pjm

Market Monitoring Unit

October 12, 2007

Steven B. Larsen
Chairman
Public Service Commission of Maryland
William Donald Shaefer Tower
6 St. Paul Street
Baltimore, MD 21202-6806

Re: 2006 State of the Market Report – Questions from the Public Service Commission of Maryland

Dear Chairman Larsen:

In response to your letter dated July 17, 2007, the Market Monitoring Unit is pleased to provide the Public Service Commission of Maryland with the enclosed answers to your questions regarding the *2006 State of the Market Report*. The enclosed answers also include responses to two transcript requests made on April 19, 2007 during the hearings in Case No. 9909. The transcript requests are listed as T1 and T2.

The enclosed answers will also be made publicly available through posting on PJM's website under "Market Monitoring."

The Market Monitoring Unit is available to discuss the information we are providing. Please contact me if you have any questions.

Sincerely,

Joseph Bowring

Joseph E. Bowring
Market Monitor
PJM Interconnection, L.L.C.

MD PSC
July 17, 2007
Letter

STATE OF MARYLAND

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PUBLIC SERVICE COMMISSION

July 18, 2007

Joseph E. Bowring
Market Monitor
PJM Interconnection
955 Jefferson Ave
Valley Forge Corporate Center
Norristown, PA 19403-2497

Re: PJM's 2006 State of the Market Report

Dear Mr. Bowring:

On March 8, 2007, the Market Monitoring Unit ("MMU") of PJM Interconnection, LLC ("PJM") released the 2006 PJM State of the Market ("SOM") Report. The SOM Report discusses the level of competition in PJM markets, which include energy, capacity, regulation, spinning, and FTR markets. The Public Service Commission of Maryland ("MD PSC") has reviewed the SOM Report and identified some areas of concern, including the shortage of capacity that is reflected in significant congestion costs experienced in Maryland. In order to address these concerns, the Commission asks that the MMU provide responses to the following items.

I. Congestion Pricing Questions for Maryland Control Zones

1. Pages 285 through 296 of the 2006 SOM Report describe congestion cost impacts in Allegheny Power ("AP"), Baltimore Gas and Electric Company ("BGE"), Delmarva Power & Light Company ("DPL"), and Potomac Electric Power Company ("Pepco") Control Zones for 2006. Please provide for the day-ahead and real-time markets the load congestion payments, generation congestion credits, the net congestion bill, and the impact on wholesale market price for each Control Zone in Maryland.

2. According to the 2006 SOM Report, in the BGE, DPL, and Pepco Control Zones, "the Cedar Grove-Roseland and Branchburg-Readington constraints contributed to negative congestion while the Bedington-Black Oak Interface and Doubs transformer constraints contributed significantly to positive congestion" in both 2005 and 2006 (see for example p. 285 of the 2006 SOM Report).

   - Please explain the difference between negative and positive congestion, including an explanation of when the system marginal price can cause both positive and negative congestion.

- Please explain the wholesale price impacts of both negative and positive congestions on each of these Control Zones.

3. The 2006 SOM Report noted that Bedington-Black Oak Interface was the largest contributor to congestion costs ($492 million in congestion costs or 31% of the PJM total congestion costs, p. 266). Please describe whether the hedging options available through the PJM markets are sufficient to offset this significant congestion and, if not, what measures can be undertaken to increase the ability to offset the congestion?

II. <u>PJM Market Capping Rules Questions</u>

4. As described on page 363 of the SOM Report, the Market Monitor may cap offers when he believes the local markets are not competitive. Were any offers capped as a result of the congestion in the AP, BGE, DPL, and Pepco Control Zones? If so, please specify the percentage of run hours impacted and the overall impact on Maryland wholesale prices.

5. Page 363 of the SOM Report states some units are grandfathered from the offer capping rules. How many units were exempt from the offer capping rules in the territories noted in question 4 above? To what extent, if any, did these exceptions affect wholesale prices in Maryland?

6. The 2006 SOM Report, at p. 37, notes that "units that are exempt from PJM's offer-capping rules did exercise market power in some local markets in 2006."

   - Did these units exercise local market power in Maryland in 2006?
   - If so, what was the impact of wholesale market prices in Maryland?

7. The 2006 SOM Report notes that eight exempt units from PJM's offer-capping rules accounted for 33% of the total markup component of the PJM prices in 2006 (Vol. II, p. 27). Please explain how much this significant markup affects PJM market prices for Maryland.

8. Please provide an analysis of the extent to which units are frequently mitigated in Maryland in calendar 2006 by run-hours and total dollar impact by unit.

9. As described on page 63 of the SOM Report, an associated unit is "electrically and economically identical" to a frequently mitigated unit. Please provide the number of frequently mitigated and associated unit designations in Maryland in 2006, and cost impact per unit.

III. Local Market Power Questions

10. As discussed on page 54 of the SOM Report, only the DPL Zone had transmission lines that were constrained for more than 100 hours, requiring application of the three-pivotal supplier test. Please provide an analysis of the details of the three pivotal supplier test in the DPL Zone where constrains occurred for 100 or more hours in 2006. Is it a fair assessment to state that in 2006 the DPL Zone was non-competitive in any particular area as a result of the Kings Creek-West Over and Mardela-Vienna locations?

11. Based on Table C-23 at p. 368, the net revenues for combustion turbine plants in the following service territories in calendar 2006 were as follows:

- BGE = $36,001 more in net revenues per installed MW-year
- Pepco = $44,666 more in net revenues per installed MW-year
- PJM's average = $22,031in net revenues per installed MW-year

Since these revenues are above the PJM average for these plants, please provide an explanation for the variations in net revenues for 2005 and 2006 and state whether the net revenues are sufficient to cover the unit's costs.

IV. Locational Marginal Price (LMP) Questions

12. Table 2.34, p. 61, of Volume II of the 2006 SOM Report shows that Pepco had on-peak ($3.92) and off-peak ($0.16) markup components of zonal prices.

- Did these markups occur on high-load days (as defined at page 142 of the SOM Report)?
- Were Pepco's markups the result of market power? Please explain.
- Please provide an explanation of the volatility of these markup indices.
- Provide a complete explanation why these markups noted at p. 61 are much less than the roughly $10 decline in LMP from 2005 to 2006 in the Control Zones of AP, BGE, and Pepco as shown on page 74 of the SOM Report.
- Please explain why there is a roughly $20 difference between the BGE and Pepco Control Zones and Western Control Zones (such as AEP) as shown on page 74 of the SOM Report.

13. Please provide a price duration curve for Maryland similar to Figure 2-11, p. 75, of the SOM Report. Please also provide a full explanation of the curve.

14. The 2006 SOM Report states that "the higher LMPs in the Eastern PJM Zones, reflecting transmission limitations and congestion, have a positive impact on the incentive to invest in those areas" (p. 16, Volume I).

    - Has there been any evidence that the higher LMPs have provided incentives to investment in transmission or generation projects in Maryland?

15. Are there any other aspects of or factors influencing the wholesale electricity markets not addressed in the SOM Report or the foregoing questions that, in your view, affects the competitiveness of the Maryland wholesale market? If so, please identify these aspects or factors and describe their impact on the competitiveness of the Maryland wholesale power market.

Thank you for your assistance in this matter. If you have any questions, please contact Mr. Gregory Carmean, Executive Director, at (410) 767-8010.

Sincerely,

Steven B. Larsen

Steven B. Larsen
Chairman

Answers to
MD PSC
Questions

1. Pages 285 through 296 of the 2006 SOM Report describe congestion cost impacts in Allegheny Power (“AP"), Baltimore Gas and Electric Company ("BGE"), Delmarva Power & Light Company ("DPL"), and Potomac Electric Power Company ("Pepco") Control Zones for 2006. Please provide for the day-ahead and real-time markets the load congestion payments, generation congestion credits, the net congestion bill, and the impact on wholesale market price for each Control Zone in Maryland.

2. According to the 2006 SOM Report, in the BGE, DPL, and Pepco Control Zones, "the Cedar Grove-Roseland and Branchburg-Readington constraints contributed to negative congestion while the Bedington-Black Oak Interface and Doubs transformer constraints contributed significantly to positive congestion" in both 2005 and 2006 (see for example p. 285 of the 2006 SOM Report).

   -Please explain the difference between negative and positive congestion, including an explanation of when the system marginal price can cause both positive and negative congestion.

   -Please explain the wholesale price impacts of both negative and positive congestions on each of these Control Zones.

3. The 2006 SOM Report noted that Bedington-Black Oak Interface was the largest contributor to congestion costs ($492 million in congestion costs or 31% of the PJM total congestion costs, p. 266). Please describe whether the hedging options available through the PJM markets are sufficient to offset this significant congestion and, if not, what measures can be undertaken to increase the ability to offset the congestion?

10. As discussed on page 54 of the SOM Report, only the DPL Zone had transmission lines that were constrained for more than 100 hours, requiring application of the three pivotal supplier test. Please provide an analysis of the details of the three pivotal supplier test in the DPL Zone where constraints occurred for 100 or more hours in 2006. Is it a fair assessment to state that in 2006 the DPL Zone was noncompetitive in any particular area as a result of the Kings Creek-West Over and Mardela-Vienna locations?

14. The 2006 SOM Report states that “the higher LMPs in the Eastern PJM Zones, reflecting transmission limitations and congestion, have a positive impact on the incentive to invest in those areas” (p. 16, Volume I).

    -Has there been any evidence that the higher LMPs have provided incentives to investment in transmission or generation projects in Maryland?

T2. Please provide the impact of congestion on BGE zonal price in 2006.

Response to questions 1, 2, 3, 10, 14 and T2

Overview of Congestion Calculations

This response provides details of congestion associated with transmission zones within the state of Maryland for the period January 1, 2006, to December 31, 2006. Congestion calculations are for each zone within the state of Maryland and not for any specific organization; the total congestion calculations are the sum of all the congestion calculations for the organizations with market activity within each transmission zone. The response includes congestion costs for the constraints which had the largest impact on congestion costs in each transmission zone in Maryland, either positive or negative, and the congestion costs associated with each constraint.

Total congestion costs are comprised of Implicit Congestion, Spot Congestion and Explicit Congestion. Implicit Congestion is the net congestion cost to serve load from generation and contractual energy purchases in a defined area, Spot Congestion is the net congestion cost associated with Spot Market purchases and sales and Explicit Congestion is the net congestion cost associated with point-to-point energy transactions. Each of these categories of congestion costs are, in turn, comprised of day-ahead and balancing congestion costs. Day-ahead congestion is based solely on day-ahead MW and price differences while balancing congestion is based on deviations between the day-ahead and real-time MW and real-time price differences.

Congestion charges can be both positive and negative as seen in Table 1-2 through Table 1-5. There are several reasons why congestion can be negative in a specific area. When a constraint binds, the price effects of that constraint vary. The unconstrained system marginal price (SMP) is the same for all areas, while the congestion component of LMP will either be positive or negative, meaning that the LMP in an area is above or below the SMP. If a transmission zone is located upstream from a constraint, LMP will be less than SMP, the congestion component of LMP will be negative and congestion costs will be negative (lower prices) as a result of that constraint. If a transmission zone is located downstream from a constraint, LMP will be greater than SMP, the congestion component of LMP will be positive and congestion costs will be positive (higher prices) as a result of that constraint.

Table 1-1 shows the average values of the components of LMP for the AP, BGE, DPL and PEPCO zones in Maryland from January 1, 2006 through December 31, 2006. The components of LMP are the unconstrained system marginal price (SMP) and the congestion component (CLMP). On average during calendar year 2006, the congestion component of LMP in the AP, BGE, DPL and PEPCO zones in Maryland was positive. All of the zones experienced higher congestion components of LMP in the real-time than in the day-ahead market.

Table 1-1 Congestion Impact on Zonal LMP: Calendar year 2006

	Day Ahead			Real Time		
Zone	SMP	CLMP	LMP	SMP	CLMP	LMP
AP	$45.2	$7.6	$52.8	$47.2	$10.6	$57.8
BGE	$45.2	$7.9	$53.1	$47.2	$10.2	$57.4
DPL	$45.2	$6.2	$51.5	$47.2	$6.4	$53.6
PEPCO	$45.2	$8.8	$54.0	$47.2	$11.6	$58.8

Table 1-2 shows the constraints with the largest impact on total congestion costs in the AP zone in Maryland from January 1, 2006 through December 31, 2006. There was a large positive contribution to congestion from the Bedington – Black Oak Interface, the Bedington Transformer and the Doubs transformer. There was a negative contribution to congestion from the Aqueduct – Doubs and Cedar Grove – Roseland 230 kV lines.

Table 1-2 AP Zone top congestion cost impacts (By facility): Calendar year 2006

			Total Congestion Costs by Constraint (in millions)		
Constraint	Type	Location	Day-Ahead	Balancing	Total
Bedington - Black Oak	Interface	500	$38.3	$0.5	$38.8
Bedington	Transformer	AP	$10.5	($0.7)	$9.8
Doubs	Transformer	AP	$8.9	$0.4	$9.3
Mount Storm - Pruntytown	Line	AP	$7.6	$0.3	$7.9
Aqueduct - Doubs	Line	AP	($7.4)	$0.3	($7.1)
AP South	Interface	500	$4.7	$0.8	$5.6
Kammer	Transformer	500	$5.8	($0.4)	$5.4
Cedar Grove - Roseland	Line	PSEG	($4.9)	$0.3	($4.5)
Meadow Brook	Transformer	AP	$4.5	($0.0)	$4.5
Kanawha - Matt Funk	Line	AEP	$4.0	($0.3)	$3.7
Cloverdale - Lexington	Line	AEP	$3.6	($0.7)	$3.0
Doubs - Mount Storm	Line	500	$2.5	$0.1	$2.6
Dickerson - Doubs	Line	PEPCO	($2.4)	($0.0)	($2.4)
West	Interface	500	($2.0)	$0.0	($2.0)
Wylie Ridge	Transformer	AP	$2.2	($0.4)	$1.8

Table 1-3 shows the constraints with the largest impact on total congestion costs in the BGE zone in Maryland from January 1, 2006 through December 31, 2006. There was a large positive contribution to congestion from the Bedington – Black Oak Interface. There was a negative contribution to congestion from the Cedar Grove – Roseland and Branchburg - Readington lines.

Table 1-3 BGE Zone top congestion cost impacts (By facility): Calendar year 2006

	Total Congestion Costs by Constraint (in millions)				
Constraint	Type	Location	Day-Ahead	Balancing	Total
Bedington - Black Oak	Interface	500	$24.1	$21.5	$45.6
Mount Storm - Pruntytown	Line	AP	$4.3	$2.4	$6.7
AP South	Interface	500	$3.3	$3.1	$6.4
Aqueduct - Doubs	Line	AP	$5.9	$0.5	$6.4
5004/5005 Interface	Interface	500	$5.2	$0.2	$5.4
Doubs - Mount Storm	Line	500	$3.8	$1.3	$5.1
West	Interface	500	$3.5	$1.1	$4.7
Kammer	Transformer	500	$1.4	$3.0	$4.4
Wylie Ridge	Transformer	AP	$1.3	$2.3	$3.6
Cloverdale - Lexington	Line	AEP	($0.7)	$4.2	$3.4
Doubs	Transformer	AP	$3.1	$0.2	$3.3
Cedar Grove - Roseland	Line	PSEG	($2.2)	($0.8)	($3.1)
Conastone	Transformer	BGE	$2.5	$0.3	$2.8
Branchburg - Readington	Line	PSEG	($0.4)	($2.1)	($2.5)
Kanawha - Matt Funk	Line	AEP	($0.6)	$3.1	$2.5

Table 1-4 shows the constraints with the largest impact on total congestion costs in the DPL zone in Maryland from January 1, 2006 – December 31, 2006. There was a positive contribution to congestion from the Bedington – Black Oak and 5004/5005 Interfaces. There was a negative contribution to congestion from the Cedar Grove - Roseland and Branchburg - Readington lines.

