STATE OF MARYLAND

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of the Commission's	**)**	
Investigation into a Residential	**)**	
Electric Rate Stabilization and	**)**	**Case No. 9052**
Market Transition Plan for	**)**	
Baltimore Gas and Electric Company	**)**	

DIRECT TESTIMONY OF

JONATHAN WALLACH

ON BEHALF OF

THE MARYLAND OFFICE OF PEOPLE'S COUNSEL

Resource Insight, Inc.

FEBRUARY 13, 2006

I. Introduction and Qualifications

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.

I graduated Phi Beta Kappa from the University of California at Berkeley with a BA in political science with honors. 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 and Delmarva Power & Light), 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). Currently, I monitor the SOS procurement process on OPC's behalf.

Q: On whose behalf are you testifying?

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

II. Overview

Q: What is the purpose of your testimony?

A: Pursuant to the Commission's Order Initiating Proceeding of January 10, 2006, Phillip VanderHeyden of the Commission Staff filed direct testimony regarding a proposal for transitioning Baltimore Gas and Electric's ("BGE") residential customers to market-based SOS rates. This testimony responds to Mr. VanderHeyden's proposal.

Q: Please summarize the major findings and conclusions of your testimony.

A: In anticipation of unprecedented rate increases due to the switch from frozen to market-based residential SOS prices, Staff proposes to defer and then recover some of these increases over a two-year period. According to Staff, the proposed deferral mechanism reasonably mitigates rate shock to consumers without unduly increasing shareholders' financial exposure.

Staff's primary objectives – spreading the impact of market-based SOS rates over time while preserving price signals and financial integrity – and basic approach – cost deferral through distribution credits over a limited span of time– are both reasonable. However, a number of elements of Staff's specific proposal are problematic, and raise concerns that the proposed mechanism may not achieve Staff's objectives.

I illustrate how Staff's model can be modified to address these concerns while preserving Staff's basic approach and primary objectives. However, I do not recommend adoption of this illustrative model (or any other specific model) at this time, since we do not yet know what actual SOS prices and bill impacts will be or what it will cost to implement a deferral mechanism.

Q: What actions do you recommend the Commission take at this time?

A: If the Commission finds that a deferral mechanism is in the public interest, I recommend that the Commission establish a second phase to this proceeding to commence immediately following issuance of an initial order in this phase of the proceeding. The Commission should direct BGE to file in this second phase a detailed deferral scheme and implementation plan based on final retail SOS prices that result from this year's SOS procurement process.

III. PSC Staff Proposal

Q: Please summarize Staff's proposal for a transition mechanism.

A: BGE's residential consumers are likely to face significant rate increases starting in July of 2006, with the implementation of market-based rates for Standard Offer Service. In order to mitigate the harm to consumers, Mr. VanderHeyden proposes to defer a portion of the expected increase. In order to mitigate financial exposure to shareholders from such a cost deferral, Mr. VanderHeyden proposes to:

- Recover all deferred costs within two years;
- Cap the maximum amount of deferred costs;
- Allow return on deferred amounts at the rate authorized in Case No. 9036;[1]
- Increase rates one month prior to the implementation of market-based rates.

Under Staff's proposal, costs would be deferred (recovered) via a non-bypassable monthly credit (surcharge) to distribution rates; customers would continue to see actual, market-based SOS rates on their bills. In addition, Staff proposes to implement the transition mechanism on a voluntary, opt-in basis that provides residential ratepayers the choice of financing their SOS costs at the authorized rate of return.

Q: Would all residential ratepayers have the opportunity to opt-in to Staff's proposed transition mechanism?

A: Mr. VanderHeyden's testimony describes the transition proposal and its impact solely in the context of the residential R class. It is not clear whether Staff intends to allow RL customers to also participate in the transition mechanism.

Q: Do you have any concerns regarding the proposal to employ credits or surcharges that vary on a monthly basis?

A: I have two concerns. First, I am concerned that the proposal to vary the credit or surcharge amounts on a monthly basis unreasonably increases price volatility for

[1] I have been informed by counsel that the rate of return authorized in Case No. 9036 is currently under appeal.

residential consumers. Second, I am concerned that the use of monthly credits or surcharges will significantly increase billing complexity and thus billing costs. I am particularly concerned that the use of monthly credits or surcharges may be difficult and costly to incorporate under budget billing. Unfortunately, Staff's proposal does not specify how such credits or surcharges will be applied to budget-billing customers.

