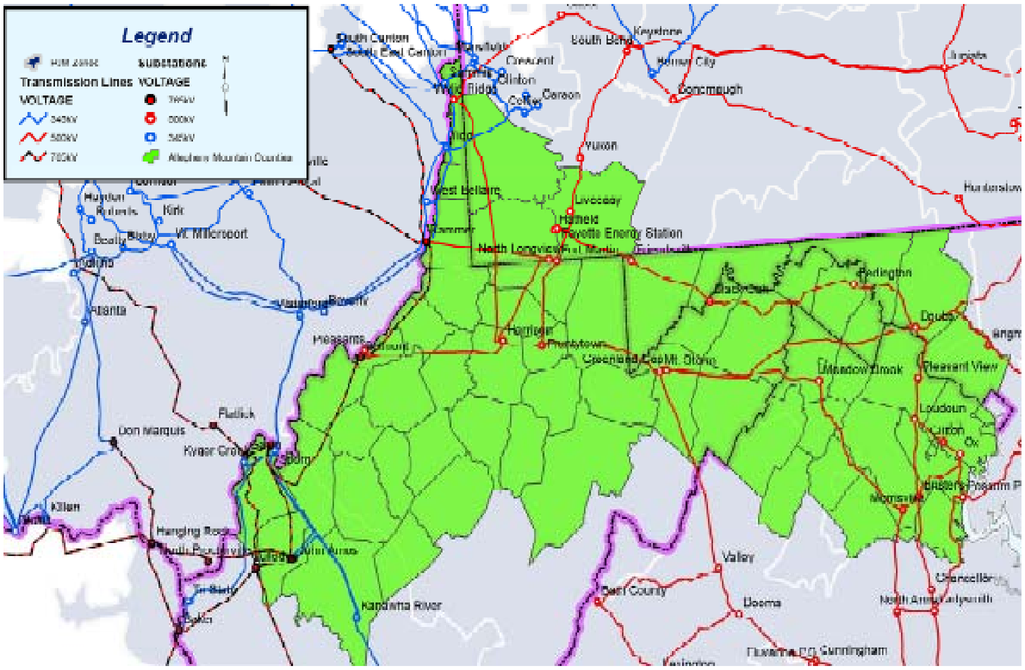


PJM submitted a response[56] to the Department of Energy National Electric Transmission Congestion Study. The comments submitted by PJM go on to identify and request that three areas be deemed NIETCs. Of the three regions, two have direct implications to Maryland.

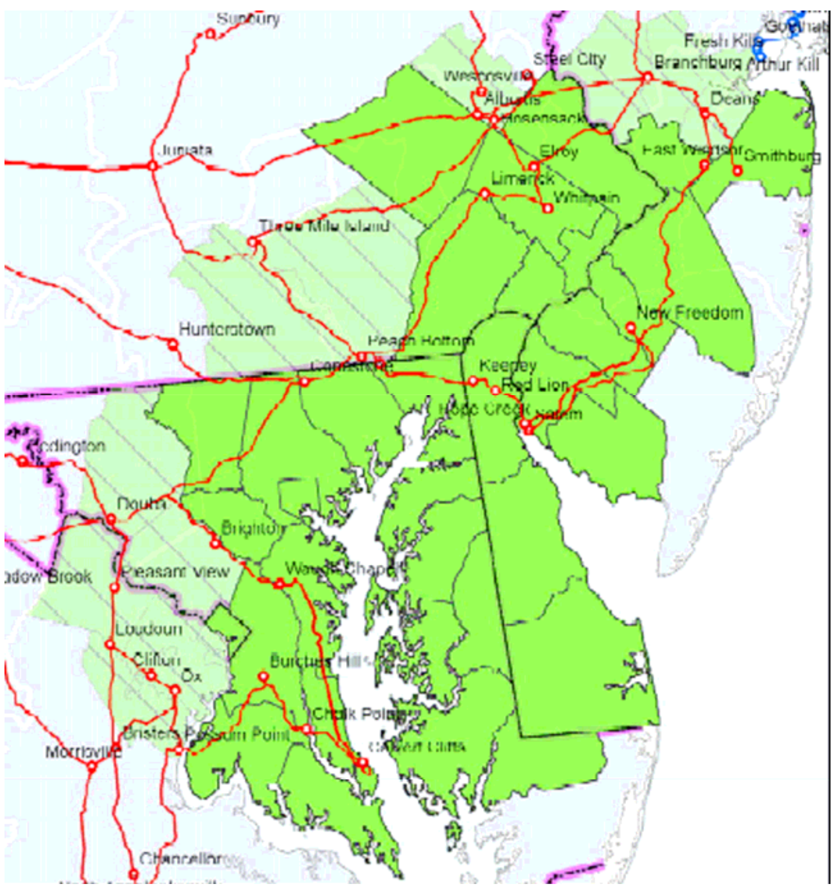
The Allegheny Mountain Corridor is a bulk power, high voltage transmission trail that exists within portions of Maryland, Pennsylvania, Virginia, and West Virginia. This path has the capacity to service the Baltimore – Washington – Northern Virginia metropolitan load centers. Benefits associated with this corridor include the improved access to the generation resources that are located west of the Allegheny Mountains.