Table 1-4 DPL Zone top congestion cost impacts (By facility): Calendar year 2006

	Total Congestion Costs by Constraint (in millions)				
Constraint	Type	Location	Day-Ahead	Balancing	Total
Bedington - Black Oak	Interface	500	$11.6	$4.3	$16.0
5004/5005 Interface	Interface	500	$5.4	$0.7	$6.1
Cedar Grove - Roseland	Line	PSEG	($3.6)	($0.6)	($4.2)
West	Interface	500	$2.6	$0.8	$3.4
Kammer	Transformer	500	$2.4	$1.0	$3.4
Mount Storm - Pruntytown	Line	AP	$2.5	$0.5	$3.0
Wylie Ridge	Transformer	AP	$1.7	$1.1	$2.8
Cloverdale - Lexington	Line	AEP	$1.5	$0.9	$2.4
AP South	Interface	500	$1.5	$0.9	$2.3
Branchburg - Readington	Line	PSEG	($1.3)	($1.1)	($2.3)
Central	Interface	500	$2.2	$0.0	$2.2
Mardela - Vienna	Line	DPL	$1.8	$0.1	$2.0
Kanawha - Matt Funk	Line	AEP	$1.3	$0.6	$1.9
Doubs - Mount Storm	Line	500	$1.0	$0.3	$1.3
East	Interface	500	$0.7	$0.0	$0.7

Table 1-5 shows the constraints with the largest impact on total congestion costs in the PEPCO zone in Maryland from January 1, 2006 – December 31, 2006. There was a large positive contribution to congestion from the Bedington – Black Oak and AP South Interfaces and the Mount Storm – Pruntytown line. There was a negative contribution to congestion from the Cedar Grove – Roseland 230 kV line.

Table 1-5 PEPCO Zone top congestion cost impacts (By facility): Calendar year 2006

	Total Congestion Costs by Constraint (in millions)				
Constraint	Type	Location	Day-Ahead	Balancing	Total
Bedington - Black Oak	Interface	500	$41.1	$11.0	$52.2
AP South	Interface	500	$6.7	$2.5	$9.2
Mount Storm - Pruntytown	Line	AP	$8.5	$0.5	$9.1
Aqueduct - Doubs	Line	AP	$7.5	($0.4)	$7.1
Cloverdale - Lexington	Line	AEP	$3.8	$3.1	$6.9
Kammer	Transformer	500	$4.5	$1.6	$6.0
Cedar Grove - Roseland	Line	PSEG	($5.2)	($0.5)	($5.7)
Kanawha - Matt Funk	Line	AEP	$3.8	$1.3	$5.2
Doubs	Transformer	AP	$4.4	($0.0)	$4.4
Doubs - Mount Storm	Line	500	$2.5	$1.1	$3.7
Wylie Ridge	Transformer	AP	$2.4	$0.8	$3.2
Unclassified	Unclassified	Unclassified	$2.5	$0.0	$2.5
Dickerson - Doubs	Line	PEPCO	$2.3	$0.1	$2.4
Bedington	Transformer	AP	$2.1	$0.2	$2.4
West	Interface	500	$2.2	$0.1	$2.3

Net Congestion Bill

The net congestion bill is one component of Implicit Congestion costs. Net congestion equals load congestion payments less generation congestion credits. The logic is that congestion payments by load are offset by congestion revenues to generation, for the area analyzed. Table 1-6 shows a summary of all load congestion payments and generation congestion credits for the AP, BGE, DPL and PEPCO zones in Maryland.

Table 1-6 Zonal Load Congestion Payments and Generation Congestion Credits: Calendar year 2006

	Load Congestion Payments		Generation Congestion Credits		Net Congestion Bill		
Zone	Day-Ahead	Balancing	Day-Ahead	Balancing	Day-Ahead	Balancing	Total
AP	$85.9	$15.1	$6.2	$14.9	$79.7	$0.2	$79.9
BGE	$410.9	$459.1	$348.4	$416.2	$62.6	$42.9	$105.5
DPL	$49.3	$50.0	$11.8	$38.9	$37.6	$11.1	$48.6
PEPCO	$714.7	$486.1	$623.3	$461.0	$91.4	$25.1	$116.5

Load congestion payments and generation congestion credits are calculated for both the Day-Ahead and Balancing Energy Markets.

- Day-ahead load congestion payments are calculated for all cleared demand, decrement bids, and day-ahead energy sale transactions. (Decrement bids and energy sales can be thought of as scheduled load.) Day-ahead load congestion payments are calculated using MW and the load bus CLMP, decrement bid CLMP, or the CLMP at the source of the sale transaction, as applicable.

- Day-ahead generation congestion credits are calculated for all cleared generation and increment offers and day-ahead energy purchase transactions. (Increment offers and energy purchases can be thought of as scheduled generation.) Day-ahead generation congestion credits are calculated using MW and the generator bus CLMP, increment offer CLMP, or the CLMP at the sink of the purchase transaction, as applicable.

- Balancing load congestion payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids, and energy sale transactions. Balancing load congestion payments are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.

- Balancing generation congestion credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing generation congestion credits are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.

Table 1-7 through Table 1-10 show the impact of the top constraints affecting load and generation, by zone. The Bedington-Black Oak constraint had the largest impact on load congestion payments in the state of Maryland.

Table 1-7 AP Zone Day-Ahead and Balancing Load Congestion Payments and Generation Congestion Credits by Constraint: Calendar year 2006

	Load Congestion Payments		Generation Congestion Credits		Net Congestion Bill		
Constraint	Day-Ahead	Balancing	Day-Ahead	Balancing	Day-Ahead	Balancing	Total
Bedington - Black Oak	$39.6	$6.7	($0.0)	$7.2	$39.6	($0.5)	$39.1
Bedington	$13.9	$2.1	$3.3	$3.0	$10.5	($0.9)	$9.6
Doubs	$10.3	$1.1	$1.4	$0.7	$8.9	$0.4	$9.3
Mount Storm - Pruntytown	$8.0	$1.4	$0.5	$1.0	$7.5	$0.3	$7.9
Aqueduct - Doubs	($8.6)	($0.7)	($1.4)	($0.8)	($7.3)	$0.2	($7.1)
AP South	$5.3	$1.9	$0.8	$1.1	$4.6	$0.8	$5.4
Kammer	$7.6	$0.4	$2.3	$0.6	$5.3	($0.3)	$5.0
Cedar Grove - Roseland	($6.7)	($0.2)	($1.9)	($0.5)	($4.8)	$0.3	($4.5)
Meadow Brook	$5.5	$0.1	$1.1	$0.2	$4.4	($0.0)	$4.4
Kanawha - Matt Funk	$4.8	$0.4	$1.0	$0.5	$3.8	($0.1)	$3.7
Cloverdale - Lexington	$4.3	$0.9	$0.9	$1.3	$3.4	($0.4)	$3.0
Doubs - Mount Storm	$2.9	$0.3	$0.4	$0.2	$2.5	$0.1	$2.6
Dickerson - Doubs	($2.9)	($0.1)	($0.5)	($0.1)	($2.3)	($0.0)	($2.4)
West	($2.9)	($0.3)	($0.9)	($0.3)	($2.0)	($0.0)	($2.0)
Wylie Ridge	$2.8	$0.2	$0.8	$0.4	$2.0	($0.2)	$1.8

Table 1-8 BGE Zone Day-Ahead and Balancing Load Congestion Payments and Generation Congestion Credits by Constraint: Calendar year 2006

	Load Congestion Payments		Generation Congestion Credits		Net Congestion Bill		
Constraint	Day-Ahead	Balancing	Day-Ahead	Balancing	Day-Ahead	Balancing	Total
Bedington - Black Oak	$199.2	$200.4	$175.5	$178.4	$23.6	$22.0	$45.7
Mount Storm - Pruntytown	$43.6	$33.7	$39.3	$31.4	$4.3	$2.4	$6.6
AP South	$24.1	$40.2	$20.9	$36.9	$3.2	$3.2	$6.4
Aqueduct - Doubs	$17.5	$11.2	$11.6	$10.7	$5.9	$0.5	$6.3
5004/5005 Interface	$13.7	$7.7	$8.6	$7.4	$5.1	$0.3	$5.4
Doubs - Mount Storm	$15.0	$8.6	$11.3	$7.3	$3.8	$1.3	$5.1
West	$17.7	$13.5	$14.3	$12.2	$3.4	$1.3	$4.7
Kammer	$23.4	$19.2	$22.2	$16.1	$1.3	$3.1	$4.4
Cloverdale - Lexington	$20.2	$42.9	$21.0	$38.5	($0.8)	$4.5	$3.7
Wylie Ridge	$12.4	$19.0	$11.2	$16.5	$1.2	$2.5	$3.7
Doubs	$8.2	$5.5	$5.1	$5.3	$3.1	$0.2	$3.3
Cedar Grove - Roseland	($29.7)	($15.2)	($27.5)	($14.4)	($2.2)	($0.9)	($3.0)
Conastone	$5.3	$8.8	$2.8	$8.4	$2.5	$0.4	$2.9
Kanawha - Matt Funk	$20.1	$21.4	$20.8	$18.1	($0.7)	$3.3	$2.6
Branchburg - Readington	($10.0)	($22.7)	($9.6)	($20.5)	($0.4)	($2.2)	($2.5)

Table 1-9 DPL Zone Day-Ahead and Balancing Load Congestion Payments and Generation Congestion Credits by Constraint: Calendar year 2006

	Load Congestion Payments		Generation Congestion Credits		Net Congestion Bill		
Constraint	Day-Ahead	Balancing	Day-Ahead	Balancing	Day-Ahead	Balancing	Total
Bedington - Black Oak	$14.9	$18.3	$3.3	$13.9	$11.6	$4.4	$16.0
5004/5005 Interface	$7.4	$3.9	$2.1	$3.2	$5.3	$0.8	$6.1
Cedar Grove - Roseland	($4.7)	($2.6)	($1.2)	($2.0)	($3.6)	($0.6)	($4.2)
West	$3.4	$3.3	$0.8	$2.5	$2.6	$0.8	$3.4
Kammer	$3.1	$3.4	$0.7	$2.4	$2.4	$1.0	$3.4
Mount Storm - Pruntytown	$3.3	$2.8	$0.8	$2.2	$2.5	$0.5	$3.0
Wylie Ridge	$2.3	$3.9	$0.6	$2.8	$1.7	$1.1	$2.8
Cloverdale - Lexington	$1.8	$4.4	$0.4	$3.4	$1.5	$1.0	$2.4
AP South	$1.8	$3.9	$0.4	$3.0	$1.5	$0.9	$2.4
Branchburg - Readington	($1.6)	($4.7)	($0.4)	($3.6)	($1.3)	($1.1)	($2.3)
Central	$2.9	$0.1	$0.8	$0.1	$2.1	$0.0	$2.2
Mardela - Vienna	$2.3	$1.6	$0.5	$1.5	$1.8	$0.1	$2.0
Kanawha - Matt Funk	$1.7	$2.4	$0.4	$1.8	$1.3	$0.6	$1.9
Doubs - Mount Storm	$1.3	$0.8	$0.3	$0.6	$1.0	$0.3	$1.3
East	$0.8	$0.1	$0.2	$0.1	$0.7	$0.0	$0.7

Table 1-10 PEPCO Zone Day-Ahead and Balancing Load Congestion Payments and Generation Congestion Credits by Constraint: Calendar year 2006

	Load Congestion Payments		Generation Congestion Credits		Net Congestion Bill		
Constraint	Day-Ahead	Balancing	Day-Ahead	Balancing	Day-Ahead	Balancing	Total
Bedington - Black Oak	$349.5	$207.8	$309.3	$196.0	$40.2	$11.8	$52.0
AP South	$41.7	$43.6	$35.1	$40.8	$6.5	$2.8	$9.3
Mount Storm - Pruntytown	$76.2	$36.7	$67.8	$36.0	$8.4	$0.7	$9.1
Aqueduct - Doubs	$45.5	$19.3	$38.1	$19.6	$7.4	($0.3)	$7.1
Cloverdale - Lexington	$35.8	$44.5	$32.1	$41.2	$3.7	$3.3	$7.0
Kammer	$37.2	$16.8	$32.9	$15.1	$4.4	$1.7	$6.0
Cedar Grove - Roseland	($45.6)	($13.9)	($40.5)	($13.4)	($5.1)	($0.5)	($5.7)
Kanawha - Matt Funk	$36.2	$20.2	$32.2	$18.9	$4.0	$1.4	$5.3
Doubs	$28.5	$10.2	$24.1	$10.2	$4.4	$0.0	$4.4
Doubs - Mount Storm	$24.0	$9.4	$21.5	$8.3	$2.5	$1.2	$3.7
Wylie Ridge	$17.6	$15.3	$15.2	$14.4	$2.3	$1.0	$3.3
Unclassified	$1.7	$0.0	($0.8)	$0.0	$2.5	$0.0	$2.5
Bedington	$12.1	$17.5	$10.0	$17.1	$2.1	$0.4	$2.5
Dickerson - Doubs	$14.6	$2.1	$12.4	$2.0	$2.3	$0.1	$2.4
West	$15.0	$5.8	$12.9	$5.6	$2.2	$0.2	$2.3

Congestion Hedging

In PJM, ARRs and FTRs are instruments which can be used as a hedge against congestion costs. Congestion may also be hedged through contractual arrangements including financial instruments or bilateral contracts with local generation. There is no assurance that any hedging instrument will provide a complete hedge against congestion costs.

One way to measure the effectiveness of FTRs as a hedge against congestion is to compare the load congestion payments to the target allocations of related FTRs. As a measure of the sufficiency of FTRs in Maryland to hedge against the congestion associated with Bedington – Black Oak, Bedington – Black Oak load congestion payments are compared to the FTR target allocations associated with Bedington – Black Oak congestion. Load congestion payments are defined as the sum of day-ahead and balancing load congestion payments associated with Bedington – Black Oak by zone, within Maryland. FTR target allocations are defined as those target allocations resulting from Bedington – Black Oak congestion and associated with FTRs with a sink location within the state of Maryland. The results of this analysis are shown in Table 1-11. Entities located within Maryland, or with load serving responsibility within Maryland, may also hold FTR positions outside the state which are affected by congestion on Bedington – Black Oak.

