STATE OF MARYLAND

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of Baltimore Gas and Electric	**)**	
Company's Proposal to Implement a Rate	**)**	
Stabilization Plan Pursuant to Section 7-548 of the	**)**	**Case No. 9099**
Public Utility Companies Article and the	**)**	
Commission's Inquiry into Factors Impacting	**)**	
Wholesale Electricity Prices	**)**	

DIRECT TESTIMONY OF

JONATHAN WALLACH

ON BEHALF OF

THE OFFICE OF PEOPLE'S COUNSEL

Resource Insight, Inc.

MARCH 30, 2007

I. Introduction and Summary

Q: Please state your name, occupation, and business address.

A: I am Jonathan F. Wallach. I am Vice President of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Please summarize your professional education and experience.

A: I have worked as a consultant to the electric-power industry for more than two decades. From 1981 to 1986, I was a research associate at Energy Systems Research Group. In 1987 and 1988, I was an independent consultant. From 1989 to 1990, I was a senior analyst at Komanoff Energy Associates. I have been in my current position at Resource Insight since September of 1990.

Over the last twenty-five years, I have advised clients on a wide range of economic, planning, and policy issues including: electric-utility restructuring; wholesale-power market design and operations; transmission pricing and policy; market valuation of generating assets and purchase contracts; power-procurement strategies; integrated resource planning; cost allocation and rate design; and energy-efficiency program design and planning.

My resume is attached as Exhibit JFW-1.

Q: Please summarize your experience with regard to the issue of electric restructuring in Maryland.

A: In 1997, I co-authored a major study of electric-utility restructuring in Maryland for the Office of People's Counsel ("OPC"). Since then, I have advised and testified on behalf of OPC in most of the major proceedings relating to Maryland's restructuring process. I assisted OPC during settlement negotiations, and testified in support of such settlements, in Case Nos. 8794, 8795, and 8797 (regarding electric restructuring), 8890 (regarding the proposed merger of Potomac Electric Power Company and Delmarva Power & Light to form PEPCo Holdings, Inc.), and 8908 (regarding procurement of Standard Offer Service.) I also testified in Case Nos. 8852 (regarding Potomac Electric Power Company's proposed fees for electricity-supplier services), 8994 and 8995 (regarding determination of the residential SOS Administrative Charge), and 8985 (regarding Southern Maryland Electric Coop's SOS procurement plan). Most recently, I testified in Case Nos. 9052 (regarding proposals to transition Baltimore Gas & Electric's ["BGE"; "the Company"] residential customers to market-based SOS rates), 9056 (regarding default service for Type II customers), 9064 (regarding residential SOS procurement), 9063 (regarding optimal structure), and 9091 (regarding Allegheny Power's transition plan). Finally, on OPC's behalf, I have monitored the SOS procurement process in every year since its inception.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Office of People's Counsel.

Q: What is the purpose of your testimony?

A: On March 8, 2007, the Commission issued Order No. 81303 initiating a proceeding to "investigate whether BGE's residential SOS rates are at a market price that permits recovery of the verifiable, prudently incurred costs to procure or produce the electricity plus a reasonable return." In addition, the Commission's order indicated that this proceeding would consider the proposal for a voluntary Rate Stabilization Plan filed by BGE on January 29, 2007.

Pursuant to Order No. 81303, this testimony addresses the ten issues set forth in that order, as well as BGE's proposal for a Rate Stabilization Plan.

Q: Please summarize your findings and conclusions with regard to the Commission's investigation into wholesale electricity prices.

A: For the last two years, in accordance with the settlement agreements in Case No. 8908 and the Commission's order in Case No. 9064, BGE has procured short-term full-requirements contracts to serve residential SOS load. In general, the 8908/9064 procurement approach has yielded the intended outcomes: short-term full-requirement contracts have been procured through a verifiable process and at prices that reasonably reflect wholesale-market conditions. Moreover, SOS prices have been designed to recover the cost of the procured contracts plus a return at a rate that is established per the 8908 settlement agreements. In short, the current procurement approach has been used by BGE to meet its obligation to provide residential SOS "at a market price that permits recovery of the verifiable, prudently incurred costs to procure or produce the electricity plus a reasonable return."[1]

However, the current procurement approach has yielded market prices for residential SOS supply that are contrary to the public interest.[2] With its sole reliance on short-term full-requirements contracts to serve residential

[1]This is the standard set forth in the 1999 Restructuring Act. Public Utility Companies Article §7-510(c)(3)(ii)(2).

[2]These concerns apply as well to residential SOS prices for Potomac Electric Power Company and Delmarva Power & Light, and will likely also apply to residential SOS prices for Allegheny Power once Allegheny transitions to market-based SOS prices.

SOS load, the 8908/9064 approach needlessly exposes consumers to the dramatic increases in price levels and volatility that have shaken PJM's spot markets. As I testified in Case No. 9063, the current approach should be modified to allow procurement of a broad portfolio of both longer-term supply and demand options and short-term full-requirements contracts. A portfolio approach would likely reduce consumers' exposure to these harmful spot-price trends, and allow for the procurement of a "portfolio of electricity supply that provides electricity at the lowest cost with the least volatility."[3]

Q: Please summarize your recommendations regarding the proposed Rate Stabilization Plan.

A: The Company's proposal for a voluntary, opt-in deferral program should be approved with three modifications. First, in order to extend mitigation benefits and in the interest of rate stability, deferrals should continue through May 31, 2008, unless such an extension is found to be prohibited by law. The end-date for deferral collections should be extended commensurately to May 31, 2010, in order to preserve the Company's proposal for a two-year recovery period. Second, if BGE does not continue to credit back to residential ratepayers the revenue from the 1.5 mill/kWh SOS return adder, such revenue should be used to offset any carrying costs on the deferral balance. In either case, carrying costs should be accrued at BGE's actual short-term cost of borrowing, as proposed by the Company. Third, BGE should not be allowed to increase the deferral recovery surcharge by expected uncollectible costs, unless the Company can show that the deferral program

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[3]This is the standard established by Senate Bill 1, enacted in June 2006. Ch. 5, SB 1 (2006 Md. Laws, 1st Spec. Session.), Section 7.

increases uncollectible costs beyond the amount already recovered through the SOS Administrative Charge.

II. Commission Issues

A. Issue No. 1

Q: Please describe the auction process used to procure contracts to serve BGE's residential SOS load.

A: The Company has used a slightly different procurement approach in each of the two years that it has procured contracts at market-based rates. In the winter of 2005/06, BGE procured contracts in accordance with the Phase I and II settlement agreements in Case No. 8908 (as codified in regulation.) In the winter of 2006/07, BGE procured contracts pursuant to the modifications adopted by the Commission in Case No. 9064.

These two procurement approaches are fundamentally the same, particularly with respect to the fact that both approaches procure only short-term full-requirements contracts to serve residential SOS load. However, they differ in two respects. First, these approaches differ with regard to the frequency of procurement and delivery dates of the procured contracts. Under the 8908 approach, contracts are procured once a year, and all contracts commence on June 1 of the upcoming year.[4] Under the 9064 approach, utilities procure contracts twice a year, with contracts commencing either

[4] In the winter of 2005/06, BGE procured contracts that commenced July 1, 2006, because the settlement agreement in Case No. 8794 provided that rates would be frozen through June 30, 2006.

June 1 or October 1. In this case, utilities conduct solicitations in the winter to procure contracts that start on June 1 of the following year, and then conduct solicitations the following spring to procure contracts that start on October 1 of that same year.

Second, these approaches differ in terms of the duration of the contracts solicited and procured. Under the 8908 approach, BGE procured in the winter of 2005/06 a mix of one-, two-, and three-year contracts for full-requirements wholesale supply.[5] Under the 9064 approach, utilities procure only two-year contracts (starting either June 1 or October 1.) In the winter of 2006/07, in order to transition to the 9064 approach, BGE procured a mix of 4-, 12-, 18-, 24-, and 28-month contracts for full-requirements wholesale supply.

Q: What is full-requirements wholesale supply?

A: Under the 8908/9064 procurement process, full-requirements wholesale supply includes the supply of energy, capacity, ancillary services, losses, and any other electrical services other than transmission and distribution services necessary to deliver power to the customer's meter to serve that customer's load at all times. Full-requirements supply is a "load-following" service, in the sense that a full-requirements supplier is obligated during the term of its supply contract to supply a fixed percentage of residential SOS load, regardless of how that load fluctuates minute-to-minute or otherwise varies over the term of the contract.[6]

[5]To be precise, because of the July 1 start date, BGE procured a mix of 11-month, 23-month, and 35-month contracts.

[6]The Commission's order in Case No. 9064 modified this load-following obligation by capping the amount of load growth that a full-requirements supplier would be obligated to

Q: Please describe the procurement process for residential SOS under the 8908 and 9064 approaches.

A: The solicitation and procurement process is essentially identical under the two approaches. Under either approach, BGE issues a Request for Proposals ("RFP") for wholesale supply to serve all of its residential SOS load. As noted above, in the winter of 2005/06, BGE's RFP solicited price offers for a mix of one-, two-, and three-year contracts. The following winter, BGE solicited offers for a mix of 4-, 12-, 16-, 24-, and 28-month contracts. In both procurements, bidders were invited to offer prices that vary by contract year, by season, and, for time-of-use load, by time period.

The RFP is designed to solicit sufficient full-requirements supply to meet total residential load. This load is divided up into bid blocks, sized as a percentage of total load; the percentage value is set so that the bid blocks are approximately 50 MW in size. A bidder may then submit a price offer for each bid block and for as many blocks as that bidder chooses to bid on.

In both the winter of 2005/06 and 2006/07, BGE conducted three rounds of bidding over a two- to three-month period to procure contracts for residential SOS load.

Q: Would the winner of a single bid block be obligated to provide 50 MW of wholesale supply?

A: No. Participants in the solicitation are bidding on the right to serve a *percentage* of total residential SOS load, as that load fluctuates minute to minute and as it grows over time.

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serve. This modification, referred to as the Volumetric Risk Mitigation provision, is the subject of a rehearing request by OPC that is currently pending before the Commission.

Q: What is the process for selecting winning bidders?

A: Supply offers for residential SOS are evaluated and selected using a three-part process. First, offers are evaluated to determine whether they conform to the bidding requirements set forth in the RFP. For example, BGE will assess whether a bidder properly completed the bid form used to submit price offers. Any offer that fails to comply with such requirements will be summarily rejected as non-conforming.

Second, conforming offers are ranked in order of increasing offer price.[7] Starting with the lowest-priced offer, conforming offers are selected in order of increasing price for inclusion in an initial portfolio of provisional winners. This selection process ends when there are enough offers in the initial portfolio to meet residential SOS load.

Third, the initial portfolio is evaluated for pricing anomalies using the Price Anomaly Threshold ("PAT") mechanism. The PAT process compares the *average* price for the offers included in the initial portfolio against a market-price threshold to determine whether initial-portfolio prices are anomalous. If the initial portfolio of offers is deemed to be anomalous, then individual offers are removed from the initial portfolio, starting with the highest-priced offer and in order of decreasing price, until the anomaly is resolved. Any offer removed in this process will then be replaced in a subsequent round of bidding. All remaining offers are deemed to be winning bidders in the current round of bidding.