56 *Comments of PJM Interconnection LLC on Designation of National Interest Electric Transmission Corridors*, October 10, 2006.

Map IV.D.2: Allegheny Mountain Corridor



Map IV.D.3: Mid-Atlantic Corridor



The Mid-Atlantic Corridor is a bulk power, high voltage transmission path traversing portions of Maryland, Delaware, Pennsylvania, New Jersey, and the District of Columbia. This passage extends from the Baltimore – Washington – Northern Virginia metropolitan area across the Chesapeake Bay and the Delaware River and can provide transmission capability to load centers in Pennsylvania, New Jersey and the Delmarva Peninsula. Energy would be provided to the load centers via the western generation resources from the Allegheny Mountain corridor and from new nuclear generation proposed to be built south of Baltimore and in eastern Virginia.

Additional transmission capacity in the Allegheny Mountain and the Mid-Atlantic Corridors would alleviate much of the critical congestion identified by DOE. According to PJM, increased transmission capability coupled with nuclear generation in Maryland and Virginia could serve to reduce the usage of less cost effective electricity generating facilities, lower the cost of energy to customers and increase reliability to a significant number of Maryland utility customers.

E. Impacts of Volatile Commodity Prices on Wholesale Electricity Markets

On May 18, 2006, FERC held a technical conference to discuss the *Summer Energy Market Assessment 2006* report.[57] Record high storage levels and strong early injections of natural gas, along with a gradual recovery in the Gulf following Hurricanes Katrina and Rita in 2005, helped to moderate natural gas futures from the high levels reached in the fall of 2005. However, concerns over high oil prices and the potential for additional hurricane activity in the Gulf of Mexico tended to exert upward pressure on prices.

On October 19, 2006, FERC held a technical conference to discuss the *Winter 2006-07 Energy Market Assessment* report. The general conclusion of FERC Staff was that current conditions for natural gas indicated that the system has significant flexibility to deal with most challenges that might arise through the winter. In addition, there would be enough natural gas in storage, as well as sufficient pipeline capacity, to meet needs for winter 2006-2007. Maryland's own natural gas distribution companies provided the Commission with similar assessments in the Commission's annual hearing on winter natural gas availability.[58]

An attempt to assess market expectations for the winter of 2006-2007 using future prices reveals that the recent moderation in prices extends into the winter. During 2005, natural gas prices rose from $6.00/MMBtu to well over $10.00/MMBtu. In 2006 prices fell, briefly dropping to under $7.00/MMBtu in October before rising recently to around $8.00/MMBtu. Distribution companies use a combination of gas in storage that is injected during the summer and gas purchased under longer-term contracts. These hedges insure reliable supplies and moderate price volatility.

But fuel price volatility remains a major challenge to the electricity market. The accompanying graph shows the sharp swings that can occur in generating fuel prices, particularly