ARR credits are also a hedge against congestion costs. ARR credit values are not deconstructed into constraint specific components. Table 1-12 shows the sufficiency of

FTR target allocations plus ARR credits in Maryland to hedge against total load congestion payments, by zone. Load congestion payments are defined as the sum of day-ahead and balancing load congestion payments by zone, within Maryland. FTR target allocations are defined as those target allocations associated with FTRs with a sink location within the state of Maryland. ARR credits are defined as those credits associated with ARRs with a sink location within the state of Maryland.

Table 1-11 Bedington – Black Oak Load Congestion Payments vs. FTR Target Allocations [Dollars (millions)]: Calendar year 2006

Zone	Constraint	FTR Target Allocations	Self-Scheduled FTR Target Allocations	Total FTR Target Allocations	Load Congestion Payments	Percent Hedged
AP	Bedington - Black Oak	($0.18)	$46.71	$46.53	$46.28	101%
BGE	Bedington - Black Oak	$18.75	$3.60	$22.35	$399.56	6%
DPL	Bedington - Black Oak	$0.23	$0.25	$0.48	$33.18	1%
PEPCO	Bedington - Black Oak	$44.43	$1.20	$45.63	$557.33	8%

Table 1-12 Congestion Hedging by Control Zone in Maryland [Dollars (millions)]: Calendar year 2006

Zone	ARR Credits	FTR Target Allocations	Self-Scheduled FTR Target Allocations	Total FTR Target Allocations	Load Congestion Payments	Percent Hedged
AP	$12.84	$1.33	$101.21	$102.54	$101.03	114%
BGE	$47.20	$44.97	$6.91	$51.88	$870.09	11%
DPL	$5.53	$10.16	$2.15	$12.31	$99.28	18%
PEPCO	$25.79	$107.59	$2.88	$110.48	$1,200.77	11%

Three Pivotal Supplier Testing

The three pivotal supplier test is applied by PJM on an ongoing basis in order to determine whether offer capping is required to prevent the exercise of local market power for any constraint not exempt from offer capping by units not exempt from offer capping. The MMU analyzed the results of the three pivotal supplier tests conducted by PJM for the Real-Time Energy Market for the period from the introduction of the three pivotal supplier test on March 1, 2006, through December 31, 2006.

Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and does not result in offer capping when that is not the case. As a result of the application of the three pivotal supplier test, offer caps are applied where appropriate so that market results are competitive although the structure of the underlying market is not. The number of hours in which one or more suppliers pass the three pivotal supplier test and are exempt from offer capping increases as the number of suppliers in the local market increases. For example, the regional constraints have a larger number of suppliers and more of the three pivotal supplier tests generally have one or more passing owners. In contrast, small local constraints have fewer suppliers and therefore are less often structurally competitive.

Information is provided for each constraint including the number of tests applied and the number of tests in which one or more owners passed and/or failed the three pivotal supplier test.[1] Additional information is provided for each constraint including the average MW required to relieve a constraint, the average supply available, the average number of owners included in each test and the average number of owners that passed or failed each test.

Constraints can have wide-ranging effects, influencing prices across multiple zones. Three pivotal supplier test results are presented for those constraints having the largest contribution to positive zonal congestion costs in Maryland. A summary of the constraints which made the largest contribution to positive congestion costs in each zone in Maryland is presented in Table 1-13.

Table 1-13 Top Positive Zonal Congestion Contributors: Calendar year 2006

	Top Positive Zonal Congestion Contributors			
Constraint	AP	BGE	DPL	PEPCO
5004/5005 Interface		X	X	
AP South	X	X		X
Aqueduct - Doubs		X		X
Bedington	X			
Bedington - Black Oak	X	X	X	X
Cloverdale - Lexington				X
Doubs	X			
Kammer			X	
Mount Storm - Pruntytown	X	X	X	X
West			X	

All of the constraints shown in Table 1-13 experienced more than 100 hours of congestion during 2006.[2] The three pivotal supplier test was applied to all of these

[1] The three pivotal supplier test in the Real-Time Energy Market is applied by PJM as necessary and may be applied multiple times within a single hour for a specific constraint. Each application of the test is done in a five-minute interval.

[2] Total number of congestion hours is the sum of day-ahead plus real-time congestion hours.

constraints. The AP South and West Interfaces are two of the four interfaces for which generation owners are exempt from offer capping. No offer capping was applied for the exempt constraints, regardless of the results of the three pivotal supplier test.

Table 1-14 includes information on the three pivotal supplier test results for the constraints affecting Maryland.[3] For the AP South and West Interfaces, which are exempt from offer capping, the percentage of tested intervals resulting in one or more owners passing ranged from 64 percent to 99 percent while 3 percent to 55 percent of the tests showed one or more owners failing. For the remaining constraints which are not exempt, the percentage of tested intervals resulting in one or more owners passing ranged from 0 percent to 88 percent while 25 percent to 100 percent of the tests showed one or more owners failing.

Table 1-14 Three pivotal supplier results summary (3/1/2006 – 12/31/2006)

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
5004/5005 Interface	Peak	863	705	82%	253	29%
	Off Peak	209	183	88%	53	25%
AP South Interface	Peak	491	327	67%	229	47%
	Off Peak	180	116	64%	99	55%
Aqueduct - Doubs	Peak	255	46	18%	241	95%
	Off Peak	127	10	8%	124	98%
Bedington Transformer	Peak	2,978	1	0%	2,978	100%
	Off Peak	933	0	0%	933	100%
Bedington - Black Oak	Peak	2,622	2,072	79%	889	34%
	Off Peak	3,254	2,708	83%	980	30%
Cloverdale - Lexington	Peak	671	390	58%	395	59%
	Off Peak	4,257	2,647	62%	2,479	58%
Doubs Transformer	Peak	1,054	0	0%	1,054	100%
	Off Peak	0	NA	NA	NA	NA
Kammer Transformer	Peak	627	520	83%	194	31%
	Off Peak	925	763	82%	302	33%
Mount Storm - Pruntytown	Peak	538	447	83%	155	29%
	Off Peak	1,206	938	78%	479	40%
West Interface	Peak	852	846	99%	28	3%
	Off Peak	566	541	96%	47	8%

Table 1-15 shows that, on average, during 2006 peak periods, the local markets created by the 5004/5005 Interface and the Kammer transformer had 17 owners with available

[3] The number of tests with one or more failing owners plus the number of tests with one or more passing owners can exceed the total number of tests applied. A single test can result in one or more owners passing and one or more owners failing. In such a case, the interval would be counted as including one or more passing owners and one or more failing owners.

supply during the peak period. [4] Of those owners, an average of 14 passed the test for the 5004/5005 Interface and an average of 13 passed the test for the Kammer transformer.[5] Bedington-Black Oak, on average, had 12 owners with available supply and nine owners passed the test. For AP South, on average, nine out of 15 owners passed the test during off-peak periods, and 10 out of 16 owners passed during on-peak periods. For the West Interface, on average, 15 out of 16 owners passed the test during off-peak periods, and all 17 owners passed the test during on-peak periods.

Table 1-15 Three pivotal supplier test details (3/1/2006 – 12/31/2006)

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005 Interface	Peak	110	397	17	14	3
	Off Peak	107	376	17	14	3
AP South Interface	Peak	101	271	16	10	6
	Off Peak	97	306	15	9	6
Aqueduct - Doubs	Peak	22	43	5	1	5
	Off Peak	25	36	4	0	4
Bedington Transformer	Peak	42	3	2	0	2
	Off Peak	31	5	2	0	2
Bedington - Black Oak	Peak	57	220	12	9	3
	Off Peak	63	239	12	9	2
Cloverdale - Lexington	Peak	114	319	16	8	8
	Off Peak	99	263	14	7	6
Doubs Transformer	Peak	22	2	2	0	2
	Off Peak	NA	NA	NA	NA	NA
Kammer Transformer	Peak	83	285	17	13	4
	Off Peak	77	301	15	12	3
Mount Storm - Pruntytown	Peak	122	423	13	10	2
	Off Peak	126	380	11	8	3
West Interface	Peak	138	829	17	17	0
	Off Peak	140	739	16	15	1

The MMU in its analysis of PJM's application of the three pivotal supplier test provides the results of all three pivotal supplier tests in the Real-Time Energy Market, whether resulting in mitigation or not and whether resulting in a decision or not. The existence of a test does not mean that a decision was made based on the test result. The existence of a

4 The 5004/5005 Interface is comprised of two, 500 kV lines, which include the Keystone-Juniata 5004 and the Conemaugh-Juniata 5005. These two lines are located between central and western Pennsylvania.

5 The average number of owners passing and the average number of owners failing are rounded to the nearest whole number and may not sum to the average number of owners, also rounded to the nearest whole number.

failed test result does not mean that mitigation was imposed. A test is triggered whenever PJM's Unit Dispatch System (UDS) software detects the need to provide incremental relief for a transmission constraint. The universe of three pivotal supplier tests is all intervals in which PJM's UDS software identifies the need to provide incremental relief for a transmission constraint.

When incremental relief is required for a transmission constraint, the three pivotal supplier test is executed. The test is an analysis of the ownership structure of units which are available to the operators to relieve the constraint. The relevant supply curve for providing incremental constraint relief includes increases in output from units already operating, reductions in output from units already operating and output from offline units that can provide the required relief in the time defined by the operators. Only offline units are subject to offer capping. In the majority of cases, the relevant supply curve consists of units which are already operating. Units which are already operating and selected to provide relief for a constraint are not subject to offer capping, regardless of the three pivotal supplier test result. Once a unit is started on its price schedule, it may not be offer capped due to a subsequent failure of a three pivotal supplier test. Mitigation is only applied to units started out of economic merit order for the purpose of relieving a constraint and which fail the test. An offline unit is brought on only if that unit provides a more cost effective solution than modifying the output of units which are already operating.

LMP and Investment in Transmission and Generation in Maryland[6]

It is difficult to make a definitive statement that LMP differentials have resulted in investment in transmission and generation projects in Maryland. It is the case that higher prices that result from constraints increase revenues to generation and therefore increase the incentive to invest. Under PJM rules, the increased incentive is more likely to have an impact on generation investment and related transmission investment than on transmission investment. Most transmission investment is a result of upgrades required for generation project deliverability or of upgrades to provide reliability under PJM's transmission planning mandate. There are currently no merchant transmission projects in Maryland. Information is provided on investment in transmission and generation in Maryland.

Planning the enhancement and expansion of transmission capability on a regional basis is one of the primary functions of regional transmission organizations. PJM implements this function pursuant to the Regional Transmission Expansion Planning (RTEP) Protocol set forth in Schedule 6 of the PJM Operating Agreement. A key part of this regional planning protocol is the evaluation of both generation interconnection and

[6] See PJM Regional Transmission Expansion Plan at http://www.pjm.com/planning/reg-trans-exp-plan.html

merchant transmission interconnection requests, the procedures for which are codified under Part IV of the PJM Open Access Transmission Tariff.

PJM annually develops a Regional Transmission Expansion Plan (RTEP) to meet system enhancement requirements for firm transmission service, load growth, interconnection requests and other system enhancement drivers. To establish a starting point for development of an RTEP, PJM performs a baseline analysis of system adequacy and security. These baseline analyses and the resultant expansion plans serve as the base system for conducting feasibility studies for all proposed generation and/or merchant transmission facility interconnection projects and subsequent System Impact Studies for those projects which decide to go forward. The enhancement recommendations revealed by these System Impact Studies become part of the RTEP approved by the PJM Board of Managers and published in the posted RTEP Report.

PJM posts reports on its website describing proposed infrastructure in the RTO.[7] Table 1-16 through Table 1-20 present a summary of proposed infrastructure investment in the state of Maryland segregated by generation and transmission projects. The transmission projects are further subdivided into those associated with baseline upgrades, network upgrades associated with a queued generation project and transmission owner identified upgrades. At this time, no transmission projects proposed in Maryland are classified as merchant projects.

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[7] See PJM Regional Transmission Expansion Plan at http://www.pjm.com/planning/reg-trans-exp-plan.html

Table 1-16 Queued Generation Projects in Maryland (as of 9/4/2007)

Queue Number	Project Name	MW	Status	In Service Date	Zone
S01	Derwood 13kV	1	Active	1-Jul-08	PEPCO
S02	Mt. Zion 13kV	4	Active	1-Jul-08	PEPCO
S14	Dans Mountain	70	Active	1-Dec-09	AP
S17	Talbert 230kV	225	Active	31-Dec-10	PEPCO
S18	Talbert 230kV	1250	Active	31-Dec-11	PEPCO
S29	Morgantown-Oak Grove	900	Active	1-Jan-11	PEPCO
S30	Gould	4	Active	31-Dec-07	BGE
S33	Riverside	300	Active	1-May-10	BGE
S32	Perryman	550	Active	1-May-10	BGE
S38	Westvaco 138kV	8	Active	2-May-07	AP
S67	Gould St.	101	Active	1-Jun-08	BGE
A29	Colora Tap	465	Interim Study	13-Jun-03	DPL
A30	Colora Tap	465	Interim Study	1-Dec-05	DPL
B02	Morgantown	80	Interim Study	17-Mar-01	PEPCO
B46	Conowingo 230kV	36	Interim Study	21-Nov-03	PECO
D10	NIH 13kV	25	Interim Study	1-Jun-04	PEPCO
D29	Derwood 13kV	3	Interim Study	29-Jun-01	PEPCO
E05	Bethlehem Steel 33kV	2.5	Interim Study	1-Jan-01	BGE
F07	Dickerson 230kV	16	Interim Study	17-Mar-01	PEPCO
F08	Chalk Point 230kV	6	Interim Study	17-Mar-01	PEPCO
G30	Perryman 115kV	10	Interim Study	1-Jun-01	BGE
G51_W62	Eastalco 230 kV	640	Under Construction	30-Jun-04	AP
H13	Dolfield	9	Interim Study	1-Jun-04	BGE
H20	Oak Grove 13.8kV	3.5	In Service - Not Capacity	31-May-03	PEPCO
H23_W70	Kelso Gap 138 kV	100	Under Construction	6-Nov-06	AP
I03_W74	Savage 138kV	40	Active	15-Nov-07	AP
I10	Bethesda (Sub 6)	2	Interim Study	1-Oct-04	PEPCO
J08	Whiteoak	6	Interim Study	15-Aug-04	PEPCO
K06	Easton 69kV	5	Interim Study	1-Nov-04	DPL
K07	Easton 69kV	5	Interim Study	1-Nov-04	DPL
K25	Savage 138kV	8	Active	15-Nov-07	AP
K28	Kelso Gap 138kV	20	Under Construction	6-Nov-06	AP
M04	Calvert Cliffs	63	Interim Study	30-Jun-05	BGE
M19	Otter Point	4.5	In Service Partially	1-Sep-06	BGE
N29	Roth Rock 138kV	40	Active	31-Dec-08	AP
O25	N. Salisbury 25kV	6	Interim Study	1-Mar-07	DPL
P32	White Oak	13.5	Under Construction	31-Dec-07	PEPCO
Q31	Wagner 34kV	10	Active	1-Jun-06	BGE
Q48	Calvert Cliffs	1640	Active	15-Dec-15	BGE
R17	Morgantown - Oak Grove 230kV	1250	Active	31-Dec-10	PEPCO
R20	Rock Springs	20	In Service - Not Capacity	1-Jan-07	PECO
R89	Conowingo	24	In Service Partially	26-Oct-06	PECO
T16	William 138kV	30	Active	31-Dec-09	AP