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[7]More precisely, conforming offers are ranked on the basis of their Discounted Average Term Price ("DATP"). The DATP is a single price calculated for each offer (using an established formula) that is used solely for the purposes of comparing and ranking offers. As discussed below, winning bidders are paid their actual offer prices, not the DATP.

Q: What is the winning bidder for a particular bid block paid?

A: The winner of a bid block is paid the actual price offered by that bidder for that particular bid block.

Q: How is the retail generation rate derived from the winning price offers?

A: The retail generation rate is set at the average of all awarded price offers.[8] For example, in the winter of 2005/06, BGE procured a mix of one-, two-, and three-year contracts to serve non-time-of-use residential load. Accordingly, the Summer, 2006 retail generation rate for non-TOU customers was set at the average of the Summer, 2006 offer prices for all of the awarded contracts.[9]

In the winter of 2006/07, BGE again procured a mix of contracts to serve non-TOU residential load. The Summer, 2007 retail generation rate was then set at the average of both: (1) the Summer, 2007 offer prices for the contracts awarded in the winter of 2006/07; and (2) the Summer, 2007 prices offered in the two- and three-year contracts awarded the previous winter.

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[8]The retail SOS rate is derived as the sum of the generation rate, transmission rate, and an "Administrative Charge" of 0.4 cents/kWh. The Administrative Charge is added to the retail SOS rate in accordance with the settlement agreements in Case No. 8908.

[9]Because of the July 1 start date, the Summer, 2006 period covers the three months from July through September of 2006. In contrast, the Summer, 2007 period covers the four months from June through September of 2007.

B. Issue No. 2

Q: Does the 8908/9064 approach allow the Commission to independently verify that SOS prices are based on the lowest-priced conforming offers?

A: Yes. Under the 8908/9064 approach, the Commission employs an independent consultant to actively monitor the bid process, in order to ensure that:

- BGE's electronic bidding platform does not prevent or discourage prospective bidders from submitting price offers.
- BGE personnel comply with all 8908/9064 procedures when determining whether a price offer is valid and conforming.
- BGE personnel comply with all procedures with regard to the ranking, selection, and PAT screening of all conforming price offers.

Q: Does the 8908/9064 approach allow the Commission to verify that the offer prices reflect competitive wholesale-market conditions?

A: Yes. The PAT evaluation process provides reasonable assurance that offer prices reflect competitive market rates for short-term full-requirements supply. The price thresholds used in the PAT evaluation incorporate estimates of market prices for all products and services bundled in full-requirements wholesale supply. Consequently, these price thresholds are representative of a competitive market price for full-requirements service. Moreover, the price thresholds are calculated using closing prices on the day that offers are submitted. As a result, these thresholds reflect market conditions prevailing at the time offers are tendered.

Q: How does the 8908/9064 approach ensure that BGE acts prudently in its evaluation of price offers and selection of winning bidders?

A: As noted above, Commission oversight of the bidding process through its consultant ensures that BGE complies with all procedures for verifying, ranking, and selecting winning bidders.

Q: Does the 8908/9064 approach provide for a reasonable return on residential SOS supply costs?

A: The 8908/9064 approach provides a return to BGE at a level established by settlement agreement in Case No. 8908, and as determined to be reasonable by the Commission in Order No. 78400 issued in Case No. 8908. The issue of a reasonable level of return has not been reviewed since it was established. It is my understanding that, pursuant to Senate Bill 1, BGE is providing a credit to customers to offset the return component of the SOS rate.

C. Issue No. 3

Q: How does the Commission's consultant verify offer prices?

A: As discussed above, prices are verified in a number of respects. First, the consultant monitors all calls into BGE's bid room from eligible bidders to ensure that all price offers are appropriately transmitted and processed through the electronic bid platform. Second, the consultant independently confirms that each bid-form spreadsheet submitted by a bidder has not been modified by that bidder, and that the spreadsheet is properly calculating the DATP based on that bidder's price offer. Third, the consultant confirms that BGE personnel have ranked and selected offers in compliance with 8908/9064 procedures. Finally, the consultant derives the market-price threshold for the PAT screening, and then confirms that BGE personnel apply that threshold and select winning bidders in accordance with established procedures.

D. Issue No. 4

Q: What are the components of wholesale power costs, and how are they determined?

A: There is little in the way of publicly available information regarding how bidders incorporate wholesale-power costs into their price offers, since such information is considered to be commercially sensitive and proprietary. However, it is likely that such offers include bidders' estimates of:

- Uncongested energy cost;
- Congestion cost (net of financial congestion hedge);
- Congestion hedge cost;
- Zonal capacity cost (net of capacity transfer rights);
- Ancillary-service costs (both market-based and tariff-based);
- Renewable Portfolio Standard compliance cost;
- Losses;
- Transaction costs; and
- Risk.

Most of these wholesale products can be provided through either self-supply (i.e., generation-asset ownership), bilateral contracts for physical delivery, over-the-counter physical transactions, or purchases from PJM-administered spot and forward energy, capacity, ancillary-service, and congestion-hedge markets. In addition, suppliers can make use of financial forwards, options, or other derivative contracts to take speculative or hedged positions.

In short, there are a number of physical and financial markets for each of these wholesale products, and thus a variety of “market prices” established for these products. In general, in the PJM region, prices in the forward markets are driven by expectations regarding future prices in the PJM-administered spot markets.

Q: How are clearing prices determined in PJM’s markets?

A: All of PJM’s product markets use a single-price auction to establish clearing prices. Bids to supply the product are selected in order of increasing offer price in order to satisfy expected market demand for the product. The most-expensive offer selected in this clearing process (i.e., the marginal offer) sets the market-clearing price.

All bids selected in this clearing process – i.e., all bids with offer prices at or below the marginal offer price – are paid the market-clearing price set by the marginal offer.

Q: Why is PJM’s energy market designed around a single-price auction?

A: In general, PJM strives to meet energy requirements in an economically efficient manner by scheduling and dispatching supply resources on the basis of their short-run marginal costs, where marginal cost is defined in this context as the increase in operating cost due to a unit increase in output.[10] In a workably competitive market, single-price clearing encourages bidding at marginal cost. Under single-price auctions, infra-marginal bidders do not need to bid above their marginal operating costs in order to generate the

[10]For the purposes of this simplified discussion, I am ignoring such complications as minimum-runtime requirements, ramp-rate constraints, start-up and no-load costs, or opportunity bidding by energy-limited units.

profits in the energy market necessary to cover their fixed costs and required return. Instead, bidders can bid at marginal cost, assured that they will be dispatched only when market price exceeds cost, and that such dispatch will generate profits in the form of the difference between the clearing price paid to bidders and those bidders' marginal costs.[11]

Q: How do congestion costs arise in PJM's energy market?

A: Congestion costs arise when transmission constraints prevent PJM from selecting and dispatching supply bids in order of increasing offer price (i.e., in "merit order") to meet load throughout the PJM control area. Such transmission constraints may require PJM to dispatch generation in the constrained area to meet area load, even though such generation is more expensive than what would have been the marginal resource in the absence of such constraints. In this case, the constrained area "separates" from the rest of the market, in the sense that the clearing price in the local area (based on the marginal local generation) is higher than the clearing price for the rest of the control area. The cost of congestion is essentially the difference between the local-area and rest-of-market clearing prices.

Q: What are the roles of PJM Interconnection, LLC and the Federal Energy Regulatory Commission ("FERC") in ensuring the reasonableness of wholesale prices?

A: Neither PJM nor FERC are responsible for evaluating whether, or ensuring that, the cost of the portfolio of wholesale contracts procured by BGE to

[11]The capacity market provides an additional source of revenues to cover fixed costs and required return. These additional capacity revenues are essential for encouraging marginal bidders to bid at cost; since marginal bids set the clearing price, marginal bidders do not generate profits in the energy market to cover fixed costs when they bid at marginal cost.

serve residential SOS load is reasonable, prudently incurred, or reflective of a reasonable level of return. The goals of SOS procurement, and the best approach to achieve those goals, must be determined at the state level.

As noted above, PJM administers wholesale spot markets for energy, capacity, and ancillary services. In addition, PJM is responsible for the safe and reliable operation of the bulk transmission system within its control area.[12] In these roles, PJM has adopted a Market Monitoring Plan and has created a Market Monitoring Unit ("MMU") within PJM to implement and carry out the objectives of that Plan. According to the Market Monitoring Plan, the MMU monitors the PJM markets and operations to ensure that: (1) market participants comply with PJM rules; (2) market designs do not inhibit competition; and (3) market participants are not exercising market power.[13] In other words, the MMU's role is limited to monitoring the markets to ensure that such markets are working as intended, yielding prices that are reflective of workably competitive conditions. However, the MMU is not responsible for determining whether such prices, competitive or otherwise, are just and reasonable.

Neither PJM nor FERC are directly responsible for ensuring the reasonableness of the bilateral or financial derivative markets.

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[12]PJM's obligations as administrator of spot markets and as control-area operator are set forth in a tariff and agreements approved by FERC.

[13]PJM Open Access Transmission Tariff, Attachment M, PJM Market Monitoring Plan.

E. Issue No. 5

Q: What assurances does the Commission have that SOS bids are not subject to collusion, price fixing, or inside information shared by and between utility companies, their generation affiliates, if any, and competing suppliers?

A: My response to this question is based solely on my experience observing the bid process from within BGE's bid room; I have no knowledge regarding voice, facsimile, or electronic communications other than calls into the bid room by eligible bidders. As far as what transpires in BGE's bid room, the consultant's monitoring of phone communications between BGE and eligible bidders provides some assurance that all such communications are appropriate.

F. Issue No. 6

Q: To what extent are BGE's SOS prices determined by the auctions that occurred in the winter of 2005/06 and in the winter of 2006/07?

A: As discussed above in Section 1.A, BGE's residential retail SOS rate is derived as the sum of the generation rate, the FERC-jurisdictional transmission rate, and an "Administrative Charge" of 0.4 cents/kWh. The residential generation rate, in turn, is set at the average of the price offers for all winning bidders.

The residential generation rates for the summer of 2006 and winter of 2006/07 were determined solely on the basis of the prices for contracts awarded in the winter of 2005/06. Thus, BGE's residential generation rate for the summer of 2006 was derived as the average of the Summer, 2006 prices in the one-, two-, and three-year contracts procured in the winter of

2005/06.[14] Likewise, the generation rate for the winter of 2006/07 was derived as the average of the Winter, 2006/07 prices in the one-, two-, and three-year contracts procured in the winter of 2005/06.

The residential generation rate for the summer of 2007 is determined by prices for contracts awarded both in the winter of 2005/06 and in the winter of 2006/07.[15] In this case, the generation rate is set at the average of Summer, 2007 prices for: (1) the two-year contracts procured in the winter of 2005/06; (2) the three-year contracts procured in the winter of 2005/06; and (3) all contracts procured in the winter of 2006/07.

Q: To what extent does BGE's residential generation rate for the summer of 2007 differ from the rate for the summer of 2006?

A: The Summer, 2007 generation rate is approximately five percent lower than the Summer, 2006 rate.

Q: Given the public perception that last year's SOS prices were at unprecedented levels, why didn't the summer rate decline more substantially from 2006 to 2007?