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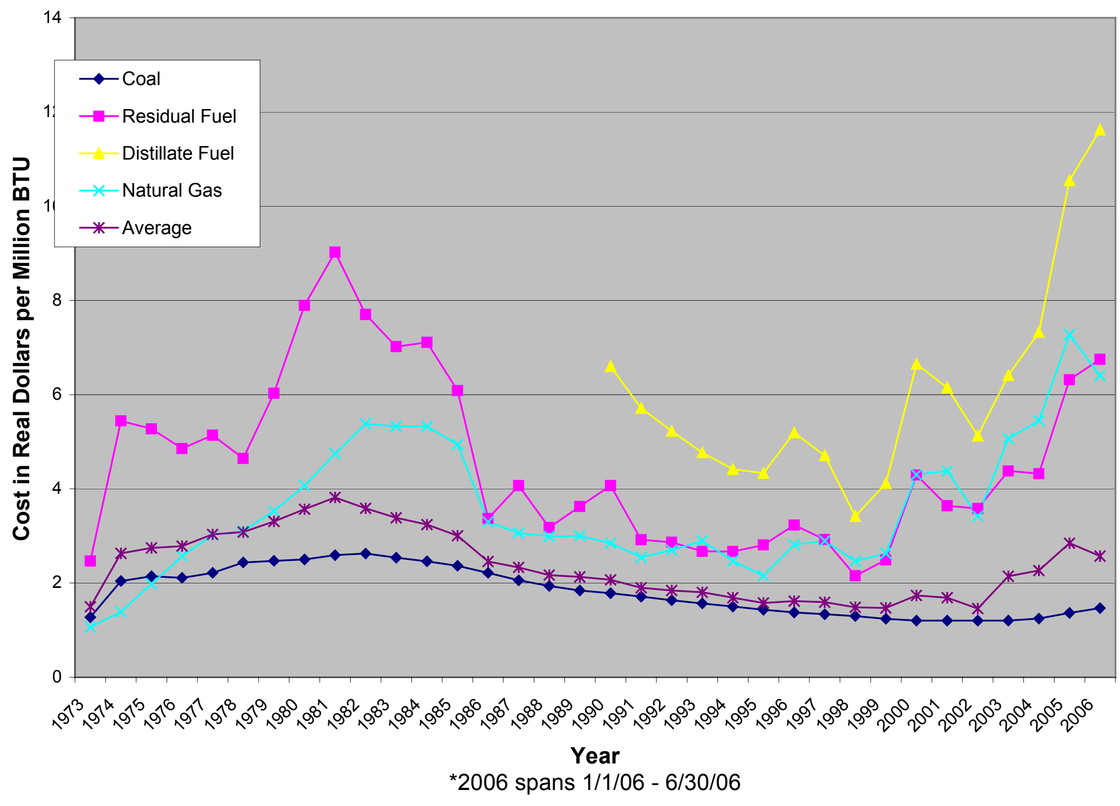
[57] The information provided in this description was largely obtained from FERC. For more information you can visit the FERC website at http://www.ferc.gov/.

[58] The most recent annual natural gas supply assessment was the 2006 Retail Gas Market Conference (Public Conference 7), held at the Commission on October 4, 2006.

natural gas and petroleum. Moreover, while coal prices on a real basis have been steady throughout the period, the price of coal relative to other fuels has swung dramatically. In addition, the price of coal does not reflect the investment and operating costs of environmental equipment, which have also increased the costs of using coal as a boiler fuel, thereby raising the price of the electricity produced. In effect, the chart demonstrates that predicting fuel price changes (both actual and relative) is almost impossible.

The 1999 Act places the financial risks associated with this market volatility on electricity suppliers, generators and investors, versus ratepayers which was the situation previously. This being said, electricity consumers cannot avoid all the economic impacts resulting from swings in fuel prices, because higher production costs inevitably lead to higher prices. But investment in transmission facilities that results in increased use of coal and nuclear facilities in western PJM, while reducing use of natural gas fired facilities in eastern and southern PJM, can lesson these economic impacts. Similarly, investment in low fuel cost facilities in eastern PJM, including nuclear facilities, can also, over the long-term, reduce electricity consumer exposure to volatile fuel markets.

Chart IV.E.1: Yearly Average Cost by Fuel



V. CONCLUSIONS AND RECOMMENDATIONS

The Commission has been actively involved in proceedings at the State, regional and national level to ensure Maryland has adequate electric supplies. This involvement includes working with PJM, other state commissions, state commission organizations such as OPSI and MACRUC[59], Maryland utilities, and the FERC. The Commission has been working with these organizations to develop and implement the policies, incentives, and administrative processes such that every possible effort is being made to ensure electric supply adequacy in Maryland.

The Commission will continue to monitor the supply, distribution, and transmission conditions within the State as well as the region. In summary, the Commission remains vigilant in its efforts to ensure that there is adequate electric supply for Maryland customers. Since the publication of the last Supply Adequacy Report two years ago, the Commission has concluded that Maryland's electricity supply adequacy has become uncertain, if not precarious, pending the construction of new electric supply and transmission infrastructure and the development of new demand side and energy efficiency measures.