Table 1-17 Proposed Baseline Transmission Upgrades in Maryland (as of 9/4/2007): b0002 through b0221

Upgrade ID	Upgrade Type	Location	Task	Transmission Owner	Projected In Service Date	Status Code
b0002	Transmission	Windy Edge Lakespring - Texas	Increase	BGE		In Service
b0010	Transmission	Northwest	Replace	BGE	1-May-03	In Service
b0030	Transmission	Brandon Shores-Riverside DCTL	Construct	BGE	1-Jan-07	In Service
b0031.1	Substation	Conastone	Replace	BGE	14-May-04	In Service
b0031.2	Substation	Conastone	Replace	BGE	7-Mar-03	In Service
b0032	Substation	Waugh Chapel	Replace	BGE		In Service
b0035	Transmission	Calvert Cliffs	Change	BGE	1-May-04	In Service
b0039.1	Substation	BGE	Upgrade	BGE	1-Jun-04	In Service
b0039.2	Substation	PEPCO	Upgrade	PEPCO	1-Jun-05	In Service
b0039.5	Substation	Waugh Chapel	Install	BGE	1-Jun-06	In Service
b0040	Substation	Doubs	Replace	AP	31-Dec-05	In Service
b0051	Substation	Aqueduct	Add	AP	1-May-03	In Service
b0052.1	Substation	Montgomery	Add	AP	15-Jun-06	In Service
b0052.2	Substation	Boonsboro	Add	AP	30-Sep-04	In Service
b0052.3	Substation	Mt. Airy	Add	AP	30-Sep-04	In Service
b0052.4	Substation	Antietam 34.5 kV	Increase	AP	15-Oct-04	In Service
b0052.5	Substation	McCain 34.5 kV	Install	AP	15-Jan-05	In Service
b0053	Substation	Davis Mill 34.5 KV	Add	AP	1-Sep-05	In Service
b0054	Substation	Ringgold 138 KV	Add	AP	30-Jun-05	In Service
b0055	Substation	Carroll 138 KV	Add	AP	30-Jun-06	In Service
b0110	Substation	Doubs 500/230 kV	Purchase Spare	AP	30-Oct-06	In Service
b0146.1	Substation	Quince Orchard 230kV	Replace	PEPCO	1-Jun-06	In Service
b0146.2	Substation	Quince Orchard 230kV	Installation	PEPCO	31-Dec-06	In Service
b0149	Transmission	Cheswald - Jones REA 138 kV	Complete	DPL		In Service
b0150	Substation	Waugh Chapel 500/230 kV	Modify	BGE	1-Jun-05	In Service
b0152.1	Substation	High Ridge	Add	BGE	1-Jun-05	In Service
b0152.2	Substation	High Ridge	Install	BGE	1-Jun-06	In Service
b0167	Substation	Oak Grove 230kV	Upgrade	PEPCO	31-Dec-05	In Service
b0168	Substation	Oak Grove 230kV	Upgrade	PEPCO	31-Dec-06	In Service
b0187	Substation	Dickerson	Upgrade	PEPCO	1-Jun-06	In Service
b0188	Substation	Dickerson	Upgrade	PEPCO	1-Jun-06	In Service
b0189	Substation	Dickerson	Upgrade	PEPCO	1-Jun-06	In Service
b0190	Substation	Dickerson	Upgrade	PEPCO	1-Jun-06	In Service
b0191	Substation	Dickerson	Upgrade	PEPCO	31-Dec-06	In Service
b0192	Substation	Dickerson	Upgrade	PEPCO	31-Dec-06	In Service
b0193	Substation	Dickerson	Upgrade	PEPCO	31-Dec-06	In Service
b0194	Substation	Dickerson	Upgrade	PEPCO	31-Dec-06	In Service
b0195	Substation	Dickerson	Upgrade	PEPCO (Mirant)	31-Mar-07	In Service
b0196	Substation	Dickerson	Upgrade	PEPCO (Mirant)	31-Mar-07	In Service
b0197	Substation	Dickerson	Upgrade	PEPCO (Mirant)	31-Mar-07	In Service
b0217	Transmission	Mt. Storm - Doubs	Upgrade	Dominion	31-May-06	In Service
b0219	Transmission	Palmers Corner - Blue Plains	Install	PEPCO	1-Jul-07	Under Construction
b0221	Substation	Edgewood - N. Salisbury	Replace	DPL	31-May-06	In Service

Table 1-18 Proposed Baseline Transmission Upgrades in Maryland (as of 9/4/2007): b0228 through b0499

Upgrade ID	Upgrade Type	Location	Task	Transmission Owner	Projected In Service Date	Status Code
b0228	Transmission	Burtonsville - Sandy Springs	Upgrade	PEPCO	1-Jun-10	Eng. & Procurement Phase
b0238	Transmission	Doubs - Dickerson and Doubs - Aqueduct - Dickerson	Reconductor	AP	30-Jun-09	Eng. & Procurement Phase
b0238.1	Substation	Dickerson Station H	Modify	PEPCO	30-Jun-09	Eng. & Procurement Phase
b0244	Substation	Waugh Chapel	Install	BGE	1-Jun-08	Eng. & Procurement Phase
b0247	Substation	Quince Orchard	Install	PEPCO	1-Jun-06	In Service
b0248	Substation	Norbeck	Install	PEPCO	1-Jun-06	In Service
b0249	Substation	Bells Mill	Install	PEPCO	2-Dec-05	In Service
b0250	Substation	various locations	Install	PEPCO	1-Jun-06	In Service
b0251	Substation	Bells Mill	Install	PEPCO	1-Jun-10	Eng. & Procurement Phase
b0252	Substation	Bells Mill	Install	PEPCO	1-Jun-10	Eng. & Procurement Phase
b0272.2	Substation	Rock Spring	Replace	ODEC		Eng. & Procurement Phase
b0282	Substation	DPL distribution system	Install	DPL	1-Jun-09	Eng. & Procurement Phase
b0288	Substation	Brighton Substation	Add	PEPCO	1-Jun-09	Eng. & Procurement Phase
b0298	Substation	Conastone	Replace	BGE	31-May-09	Eng. & Procurement Phase
b0298.1	Substation	Conastone	Replace	BGE	23-Sep-07	Eng. & Procurement Phase
b0319	Substation	Burches Hill	Add	PEPCO	1-Jun-11	Eng. & Procurement Phase
b0322	Substation	Lime Kiln	Convert	AP	28-Feb-08	Under Construction
b0343	Substation	Doubs	Replace	AP	30-Jun-11	Eng. & Procurement Phase
b0344	Substation	Doubs	Replace	AP	30-Jun-10	Eng. & Procurement Phase
b0345	Substation	Doubs	Replace	AP	31-May-11	Eng. & Procurement Phase
b0347.1	Transmission	Mt. Storm - 502 Junction	Build	AP	31-May-11	Eng. & Procurement Phase
b0366	Substation	Richie	Install	PEPCO	1-Jun-11	Eng. & Procurement Phase
b0367	Transmission	Quince Orchard Dickerson	Reconductor	PEPCO	1-Jun-11	Eng. & Procurement Phase
b0373	Substation	Doubs - Monocacy	Convert	AP	30-Jun-09	Eng. & Procurement Phase
b0375	Substation	Dickerson - Pleasant View	Install	PEPCO	1-Jun-11	Eng. & Procurement Phase
b0385	Transmission	Oak Hall - New Church	Upgrades	DPL	31-May-08	Eng. & Procurement Phase
b0388	Transmission	Hallwood - Parksley	Upgrade	DPL	1-Jun-08	Eng. & Procurement Phase
b0392	Substation	East New Market	Establish	DPL	8-Jun-07	Under Construction
b0467.1	Transmission	Dickerson - Pleasant View	Reconductor	PEPCO		Eng. & Procurement Phase
b0467.2	Transmission	Dickerson - Pleasant View	Reconductor	Dominion		Eng. & Procurement Phase
b0474	Substation	Waugh Chapel	Add	BGE		Eng. & Procurement Phase
b0475	Substation	Northwest	Build	BGE		Eng. & Procurement Phase
b0476	Substation	High Ridge	Rebuild	BGE		Eng. & Procurement Phase
b0477	Substation	Waugh Chapel	Replace	BGE	1-Jun-11	Eng. & Procurement Phase
b0478	Transmission	Burches Hill & Palmers Corner	Reconductor	PEPCO		Eng. & Procurement Phase
b0483	Substation	Church	Replace	DPL		Eng. & Procurement Phase
b0483.1	Transmission	Oak Hall - Wattsville	Build	DPL		Eng. & Procurement Phase
b0483.2	Substation	Wattsville	Install	DPL		Eng. & Procurement Phase
b0483.3	Substation	Oak Hall	Establish	DPL		Eng. & Procurement Phase
b0484	Transmission	Worcester - Berlin	Re-tension	DPL		Eng. & Procurement Phase
b0485	Transmission	Taylor - North Seaford	Re-tension	DPL		Eng. & Procurement Phase
b0492	Transmission	Bedington - Kemptown	Construct	AP	1-Jun-12	Eng. & Procurement Phase
b0496	Substation	Brighton	Replace	PEPCO		Eng. & Procurement Phase
b0497	Transmission	Conastone and Graceton	Install	BGE		Eng. & Procurement Phase
b0499	Transmission	Burches Hill	Install	PEPCO		Eng. & Procurement Phase

Table 1-19 Proposed Transmission Upgrades Associated with Queued Generation Projects in Maryland (as of 9/4/2007)

Upgrade ID	Queue Association	Upgrade Type	Location	Task	Transmission Owner	Projected In Service Date	Status Code
n0001	Queue A02	Substation	Loretto	Upgrade	DPL		In Service
n0008	Queue A02	Transmission	Oak Hall - Piney Grove	Upgrade	DPL		In Service
n0010		Substation	Pockomoke	Conversion	DPL		In Service
n0012		Transmission	Loretto - Kings Creek	Relocate	DPL		In Service
n0013		Substation	Loretto - Kings Creek		DPL		In Service
n0014		Transmission	MD/VA	Rearrangement	DPL		In Service
n0022		Substation	Conastone	Install	BGE	6-Dec-02	In Service
n0258	Queue G51_W62	Substation	Dickerson Station H	Upgrade	PEPCO	1-Jun-09	Eng. & Procurement Phase
n0259	Queue G51_W62	Substation	Dickerson Station H	Upgrade	PEPCO	1-Jun-09	Eng. & Procurement Phase
n0260	Queue G51_W62	Substation	Dickerson Station H	Upgrade	PEPCO	1-Jun-09	Eng. & Procurement Phase
n0261	Queue G51_W62	Substation	Dickerson Station H	Upgrade	PEPCO	1-Jun-09	Eng. & Procurement Phase
n0262	Queue G51_W62	Substation	Dickerson Station H	Upgrade	PEPCO	1-Jun-09	Eng. & Procurement Phase
n0263	Queue G51_W62	Substation	Dickerson Station H	Upgrade	PEPCO	1-Jun-09	Eng. & Procurement Phase
n0264	Queue G51_W62	Substation	Dickerson Station H	Upgrade	PEPCO	1-Jun-09	Eng. & Procurement Phase
n0265	Queue G51_W62	Substation	Dickerson Station H	Upgrade	PEPCO	1-Jun-09	Eng. & Procurement Phase
n0266	Queue G51_W62	Substation	Dickerson Station H	Upgrade	PEPCO	1-Jun-09	Eng. & Procurement Phase
n0267	Queue G51_W62	Substation	Dickerson Station H	Upgrade	PEPCO	1-Jun-09	Eng. & Procurement Phase
n0268	Queue G51_W62	Substation	Dickerson Station H	Upgrade	PEPCO	1-Jun-09	Eng. & Procurement Phase
n0269	Queue G51_W62	Substation	Dickerson Station H	Upgrade	PEPCO	1-Jun-09	Eng. & Procurement Phase
n0270	Queue G51_W62	Substation	Dickerson Station H	Upgrade	PEPCO	1-Jun-09	Eng. & Procurement Phase
n0321	Queue G51_W62	Substation	Doubs	Replace	AP		Eng. & Procurement Phase
n0322	Queue G51_W62	Substation	Doubs	Replace	AP		Eng. & Procurement Phase
n0323	Queue G51_W62	Substation	Doubs	Replace	AP		Eng. & Procurement Phase
n0324	Queue G51_W62	Substation	Doubs	Replace	AP		Eng. & Procurement Phase
n0325	Queue G51_W62	Substation	Doubs	Replace	AP		Eng. & Procurement Phase
n0326	Queue G51_W62	Substation	Doubs	Replace	AP		Eng. & Procurement Phase
n0327	Queue G51_W62	Substation	Doubs	Replace	AP		Eng. & Procurement Phase
n0355	Queue I03_W74	Substation	Savage Mountain		AP		Eng. & Procurement Phase
n0356	Queue I03_W74	Transmission	Savage	Install	AP		Eng. & Procurement Phase
n0385	Queue G51_W62	Substation	Doubs	Replace	AP		Eng. & Procurement Phase
n0386	Queue G51_W62	Substation	Doubs	Replace	AP		Eng. & Procurement Phase
n0487	Queue G51_W60	Substation	Eastalco	Support	AP		Eng. & Procurement Phase
n0555	FE LTF	Substation	Black Oak	Replace	AP	31-May-07	In Service
n0620.1	Queue N29	Substation	Roth Rock		AP	13-Apr-09	Active
n0620.2	Queue N29	Substation	Roth Rock	Loop	AP	13-Apr-09	Active
n0620.3	Queue N29	Substation	Albright and William	Construct	AP	13-Apr-09	Active
n0621.1	Queue N29	Transmission	William	Construct	AP	13-Apr-09	Active
n0621.2	Queue N29	Transmission	Loughs Lane - William	Reconductor	AP	13-Apr-07	Active
n0726	Queue G51_W62	Substation	Dickerson "H"	Upgrade	PEPCO		Active
n0751	Queue Q48	Substation	Calvert Cliffs	Construct	BGE		Active
n0752	Queue Q48	Substation	Calvert Cliffs	Upgrade	BGE		Active
n0753	Queue Q48	Substation	Calvert Cliffs	Construct	BGE		Active
n0754	Queue Q48	Substation	Waugh Chaple	Upgrade	BGE		Active
n0755	Queue Q48	Substation	Riverside	Upgrade	BGE		Active
n0756	Queue Q48	Substation		Construct	BGE		Active
n0757	Queue Q48	Substation		Construct	BGE		Active
n0758	Queue Q48	Substation	Clavert Cliffs, Waugh Chapel and Chalk Point	Upgrade	BGE		Active

Table 1-20 Proposed Transmission Owner Identified Upgrades in Maryland (as of 9/4/2007)