It is not necessary to use monthly credits or surcharges. As I show in Section IV, it is possible to devise a deferral mechanism that achieves all of Staff's objectives, yet which employs seasonal rather than monthly credits and surcharges.

Q: What is the basis for Staff's proposal to limit the deferral period to two years?

A: Mr. VanderHeyden offers three reasons for selecting a two-year deferral period. First, he asserts that a shorter period provides the financial community greater assurance of cost recovery, while minimizing carrying costs on the deferral paid by consumers. Second, Mr. VanderHeyden wants to limit the time required to transition consumers to market prices, since:

> Holding generation prices artificially low over the past seven years created the instant problem. Consumers have come to expect the artificially low prices. (pp. 18-19)

Third, Mr. VanderHeyden claims that a quick transition period reduces the risk that customers will leave BGE's service territory before they have paid back their share of the deferred costs, and thus reduces the risk that remaining customers will be on the hook for such unrecovered costs.

Q: Does Staff's proposal provide adequate assurance of cost recovery?

A: Staff's proposal not only provides adequate assurance of cost recovery, but also more than adequately compensates shareholders for the risk of unrecovered costs. Staff's proposal to allow a return on deferrals at the authorized weighted average cost of capital is extremely generous, as it compensates shareholders for the risk associated with guaranteed recovery over a two-year deferral period at the same rate as afforded for the substantially greater risk associated with the uncertain recovery of utility-plant investment over decades-long amortization periods.

Q: Are concerns regarding appropriate SOS price signals relevant to the consideration of the appropriate length for a deferral period?

A: Mr. VanderHeyden's concerns in this regard are not relevant, since Staff's proposal is designed to mitigate the bill impact of the switch from frozen to market-based SOS prices without reducing the SOS prices that customers see on their bills. Under Staff's proposal, the SOS price paid by consumers, and thus the price against which consumers compare competing offers, will be the market-based price set by the SOS procurement process. Staff further proposes to offset some of the immediate bill impact of the switch from frozen to market-based SOS rates through a credit to distribution rates. Thus, regardless of the length of the deferral period or the magnitude of the bill-impact offset, consumers will be fully exposed to market-based price signals starting on July 1, 2006.

Q: Are concerns regarding subsidization of departing customers by remaining customers a relevant consideration when setting the length of the deferral period?

A: Only to the extent that costs stranded by departing customers are to be directly recovered from remaining customers. Mr. VanderHeyden apparently presumes that deferrals not recovered from departing transition-program participants will be recovered from remaining participants.[2] However, it may be more appropriate to impose some form of exit fee or reconciliation charge on departing participants.[3]

Q: How does Staff propose to cap the total amount of deferred costs over the two-year transition period?

A: Mr. VanderHeyden caps the maximum amount of total deferred costs over the two-year period by specifying maximum values for the monthly deferral credits or surcharges.

Q: How does Mr. VanderHeyden determine the maximum values for the monthly credits or surcharges?

A: Mr. VanderHeyden first estimates summer and non-summer price levels for residential SOS starting in July.[4] Mr. VanderHeyden then derives monthly credit or surcharge values that: (1) defer from the first year to the second year of the deferral period a portion of the bill impact associated with the change from frozen to the assumed market-based SOS prices; and (2) fully recover deferred amounts (including a return on deferrals) by the end of the deferral period. Finally, Mr. VanderHeyden simply deems these monthly *derived* values for the

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[2] Presumably, these outstanding deferrals would be recovered through an adjustment to the monthly deferral credits or surcharges. However, Staff's proposal does not specify how such costs will be recovered.

[3] Some form of reconciliation charge would also be necessary for any participant that switches to a competitive supplier.

[4] In his direct testimony (p. 9), Mr. VanderHeyden states that he estimated market prices of $120/MWh for the summer months and $102/MWh for the non-summer months for the purposes of calculating monthly credits and surcharges. In fact, as shown on page 1 of his Attachment 1, his calculation is based on market prices of $115/MWh for the summer and $95/MWh for the non-summer.

credit or surcharge – as derived based on his initial estimate of SOS prices – to be the monthly *maximum* values.

Mr. VanderHeyden's estimate of SOS prices results in an average bill impact relative to frozen prices of approximately 67%.[5] Thus, absent mitigation and assuming Mr. VanderHeyden's price estimate, bills would increase 67% in the first year of market-based rates. Since Mr. VanderHeyden assumes that these market prices remain constant over time, there would be no increase in bills in the second year compared to the first. Based on his estimate of market price, Mr. VanderHeyden derives monthly credit and surcharge values that reduce the bill impact in the first year of the deferral period from 67% to about 43%.[6] However, recovery of the deferred costs results in an additional 30% bill increase in the second year relative to the first.