A: There are two factors that may explain this result. First, the underlying wholesale costs that drive contract prices did not decline as steeply as might have been expected. For example, at the time the contracts were procured in

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[14]All such averages are weighted by the percentage of load served by each contract type. For the Summer, 2006 and Winter, 2006/07 averages, the load weights are approximately 50%, 25%, and 25% for one-, two-, and three-year contracts, respectively.

[15]These contract prices will also partially determine generation rates for the winter of 2007 and beyond. For example, the residential generation rate for the winter of 2007/08 will be set at the average of prices for contracts procured in the winter of 2005/06, the winter of 2006/07, and the spring of 2007.

the winter of 2005/06, PJM on-peak forward prices for the summer months of 2006 averaged around $89/MWh.[16] By the time of the following year's bidding in the winter of 2006/07, PJM on-peak forward prices for the summer months of 2007 averaged around $79/MWh, or only about eleven percent less than the forward prices for the summer of 2006. Moreover, this decline in forward energy prices was offset by an almost order-of-magnitude increase in the market price for capacity from the summer of 2006 to the summer of 2007, reflecting market expectations regarding the impact of implementation of the RPM capacity construct in 2007.

Second, as discussed above, the residential generation rate for the summer of 2007 is determined as the blended average of the Summer, 2007 prices for contracts awarded in the winter of 2005/06 and of the Summer, 2007 prices for contracts awarded in the winter of 2006/07. This averaging of Summer, 2007 prices from contracts procured at different times will likely moderate the change in generation rates from Summer, 2006 to Summer, 2007.

I illustrate the impact of this averaging in the following table, using a simulation of the residential generation rate that assumes that all contracts procured by BGE during the last two winters are priced at PJM on-peak forward prices prevailing at the time of contract award. As shown in the table, Summer, 2006 prices for contracts procured in the winter of 2005/06 would have been $89/MWh, if all of those contracts were priced at Summer, 2006 forward prices prevailing at the time those contracts were procured.

[16] As discussed above in Section 1.D, contract prices for full-requirements service will reflect costs other than for on-peak forwards. However, changes in on-peak forward prices are primary drivers of movements in such contract prices.

Summer, 2007 prices for those same contracts would have been about $86/MWh. In contrast, Summer, 2007 prices for contracts procured in the winter of 2006/07 would have declined to $79/MWh, reflecting the drop in market prices for the Summer, 2007 forward contracts between the winters of 2005/06 and 2006/07.

Contract Vintage	Summer, 2006 Proxy Price ($/MWh)	Summer, 2007 Proxy Price ($/MWh)
Winter, 2005/06	89.05	86.35
Winter, 2006/07	----	79.37
Blended Average	----	82.67

If the Summer, 2007 generation rate was based solely on the Summer, 2007 prices in contracts procured in the winter of 2006/07, then the Summer generation rate (according to my proxy simulation) would have declined from $89/MWh in 2006 to $79/MWh in 2007, or about eleven percent. However, because the Summer, 2007 generation rate is based on Summer, 2007 prices for contracts procured in the winters of 2005/06 and 2006/07, the Summer generation rate under my proxy simulation declines from $89/MWH in 2006 to $83/MWh in 2007, or about seven percent.

G. Issue No. 7

Q: To what extent has BGE's residential generation rate increased since 1999?

A: The average annual residential generation rate for the period July 1, 2006 through May 31, 2007 was about 10 ¢/kWh, or about double the average cost to residential customers of BGE's generation assets in 1999.

Q: What are the major factors driving increases in BGE's residential generation rates since 1999?

A: There are two major factors that led to this doubling of residential generation costs between 1999 and 2006. First, per the terms of the settlement agreements in Case Nos. 8794 and 8908, BGE divested its generation assets in 2000 and instead procured short-term full-requirement contracts to serve residential load starting in 2006. As a result, the cost basis for residential generation rates changed from the average cost of BGE's assets in 1999 to the market price for short-term full-requirements contracts in 2006.

Second, developments in PJM's spot markets during this period dramatically increased spot-price levels and volatility, which in turn increased commodity costs and risk premiums for the short-term full-requirements contracts procured under the 8908 approach in 2006.

Q: What are the likely wholesale-market drivers of these price increases?

A: There have been a number of developments in PJM's spot markets that have contributed to generation price trends for residential customers. These developments include:

- A growing reliance on natural gas as the marginal fuel, along with unprecedented increases in gas prices and price volatility over the last few years.[17]
- Rising congestion costs, due to rising marginal fuel prices and the failure of merchant generation or transmission investors to invest in projects to relieve congestion in response to spot price signals.[18]

[17]The spot price of natural gas at the Henry Hub *tripled* between 1999 and 2006, representing an annual average escalation rate of 17% over this seven-year period.

- A radical restructuring of PJM's installed-capacity market that, once implemented, is expected to significantly increase capacity costs.
- The implementation of scarcity-pricing rules, including exemptions on market mitigation, increasing the risk of higher prices and greater price volatility during high-load hours.

These market developments have increased both spot-market price levels and price risk over the last few years.[19] These spot-price trends have driven trends in the forward markets, which, in turn, have increased the costs and exacerbated the risks associated with providing full-requirements service.

Q: Why are gas prices driving price levels and volatility in electric markets?

A: Natural gas is the predominant "marginal fuel" in the PJM spot market. In other words, prices in PJM's energy market are set by gas-fired generators in a substantial number of on-peak hours, even though gas-fired generation represents a minor share of total energy production.[20] According to PJM's Market Monitoring Unit, in 2006, units fueled by natural gas were the marginal unit 25% of the time, yet represented only 6% of total PJM

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[18]Between 2000 and 2006, congestion costs rose from $132 million to $1,603 million, or about twelve times. Congestion costs peaked in 2005 at $2,092 million. The 23% decline in congestion costs between 2005 and 2006 almost exactly matches the decline in Henry Hub spot gas prices during this same period.

[19]For example, average annual prices in PJM's real-time market increased 75% between 2000 and 2006, for an average escalation rate of about ten percent per year.

[20]As noted above, gas prices are not the sole driver of PJM spot-price levels and volatility. In fact, in 2005, PJM Western Hub daily spot prices were significantly more volatile than Henry Hub daily spot prices.

generation in that year.[21] As a result, PJM spot prices are increasingly driven by natural-gas prices. For example, between 2000 and 2006, PJM real-time on-peak prices increased 51%, while Henry Hub spot prices increased 57%.

Forward electric prices, which reflect expectations regarding future spot prices, also tend to follow natural-gas prices. This effect is illustrated in Exhibits JFW-2 and JFW-3, which compare daily closing prices for PJM on-peak forwards against daily closing prices for Henry Hub natural gas forwards. For both the electric and gas forwards, Exhibit JFW-2 shows for each trading day in 2006 the closing price for the twelve-month strip for calendar-year 2007.[22] Exhibit JFW-2 shows the extremely tight correlation between gas and electric forward prices. Using the closing-price data shown in Exhibit JFW-2, Exhibit JFW-3 provides the percentage change in daily closing prices relative to the previous day's closing price. Exhibit JFW-3 further illustrates the close correlation between gas- and electric-forward price changes, as well as the fact that both markets exhibit large daily price swings.

Q: Have these developments in PJM's spot markets heightened the risks associated with providing full-requirements service?

A: Yes. Suppliers of full-requirements service assume all price- and volume-related risk associated with serving residential SOS load. These developments – e.g., increased gas prices and volatility, increased congestion

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[21]PJM Interconnection, LLC, *2006 State of the Market Report*, March 8, 2007, Table 2-30, p. 56 and Figure 3-27, p. 131.

[22]For each trading day, Exhibit JFW-2 provides the average of that day's twelve closing prices for the twelve monthly forward contracts for 2007.

costs – amplify the consequences of unanticipated movements in spot prices or changes in load.

Potential suppliers of full-requirements service are likely to respond to this enhanced risk by either increasing risk premiums on price offers or by declining to participate in the bidding process.

H. Issue No. 8

Q: If Maryland had not restructured its electricity industry in 1999, what would electricity rates for BGE's residential customers be as of June 1, 2007?

A: I have not conducted an independent analysis of likely rate levels if Maryland had not restructured its electricity industry. However, in Case No. 9063, Dr. Jonathan Lesser, on behalf of BGE, undertook an analysis of what BGE residential rates would have been between 2000 and 2006, and what they would be in the following three years, if BGE's generation function had not been restructured in 1999. As part of my rebuttal testimony in that case, I revised Dr. Lesser's analysis, correcting for a number of problematic assumptions.[23]

I showed in my rebuttal testimony that, with these corrections, Dr. Lesser's analysis projected residential generation rates in 2007 through 2009 that were lower under continued regulation than under the 8908 procurement approach in place at that time. The results of this revised analysis are shown in Exhibit JFW-4, which reproduces Exhibit JFW-R3 of my rebuttal testimony in Case No. 9063. As indicated in Exhibit JFW-4, Dr. Lesser's

[23] A copy of my rebuttal testimony in Case No. 9063 is attached.

corrected simulation projects SOS generation rates to exceed regulated generation rates by about 20%-30% between 2007 and 2009.

I. Issue No. 9

Q: How do BGE's residential SOS prices compare to residential SOS prices for Southern Maryland Electric Cooperative ("SMECo")?

A: According to the BGE website, the non-time-of-use residential SOS rate for the summer of 2006 was 11.7 ¢/kWh. According to the SMECo website, the residential SOS rate for that same period was 9.1 ¢/kWh, or about 22% less than BGE's rate.

Q: Why are these two companies' residential rates different?

A: Two factors likely contribute to the rate differential. First, SMECo procures SOS supply using an approach that is fundamentally different than the 8908/9064 approach. Instead of procuring short-term full-requirements contracts to serve SOS load, SMECo procures and actively manages a portfolio of medium- and short-term physical and financial products that is designed to meet load at minimum cost and volatility.[24] In other words, instead of buying a short-term bundled product (i.e., full-requirements supply), SMECo separately purchases the underlying wholesale components in quantities and terms that minimizes cost and volatility.

Second, unlike for BGE, SMECo's SOS rate for the summer of 2006 reflects a blended average of contract prices for contracts procured over time. As discussed above in Section 1.F, BGE's residential SOS rate for the

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[24]In Case No. 9063, SMECo indicated that it was interested in procuring longer-term products, but was precluded from doing so by Commission order.

summer of 2006 was determined solely on the basis of the prices for contracts procured in the winter of 2005/06, when market prices were extremely high and extremely volatile. In contrast, SMECo's SOS rate for the summer of 2006 likely reflects contract prices for contracts procured well before and after the winter of 2005/06.

J. Issue No. 10

Q: What would BGE's residential SOS prices be today if that load were served by newly-acquired generating facilities owned and operated by BGE?

A: SOS prices would likely be even higher than actual prices if all residential load were served by new investments. Moreover, SOS prices under this hypothetical would likely be substantially higher than if BGE had not restructured and transferred its assets to an unregulated affiliate.

PJM has been awash in excess capacity since 1999. This glut has depressed wholesale-market prices to levels that are well below the cost of new capacity.[25] These depressed wholesale-price levels, in turn, are reflected in today's SOS prices. Consequently, if residential load were served by new generation, then SOS prices would likely be higher than actual prices.