Upgrade ID	Upgrade Type	Location	Equipment	Task	Transmission Owner	Projected In Service Date	Status Code
TOI067	Transmission	Maridel - Ocean Bay		Upgrade	DPL		In Service
TOI093	Transmission	Colora		Replacement	DPL	1-May-04	In Service
TOI100	Substation	Piney Grove		Replacement	DPL	1-May-05	In Service
TOI135	Transmission	Piney Grove		Rebuild	DPL	1-Mar-12	Eng. & Procurement Phase
TOI137	Transmission	Loretto		Replacements	DPL	1-Jun-10	Eng. & Procurement Phase
TOI150	Substation	Westport	Switching Station	Build	BGE	1-Jun-07	Under Construction
TOI151	Transmission	Westport	Cable	Parallel	BGE	1-Nov-07	Eng. & Procurement Phase
TOI152	Substation	Wilkins	Distribution Substation	Build	BGE	1-Jun-10	Eng. & Procurement Phase
TOI155	Substation	Wattsville	Capacitor		DPL	31-Dec-04	In Service
TOI159	Transmission	Easton-Bozman	Circuit	Convert	DPL	1-Jun-11	Eng. & Procurement Phase
TOI163	Substation	Wattsville	Autotransformer	Add	DPL	1-Jun-09	Eng. & Procurement Phase
TOI184	Transmission	Oak - Hallwood		Upgrade	DPL	1-Jun-04	In Service
TOI185	Substation	N. Salisbury	Bus		DPL	31-Dec-04	In Service
TOI186	Transmission	Maridel - Ocean City	Circuit	Upgrade	DPL	1-Jun-07	In Service
TOI194	Transmission	Hazelton - Jennings	Metering	Reconductor	AP	1-Nov-04	In Service
TOI198	Substation	Berryville	Capacitor	Install	AP	30-Jun-04	In Service
TOI203.1	Substation	Boonsboro	Transformer	Install	AP	15-Jul-04	In Service
TOI203.2	Transmission	Frostown - Boonsboro		Convert	AP		In Service
TOI204	Substation	Doubs	Breaker	Install	AP	31-May-07	In Service
TOI206	Substation	Flintstone Substation	Capacitor Bank	Install	AP		Eng. & Procurement Phase
TOI207	Substation	Oldstown Substation	Capacitor Bank	Install	AP		Eng. & Procurement Phase
TOI212	Substation	Lime Kiln SS	Bus	Install	AP	28-Feb-08	Under Construction
TOI213	Substation	Coverwood Substation	Capacitor	Install	AP		Eng. & Procurement Phase
TOI216	Substation	Huyetts Substation	Capacitor	Install	AP		Eng. & Procurement Phase
TOI217	Substation	Doubs	Control Building	Replace	AP	30-Nov-08	Under Construction
TOI229	Substation	Quince Orchard	Breakers	Install	PEPCO	1-Jun-13	Eng. & Procurement Phase
TOI248	Substation	Wye Mills	Autotransformer	Add	DPL	1-Jun-11	Eng. & Procurement Phase
TOI324	Transmission	Northwest to Finksburg	Circuit	Rebuild	BGE	31-Dec-08	Eng. & Procurement Phase
TOI351	Transmission	Church - Massey			DPL	31-Dec-06	In Service
TOI352	Transmission	Queenstown	Transmission Line		DPL	31-May-09	Eng. & Procurement Phase
TOI353	Transmission	Price	Transmission Line		DPL	31-Dec-07	Under Construction
TOI354	Substation	Jackson	In-Line Switches	Install	DPL	1-Jun-08	Eng. & Procurement Phase
TOI355	Transmission	Wye Mills - Easton		Convert	DPL	1-Jun-11	Eng. & Procurement Phase
TOI358	Substation	Easton	Bus Position	Create	DPL	1-Jun-11	Eng. & Procurement Phase
TOI359	Substation	Bozman	Bus Position	Create	DPL	1-Jun-11	Eng. & Procurement Phase
TOI363	Substation	Vienna	Breaker	Replace	DPL	31-May-06	In Service
TOI366	Transmission	Westport - Center	Underground Line	Build	BGE	1-Oct-07	Under Construction
TOI367	Substation	Orchard Street	Switching Station	Build	BGE	31-Dec-08	Eng. & Procurement Phase
TOI368	Substation	Center	Tie Breaker	Install	BGE	31-Dec-08	Eng. & Procurement Phase
TOI369	Transmission	Westport-Orchard	Underground Line	Build	BGE	31-Dec-08	Eng. & Procurement Phase
TOI370	Transmission	Westport - Orchard Center	Underground Line	Build	BGE	31-Dec-08	Eng. & Procurement Phase
TOI371	Transmission	Crystal Springs - Dorsey Tap	Circuit	Resag	BGE	1-Jun-07	In Service
TOI417	Substation	Doubs		Install	AP	1-Jun-07	In Service
TOI418	Substation	Black Oak - Bedington	Substation	Upgrade	AP	31-Dec-05	In Service
TOI419	Substation	Doubs		Upgrade	AP	1-Jun-07	Eng. & Procurement Phase

4. As described on page 363 of the SOM Report, the Market Monitor may cap offers when he believes the local markets are not competitive. Were any offers capped as a result of the congestion in the AP, BGE, DPL, and PEPCO Control Zones? If so, please specify the percentage of run hours impacted and the overall impact on Maryland wholesale prices.

The referenced discussion is in Appendix C to the 2006 State of the Market Report. The topic of offer capping is also addressed beginning at page 40 of the Report.

The PJM Market Monitor has no active role in the capping of offers in the PJM energy markets. Offer capping occurs as the result of the application of the three pivotal supplier test in the real-time and day-ahead energy markets by PJM staff in the markets division and in the operations division. PJM has clear rules limiting the exercise of local market power and it is the responsibility of PJM staff in the markets and operations division to implement these rules.[8] The rules provide for offer capping when conditions on the transmission system create a structurally noncompetitive local market, when units in that local market have made noncompetitive offers and when such offers would set the price above the competitive level in the absence of mitigation.

In 2006, there were 2,182 hours during which offer-capped units located within the PJM area had an impact on hourly real-time LMP in Maryland. The 2,182 hours includes 955 hours during which offer capped units in Maryland were marginal. The PJM MMU calculated the potential impact of removing the offer caps from the marginal units located in PJM, and within Maryland, that affected Maryland real-time LMP in 2006. The calculation is not based on a full redispatch of the system to determine the marginal units that would have occurred if all units had been taken on their price offers instead of their cost offers. Thus the results do not reflect a counterfactual market outcome based on the assumption that all capped units were dispatched on price. Instead, the set of marginal units is held constant and price offers are substituted for capped cost offers where relevant and the resulting effect on LMP determined. In addition, the results do not account for actual behavior that might result if offer capping were suspended. The existing price offers are based on the knowledge that offer capping will occur when structural market power exists and offers are above the competitive level.

Table 4- 1 shows the impact of removing the offer caps on marginal units located in the PJM area during the 2,182 hours when these units had an impact on real-time LMP in Maryland, by month. Removing the offer caps from the marginal units would have increased Maryland's load-weighted average LMP by an amount ranging from a minimum of $0.03/MWh in March to a maximum of $4.87/MWh in August. Removing

[8] See PJM Amended and Restated Operating Agreement, Schedule 1, Section 6.4.2.

the caps would have increased monthly 2006 real-time energy charges in Maryland by an amount ranging from a minimum of $.16 million in March to a maximum of $36 million in August of 2006. The total annual increase would have been $83.8 million.

Table 4- 1 Effect of removing offer capping from PJM area 2006 marginal units on monthly load-weighted average Maryland LMP

Affected area	Month	Load-weighted LMP	Load-weighted LMP without capping	Load-weighted net LMP effect of no capping	Percent change in LMP	Total dollar effect of removing capping (1000s)
MD	January	$64.66	$65.32	$0.66	1.02%	$4,138
MD	February	$65.95	$66.37	$0.42	0.64%	$2,501
MD	March	$64.81	$64.84	$0.03	0.04%	$159
MD	April	$52.92	$53.04	$0.12	0.23%	$596
MD	May	$60.28	$61.13	$0.85	1.41%	$4,596
MD	June	$59.54	$60.07	$0.54	0.90%	$3,368
MD	July	$82.88	$86.26	$3.39	4.09%	$25,881
MD	August	$104.00	$108.87	$4.87	4.68%	$36,809
MD	September	$38.48	$38.60	$0.12	0.30%	$629
MD	October	$43.24	$43.84	$0.59	1.38%	$3,184
MD	November	$51.01	$51.27	$0.26	0.52%	$1,421
MD	December	$50.00	$50.09	$0.08	0.17%	$517
MD	Annual	$63.44	$64.60	$1.16	1.83%	$83,800

Table 4-2 shows the impact of removing the offer caps on marginal units located in Maryland during the 995 hours when these units had an impact on real-time LMP in Maryland, by month. Removing the offer caps from the marginal units would have increased Maryland's load-weighted average LMP by an amount ranging from a minimum of $0.02/MWh in March to a maximum of $3.44/MWh in August. Removing the caps would have increased monthly 2006 real-time energy charges in Maryland by a an amount ranging from a minimum of $0.14 million in March to a maximum of $26 million in August of 2006. The total annual increase would have been $59.1 million.

Table 4-2 Effect of removing offer capping from Maryland 2006 marginal units on monthly load-weighted average Maryland LMP

Zone	Month	Load-weighted LMP	Load-weighted LMP without capping	Load-weighted net LMP effect of no capping	Percent change in LMP	Total dollar effect of removing capping (1000s)
MD	January	$64.66	$64.92	$0.26	0.39%	$1,599
MD	February	$65.95	$66.13	$0.18	0.27%	$1,052
MD	March	$64.81	$64.84	$0.02	0.04%	$142
MD	April	$52.92	$53.01	$0.09	0.18%	$463
MD	May	$60.28	$61.06	$0.78	1.30%	$4,238
MD	June	$59.54	$60.03	$0.49	0.83%	$3,098
MD	July	$82.88	$85.44	$2.56	3.09%	$19,596
MD	August	$104.00	$107.44	$3.44	3.31%	$26,022
MD	September	$38.48	$38.59	$0.10	0.27%	$553
MD	October	$43.24	$43.33	$0.09	0.21%	$486
MD	November	$51.01	$51.27	$0.26	0.51%	$1,403
MD	December	$50.00	$50.08	$0.07	0.15%	$450
MD	Annual	$64.44	$64.26	$0.82	1.29%	$59,103

5. Page 363 of the SOM Report states some units are grandfathered from the offer capping rules. How many units were exempt from the offer capping rules in the territories noted in question 4 above? To what extent, if any, did these exceptions affect wholesale prices in Maryland?

PJM's offer-capping rules provide that specific units are exempt from offer capping, based on their date of construction. During 2005, two orders issued by the FERC modified the rules governing exemptions from the offer-capping rules. In the January 25, 2005, order, the FERC found "that the exemption for post-1996 units from the offer capping rules is unjust and unreasonable under section 206 of the Federal Power Act and that the just and reasonable practice under section 206 is to terminate the exemption, with provisions to grandfather units for which construction commenced in reliance on the exemption."[9] The FERC noted, however, that grandfathered units would "still be subject to mitigation in the event that PJM or its market monitor concludes that these units exercise significant market power."[10] In the July 5, 2005 order, the FERC modified the dates governing unit exemptions by zone. The effect of these orders was to reduce the number of units exempt from local market power mitigation rules from 215 to 56 as of the end of 2005 and that number did not change in 2006.

A small number of exempt units accounted for a disproportionate share of markup in 2006. Eight exempt units accounted for 33 percent of the overall markup component of PJM prices in 2006. The offer-capping rules exempt certain units from offer capping based on the date of their construction. Such exempt units can and do exercise market power, at times, that would not be permitted if the units were not exempt.

The markup component of the overall system load-weighted, average LMP was $1.54 per MWh (2006 State of the Market Report, page 62). The units that are exempt from offer capping for local market power accounted for $0.56 per MWh, or 36 percent, of the PJM-wide markup for all days. This is a disproportionate share, given that only 43 of 56 exempt units were marginal and that only eight exempt units of the 43 accounted for $0.50, or 90 percent, of this markup component of price. The average markup per exempt unit is about nine times higher than for non-exempt units, and the average markup for the top eight exempt units is about 43 times higher than for non-exempt units.

Table 5-1 shows that, in 2006, of the 43 marginal exempt units in PJM, 17 were located in Maryland. Of the $0.56 per MWh total impact of exempt unit markup on 2006 load-weighted average hourly PJM LMP, $0.28 per MWH, or 50 percent, was attributable to

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[9] 110 FERC ¶ 61,053 (2005).

[10] 110 FERC ¶ 61,053 (2005).

the 17 exempt marginal units located in Maryland. These 17 units contributed 18 percent of the markup related component of PJM's load-weighted hourly average LMP.

Table 5-1 Comparison of exempt and non-exempt markup component effect on PJM load-weighted hourly average LMP by location of marginal unit: Calendar year 2006

	Zone	Marginal Units	Markup Component	Percent contribution to total mark-up component of hourly average LMP	Dollar impact of markup component on zone (1000s)
Non-Exempt Units	PJM	667	$0.98	63.8%	$681,242
Exempt Units Not In MD	PJM	26	$0.28	18.3%	$195,449
Exempt Units In MD	PJM	17	$0.28	18.0%	$191,787
Total		710	$1.54	100.0%	$1,068,478

Table 5-2 shows the effect of exempt and non-exempt unit markup on the 2006 load-weighted hourly average LMP in Maryland. Of the $1.21 per MWh of total exempt unit based markup effects ($.49 from exempt units not in Maryland and $0.73 from exempt units in Maryland) on 2006 load-weighted average hourly Maryland LMP, $0.73 per MWH, or 60 percent, was attributable to the markup of the 17 exempt marginal units located in Maryland. These 17 units contributed 33 percent of the markup related component of Maryland's load-weighted hourly average LMP.

Table 5-2 Comparison of exempt and non-exempt markup component effect on Maryland load-weighted hourly average LMP by location of marginal unit: Calendar year 2006

Unit Type	Zone	Marginal Units	Markup Component	Percent contribution to total mark-up component of hourly average LMP	Dollar impact of markup component on zone (1000s)
Non-Exempt Units	MD	667	$0.97	44.4%	$69,797
Exempt Units Not In MD	MD	26	$0.49	22.3%	$35,063
Exempt Units In MD	MD	17	$0.73	33.4%	$52,492
Total		710	$2.18	100.0%	$157,352

6. The 2006 SOM Report, at p. 37, notes that "units that are exempt from PJM's offer - capping rules did exercise market power in some local markets in 2006."

   -Did these units exercise local market power in Maryland in 2006?

   -If so, what was the impact of wholesale market prices in Maryland?

Table 5-2, from the response to the prior question, shows the effect of exempt and non-exempt unit markup on the 2006 load weighted hourly average LMP in Maryland. Of the $1.21 per MWh of total exempt unit based markup effects on 2006 load weighted average hourly Maryland LMP, $0.73 per MWH, or 60 percent, was attributable to the 17 exempt marginal units located in Maryland. These 17 units contributed 33 percent of the total markup related component of Maryland's load-weighted hourly average LMP. The units identified did exercise local market power in Maryland in 2006. The exercise of market power by exempt units contributed $1.21 per MWh to Maryland's 2006 annual load weighted hourly average LMP and $87.5 million to Maryland's 2006 real-time energy related charges.