Q: Is it reasonable to establish maximum values in this fashion?

A: No. Staff's proposal inappropriately fixes the maximum values, and thus the maximum allowable mitigation, before knowing what actual prices and bill impacts might be. Instead of using actual prices, Staff's proposal caps the mitigation amount based on an estimate of market prices that Mr. VanderHeyden acknowledges "are virtually impossible to estimate with reasonable assuredeness." (p. 22)

As just discussed, the proposed credit and surcharge values lead, under Mr. VanderHeyden's estimate of market prices, to annual bill increases of 43% in the first year and 30% in the second year. However, since these are the

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[5] That is, according to Mr. VanderHeyden's calculations, electric bills for the 11-month period starting July 1, 2006 are expected to be 67% higher than for the 11-month period ending June 30, 2005.

[6] This 43% figure is inclusive of the rate increase in June of 2006 under Staff's proposal.

maximum allowed credit and surcharge values, actual bill impacts could be significantly greater if Mr. VanderHeyden has under-estimated SOS prices. In other words, Staff's proposal would cap shareholders' exposure to cost deferrals at a pre-determined level, regardless of the potential impact on consumer bills from actual SOS price increases.

In fact, Staff's proposal allows consumer bills to increase by a greater percentage than calculated by Mr. VanderHeyden, even when BGE's total exposure is less than the maximum amount allowed under Staff's approach. Mr. VanderHeyden's calculation of the maximum credit and surcharge values, and of the resulting deferral amount, assumes 100% participation in the voluntary program. If SOS prices are greater than estimated by Mr. VanderHeyden, but participation is less than 100%, Staff's proposal would require bill increases greater than the 43% estimated by Mr. VanderHeyden, even though the total amount of deferred costs is less than the maximum amount allowable under the proposal.

Q: What is the basis for Staff's proposal to provide a return on deferred amounts at the rate authorized in Case No. 9036?

A: Staff proposes to treat deferred amounts as a regulatory asset. According to Mr. VanderHeyden, since deferred costs "will become a balance sheet asset, the asset should be afforded the same return opportunity as any other asset." (p. 18)

Q: Should the return on deferred costs under Staff's proposal be the same as for other ratebase assets?

A: Not necessarily. Deferred costs under Staff's proposal are significantly less risky than other regulated investments, since:

- Deferred costs will be recovered over a much shorter period than is typical for amortization of utility-plant investment.

- Unlike costs associated with other regulated assets, Staff proposes a true-up to ensure recovery of the full deferred amount (with return.)
- Also unlike other regulated assets, Staff apparently presumes that under-collection of deferred costs from customers leaving the system will be recovered from remaining customers.

These attributes minimize the risk associated with recovery of deferred costs, and thus reduce the return required to appropriately compensate for that risk.

Another important consideration is that, under the terms of the settlement agreements in Case No. 8908, residential ratepayers will provide shareholders a return on SOS costs equal to 1.5 mills/kWh.[7] One could reasonably view this return adder as providing compensation for the risks of cost deferral.

Q: How should the rate of return on the deferral asset be determined?

A: The rate of return should be based on the cost of funds secured to cover the deferral balance. Setting the return in excess of actual finance costs would inappropriately provide a windfall to shareholders.

For example, pursuant to a December 13, 2005 notice from the Commission, the interest rate payable by BGE on customer deposits is currently 4.12%. The wide spread between the rate paid on customer deposits and the return on deferrals recovered from customers could raise equity concerns, creating the perception that BGE is borrowing from financially vulnerable customers at 4.12% and loaning out these funds to these same vulnerable customers at 12.5%.

[7] This return adder is equivalent to an average return on deferrals of about three percent.

Q: Why does Staff propose to increase SOS rates one month prior to the implementation of market-based rates?

A: According to Mr. VanderHeyden, increasing rates starting on June 1 amounts to a pre-payment of the deferral "loan", which reduces the carrying costs paid by participants on the deferral balance. In essence, participants will loan BGE funds at 12.5% in June and then borrow back those funds (and more) at 12.5% starting in July.

Q: Do you have any concerns regarding the proposal to increase SOS rates on June 1, 2006?