This price differential would likely be even more dramatic if BGE had retained its generating assets after 1999. In that case, a significant portion of today's residential load would be served at the cost of existing, depreciated

[25]According to PJM, investment in new combustion-turbine, combined-cycle, or pulverized-coal generation would not have been economic relative to PJM market prices from 2000 to 2006. See PJM Interconnection, LLC, *2006 State of the Market Report*, March 8, 2007, Tables 3-22 through 3-24, pp. 128-129.

plant. Any load growth since 1999 in excess of BGE's retained generating capacity could have been served at depressed wholesale-market prices. As a result, as discussed above in Section 1.H, SOS prices under the retained-generation scenario would likely be lower than SOS prices under the 8908/9064 approach, and, consequently, substantially lower than under a scenario where all load is met with new generation.

Q: Does this mean that utility investment in new generation is not a viable option for serving residential SOS load in the future?

A: No. As I discussed in my testimony in Case No. 9063, generation investment is one of several supply and demand-side options that should be evaluated for possible inclusion in a resource portfolio for serving residential SOS load. While new generation may be more expensive than today's depressed wholesale prices, some investment could prove to be economic when measured against spot-market prices over the life of the asset. Residential load would also benefit if asset costs are less volatile than spot prices.

III. BGE Rate Stabilization Plan

Q: Please describe the Company's proposal for a Rate Stabilization Plan.

A: Residential SOS customers are expected to face a substantial rate increase when the current deferral program expires on May 31, 2007 and rates transition to full market-based levels on June 1, 2007. The Company proposes to implement on June 1, 2007 a short-term, opt-in deferral mechanism that provides residential customers the opportunity to extend the transition to market-based rates to January 1, 2008.

Under the Company's proposal, customers that choose to participate in the program will receive a bill credit starting June 1, 2007 that effectively halves the SOS rate increase from full transition to market-based rates. This credit will expire on December 31, 2007, thereby effectively increasing rates to full market-based levels on January 1, 2008.

The amounts credited to customers will be deferred through a regulatory asset, with interest accrued at the Company's actual short-term cost of borrowing. Starting on January 1, 2008, and extending through December 31, 2009, the Company will charge participants a deferral surcharge in an amount sufficient to fully amortize the regulatory asset over a two-year period. In addition, the Company proposes to include in the deferral surcharge an additional amount to recover "anticipated uncollectible costs."

Q: Do you recommend any modifications to the Company's proposal?

A: I recommend three modifications to the Company's proposal. First, I recommend that the end of the deferral period be extended from December 31, 2007 to May 31, 2008.[26] The end-date for deferral collections should be extended commensurately to May 31, 2010, in order to preserve the Company's proposal for a two-year recovery period. Second, if BGE does not continue to credit back to residential ratepayers revenues from the 1.5 mill/kWh SOS return adder, I recommend that such revenues be used to offset any carrying costs on the deferral balance. In either case, carrying costs should be accrued at BGE's actual short-term cost of borrowing, as proposed

[26] I have been advised by Counsel that the question of whether such an extension is allowed under Senate Bill 1 is a matter of statutory interpretation. People's Counsel intends to argue this issue in this proceeding.

by the Company. Third, BGE should not be allowed to increase the deferral recovery surcharge by expected uncollectible costs, unless the Company can show that the deferral program increases uncollectible costs beyond the amount already recovered through the SOS Administrative Charge.

Q: Why do you recommend an extension of the deferral period?

A: Extending the deferral period to a full year increases the amount of time that participants can benefit from rate mitigation. Absent deferral, average residential bills are expected to increase from 45% to 50%, a substantial increase with as much potential for harm as the 72% increase experienced last year. As such, it would be appropriate to offer consumers the opportunity to defer the upcoming increase for as long as last year's increase is being deferred.

An extension to a full year would also reduce rate volatility. Under the Company's proposal, participants' rates will change four times between June 1, 2007 and June 1, 2008. Rates will: (1) increase on June 1, 2007 at the start of the Rate Stabilization Plan; (2) decrease on October 1, 2007 with the change from summer to winter rates; (3) increase on January 1, 2008 at the end of the deferral period; and (4) increase or decrease on June 1, 2008 with the change from winter to summer rates. My proposal to extend the deferral period to May 31, 2008 would eliminate the need for a rate change on January 1, 2008, only three months after the change to winter rates on October 1, 2007.

Q: Why is it reasonable for BGE to offset carrying costs with revenues from the return adder?

A: As I noted in my testimony in Case No. 9052, it is reasonable to view this return adder as providing compensation for the risks of cost deferral. Consequently, if BGE does not continue to credit back to residential ratepayers revenues from the 1.5 mill/kWh SOS return adder, such revenues should be applied as an offset to the carrying costs accrued on the deferral balance.[27]

Q: Why do you oppose BGE's proposal to increase the deferral-recovery surcharge to recover expected uncollectible costs?

A: SOS-related uncollectible costs are already being recovered through the 4 mill/kWh SOS Administrative Charge. Unless BGE is suggesting that the deferral will increase uncollectible costs over and above that already collected through the Administrative Charge, any increase to the deferral surcharge would amount to double recovery of such costs.

The Commission should reject the Company's proposal to increase the deferral surcharge, unless and until BGE can show that such an increase does not constitute double recovery of uncollectible costs. In this regard, the Company should be directed to include in future filings for specific surcharge rates its estimates of deferral-related incremental uncollectible costs, along with all workpapers and other documentation supporting such estimates.

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[27]Senate Bill 1, Section 20(4) requires Potomac Electric Power Company and Delmarva Power and Light to apply a portion of the return component to offset carrying charges from their voluntary, opt-in deferral programs.

Q: Does this conclude your testimony?

A: Yes.

Exhibit JFW-1

Qualifications of

JONATHAN F. WALLACH

Resource Insight, Inc.
5 Water Street
Arlington, Massachusetts 02476

SUMMARY OF PROFESSIONAL EXPERIENCE

1990–Present **Vice President, Resource Insight, Inc.** Provides research, technical assistance, and expert testimony on electric- and gas-utility planning, economics, regulation, and restructuring. Designs and assesses resource-planning strategies for regulated and competitive markets, including estimation of market prices and utility-plant stranded investment; negotiates restructuring strategies and implementation plans; assists in procurement of retail power supply.

1989–90 **Senior Analyst, Komanoff Energy Associates.** Conducted comprehensive cost-benefit assessments of electric-utility power-supply and demand-side conservation resources, economic and financial analyses of independent power facilities, and analyses of utility-system excess capacity and reliability. Provided expert testimony on statistical analysis of U.S. nuclear plant operating costs and performance. Co-wrote *The Power Analyst*, software developed under contract to the New York Energy Research and Development Authority for screening the economic and financial performance of non-utility power projects.

1987–88 **Independent Consultant.** Provided consulting services for Komanoff Energy Associates (New York, New York), Schlissel Engineering Associates (Belmont, Massachusetts), and Energy Systems Research Group (Boston, Massachusetts).

1981–86 **Research Associate, Energy Systems Research Group.** Performed analyses of electric utility power supply planning scenarios. Involved in analysis and design of electric and water utility conservation programs. Developed statistical analysis of U.S. nuclear plant operating costs and performance.

EDUCATION

BA, Political Science with honors and Phi Beta Kappa, University of California, Berkeley, 1980.

Massachusetts Institute of Technology, Cambridge, Massachusetts. Physics and Political Science, 1976–1979.

PUBLICATIONS

"The Future of Utility Resource Planning: Delivering Energy Efficiency through Distributed Utilities" (with Paul Chernick), *International Association for Energy Economics Seventeenth Annual North American Conference* (460–469). Cleveland, Ohio: USAEE. 1996.

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"Comments Regarding Retail Electricity Competition." 2001. Filed by the Maryland Office of People's Counsel in U.S. FTC Docket No. V010003.

"Final Comments of the City of New York on Con Edison's Generation Divestiture Plans and Petition." 1998. Filed by the City of New York in PSC Case No. 96-E-0897.

"Response Comments of the City of New York on Vertical Market Power." 1998. Filed by the City of New York in PSC Case Nos. 96-E-0900, 96-E-0098, 96-E-0099, 96-E-0891, 96-E-0897, 96-E-0909, and 96-E-0898.

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"Maryland Office of People's Counsel's Comments in Response to the Applicants' June 5, 1998 Letter." 1998. Filed by the Maryland Office of People's Counsel in PSC Docket No. EC97-46-000.

"Economic Feasibility Analysis and Preliminary Business Plan for a Pennsylvania Consumer's Energy Cooperative" (with John Plunkett et al.). 1997. 3 vols. Philadelphia, Penn.: Energy Coordinating Agency of Philadelphia.

"Good Money After Bad" (with Charles Komanoff and Rachel Brailove). 1997. White Plains, N.Y.: Pace University School of Law Center for Environmental Studies.

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“Review of Rockland Electric Company’s 1992 DSM Plan and the Demand-Side Management Rules” (with Paul Chernick et al.). 1992.

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“Comments on the Utility Responses to Commission’s November 27, 1990 Order and Proposed Revisions to the 1991–1992 Annual and Long Range Demand Side Management Plans” (with John Plunkett et al.). 1991.

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“Profitability Assessment of Packaged Cogeneration Systems in the New York City Area.” 1989. Principal investigator.

“Statistical Analysis of U.S. Nuclear Plant Capacity Factors, Operation and Maintenance Costs, and Capital Additions.” 1989.

“The Economics of Completing and Operating the Vogtle Generating Facility.” 1985. ESRG Study No. 85-51A.

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"Direct Access Implementation: The California Experience." Presentation to the Maryland Restructuring Technical Implementation Group on behalf of the Maryland Office of People's Counsel. June 1998.

"Reflecting Market Expectations in Estimates of Stranded Costs," speaker, and workshop moderator of "Effectively Valuing Assets and Calculating Stranded Costs." Conference sponsored by International Business Communications, Washington, D.C., June 1997.

EXPERT TESTIMONY

1989 **Mass. DPU** on behalf of the Massachusetts Executive Office of Energy Resources. Docket No. 89-100. Joint testimony with Paul Chernick relating to statistical analysis of U.S. nuclear-plant capacity factors, operation and maintenance costs, and capital additions; and to projections of capacity factor, O&M, and capital additions for the Pilgrim nuclear plant.

1994 **NY PSC** on behalf of the Pace Energy Project, Natural Resources Defense Council, and Citizen's Advisory Panel. Case No. 93-E-1123. Joint testimony with John Plunkett critiques proposed modifications to Long Island Lighting Company's DSM programs from the perspective of least-cost-planning principles.

1994 **Vt. PSB** on behalf of the Vermont Department of Public Service. Docket No. 5270-CV-1 and 5270-CV-3. Testimony and rebuttal testimony discusses rate and bill effects from DSM spending and sponsors load shapes for measure- and program-screening analyses.

1996 **New Orleans City Council** on behalf of the Alliance for Affordable Energy. Docket Nos. UD-92-2A, UD-92-2B, and UD-95-1. Rates, charges, and integrated resource planning for Louisiana Power & Lights and New Orleans Public Service, Inc.

1996 **New Orleans City Council** Docket Nos. UD-92-2A, UD-92-2B, and UD-95-1. Rates, charges, and integrated resource planning for Louisiana Power & Lights and New Orleans Public Service, Inc.; Alliance for Affordable Energy. April, 1996.

Prudence of utilities' IRP decisions; costs of utilities' failure to follow City Council directives; possible cost disallowances and penalties; survey of penalties for similar failures in other jurisdictions.