7. The 2006 SOM Report notes that eight exempt units from PJM's offer-capping rules accounted for 33% of the total markup component of the PJM prices in 2006 (Vol. II, p. 27). Please explain how much this significant markup affects PJM market prices for Maryland?

Table 7-1 shows the markup component for all units and the markup component for the eight referenced exempt units of the 2006 load-weighted hourly average LMP in PJM and Maryland. The total markup component was $1.54 per MWh of the 2006 load-weighted average hourly PJM LMP. The markup component for the eight referenced exempt units was $.50 per MWH, or 33 percent of the total markup component. The total markup component was $2.18 per MWh of the 2006 load-weighted average hourly Maryland LMP. The markup component for the eight referenced units was $1.09 per MWH, or 50% of the total markup component for Maryland's load-weighted hourly average LMP in 2006.

Table 7-1 Markup component effect of PJM's 2006 top eight mark-up contributing exempt units on PJM and Maryland load-weighted hourly average LMP: Calendar year 2006

Zone	Total markup effect on zone	Total top eight exempt unit markup effect on zone	Top eight exempt unit contribution as a percentage of total markup
PJM	$1.54	$0.50	33%
MD	$2.18	$1.09	50%

8. Please provide an analysis of the extent to which units are frequently mitigated in Maryland in calendar 2006 by run-hours and total dollar impact by unit.

9. As described on page 63 of the SOM Report, an associated unit is "electrically and economically identical" to a frequently mitigated unit. Please provide the number of frequently mitigated and associated unit designations in Maryland in 2006, and cost impact per unit.

Table 8-1 provides the 2006 frequently mitigated unit (FMU) and associated unit (AU) counts by tier and month. Tables 8-2, 8-3, 8-4 and 8-5 show the LMP component of the offer-cap adders for frequently mitigated units and associated units for the indicated periods and zones. The impact is calculated by comparing the actual LMP to what the LMP would have been in the absence of the FMU and AU adders. The zone indicates the location of the LMP and not the location of the FMUs or AUs. The additional energy cost is the affected load multiplied by the locational price impacts. Table 8-2 shows the impact of FMU and AU adders on PJM load-weighted average hourly LMP and real time related energy costs by month for 2006. Table 8-3 shows the impact of FMU and AU adders on Maryland load weighted average hourly LMP and real time related energy costs for 2006. Table 8-4 shows the annual impact of FMU and AU adders on PJM's annual load-weighted average hourly LMP and annual real time related energy costs. Table 8-5 shows the annual impact of FMU and AU adders on Maryland's annual load-weighted average hourly LMP and annual real time related energy costs.

Table 8-1 FMU and AU unit counts by Tier and Month: Calendar year 2006

	FMUs and AUs			
Month	Tier 1	Tier 2	Tier 3	Total
January	0	0	43	43
February	0	0	49	49
March	21	27	87	135
April	10	28	87	125
May	11	27	87	125
June	5	27	90	122
July	9	26	87	122
August	18	20	88	126
September	22	19	73	114
October	32	30	72	134
November	32	33	67	132
December	29	40	61	130

Table 8-2 Effect of FMU and AU adders on PJM load weighted average hourly LMP and real time related energy costs by month: 2006 calendar year

Aggregate Name	Month	Category	Total Adder Impacts (In millions)	Percent of Total Real Time Cost	FMU/AU Adder LMP Impact
PJM	January	AU	NA	NA	NA
		FMU	$5.47	0.17%	$0.09
PJM	February	AU	NA	NA	NA
		FMU	$10.56	0.35%	$0.19
PJM	March	AU	NA	NA	NA
		FMU	$1.80	0.06%	$0.03
PJM	April	AU	NA	NA	NA
		FMU	$1.59	0.07%	$0.03
PJM	May	AU	$1.31	0.05%	$0.02
		FMU	$12.44	0.47%	$0.23
PJM	June	AU	$0.36	0.01%	$0.01
		FMU	$18.57	0.65%	$0.31
PJM	July	AU	$4.95	0.10%	$0.07
		FMU	$60.17	1.25%	$0.85
PJM	August	AU	$10.26	0.18%	$0.15
		FMU	$69.71	1.23%	$1.00
PJM	September	AU	$0.93	0.05%	$0.02
		FMU	$1.69	0.09%	$0.03
PJM	October	AU	$0.08	0.00%	$0.00
		FMU	$3.48	0.15%	$0.06
PJM	November	AU	$1.76	0.07%	$0.03
		FMU	$5.09	0.20%	$0.09
PJM	December	AU	$0.88	0.04%	$0.01
		FMU	$3.96	0.16%	$0.07

Table 8-3 Effect of FMU and AU adders on Maryland load weighted average hourly LMP and real time related energy costs: 2006 calendar year.

Aggregate Name	Month	Category	Total Adder Impacts (In millions)	Percent of Total Engergy Cost	FMU/AU Adder LMP Impact
MD	January	AU	NA	NA	NA
		FMU	$1.14	0.28%	$0.18
MD	February	AU	NA	NA	NA
		FMU	$2.69	0.69%	$0.45
MD	March	AU	NA	NA	NA
		FMU	$0.47	0.12%	$0.08
MD	April	AU	NA	NA	NA
		FMU	$0.28	0.11%	$0.06
MD	May	AU	$0.62	0.19%	$0.11
		FMU	$5.21	1.58%	$0.96
MD	June	AU	$0.13	0.03%	$0.02
		FMU	$3.49	0.91%	$0.55
MD	July	AU	$0.99	0.16%	$0.13
		FMU	$12.99	2.05%	$1.70
MD	August	AU	$3.40	0.42%	$0.45
		FMU	$20.67	2.55%	$2.73
MD	September	AU	$0.32	0.15%	$0.06
		FMU	$0.15	0.07%	$0.03
MD	October	AU	$0.01	0.00%	$0.00
		FMU	$0.53	0.23%	$0.10
MD	November	AU	$0.42	0.15%	$0.08
		FMU	$1.12	0.41%	$0.21
MD	December	AU	$0.23	0.08%	$0.04
		FMU	$0.49	0.16%	$0.08

Table 8-4 Effect of FMU and AU adders on PJM's annual load weighted average hourly LMP and annual real time related energy costs: Calendar year 2006.

Aggregate Name	Category	Adder LMP Impact	Total Adder Impacts (In millions)
PJM	FMU	$0.28	$195
PJM	AU	$0.03	$21
PJM	Combined effect	$0.31	$215

Table 8-5 Effect of FMU and AU adders on Maryland's annual load weighted average hourly LMP and annual real time related energy costs: Calendar year 2006.

Aggregate Name	Category	Adder LMP Impact	Total Adder Impacts (In millions)
MD	FMU	$0.68	$49
MD	AU	$0.08	$6
MD	Combined effect	$0.77	$55

11. Based on Table C-23 at p. 368, the net revenues for combustion turbine plants in the following service territories in calendar 2006 were as follows:

    BGE = $36,001 more in net revenues per installed MW-year

    Pepco = $44,666 more in net revenues per installed MW-year

    PJM's average = $22,031 in net revenues per installed MW-year

    Since these revenues are above the PJM average for these plants, please provide an explanation for the variations in net revenues for 2005 and 2006 and state whether the net revenues are sufficient to cover the unit's costs.

The question refers to Table C-23, an Appendix Table showing zonal energy market net revenue differentials using the assumption of perfect economic dispatch. The perfect economic dispatch calculations generally represent an upper bound of net revenues (2006 State of the Market Report, page 110.) The peak hour dispatch calculations more closely approximate likely actual dispatch results. Total net revenues for a new entrant CT also include capacity market revenues and ancillary market revenues although these revenue sources will not affect the zonal differentials.

This answer refers to Table 3-18 on page 124 of the State of the Market Report for the zonal net real-time energy market revenue differentials based on peak-hour dispatch.

Figure 11-1 and Table 11-1 show the monthly average LMP for PJM and for the BGE and PEPCO zones. The monthly average LMP for BGE and PEPCO zones is higher than the monthly average LMP for PJM for all months.

Figure 11-1 Average LMP for all hours (Dollars per MWh): Calendar years 2005 to 2006

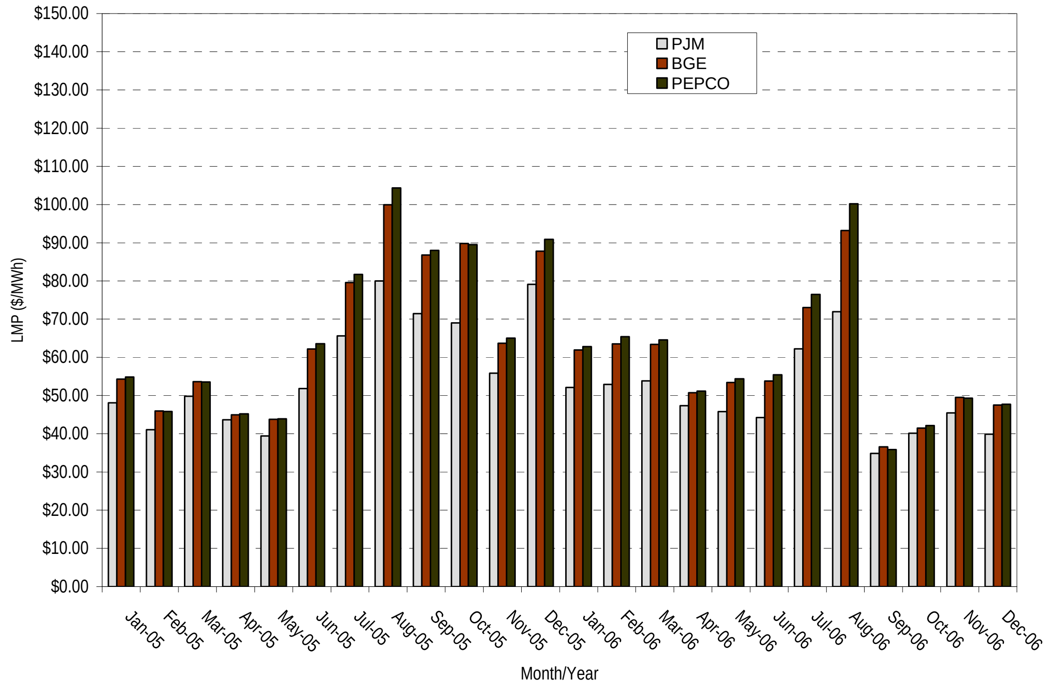

Table 11-1 Average LMP for all hours (Dollars per MWh): Calendar years 2005 and 2006

	All Hours Average LMP ($/MWh)				
Month/Year	PJM	BGE	PEPCO	BGE - PJM	PEPCO - PJM
Jan-05	$48.11	$54.33	$54.84	$6.22	$6.73
Feb-05	$41.08	$45.93	$45.85	$4.84	$4.77
Mar-05	$49.81	$53.66	$53.58	$3.85	$3.77
Apr-05	$43.65	$44.92	$45.23	$1.27	$1.57
May-05	$39.42	$43.78	$43.88	$4.36	$4.46
Jun-05	$51.84	$62.20	$63.54	$10.35	$11.70
Jul-05	$65.60	$79.58	$81.72	$13.98	$16.12
Aug-05	$79.96	$99.93	$104.35	$19.96	$24.38
Sep-05	$71.48	$86.79	$88.00	$15.31	$16.52
Oct-05	$69.04	$89.79	$89.51	$20.76	$20.48
Nov-05	$55.84	$63.70	$65.07	$7.86	$9.22
Dec-05	$79.11	$87.80	$90.90	$8.69	$11.79
Jan-06	$52.12	$61.94	$62.79	$9.82	$10.67
Feb-06	$52.95	$63.51	$65.42	$10.56	$12.47
Mar-06	$53.87	$63.40	$64.54	$9.53	$10.68
Apr-06	$47.35	$50.74	$51.17	$3.38	$3.82
May-06	$45.78	$53.43	$54.38	$7.65	$8.60
Jun-06	$44.21	$53.81	$55.44	$9.60	$11.23
Jul-06	$62.24	$73.05	$76.47	$10.81	$14.23
Aug-06	$71.95	$93.19	$100.15	$21.23	$28.20
Sep-06	$34.82	$36.56	$35.85	$1.73	$1.02
Oct-06	$40.18	$41.49	$42.18	$1.32	$2.00
Nov-06	$45.49	$49.53	$49.32	$4.04	$3.83
Dec-06	$39.86	$47.55	$47.74	$7.69	$7.88

Figure 11-2 through Figure 11-4 and Table 11-2 through Table 11-4 show monthly average LMP values for the weekday peak, weekend peak and weekly off peak periods respectively. The weekday peak includes Monday through Friday from hour ending 0800 to 2300 EPT (5 x 16), excluding NERC holidays. The weekend peak includes Saturday, Sunday and NERC holidays from hour ending 0800 to 2300 EPT (2 x 16). The weekly off peak includes Sunday through Saturday from hour ending 2400 to hour ending 0700 EPT (7 x 8).

The difference between the BGE and PEPCO zonal monthly average LMP and the corresponding PJM monthly average LMP is greater for the peak period than for all hours.