A: I am concerned that a rate increase in June will greatly limit the appeal and effectiveness of the transition program, and also complicate the effort to educate consumers regarding this program. Consumers may not understand the benefits of, or have much interest in opting in to, a program that requires them to accept a one-month advancement of a rate increase in order to forestall a larger increase in July. In addition, advancing program start-up to June means that there is one less month available to educate consumers about the program; the time available for consumer education is already too short to consider advancing the implementation date by a month.

I am also concerned that, in the event that a voluntary program is not feasible or cost-effective, a mandatory increase in June SOS rates above their frozen levels would be contrary to key provisions of the restructuring settlement agreement in Case No. 8794. Although I am not a lawyer, Section VII of the settlement agreement appears to preclude imposition of a deferral surcharge on the rates established in the settlement agreement for June of 2006. In addition, imposition of a surcharge prior to July 1 may prevent full recovery of the $50.2

million annual revenue reduction due customers, as set forth in paragraph 24 of the settlement agreement.

Q: Can Staff's objectives be met without raising rates in June?

A: Yes. As I show in Section IV, it is possible to devise a deferral mechanism that achieves all of Staff's objectives, yet which does not raise rates in June.

Q: Do you support Staff's proposal to implement the transition plan on a voluntary, opt-in basis?

A: I support the proposal in concept, but do not at this time have the requisite information to determine whether a voluntary approach is feasible or cost-effective. As of the filing date for this testimony, BGE has not determined whether it is feasible, or what it will cost, to implement a voluntary mechanism by June 1.

IV. Illustrative Modified Deferral Mechanism

Q: Given the concerns discussed above, are you opposed to Staff's basic approach to cost mitigation?

A: No. Staff's primary objectives – spreading the impact of market-based SOS rates over time while preserving price signals and financial integrity – and basic approach – cost deferral through distribution credits over a limited span of time– are both reasonable. However, as discussed above, a number of elements of Staff's specific proposal for achieving these objectives are not reasonable and in need of modification.

Q: Have you modified Staff's deferral model to illustrate how your concerns could be addressed?

A: Yes. By modifying the problematic elements of Staff's proposal, I show that Staff's basic approach and primary objectives can be preserved while addressing my concerns.

I present this illustrative model in Exhibit JFW-2. As indicated in Exhibit JFW-2, I made the following modifications to Staff's model:

- Extension of the deferral period from two to three years;
- Use of seasonal, rather than monthly credits or surcharges;
- Removal of the presumptive cap on credits or surcharges;
- Elimination of the June 1, 2006 rate increase.

As with Staff's proposal, this illustrative model spreads the impact of market-based SOS rates over time, while holding the deferral balance and accumulated carrying costs to acceptable levels.[8] In fact, the maximum cumulative deferral balance is lower under this illustrative model than under Staff's proposal.

Q: What is the average bill impact under the illustrative model?

A: Similar to Staff's model, the mitigation scheme under the illustrative model reduces the first-year average bill impact from 67% to about 40%. This 40% increase is followed by 22% and 10% increases in the second and third years, respectively. In other words, the 30% increase in the second year under Staff's proposal is spread out over the second and third years under the illustrative model.

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[8] This illustrative model also mimics Staff's approach by timing the deferrals and recovery so that bills in the shoulder months are lower than in the heating or air-conditioning months.

Q: Is it possible to further mitigate the average bill impact under the illustrative model?

A: Yes. It is possible to achieve a slower phase-in of the bill impact, while still holding carrying costs to acceptable levels, by applying a lower rate of return than assumed in Exhibit JFW-2.

As with Staff's approach, I assumed a rate of return at the authorized weighted average cost of capital for the purposes of developing this illustrative deferral scheme. Using a lower rate of return would allow additional deferrals in the first year, thereby mitigating the bill impact in the first year to less than 40%, while still holding carrying costs to reasonable levels.[9]

Q: Why did you extend the deferral period to three years?

A: There are two reasons for adding a third year onto the deferral period. First, it allows for elimination of the June, 2006 rate increase. With a three-year deferral period, the deferral balance and accumulated carrying charges can be maintained at acceptable levels without a rate increase in June.[10]

Second, it provides some mitigation "headroom" in the second and third years of the deferral period in the event that SOS prices in the second or third year are higher than assumed under Staff's proposal. As discussed above, Staff assumed that its estimated market prices would remain the same in the first and second years of the deferral period. Under that assumption, the recovery of deferred costs under Staff's proposal would increase bills from the first year to

[9] For example, at a 5% rate of return, the average bill increase can be mitigated to 30% in the first year (followed by 30% and 15% increases in the next two years), with less carrying costs than accumulated in the deferral scheme shown in Exhibit JFW-2.