1998 **Massachusetts Department of Telecommunications and Energy** Docket No. 97-111, Commonwealth Energy proposed restructuring; Cape Cod Light Compact. Joint testimony with Paul Chernick, January, 1998.

Critique of proposed restructuring plan filed to satisfy requirements of the electric-utility restructuring act of 1997. Failure of the plan to foster competition and promote the public interest.

Massachusetts Department of Telecommunications and Energy Docket No. 97-120, Western Massachusetts Electric Company proposed restructuring; Massachusetts Attorney General. Joint testimony with Paul Chernick, October, 1998. Joint surrebuttal with Paul Chernick, January, 1999.

Market value of the three Millstone nuclear units under varying assumptions of plant performance and market prices. Independent forecast of wholesale market prices. Value of Pilgrim and TMI-1 asset sales.

1999 **Maryland PSC** Case No. 8795, Delmarva Power & Light comprehensive restructuring agreement, Maryland Office of People's Counsel. July 1999.

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2000 **U.S. FERC** Docket No. RT01-02-000, Order No. 2000 compliance filing, Joint Consumer Advocates intervenors. Affidavit, November 2000.

Evaluation of innovative rate proposal by PJM transmission owners.

2001 **Maryland PSC** Case No. 8852, Charges for electricity-supplier services for Potomac Electric Power Company, Maryland Office of People's Counsel. March 2001.

Reasonableness of proposed fees for electricity-supplier services.

Maryland PSC Case No. 8890, Merger of Potomac Electric Power Company and Delmarva Power and Light Company, Maryland Office of People's Counsel. September 2001; surrebuttal, October 2001. In support of settlement: Supplemental, December 2001; rejoinder, January 2002.

Costs and benefits to ratepayers. Assessment of public interest.

Maryland PSC Case No. 8796, Potomac Electric Power Company stranded costs and rates, Maryland Office of People's Counsel. December 2001; surrebuttal, February 2002.

Allocation of benefits from sale of generation assets and power-purchase contracts.

2002 **Maryland PSC** Case No. 8908, Maryland electric utilities' standard offer and supply procurement, Maryland Office of People's Counsel. Direct, November 2002; Rebuttal December 2002.

Benefits of proposed settlement to ratepayers. Standard-offer service. Procurement of supply.

2003 **Maryland PSC** Case No. 8980, adequacy of capacity in restructured electricity markets; Maryland Office of People's Counsel. Direct, December 2003; Reply December 2003.

Purpose of capacity-adequacy requirements. PJM capacity rules and practices. Implications of various restructuring proposals for system reliability.

2004 **Maryland PSC** Case No. 8995, Potomac Electric Power Company recovery of generation-related uncollectibles; Maryland Office of People's Counsel. Direct, March 2004; Supplemental March 2004, Surrebuttal April 2004.

Calculation and allocation of costs. Effect on administrative charge pursuant to settlement.

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Calculation and allocation of costs. Effect on administrative charge pursuant to settlement.

Maryland PSC Case No. 8985, Southern Maryland Electric Coop standard-offer service; Maryland Office of People's Counsel. Direct, July 2004.

Reasonableness and risks of resource-procurement plan.

2005 **FERC** Docket No. ER05-428-000, revisions to ICAP demand curves; City of New York. Statement, March 2005.

Net-revenue offset to cost of new capacity. Winter-summer adjustment factor. Market power and in-City ICAP price trends.

FERC Docket No. PL05-7-000, capacity markets in PJM; Maryland Office of People's Counsel. Statement, June 2005.

Inefficiencies and risks associated with use of administratively determined demand curve. Incompatibility of four-year procurement plan with Maryland standard-offer service.

FERC Dockets Nos. ER05-1410-000 & EL05-148-000, proposed market-clearing mechanism for capacity markets in PJM; Coalition of Consumers for Reliability, Affidavit October 2005, Supplemental Affidavit October 2006.

Inefficiencies and risks associated with use of administratively determined demand curve. Effect of proposed reliability-pricing model on capacity costs.

2006 **MD PSC** Case No. 9052, Baltimore Gas & Electric rates and market-transition plan; Maryland Office of People's Counsel, February 2006.

Transition to market-based residential rates. Price volatility, bill complexity, and cost-deferral mechanisms.

MD PSC Case No. 9056, default service for commercial and industrial customers; Maryland Office of People's Counsel, April 2006.

Assessment of proposals to modify default service for commercial and industrial customers.

MD PSC Case No. 9054, merger of Constellation Energy Group and FPL Group; Maryland Office of People's Counsel, June 2006.

Assessment of effects and risks of proposed merger on ratepayers.

Illinois Commerce Commission Docket No. 06-0411, Commonwealth Edison Company residential rate plan; Citizens Utility Board, Cook County State's Attorney's Office, and City of Chicago, Direct July 2006, Reply August 2006.

Transition to market-based rates. Securitization of power costs. Rate of return on deferred assets.

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Procurement of standard-offer power. Structure and format of bidding. Risk and cost recovery.

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Distorting effects of proposed reliability-pricing model on clearing prices. Economically efficient alternative treatment.

MD PSC Case No. 9063, optimal structure of electric industry; Maryland Office of People's Counsel, Direct Testimony, October 2006; Rebuttal November 2006; surrebuttal November 2006.

Procurement of standard-offer power. Risk and gas-price volatility, and their effect on prices and market performance. Alternative procurement strategies.

MD PSC Case No. 9073, stranded costs from electric-industry restructuring; Maryland Office of People's Counsel, Direct Testimony, December 2006.

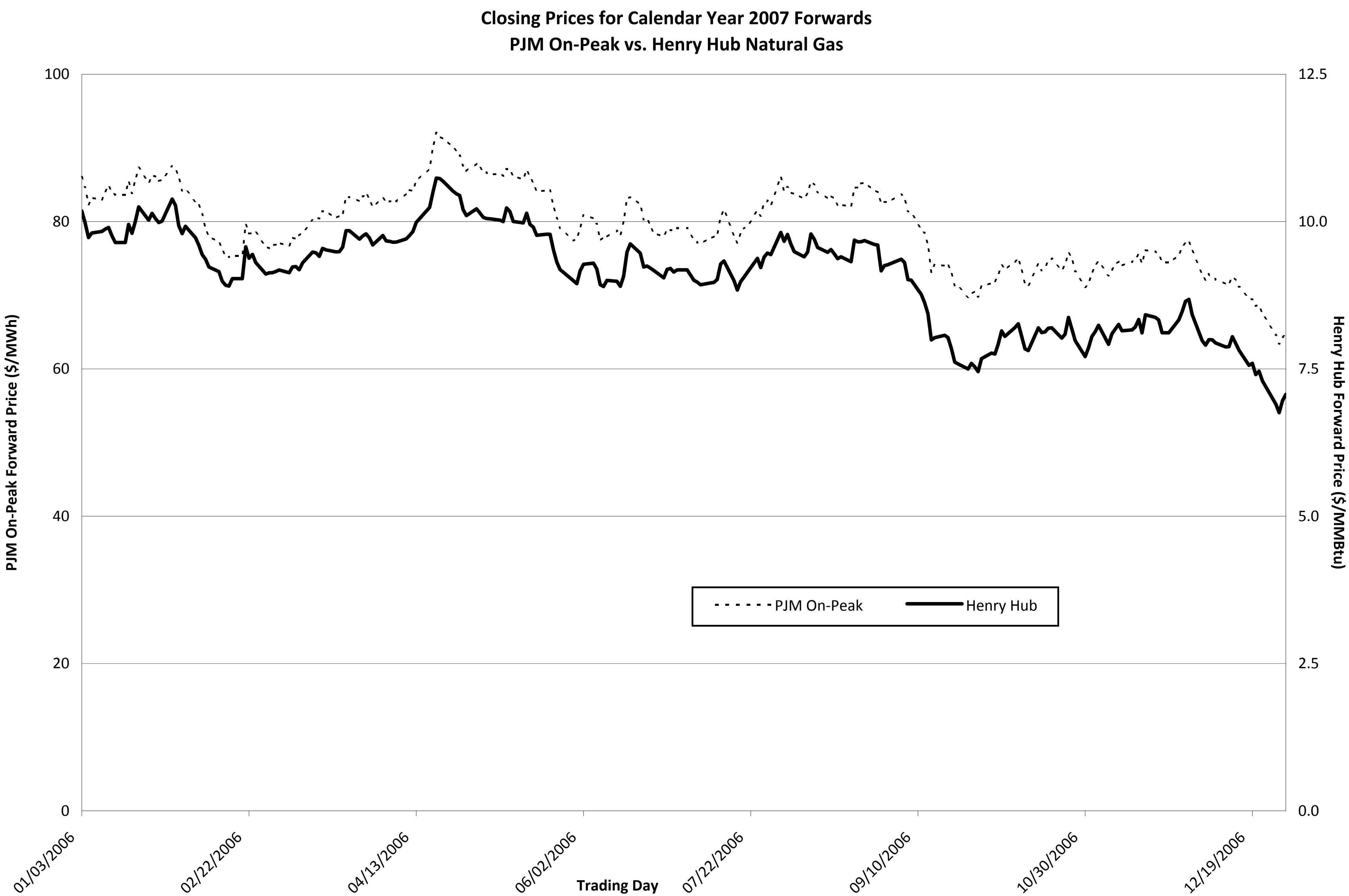
Review of estimates of stranded costs for Baltimore Gas & Electric.