Figure 11-2 Average LMP for the 5 x 16 period (Dollars per MWh): Calendar years 2005 and 2006

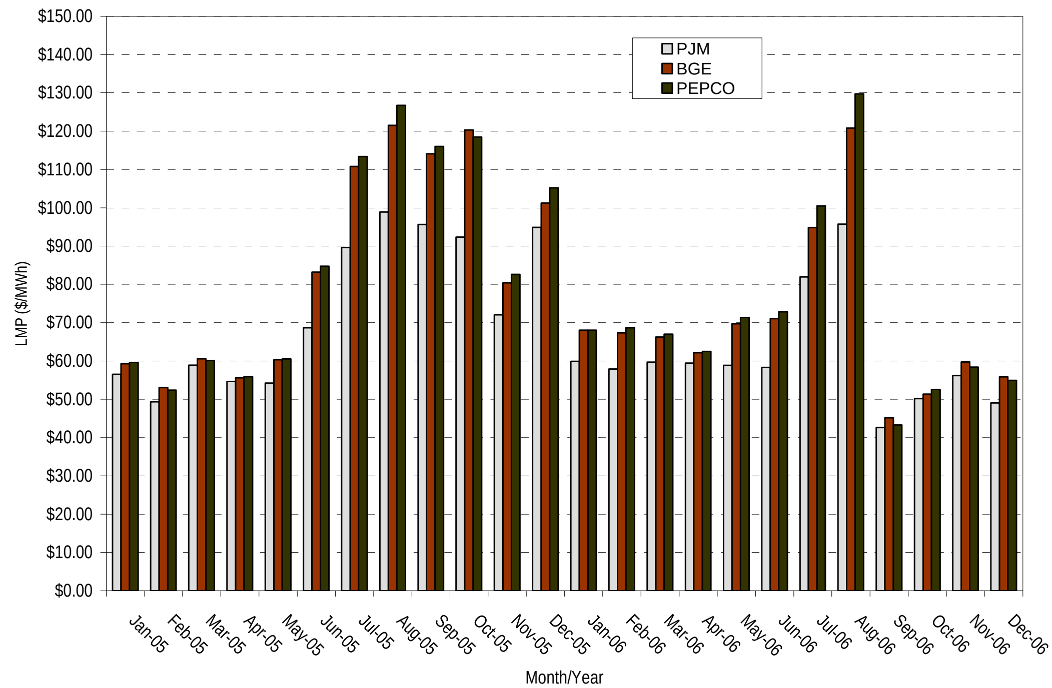

Table 11-2 Average LMP for the 5 x 16 period (Dollars per MWh): Calendar years 2005 and 2006

	5 x 16 Average LMP ($/MWh)				
Month/Year	PJM	BGE	PEPCO	BGE - PJM	PEPCO - PJM
Jan-05	$56.50	$59.27	$59.58	$2.77	$3.08
Feb-05	$49.37	$53.05	$52.38	$3.68	$3.02
Mar-05	$58.87	$60.54	$60.10	$1.68	$1.23
Apr-05	$54.66	$55.60	$55.88	$0.94	$1.22
May-05	$54.20	$60.30	$60.51	$6.10	$6.31
Jun-05	$68.66	$83.20	$84.72	$14.54	$16.05
Jul-05	$89.65	$110.81	$113.38	$21.16	$23.73
Aug-05	$98.91	$121.52	$126.72	$22.62	$27.81
Sep-05	$95.66	$114.09	$116.02	$18.43	$20.36
Oct-05	$92.35	$120.31	$118.49	$27.97	$26.14
Nov-05	$72.05	$80.38	$82.65	$8.34	$10.60
Dec-05	$94.87	$101.22	$105.20	$6.35	$10.32
Jan-06	$59.87	$68.02	$68.04	$8.15	$8.17
Feb-06	$57.90	$67.31	$68.65	$9.42	$10.76
Mar-06	$59.70	$66.22	$66.99	$6.52	$7.29
Apr-06	$59.48	$62.17	$62.51	$2.69	$3.04
May-06	$58.81	$69.71	$71.35	$10.89	$12.53
Jun-06	$58.33	$71.05	$72.85	$12.72	$14.52
Jul-06	$81.96	$94.85	$100.45	$12.89	$18.49
Aug-06	$95.74	$120.82	$129.74	$25.07	$34.00
Sep-06	$42.64	$45.16	$43.27	$2.52	$0.63
Oct-06	$50.16	$51.36	$52.56	$1.21	$2.41
Nov-06	$56.15	$59.72	$58.39	$3.57	$2.24
Dec-06	$49.06	$55.83	$54.92	$6.77	$5.86

Figure 11-3 and Table 11-3 show the difference between the BGE and PEPCO zonal monthly average LMP for the 2 x 16 weekend peak hours and the corresponding PJM monthly average LMP.

Figure 11-3 Average LMP for the 2 x 16 period (Dollars per MWh): Calendar years 2005 and 2006

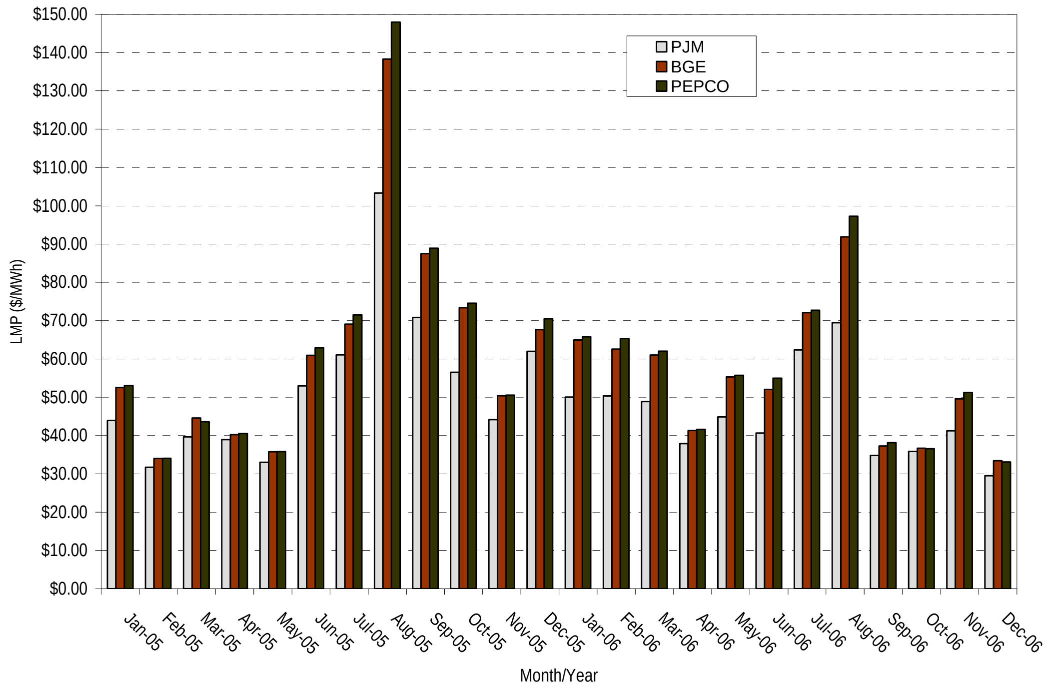

Table 11-3 Average LMP for the 2 x 16 period (Dollars per MWh): Calendar years 2005 and 2006

	2 x 16 Average LMP ($/MWh)				
Month/Year	PJM	BGE	PEPCO	BGE - PJM	PEPCO - PJM
Jan-05	$43.94	$52.55	$53.06	$8.61	$9.12
Feb-05	$31.72	$33.97	$34.03	$2.25	$2.31
Mar-05	$39.68	$44.60	$43.64	$4.92	$3.96
Apr-05	$38.97	$40.23	$40.55	$1.26	$1.58
May-05	$33.00	$35.78	$35.80	$2.77	$2.80
Jun-05	$52.96	$60.93	$62.88	$7.97	$9.92
Jul-05	$61.10	$69.11	$71.53	$8.01	$10.44
Aug-05	$103.33	$138.32	$147.96	$34.99	$44.63
Sep-05	$70.84	$87.49	$88.93	$16.65	$18.10
Oct-05	$56.52	$73.40	$74.58	$16.88	$18.07
Nov-05	$44.14	$50.42	$50.54	$6.28	$6.40
Dec-05	$62.01	$67.65	$70.51	$5.64	$8.50
Jan-06	$50.07	$64.95	$65.81	$14.88	$15.74
Feb-06	$50.33	$62.54	$65.31	$12.21	$14.98
Mar-06	$48.86	$61.05	$62.02	$12.19	$13.16
Apr-06	$37.89	$41.32	$41.61	$3.42	$3.72
May-06	$44.86	$55.32	$55.75	$10.46	$10.89
Jun-06	$40.67	$52.09	$54.97	$11.41	$14.29
Jul-06	$62.35	$72.10	$72.70	$9.76	$10.35
Aug-06	$69.45	$91.88	$97.26	$22.43	$27.81
Sep-06	$34.81	$37.29	$38.16	$2.48	$3.35
Oct-06	$35.87	$36.66	$36.58	$0.80	$0.71
Nov-06	$41.25	$49.57	$51.24	$8.32	$9.99
Dec-06	$29.52	$33.41	$33.08	$3.89	$3.56

Figure 11-4 and Table 11-4 show the difference the BGE and PEPCO zonal monthly average LMP for the 7 x 8 off peak hours and the corresponding PJM monthly average LMP.

Figure 11-4 Average LMP for the 7 x 8 period (Dollars per MWh): Calendar years 2005 and 2006

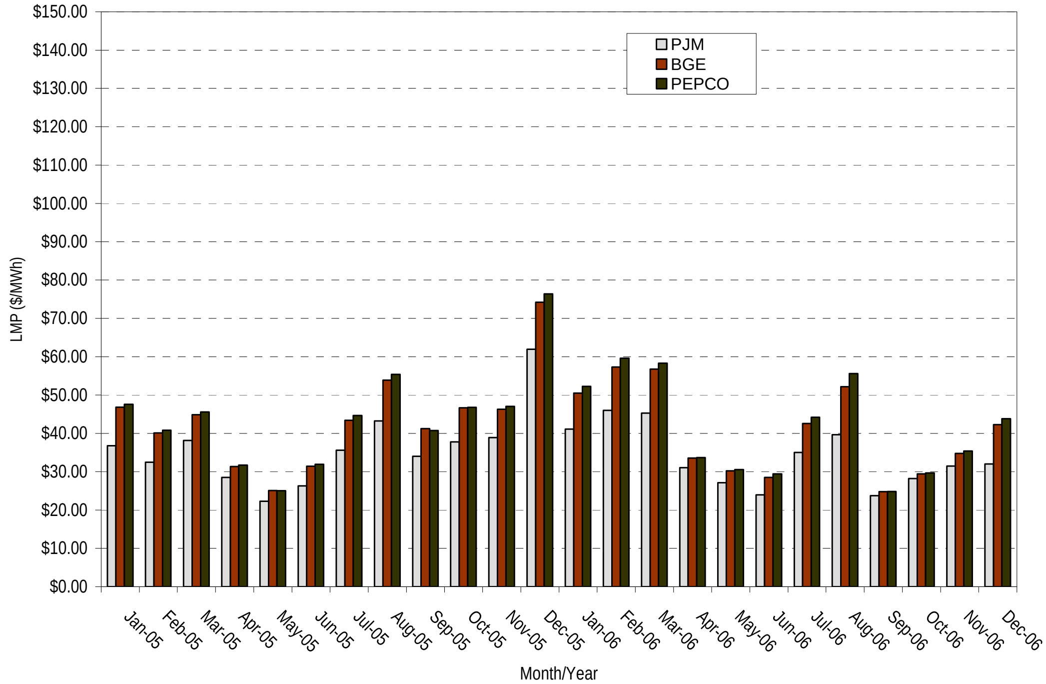

Table 11-4 Average LMP for the 7 x 8 period (Dollars per MWh): Calendar years 2005 and 2006

	7 x 8 Average LMP ($/MWh)				
Month/Year	PJM	BGE	PEPCO	BGE - PJM	PEPCO - PJM
Jan-05	$36.75	$46.83	$47.56	$10.08	$10.81
Feb-05	$32.45	$40.08	$40.83	$7.64	$8.39
Mar-05	$38.16	$44.84	$45.60	$6.68	$7.44
Apr-05	$28.52	$31.33	$31.73	$2.81	$3.21
May-05	$22.25	$25.06	$25.02	$2.81	$2.78
Jun-05	$26.29	$31.43	$31.96	$5.14	$5.67
Jul-05	$35.62	$43.41	$44.66	$7.79	$9.04
Aug-05	$43.27	$53.90	$55.41	$10.63	$12.15
Sep-05	$33.99	$41.24	$40.74	$7.25	$6.74
Oct-05	$37.75	$46.69	$46.79	$8.94	$9.04
Nov-05	$38.89	$46.31	$47.06	$7.42	$8.17
Dec-05	$61.94	$74.21	$76.39	$12.27	$14.45
Jan-06	$41.10	$50.50	$52.24	$9.40	$11.14
Feb-06	$45.99	$57.32	$59.59	$11.33	$13.60
Mar-06	$45.27	$56.78	$58.30	$11.51	$13.02
Apr-06	$31.03	$33.55	$33.65	$2.52	$2.62
May-06	$27.11	$30.25	$30.56	$3.14	$3.45
Jun-06	$23.94	$28.53	$29.40	$4.59	$5.46
Jul-06	$34.98	$42.59	$44.19	$7.61	$9.21
Aug-06	$39.67	$52.15	$55.60	$12.49	$15.93
Sep-06	$23.72	$24.77	$24.85	$1.05	$1.13
Oct-06	$28.21	$29.41	$29.64	$1.19	$1.43
Nov-06	$31.47	$34.78	$35.36	$3.31	$3.89
Dec-06	$32.00	$42.30	$43.80	$10.30	$11.80

Table 11-5 shows the zonal net revenues from the energy market for a new entrant CT in PJM and in the BGE and PEPCO zones using peak hour dispatch. The BGE and PEPCO energy market net revenues are 215 percent and 270 percent higher than the PJM average.

Table 11-5 Zonal economic dispatch net revenue for a new entry CT (Dollars per MW ICAP): Calendar Years 2005 and 2006.

Zone	2005	2006	Average
PJM	$6,141	$10,996	$8,569
BGE	$22,293	$31,725	$27,009
PEPCO	$25,840	$37,801	$31,820

In addition to energy market net revenues, total net revenues include revenue from the capacity market and ancillary service markets. The zonal capacity market revenues are shown in Table 11-6 and the ancillary service revenues are shown in Table 11-7. In 2005 and 2006 there was a single capacity market and therefore no zonal differences in capacity prices. Capacity market revenues rose significantly in 2007 with the implementation the Reliability Pricing Model market on June 1, 2007, and zonal differences in capacity market revenues were introduced for the first time. Since the reference CT is not capable of providing black start service, regulation or spinning reserves, the only ancillary service market revenues are from the provision of reactive service.

Table 11-6 Zonal capacity revenue (Dollars per installed MW-year): Calendar years 2005 and 2006

Zone	2005	2006	Average
PJM	$2,048	$1,758	$1,903
BGE	$2,048	$1,758	$1,903
PEPCO	$2,048	$1,758	$1,903

Table 11-7 Zonal reactive service revenue (Dollars per installed MW-year): Calendar years 2005 and 2006

Zone	2005	2006	Average
PJM	$2,248	$2,194	$2,221
BGE	$2,248	$2,194	$2,221
PEPCO	$2,248	$2,194	$2,221

Table 11-8 shows the total zonal net revenues for the reference new entrant CT under the economic dispatch scenario. The BGE and PEPCO total net revenues are about 145 percent and 185 percent higher than the PJM aggregate net revenue.

Table 11-8 Total zonal net revenues for a new entrant CT (Dollars per installed MW-year)

Zone	2005	2006	Average
PJM	$10,437	$14,948	$12,693
BGE	$26,589	$35,678	$31,133
PEPCO	$30,135	$41,753	$35,944

In order to determine if these net revenues were adequate to cover the costs of new entry, total net revenues must be compared to the fixed costs of new entry. These fixed costs are shown in Table 11-9.[11]

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[11] See pg. 126 of the *2006 State of the Market Report* for a detailed discussion of the calculation assumptions of new entrant CT marginal cost.

Table 11-9 New entrant first year and 20-year levelized fixed costs (Dollars per Installed MW-year)

Year	First Year Operating Fixed Cost	20-Year Levelized Fixed Cost
2005	$61,726	$72,207
2006	$68,657	$80,315

Table 11-10 and Table 11-11 show the first year and 20 year levelized costs for a new entrant CT compared to the economic dispatch net revenues. The zonal net revenues are less than either the first year or 20 year levelized fixed costs.