The outlook for the adequacy of Maryland's electricity supply can perhaps be best characterized as fragile. While the Commission is not predicting that a reliability crisis will occur in the next five years, it has concluded that avoiding a crisis is dependent on several electric grid infrastructure additions and upgrades whose timing may be problematic.

A. Maryland's Growing Reliance on Imported Electricity

The uncertainty of future adequacy of electricity supply in Maryland begins with the fact that the State cannot meet its own electricity needs from internal resources, and has not done so for over 15 years. This means that Maryland must import a large percentage of its electricity need; presently, nearly 30 percent of all electricity used in Maryland is generated from sources that are out of State. Another indicator of Maryland's dependence on out of State generation is that Maryland has an estimated summer peak demand of 15,000 MW, but has in State generation resources of about 12,500 MW. If Maryland was a stand-alone system it would need to install at least another 4,000 MW to meet both peak load and have a satisfactory generating capacity reserve margin.

Other states in or bordering the Mid-Atlantic and Southern regions of PJM are in a similar situation. New Jersey, Delaware, Virginia, the District of Columbia, and New York are all very dependent on imports to satisfy energy and capacity requirements. Virginia, New Jersey, and Maryland are the third, fourth, and fifth largest electricity importing states in the country. The District of Columbia ranks fifteenth and Delaware ranks twentieth. New York is sixth, just after Maryland despite it being significantly larger. These states will not be a source of electricity supply for Maryland. Instead they have been competing, and will continue to compete, with Maryland for access to electricity sources in the PJM Western region.

West Virginia and Pennsylvania are the states that supply nearly all of Maryland's electricity imports, as well as being the source of energy for the other energy importing states

59 MACRUC is the acronym for the Mid-Atlantic Conference of Regulatory Utilities Commissioners.

identified above. Nationally, Pennsylvania and West Virginia are ranked first and second as states that export electricity, with the amount of energy needed by energy importing states almost exactly matching the amount exported by Pennsylvania and West Virginia. Over 90% of the electricity imported into Maryland and the other energy importing PJM states is coal by wire.

Maryland's dependence on out of State generation resources will likely increase over the next five to ten years due to both growth in electricity demand, and the possible de-rating or retirement of existing generating units. Both Maryland utilities and PJM are forecasting electricity demand to grow by between 1 percent and 2 percent per year. Military base realignments, proximity to the national capital, Maryland's attractive port facilities, its central location in the Atlantic economic corridor, and Maryland's attractiveness as a recreational destination lends credence to these forecasts.

It is important to remember that any long-term forecast for electricity consumption contains a great deal of uncertainty and that demand could be significantly higher or lower than current forecasts. Several Maryland-specific factors add to this unpredictability. As mentioned, a key driver of electricity consumption that is difficult to predict is the underlying growth rate of the Maryland economy, in particular the timing and size of the BRAC impact. Another factor is whether the Eastalco smelter outside Frederick, until recently the largest electricity consumer in the State, will reopen at a latter point in time. Finally, forecasting the short-term and long-term elasticity of consumer response to sharply higher electricity prices is a difficult challenge. New demand response and energy efficiency programs should become more cost-effective and could reduce the rate of growth of consumer demand for electricity below expected levels.

B. Need for Infrastructure Additions; Focus on Transmission

Further contributing to the uncertain outlook for supply adequacy is that over the next 10 years, only a small amount of new electricity generation will likely be built in Maryland. In 2003 the Commission granted a CPCN for a new 640 MW generating unit to be built at the Doubs substation near Frederick, but the site developer has taken no action to initiate construction, and no prospective action appears to be likely. The only significant new baseload generation plants which are in the PJM generation project queues are two nuclear units at Calvert Cliffs. But these units, even if licensed and built in a timely fashion, would not enter service until 2015 and 2016 at the earliest.

It has been previously stated that selective in-State generating capacity may be de-rated or retired over the next decade. Much of the generation in Maryland is relatively old, with several fossil units over 40 years old. The older the unit the less efficient it is likely to be and the more costly to retrofit, increasing the possibility for deactivation.

In addition, federal government and Maryland regulations require sharp reductions in SO_2, NO_X, and mercury emissions from fossil-fired generating plants. Some of the older generating units may have difficulty in satisfying the stricter emission limits, or may be unable to satisfy them at all. If they are unable to comply it is possible they would discontinue operations. Even units that achieve compliance may see net energy output reduced because of parasitic losses associated with operation of the emission control equipment. Other states in PJM have also put in place strict air emission requirements, with similar potential effects on fossil-fired generating units.