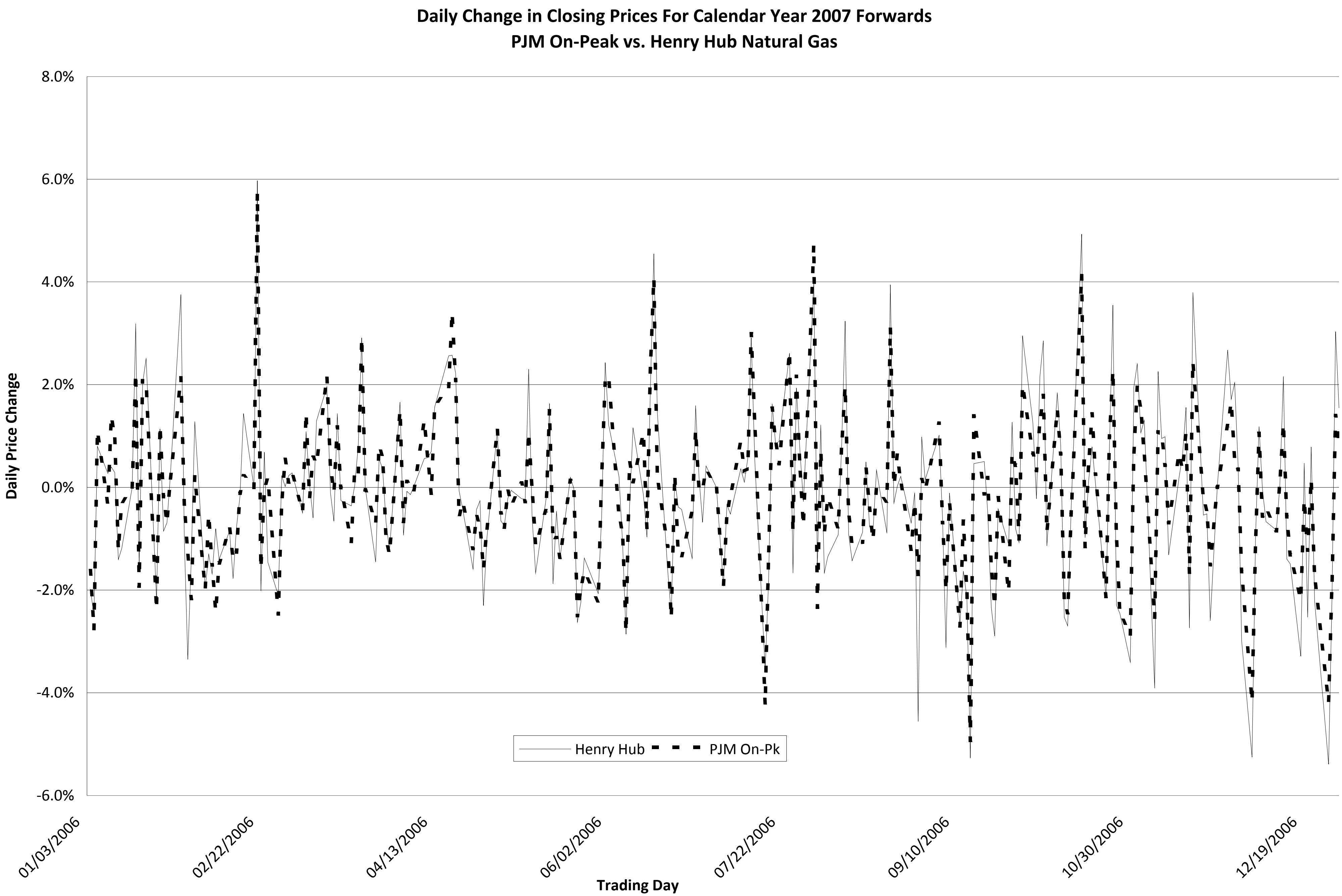
2007 **MD PSC** Case No. 9092, rates and rate mechanisms for the Potomac Electric Power Company; Maryland Office of People's Counsel, Direct Testimony, March 2007

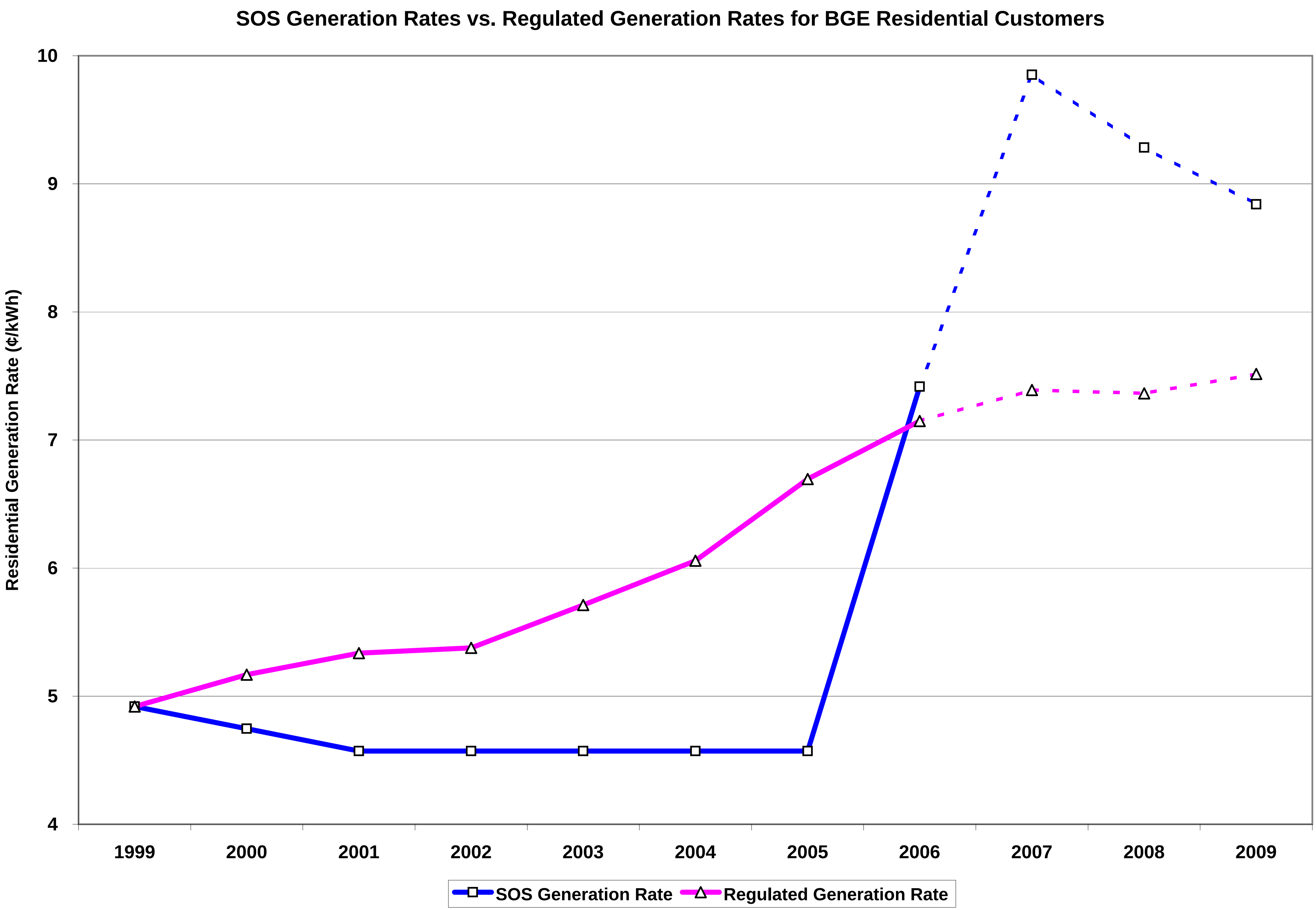
Cost allocation and rate design. Revenue-decoupling mechanism.

MD PSC Case No. 9093, rates and rate mechanisms for Delmarva Power & Light; Maryland Office of People's Counsel, Direct Testimony, March 2007

Cost allocation and rate design. Revenue-decoupling mechanism.


Closing Prices for Calendar Year 2007 Forwards
PJM On-Peak vs. Henry Hub Natural Gas
PJM On-Peak Forward Price ($/MWh)
Henry Hub Forward Price ($/MMBtu)
100
80
60
40
20
0
12.5
10.0
7.5
5.0
2.5
0.0
01/03/2006
02/22/2006
04/13/2006
06/02/2006
07/22/2006
09/10/2006
10/30/2006
12/19/2006
Trading Day
PJM On-Peak
Henry Hub


Daily Change in Closing Prices For Calendar Year 2007 Forwards
PJM On-Peak vs. Henry Hub Natural Gas
8.0%
6.0%
4.0%
2.0%
0.0%
-2.0%
-4.0%
-6.0%
Daily Price Change
Henry Hub
PJM On-Pk
01/03/2006
02/22/2006
04/13/2006
06/02/2006
07/22/2006
09/10/2006
10/30/2006
12/19/2006
Trading Day


SOS Generation Rates vs. Regulated Generation Rates for BGE Residential Customers
Residential Generation Rate (¢/kWh)
10
9
8
7
6
5
4
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
SOS Generation Rate
Regulated Generation Rate

ATTACHMENT 1

Rebuttal Testimony of Jonathan Wallach
Case No. 9063
November 3, 2006

STATE OF MARYLAND

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of the Optimal Structure of the	**)**	
Electric Industry of Maryland	**)**	**Case No. 9063**

REBUTTAL TESTIMONY OF

JONATHAN WALLACH

ON BEHALF OF

THE OFFICE OF PEOPLE'S COUNSEL

Resource Insight, Inc.

NOVEMBER 3, 2006

I. Introduction

Q: Please state your name, occupation, and business address.

A: I am Jonathan F. Wallach. I am Vice President of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Are you the same Jonathan F. Wallach that submitted direct testimony in this proceeding?

A: Yes.

Q: What is the purpose of your rebuttal testimony?

A: On October 3, 2006, a number of parties to this proceeding submitted direct testimony asserting that implementation of portfolio planning would harm consumers and competitive markets. Specifically, parties claim that acquisition of longer-term contracts or generation assets will: (1) yield prices that diverge from "prevailing" market prices; (2) undermine the competitive wholesale generation market and development of demand resources; (3) create stranded costs; and (4) potentially increase utilities' cost of capital. This rebuttal testimony addresses each of these claims.

In addition, Dr. Jonathan Lesser, on behalf of Baltimore Gas and Electric ("BGE"), estimates what BGE's rates would have been if Maryland's electric industry had not been restructured, and then compares those hypothetical rates against actual and projected BGE SOS prices. This rebuttal testimony critiques and corrects a number of unrealistic assumptions in Dr. Lesser's analysis.

People's Counsel is also sponsoring direct and rebuttal testimony from Ms. Barbara Alexander.

Q: Please summarize your findings and conclusions.

A: A number of parties to this proceeding have made unsubstantiated, inaccurate, or inconsequential claims regarding the impact on consumers and markets of including longer-term contracts or assets in SOS resource portfolios. Parties have offered no evidence to support the allegation that prices for short-term contracts more closely track prevailing market rates. In fact, a comparison of monthly contract pricing and prevailing retail price offers shows that monthly prices move in opposite directions to retail pricing trends.

Contrary to some parties' claims, longer-term contracts or generation investments neither undermine competitive markets, nor pose a significant risk of stranded costs in the future. Longer-term contracts or assets can co-exist with other physical and financial products that comprise competitive wholesale markets; utility procurement of such assets through a competitive process will not impair the liquidity of these other products. Moreover, as part of a larger and broader resource portfolio, longer-term contracts or assets are unlikely to cause the portfolio as a whole to be uneconomic.

Parties' concerns regarding the potential financial impact of longer-term contracting appear theoretically valid, yet may be of little practical consequence. Regardless, this risk should be addressed by subjecting all potential resource plans to comprehensive testing of financial impacts.

Dr. Lesser's comparison of hypothetical regulated rates and BGE SOS prices is not particularly relevant to this proceeding. Dr. Lesser's analysis of what rates would have been if BGE continued to operate as a vertically integrated utility provides little indication as to what rates might be if the Commission were to implement a portfolio planning and procurement process such as recommended by Ms. Alexander. Moreover, Dr. Lesser's analysis relies on a number of unrealistic assumptions and inputs; correcting for these improbable assumptions reverses Dr. Lesser's primary finding that consumers would pay higher rates in the future under regulation than under the current SOS procurement process.

II. Impact of Longer-Term Contracts and Generation Investments

Q: Please summarize parties' direct testimony in this proceeding with regard to the procurement of longer-term contracts or generation assets for the purposes of serving SOS load.

A: The testimony of a number of parties to this proceeding is that reliance on longer-term contracts or generation assets is harmful to consumers and the competitive wholesale and retail generation markets. Specifically, parties claim that acquisition of longer-term contracts or generation assets will: (1) yield prices that diverge from "prevailing" market prices; (2) undermine the competitive wholesale generation market and development of demand resources; (3) create stranded costs; and (4) potentially increase utilities' cost of capital.

Q: What do these parties recommend with regard to procurement of supply resources for SOS load?