Table 11-10 First year fixed cost vs. economic dispatch net revenue (Dollars per installed MW-year): Calendar years 2005 and 2006

Year	First Year Operating Fixed Cost	PJM Economic Dispatch Net Revenue	BGE Economic Dispatch Net Revenue	PEPCO Economic Dispatch Net Revenue
2005	$61,726	$10,437	$26,589	$30,135
2006	$68,657	$14,948	$35,678	$41,753
Average	$65,192	$12,693	$31,133	$35,944

Table 11-11 20-year levelized fixed cost vs. economic dispatch net revenue (Dollars per installed MW-year): Calendar years 2005 and 2006

Year	20-Year Levelized Fixed Cost	PJM Economic Dispatch Net Revenue	BGE Economic Dispatch Net Revenue	PEPCO Economic Dispatch Net Revenue
2005	$72,207	$10,437	$26,589	$30,135
2006	$80,315	$14,948	$35,678	$41,753
Average	$76,261	$12,693	$31,133	$35,944

The PJM average net revenues equal 19 percent of the first year fixed costs while BGE and PEPCO equal 48 percent and 55 percent respectively of the first year fixed costs. The PJM average net revenues equal 17 percent and BGE and PEPCO equal 41 percent and 47 percent respectively of the 20 year levelized fixed costs.

12. Table 2.34, p. 61, of Volume I1 of the 2006 SOM Report shows that Pepco had on-peak ($3.92) and off-peak ($0.16) markup components of zonal prices. Did these markups occur on high-load days (as defined at page 142 of the SOM Report)? Were Pepco's markups the result of market power? Please explain. Please provide an explanation of the volatility of these markup indices. Provide a complete explanation why these markups noted at p. 61 are much less than the roughly $10 decline in LMP from 2005 to 2006 in the Control Zones of AP, BGE, and Pepco as shown on page 74 of the SOM Report. Please explain why there is a roughly $20 difference between the BGE and Pepco Control Zones and Western Control Zones (such as AEP) as shown on page 74 of the SOM Report.

Table 12-1 shows the markup component of the load-weighted average hourly LMP for PJM and Maryland on high load days and on "normal" load days for peak and off peak hours. The table shows that $0.60 per MWh, or 39 percent, of the markup component of PJM's annual load-weighted hourly average price occurred on high-load days. The table also shows that $0.84 per MWh, or 39 percent, of the markup component of Maryland's annual load-weighted hourly average price occurred on high-load days.

Table 12-1 Load-weighted average hourly markup component of PJM and Maryland hourly LMP by high and "normal" load day and peak and off peak hour: Calendar year 2006.

Aggregate Name	Type of Day	On-Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)
MD	High Load	$1.64	$0.01	$0.84
	Normal Load	$2.41	$0.20	$1.33
	All days	$4.05	$0.21	$2.18
PJM	High Load	$1.15	$0.00	$0.60
	Normal Load	$1.92	($0.11)	$0.94
	All days	$3.08	($0.10)	$1.54

The State of the Market Report concludes that "the overall results support the conclusion that prices in PJM are set, on average, by units operating at or very close to their marginal costs."[12] Markup is a direct measure of market power and the larger the markup the greater the concern about the exercise of market power. The fact that unit markups affect prices in a zone does not mean that the actions of owners of units in that zone have resulted in those markup components or that they have exercised market power.

[12] See pg. 31 of the *2006 State of the Market Report*.

Scarcity exists when the total demand for power approaches the generating capability of the system. Scarcity pricing means that market prices reflect the fact that the system is close to its available capacity and that competitive prices may exceed accounting short-run marginal costs. Under the current PJM rules, high prices, or scarcity pricing, result from high offers by individual generation owners for specific units when the system is close to its available capacity. These offers give the aggregate energy supply curve its steep upward sloping tail. As demand increases and units with higher markups and higher offers are required to meet demand, prices increase. As a result, markup on high-load days is likely to be the result of appropriate scarcity pricing rather than market power. Under the current PJM rules, administrative scarcity pricing, based on the scarcity pricing provisions in the Tariff, results when PJM takes identified emergency actions and is based on the highest offer of an operating unit.

Markup, as a component of LMP, varies based on the markup of specific marginal units and the relative importance of the marginal units meeting incremental load at the buses that make up the area of interest. System topography, load levels and unit location all contribute to the relative importance of a specific marginal unit in the formation of price at any given load bus, and thereby contribute to locational variations in both LMP and markup components of LMP .

PJM real time energy market prices decreased in 2006 relative to PJM real time energy prices in 2005. The hourly load-weighted LMP for 2006 was 15.9 percent lower than it had been for the 2005 annual average; $53.35 per MWh versus $63.46 per MWh. Energy Market results, including prices, for 2006 generally reflected supply-demand fundamentals. Aggregate supply increased by about 1,160 MW when comparing the summer of 2006 to the summer of 2005 while aggregate peak load increased by 10,881 MW, modifying the general supply-demand balance from 2005 with a corresponding impact on peak energy market prices. However, overall load was lower than in 2005, when measured on a comparable footprint basis, with a corresponding moderating impact on overall average prices. Lower nominal and load-weighted prices are consistent with a competitive outcome as the lower prices reflect both lower input fuel costs and lower overall demand. If fuel costs for the year 2006 had been the same as for 2005, the 2006 load-weighted LMP would have been higher than it was, $59.89 per MWh instead of $53.35 per MWh. Fuel-cost reductions were a substantial part (64.7 percent) of the reason for lower LMP in 2006, but prices would have been lower in the absence of the lower fuel costs.

13. Please provide a price duration curve for Maryland similar to Figure 2-1 1, p. 75, of the SOM Report. Please also provide a full explanation of the curve.

A price duration curve shows the percent of hours when LMP is at, or below, a given price for the year. Figure 13-1 presents price duration curves of Maryland for hours above the 95th percentile from 2005 to 2006. Figure 13-2 shows Maryland's 2006 real time hourly LMP, by hour.

Figure 13-1 Price duration curves for the Maryland real-time energy market during hours above the 95th percentile: Calendar years 2005 to 2006 <<MD Annual RT Price Duration Curves.xls FIG A>>

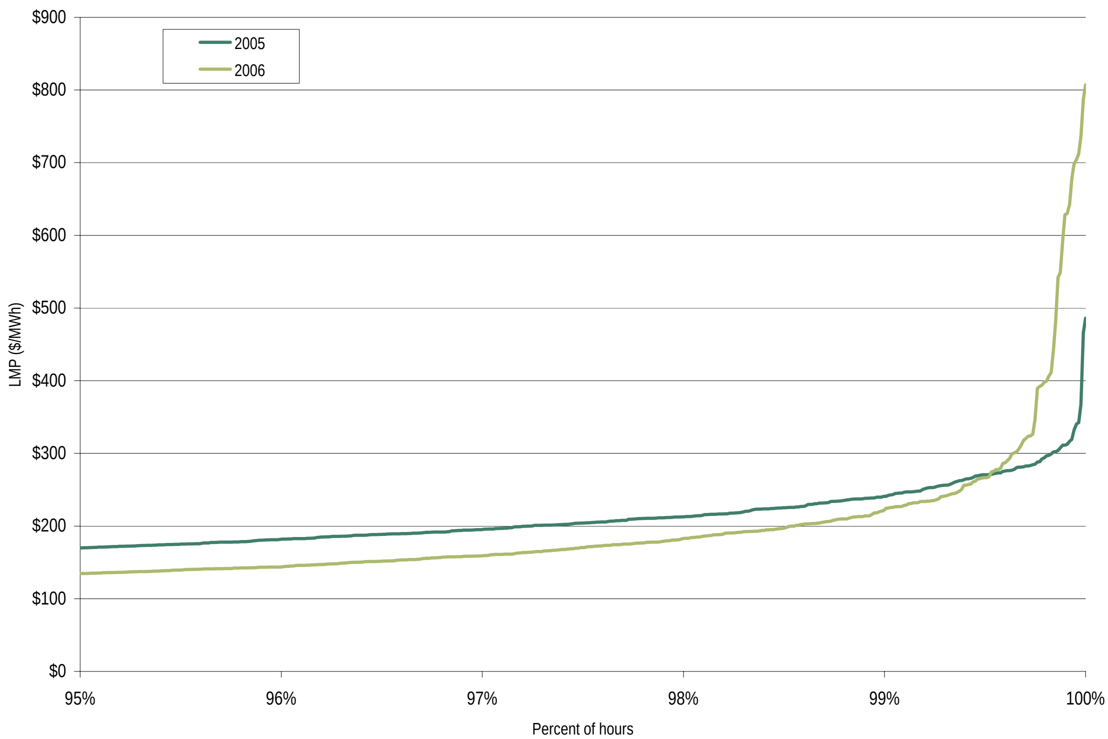
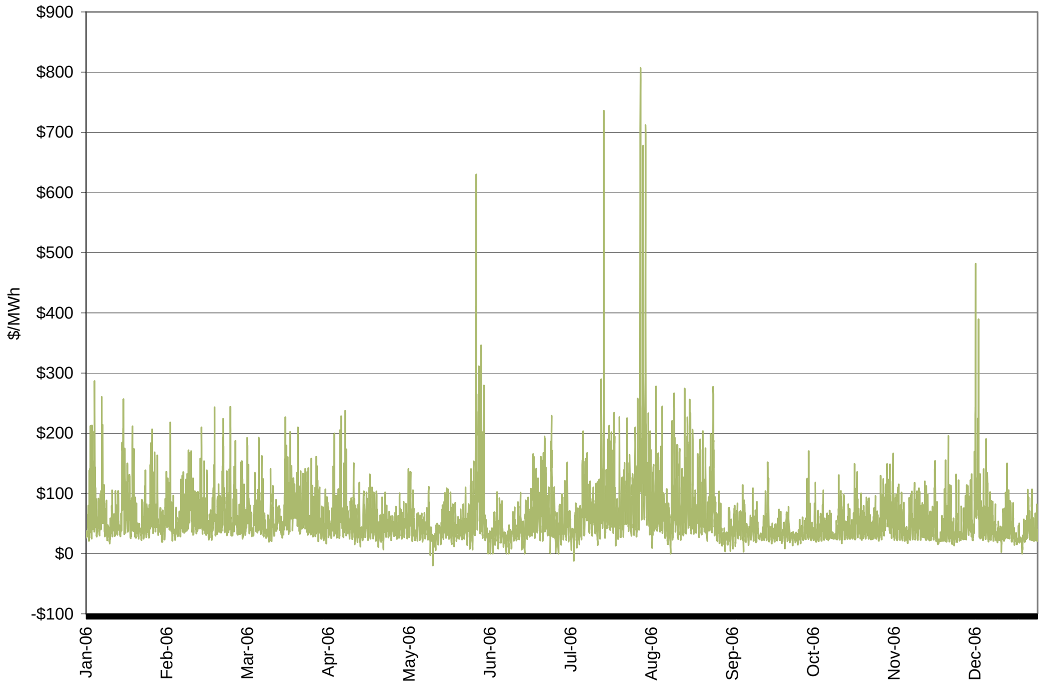


Figure 13-2 Maryland real time hourly LMP: Calendar year 2006



15. Are there any other aspects of or factors influencing the wholesale electricity markets not addressed in the SOM Report or the foregoing questions that, in your view, affects the competitiveness of the Maryland wholesale market? If so, please identify these aspects or factors and describe their impact on the competitiveness of the Maryland wholesale power market.

The 2006 SOM report was a comprehensive review of the PJM wholesale markets, of which Maryland is a part, and the factors that influenced the competitiveness of those markets. The MMU is currently developing an analysis of the interaction between the wholesale market and the Maryland auctions which may lead to additional conclusions on these issues.

T1. Please provide fuel cost adjusted load weighted annual average PJM LMP from 1998 until the present.

Changes in LMP can result from changes in the marginal costs of marginal units, the units that set LMP. In general, fuel costs make up between 80 percent and 90 percent of marginal costs depending on generating technology, unit age and other factors. The impact of changes in fuel costs on marginal costs and on LMP depends on the fuel burned by marginal units.

LMP can be calculated to hold constant the impact of fuel costs. The purpose of such a calculation is to show the changes in LMP that resulted from factors other than fuel costs. In a competitive market, it is expected that changes in input prices will be reflected in the marginal costs of production. Separating the changes in LMP that result from non-fuel factors permits a more focused analysis of whether the price outcomes are competitive.

To account for the changes in fuel cost between contiguous years, the load-weighted LMP for a given year is adjusted to reflect the changes in the price of fuels used by marginal units and the change in the amount of load affected by marginal units relative to the previous year. Table 16-1 shows the compilation of the year over year fuel cost-adjusted, load-weighted, average LMP from 1998 until 2006, as reported in the MMU's SOM reports. Each year's fuel cost adjusted, load-weighted, average LMP is calculated using the fuel costs in the previous year for purposes of calculating the effect of fuel cost changes on load weighted average LMP. Table 16-1 shows that if fuel costs for the year 2006 had been the same as for 2005, the 2006 load-weighted LMP would have been higher, \$59.89 per MWh instead of \$53.35 per MWh. Similarly, if fuel costs for 2005 had been the same as for 2004, the 2005 load-weighted LMP would have been lower, \$45.02 per MWH instead of \$63.46 per MWh.

It is important to note that the methodology used to generate the year-over-year fuel cost adjusted LMP in 2006 represents a significant improvement from the methodology used in previous years. To account for the changes in fuel cost between 2005 and 2006, the 2006 load-weighted LMP was recomputed to reflect the changes in the daily price of fuels used by the specific 2006 marginal units and the level of load affected by those marginal units, using sensitivity factors. In prior years, year-over-year fuel-cost-adjusted LMP was calculated using a monthly chain weighted average index approach based on monthly average fuel costs, the proportion of marginal unit intervals by fuel type by month and approximate measures of monthly average affected load. In combination, these limitations in the chain weighted index approach attenuate the value of analysis that extends beyond contiguous years.

The approach to fuel cost adjusted LMP reflected in the table limits the comparisons to contiguous years. For example, the calculations show the impact of fuel costs in explaining LMP changes between 2005 and 2006 but not between 1999 and 2006. Under any approach, comparisons across longer periods of time must be interpreted carefully because of changes in the mix of marginal units, changes in the load affected by marginal units and the changes in the size of the PJM market.

Table 16-1 PJM fuel-cost adjusted, load-weighted LMP (Dollars per MWh): Year-over-year method

Year	Nominal Load Weighted LMP	Fuel Cost Adjusted LMP	Notes
1998	$ 22.04	NA	
1999	$ 34.06	$ 28.64	Adjusted for 1998 fuel costs
2000	$ 30.72	$ 24.78	Adjusted for 1999 fuel costs
2001	$ 36.65	$ 33.05	Adjusted for 2000 fuel costs
2002	$ 31.60	$ 35.93	Adjusted for 2001 fuel costs
2003	$ 41.23	$ 28.60	Adjusted for 2002 fuel costs
2004	$ 44.34	$ 39.49	Adjusted for 2003 fuel costs
2005	$ 63.46	$ 45.02	Adjusted for 2004 fuel costs
2006	$ 53.35	$ 59.89	Adjusted for 2005 fuel costs