Joining RGGI may also result in reduced output in fossil generating stations in Maryland, the District of Columbia, Delaware, New Jersey, and New York, depending on the carbon allowances and other terms of the final rule currently being negotiated.

As a result of the above, Maryland and other states in Eastern PJM appear to have little or no choice but to increase their levels of electricity imports, if the bulk transmission network permits it. While nearly all these imports presently come from West Virginia and Pennsylvania, in the future some of the imports may come from as far away as Ohio and Kentucky. According to the generation queues kept by PJM the bulk of new generation additions will occur in the region of southeast Ohio, southwest Pennsylvania, eastern Kentucky, and West Virginia. Importing additional capacity and energy from this region will require significant upgrades to the transmission system.

Incremental transmission upgrades are being implemented on the PJM system to ensure reliability and reduce congestion to allow for more electricity trade between western and eastern PJM, including from the region where new clean coal capacity will likely be built. PJM has also announced that a major 500 kV transmission line running from southwest Pennsylvania to Loudoun, Virginia will be needed by 2011 to ensure reliability. The line will increase the west to east transfer capability within PJM by about 5,300 MW, in part by relieving restraints on other 500 kV transmission lines serving Maryland and eastern PJM.

C. Energy Efficiency; Retail and Wholesale Opportunities

More efficient use of electricity is occurring in Maryland. Electricity demand growth has been moderate despite strong economic growth. Since 1999, the year restructuring legislation was passed, electric consumption in Maryland has increased at an average annual rate of 2.5% per year. The recent increase in wholesale electricity rates will likely reduce this rate of electric load growth. Both the Maryland utilities and PJM Interconnection are forecasting that over the next 10 years, electricity demand growth in the Maryland LDAs will be about 1.5% per year.

The Commission has undertaken initiatives to determine the energy efficiency programs that might further reduce electricity demand growth without negatively effecting the state's economy. The Commission has directed the formation of a Demand Response/Distributed Generation Working Group. The first meeting of the DSDG Working Group was held on December 13, 2006, and the Commission anticipates that proposals for demand response and distributed generation will be forthcoming within the next several months.

PJM is also active in encouraging reduced consumption, particularly at peak usage periods. PJM has in place load response programs to encourage customers to curtail consumption during high demand periods. The PJM programs provide incentives to customers to take proactive approaches to reduce demand by at peak periods by compensating customers at a rate comparable to the cost of adding new generation. Also, PJM has a load response working group established which is continually reviewing additional initiatives that might be undertaken to encourage more efficient energy usage. The long-term objective is to establish market conditions so that demand response and generation are, in effect, competing with one another.

D. Supply Adequacy Outlook

If new generating capacity is not built, and/or upgrades to the transmission system are not made, the likelihood of a reliability crisis in Maryland, and eastern PJM generally, will increase, and may become unavoidable. As shown in earlier sections, not only will Maryland likely become more capacity deficient in the near-term but PJM is also projecting that capacity reserve margins will decline throughout the system. By the middle of the next decade, reserve margins in PJM may decline below the levels generally associated with ensuring reliable service. Maryland is in a large capacity deficit position, with little new capacity likely to be added and some older generating units possibly being de-rated or retired. Maryland will likely be confronted with a large and growing capacity deficiency unless transmission upgrades are made that will provide increased access to generating resources in western PJM.

Renewables do not appear to be a substitute for traditional enhancements to the electric generation and transmission network. Renewable sources (excepting large hydroelectric projects) supply less than one percent of Maryland's and PJM's energy and capacity. This contribution may grow somewhat with time, but not by enough to meet electric load growth or replace older fossil units that may be de-rated or retired. Siting renewable resources can also be controversial (e.g., siting wind generation in Maryland is opposed by elements of the environmental community).

In closing, Maryland faces major challenges in securing reliable and economic electricity supplies that will support its economy. The Commission recognizes that a balanced approach is required to ensure adequate electricity supplies, including adding new generation, upgrading the transmission system, preserving existing generation resources, and encouraging cost-effective conservation and demand response actions on the part of energy consumers. The Commission has been proactive in each of these areas and is committed to sustaining its efforts. The Commission is also committed to working with Maryland utilities, energy suppliers, and consumers; PJM and its stakeholders; and Maryland policymakers in moving initiatives forward in each of these areas.