A: Based on their assessments of the impact of longer-term resources, these parties recommend that SOS load continue to be supplied through short-term full-requirements contracts with terms ranging from as short as one month to up to three years.

Q: In general, do these parties accurately characterize the impact of longer-term contracting or asset investment?

A: No. As I discuss specifically below, these claims regarding the harm from longer-term contracting or investment are for the most part unsubstantiated and inaccurate.

Generally, these claims appear to arise from a mistaken premise: that the outcome of a portfolio-planning process will necessarily be a requirement to procure only longer-term contracts or assets. For example, in response to discovery, BGE characterizes the outcome of a portfolio-planning process as a "… requirement that utilities, as the providers of SOS service, purchase all or a significant part of their supplies on the basis of long-term bilateral contracts…."[1]

In fact, as described more fully in Ms. Alexander's testimony, portfolio planning is a process whereby utilities determine the least-cost mix of resources of varying types and durations and then acquire such resources through a dynamic and competitive process. In other words, portfolio procurement entails utilities acting like other buyers in competitive markets, procuring the mix of resources that serves their customers' interests in paying reasonable and stable SOS prices.

Q: Please summarize parties' comments with regard to the divergence between contract pricing and market pricing.

A: A number of parties assert that prices for longer-term contracts (or generation assets) are more likely to diverge from "prevailing" market prices than prices for short-term contracts. For example, PSC Staff witness Phillip E. VanderHeyden

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[1] BGE response to OPC Data Request No. 2, Item No. 20. Emphasis in original.

claims that: "The longer the contract, the more opportunity for SOS rates to diverge from market rates."[2] Mr. VanderHeyden then goes on to claim that procurement of monthly contracts "… would mitigate the risk that SOS is priced significantly differently than prevailing market offers."[3]

Charles S. Griffey, on behalf of the Retail Energy Supply Association, similarly supports his proposal for procurement of monthly contracts by noting that "… monthly priced SOS will allow for competitive entry by avoiding the disconnect between SOS and market prices that can occur over the duration of long-term contracts."[4]

Q: What do these parties mean when they refer to prevailing "market rates" or "market prices"?

A: These parties do not precisely define what they mean by either "prevailing" or "market prices." As best as I can discern from their testimony and responses to discovery, these parties are referring to current price offers by competitive retail suppliers for any product offered.

Q: According to these parties, what drives the divergence between longer-term contract prices and prevailing retail price offers?

A: Although not stated explicitly, these parties appear to believe that the extent of price divergence depends on how often SOS contracts are re-priced through the procurement process. According to this logic, competitive retail prices change frequently, reflecting changes in underlying wholesale market prices for the product being offered (e.g., a one-year contract for full-requirements service.) In

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[2] *Direct Testimony of Phillip E. VanderHeyden*, Case No. 9063, October 3, 2006, p. 15.

[3] *Id.*

[4] *Direct Testimony of Charles S. Griffey*, Case No. 9063, October 3, 2006, p. 11.

contrast, the price of a longer-term SOS contract is set once at the time of procurement, reflecting underlying wholesale market prices at that point in time, and fixed for the duration of the contract.[5] Thus, price divergence is driven by the fact that underlying wholesale market prices can and will vary considerably over time.

Following this line of reasoning, the shorter the term of the SOS contract, the lower the risk of price divergence. Since, for example, monthly SOS contracts have to be procured on a monthly basis, SOS would be re-priced each month, more closely tracking changes in the wholesale market prices underlying retail price offers.

Q: Have these parties offered any evidence to support this alleged divergence between longer-term contract prices and prevailing price offers?

A: No.

Q: What does the experience with residential retail choice in Maryland indicate with regard to the impact of this alleged divergence on competitive entry?

A: Experience over the last six years does not support the contention that the alleged price divergence has been a barrier to competitive entry and the development of retail markets. In fact, trends in residential-customer migration appear to support the opposite conclusion.

Exhibit JFW-R1 shows monthly switching statistics for Potomac Electric Power Company ("PEPCo") residential customers from the start of retail choice in 2000 through September of this year. If, as Mr. Griffey contends, the alleged price divergence hinders competitive entry, then one would expect to see

[5] Although fixed for the term of the contract, prices for a multi-year SOS contract can vary by year and by season within each year.

increased migration to competitive supply whenever there was a significant re-pricing of residential SOS, since such re-pricing should decrease price divergence. Thus, one would expect increased migration after July of 2004, when PEPCo SOS switched from capped to market-based rates, and after June of the following two years, when SOS rates were re-priced to reflect procurement of new contracts in those years.

Instead, as indicated in Exhibit JFW-R1, the only period of increased switching was in the first two years of retail choice, when residential SOS was priced at capped rates. After reaching a peak of almost 16% in mid-2003, residential migration has steadily declined through all re-pricing periods.

Q: Would you expect a strong correlation between prices for shorter-term contracts, such as monthly contracts, and prevailing price offers?

A: No. A monthly contract is a different market product, with different market pricing dynamics, than those being offered by retail suppliers. There is no reason to expect that pricing of a monthly SOS contract would track that for a significantly longer-term retail offer for full-requirements service, since the underlying wholesale market prices for these two different products are unlikely to be strongly correlated.

Exhibit JFW-R2 illustrates how unlikely it is that monthly SOS contract prices will track prevailing price offers for competitive retail supply. Exhibit JFW-R2 graphs two data series. First, it shows actual price offers by Washington Gas Energy Services ("WGES") for residential customers in PEPCo's service territory between March 26 and September 6 of this year.[6]

[6] These price offers are provided in Attachment 1 to WGES response to OPC Data Request 2, Item No. 2. Between March 26 and September 6 of this year, WGES offered only one product to PEPCo residential customers; this product had a contract term that ended in June of 2008. Exhibit JFW-R2 shows price offers for non-time-of-use residential customers.

Second, Exhibit JFW-R2 shows a simulation of monthly SOS prices during this same period under a monthly procurement scheme, assuming that: (1) SOS contracts for delivery in one month (e.g., June) are procured the prior month (e.g., May); and (2) monthly SOS contracts are priced at PJM on-peak monthly forward prices prevailing at the time of procurement.[7]

As indicated in Exhibit JFW-R2, monthly SOS prices would not have tracked very closely with changes in WGES' retail price offers over the sample period. In fact, simulated monthly prices appear to trend in opposite directions from WGES' offers, rising when offers are falling, and vice versa.[8]

Q: Would evidence of strong correlation between monthly contract prices and retail price offers be a valid basis for adopting monthly procurement of SOS contracts?

A: No. As Ms. Alexander discusses in her rebuttal testimony, monthly procurement would expose consumers to unreasonable price volatility, and would be contrary to the objective to minimize volatility established in Senate Bill 1.

Q: What are parties' concerns with regard to the impact of longer-term contracting or asset investment on wholesale markets?

A: Some parties express a general concern that longer-term contracting or asset investment would undermine the wholesale generation or demand-response

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[7] As I noted in my direct testimony, contract prices for full-requirements service will reflect costs other than for on-peak forwards. However, changes in on-peak forward prices are primary drivers of movements in such contract prices. Thus, monthly forward prices provide a reasonable indication of movements in monthly SOS contract prices and of the correlation between monthly SOS prices and retail price offers.

[8] This apparent negative correlation is confirmed with the calculation of the correlation coefficient for these two data series; the correlation coefficient indicates a weak, but negative correlation between these two data series.

markets. Specifically, parties claim that longer-term contracts or investments by utilities would create a barrier to entry by new merchant generation in PJM. For example, according to Michael M. Schnitzer, testifying on behalf of Constellation Energy Commodities Group:

> A decision by a utility to put a new plant in rate base or to enter into long-term contracts will require some form of regulated cost recovery. But who would want to build a merchant plant when the possibility exists that a competing developer could get a long-term contract with assured cost recovery? A return to rate base construction would fundamentally undermine wholesale competition. It will discourage future market-based investment in new capacity.[9]

Mark D. Case, on behalf of BGE, further argues that longer-term contracts will undermine the development of demand resources:

> Wholesale market pricing disrupted by quasi-regulated generation will have the same negative effect on demand resources as it will have on merchant generation. The ability for new demand resources to compete in a market with quasi-regulated generation resources will be diminished and result in less or even no further development, even though demand response services may be the most economically efficient resources to deploy.[10]

Q: Does Mr. Schnitzer reasonably characterize the impact of longer-term contracting or asset investment on the merchant-generation market?

A: No. Mr. Schnitzer mischaracterizes competitive market dynamics when he claims that longer-term contracts or asset investment will stifle development of merchant generation. As with other competitive markets, long-term contracts can co-exist with pure merchant plays in wholesale generation markets, with market participants taking hedged (i.e., contractual) or speculative (i.e.,

[9] *Direct Testimony of Michael M. Schnitzer*, Case No. 9063, October 3, 2006, p. 14.

[10] *Direct Testimony of Mark D. Case*, Case No. 9063, October 3, 2006, p. 19.

merchant) positions depending on the extent of their risk aversion. According to Mr. Case:

> … [A] workably competitive wholesale market provides market discipline for all types of contractual arrangements and there can be many types of contractual arrangements between buyers and sellers. The terms, conditions, length of any contract will depend on the risks that the buyers and sellers are willing to bear, the different expectations of all market players as to future price trends, the price responsiveness of demand in the market, as well as the creativity of buyers and sellers in negotiating contracts that meet their respective needs.[11]

Mr. Schnitzer asks: "[W]ho would want to build a merchant plant when the possibility exists that a competing developer could get a long-term contract with assured cost recovery?"[12] The answer is: In a competitive market, someone would choose to build a merchant plant if they believe they could maximize their profit by selling into the spot market, and are willing to assume spot-price risk. The fact that other market participants choose to hedge that risk with longer-term contracts or investments should have little bearing on that decision.

Q: What is the basis for Mr. Case's assertion that longer-term contracts will undermine merchant generation and development of demand resources?

A: In response to discovery, Mr. Case argues that:

> If … there is a <u>requirement</u> that utilities, as the providers of SOS service, purchase all or a significant part of their supplies on the basis of long-term bilateral contracts, then the market discipline provided by a workably competitive wholesale spot market will be eroded….[13]

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[11] Response to OPC Data Request No. 2, Item No. 20.

[12] In fact, as I discussed in my direct testimony in this proceeding, the more-pertinent question in today's wholesale generation market is: Who would want to finance or invest in new generation without the long-term revenue assurance associated with a longer-term contract for the output of that asset?

[13] Response to OPC Data Request No. 2, Item No. 20. Emphasis in original.

In essence, Mr. Case appears to be arguing that excessive reliance on longer-term contracts will substantially reduce the amount of generation traded in the spot market, severely eroding the value of spot-market prices as a revenue source for merchant generation and as a competitive benchmark for valuing demand resources.

Q: Is this a valid argument?

A: No. As noted above, the premise of this argument is not valid, since a resource portfolio such as that envisioned by Ms. Alexander to be in compliance with SB1 will not consist entirely or in large part of longer-term contracts or assets. Moreover, regardless of the extent of that reliance on longer-term resources, it is not reasonable to presume that such resources will not be offered into PJM's spot energy markets. In fact, PJM's market rules require resources to be offered into the day-ahead market in order to be counted toward a load-serving entity's capacity obligation. Finally, even if such resources were not offered into PJM's spot markets, the impact on liquidity in markets that typically clear 80-90 gigawatts of generation per hour is likely to be negligible.

Q: What concerns do parties raise concerning stranded costs?

A: Some parties express the concern that the costs of a longer-term contract or generation investment may eventually be stranded, i.e., that the cost of the contract may exceed the contract's market value. According to Mr. Schnitzer: "Long-term contracts also create the potential for a new round of stranded costs, as we have seen in California."[14] In essence, the concern is that utilities may enter into a longer-term contract or investment commitment based on

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[14] Schnitzer direct, p. 14.

expectations about future market-price trends, only to find that market prices fall below expected levels.

Q: Is the potential for stranded costs a significant concern?

A: This concern is not significant enough to exclude longer-term contracts or generation assets from the menu of resource options to be evaluated as part of the portfolio-planning process.

Three considerations temper such concerns. First, a longer-term contract or investment will be one of several resources in a much-larger, diversified resource portfolio. This diversification hedges the risk of any one contract or investment becoming stranded, and increases the likelihood that the portfolio as a whole will be economic over the long term.

Second, a narrow focus on the risk of stranded costs fails to capture the insurance value of a longer-term contract or investment. Whether or not a contract is ultimately economic over its term, it can provide a long-term hedge against market-price risk, providing insurance against the harm of unanticipated price volatility.

Finally, any concern about a "new round of stranded costs" in Maryland needs to be weighed against the possibility that, contrary to some parties' expectations in 1998 and unlike in California, there may not actually have been a first round of stranded costs in this State.[15] One indication of this possibility is provided by the 1998 testimony of Paul Chernick on behalf of OPC in Case No.

[15] Mr. Schnitzer's reference to the California experience is ironic, since the State entered into over-priced contracts in response to the exercise of market power, and since, in turn, the ability to exercise market power was partly due to the fact that the California Commission severely limited the utilities' ability to enter into longer-term contracts at the outset of restructuring. See, for example, Federal Energy Regulatory Commission, *Order Proposing Remedies for California Wholesale Electric Markets*, 93 FERC ¶ 61,121, November 1, 2000.

8794 regarding BGE's stranded costs. Based on a forecast of market prices, Mr. Chernick found that the market value of BGE's generation portfolio exceeded the portfolio's expected costs. In other words, based on his market-price forecast, Mr. Chernick found that BGE's portfolio produced stranded benefits, not stranded costs. It now turns out that market prices in PJM in the eight years since Mr. Chernick's analysis have been substantially higher than were forecasted by Mr. Chernick for this same period of time. Thus, the experience in PJM over the past eight years indicates that Mr. Chernick may have in fact underestimated the market value of BGE's assets and thus the true magnitude of stranded benefits.[16]

Q: Please discuss parties' claims regarding the potential impact of longer-term contracts on utilities' cost of capital.

A: According to BGE and PEPCo, credit agencies will treat a portion of longer-term contract payments as equivalent to debt for the purposes of determining debt leverage on a utility's balance sheet and for deriving interest coverage ratios. As a result, utility procurement of longer-term contracts, by increasing imputed debt leverage, could lead to a ratings downgrade or require an offsetting increase in equity to restore credit quality. In either case, BGE and PEPCo assert, contract procurement would increase the utility's overall cost of capital.

Q: Is this a valid concern?

A: This appears to be a valid theoretical concern. However, the actual financial impact may not be significant, since such contracts might represent only a small portion of a utility's total SOS portfolio.

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[16] Mr. Chernick's underestimate of actual market prices would be offset by any underestimate of actual prices for fuel burned by BGE's assets.

Q: How should this risk be addressed?

A: This risk should be addressed as part of a comprehensive economic and financial evaluation of various portfolio plans. The financial impact of longer-term contract obligations should be weighed against the financial risks associated with reliance on shorter-term contracts, such as the potential financial impact of substantial deferrals of large price increases.

III. BGE Analysis of Regulated Rates

Q: Please describe Dr. Lesser's analysis of regulated rates.

A: Dr. Lesser believes that "[t]he claim that Maryland consumers would be better off had restructuring never occurred is central to the matter under consideration in this proceeding."[17] In order to test the validity of this "central" claim, Dr. Lesser undertook an analysis of what BGE residential rates would have been between 2000 and 2006, and what they would be in the next three years, if BGE's generation function had not been restructured in 1999. Comparing these hypothetical regulated rates against his forecast of SOS rates for the next three years, Dr. Lesser concludes that "… BGE residential customers are better off with competitive procurement than they would have been under regulation, notwithstanding the result of the 2006 RFP process."[18]

[17] *Direct Testimony of Jonathan A. Lesser*, Case No. 9063, October 23, 2006, p. 34.

[18] *Id*.

Q: Do you agree that the issue of whether consumers would have been better off under continued regulation is central to this proceeding?

A: No.[19] As Ms. Alexander discusses in her testimony, the central issue in this proceeding is how to establish a procurement process for residential SOS customers that complies with the mandates in SB1. The focus of this proceeding should be on the concrete issue of how to move forward with a procurement process that achieves the "best price" with minimum price volatility, not on speculative ruminations as to how consumers would have fared if the electric restructuring statute had never become law.

Q: Are the results of Dr. Lesser's analysis relevant to the consideration of the likely costs of an SB1-compliant resource portfolio?

A: These results are not particularly relevant to this case. Dr. Lesser's projection of costs for BGE's generation assets that were transferred to Constellation Power provides little indication as to what the costs might be for a portfolio of resources compiled under a portfolio planning and procurement process such as recommended by Ms. Alexander. It is unlikely that an SB1-compliant portfolio would bear any resemblance to that assembled by BGE over the last fifty years, spanning a period of momentous change in generation technology, industry structure, and regulatory practice.

Q: Notwithstanding the issue of relevance, are the results of Dr. Lesser's analysis reliable?

A: No. A number of unrealistic assumptions and data inputs seriously impair the reliability of his results.

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[19] Nor is it even clear who Dr. Lesser believes is making this claim. As far as I am aware, no party to this proceeding filed testimony contending that consumers would have been better off without electric restructuring.

Dr. Lesser's methodological approach is problematic in two respects. First, the analysis assumes that non-generation-related costs would be greater without restructuring than with restructuring. Specifically, the analysis assumes that distribution and transmission rates, and thus underlying costs, would have risen from 1999 levels at the general rate of inflation in the absence of restructuring, but would be constant at 1999 levels with restructuring.[20] It is not reasonable to assume lower T&D costs for the with-restructuring case, since restructuring of the generation function would not directly affect non-generation-related costs.[21] Nor is it reasonable to assume that T&D *cost* increases will necessarily translate into T&D *rate* increases, since rate changes depend on earned rates of return, cost of capital, and other factors in addition to cost of service.[22]

Second, Dr. Lesser assumes that, in the absence of restructuring, BGE would not have been able to purchase power from the PJM wholesale market in order to meet load growth. Dr. Lesser supports this assumption by arguing that "… it is not reasonable to assume that the PJM market would have developed the way it did had restructuring not occurred."[23] Instead, even though PJM has

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[20] The fact that the restructuring settlement agreement reduced and froze residential distribution *rates* is not relevant to the impact of generation restructuring on distribution *costs*. Dr. Lesser's analysis unrealistically assumes that T&D rates after the end of the rate freeze would be higher in the absence of restructuring, as if the underlying T&D costs would have been greater in the absence of restructuring.

[21] Indeed, if any differential were to be assumed, it would be greater transmission costs with restructuring, reflecting the additional investment in transmission upgrades to support increased wholesale transactions.

[22] See, for example, OPC's petition of September 3, 1998 in Case No. 8804, which argues for a reduction in BGE's rates due to over-earnings. The findings in this petition would support an assumption of a decrease in BGE's rates in the absence of restructuring.

[23] Lesser direct, p. 35

been awash in excess capacity since 1999 and wholesale-market prices have consequently been at depressed levels, he assumes that all load growth from 1999 is met with investment in new gas-fired combined-cycle capacity at prices that far exceed actual wholesale-market price levels.[24]

This assumption is unrealistic. PJM has operated as a tight power pool, providing BGE access to wholesale economy-energy purchases and sales, for many decades. The PJM system was restructured to create a competitive wholesale market in 1997, with market-based pricing implemented in 1999; it was this restructuring, not that of BGE's generation function, along with subsequent trends in fuel prices, capacity additions, and regional expansion, that determined wholesale market prices after 1999. Whether or not its generation had been restructured in 2000, BGE would have had access to wholesale power from this glutted market, just as it had as part of the PJM power pool for all those years.

Finally, Dr. Lesser unreasonably assumes that fuel prices for BGE's coal and nuclear assets would have increased at spot-price escalation rates, as if coal and nuclear fuel requirements were purchased predominantly on the spot market and not through a combination of contract and spot purchases, as had been actual practice prior to the divestiture of BGE's assets.[25] This assumption yields unrealistically high fuel-price growth rates. For example, Dr. Lesser projects a doubling of nuclear fuel prices between 1999 and 2005, when, according to data

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[24] According to PJM, investment in new combined-cycle generation would not have been economic relative to wholesale market prices from 2000 to 2005. See PJM Interconnection, LLC, *2005 State of the Market Report*, March 8, 2006, Table 3-13, p. 131.

[25] For a description of BGE's fuel contracts as of 1998, see *Testimony of Bruce A. Barnaba*, Case No. 8520V, January 2, 1998.

published by the Energy Information Administration, actual industry-wide average growth over that same period was less than 25%.

Q: Did you correct for these improbable assumptions?

A: Yes. I corrected each of these assumptions as follows:[26]

- I revised the analysis so that it simulates and compares only the generation portions of SOS and hypothetical regulated rates. By so doing, I effectively assume that T&D costs would be the same in both the restructuring and continued-regulation scenarios.
- In the continued-regulation scenario, I assume that load growth after 1999 would be served with purchases from the PJM wholesale market at actual or forward market prices for energy (as adjusted for congestion and load shape) and capacity.
- I assume that coal and nuclear fuel prices escalate at industry-wide average rates, as reported by the Energy Information Administration.

Q: How do these corrections affect the results of Dr. Lesser's analysis?

A: With these corrections, Dr. Lesser's analysis finds that residential generation rates in 2007 through 2009 would be lower under continued regulation than under the current SOS procurement approach. In other words, correcting the unrealistic assumptions discussed above reverses Dr. Lesser's primary finding that consumers would pay higher rates in the future under regulation than under the current SOS procurement process.

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[26] I also corrected a few less-significant calculation errors in Dr. Lesser's model. For example, in his calculation of SOS generation rates for 2007 and beyond, Dr. Lesser mistakenly assumed that a mix of one-, two-, and three-year contracts would be procured in each year. In fact, per the terms of the settlement agreement in Case No. 8908, only one-year contracts will be procured in 2007, one- and two-year contracts will be procured in 2008, and only one-year contracts will be procured in 2009.

The impact of these corrections is shown in Exhibit JFW-R3, which mimics Dr. Lesser's Exhibit BGE-JAL-3 for the corrected simulations of the two scenarios. As indicated in Exhibit JFW-R3, Dr. Lesser's corrected simulation projects SOS generation rates to exceed regulated generation rates by about 20%-30% between 2007 and 2009.

Q: Does this conclude your testimony?

A: Yes.