[10] A longer deferral period also allows for a more gradual build-up of the deferral balance.

the second year by 30%. However, if SOS prices in the second year are higher than in the first, then the actual bill increase could significantly exceed 30%.

Under the illustrative model, the second- and third-year bill increases, assuming that SOS prices do not increase, will be only 22% and 10%, respectively. As a result, even if SOS prices increase in years 2 or 3, the actual bill increases may still fall within acceptable bounds (or at least not be as severe as under Staff's approach.) Thus, the extension to three years acts as a safety valve, reducing the risk that a mid-course change to the deferral scheme (with its potential to increase BGE's financial exposure) will be required in order to mitigate excessive bill impacts unanticipated at the start of the deferral period.

Q: Should the Commission approve the specific seasonal credits and surcharges presented in Exhibit JFW-2?

A: I do not recommend that the Commission adopt at this time the seasonal values shown in Exhibit JFW-2, or even find at this time that three years is the appropriate duration for the deferral period. The model presented in Exhibit JFW-2 represents a reasonable approach based on the assumed SOS prices and bill impacts.[11] However, the illustrative model's deferral period or specific deferral and recovery scheme may not best serve the public interest if actual SOS prices differ substantially from those assumed for the purposes of developing the illustrative model.

More fundamentally, I cannot at this time recommend that the Commission approve any deferral mechanism, voluntary or otherwise, since I do not know

[11] As noted above, this deferral scheme also assumed a return on deferrals at the authorized weighted average cost of capital. First-year deferrals could be reasonably increased above levels shown in Exhibit JFW-2, allowing for additional mitigation of bill increases, if the Commission were to adopt a lower rate of return.

what it will cost to implement such a mechanism and therefore whether the benefits of deferral outweigh the costs. Presumably, BGE's filing in this proceeding will provide sufficiently detailed cost estimates to determine whether a deferral mechanism is cost-effective to implement.

If the Commission does find that either a voluntary or mandatory deferral mechanism is in the public interest, I recommend that the Commission establish a second phase to this proceeding to commence immediately following issuance of an initial order in this phase.[12] The Commission should direct BGE to file in this second phase a detailed deferral scheme and implementation plan – including specification of the deferral period and of seasonal values for distribution credits and surcharges – based on final retail SOS prices that result from this year's SOS procurement process.[13]

V. Unresolved Implementation Issues

Q: Are there other issues that may need to be resolved during the proposed second phase?

A: Yes. As I indicated above, there a number of implementation details that were not addressed in Staff's proposal. Unless these issues are addressed in testimony by other parties and resolved to the Commission's satisfaction in this phase, they will need to be considered during the second phase and resolved prior to the roll-out date for consumer education on the deferral mechanism.

[12] Final SOS prices will be known by the time the Commission issues its decision, since the third and final tranche will be completed by the end of this month.

[13] BGE will need to develop separate deferral schemes for R and RL customers.

Q: What are some of the outstanding implementation issues?

A: First and foremost is the cost of implementing a deferral mechanism, along with the mechanism for recovering such costs. For example, should implementation costs be recovered from participants or from all residential customers? The decision that best serves the public interest could very well depend on the magnitude of such costs and expected participation in the voluntary program.

Other unresolved implementation issues include:

- How to manage the opt-in process, including setting the deadline for opting in and deciding whether new customers can opt in after the deadline for existing customers.
- How to structure and implement a consumer-education program regarding the deferral mechanism and opt-in process.
- How and from whom to recover deferred costs stranded by customers that leave BGE's service territory before the end of the deferral period.
- How to recover outstanding deferred costs from participants that switch to competitive suppliers.
- How and from whom to collect or return reconciled balances at the end of the deferral period.
- How to implement deferrals for budget-billing customers.

Q: Does this conclude your testimony?

A: Yes.

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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“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.

“Maryland Office of People’s Counsel’s Comments on Staff Restructuring Report: Case No. 8738.” 1997. Filed by the Maryland Office of People’s Counsel in PSC Case No. 8738.

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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.

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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.

Support of proposed comprehensive restructuring settlement agreement

Maryland PSC Case Nos. 8794 and 8808, Baltimore Gas & Electric Company comprehensive restructuring agreement, Maryland Office of People's Counsel. Initial Testimony July 1999; Reply Testimony August 1999; Surrebuttal Testimony August 1999.

Support of proposed comprehensive restructuring settlement agreement

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Reasonableness of proposed revisions to standard-offer-supply energy costs. Implications of revisions for other elements of proposed settlement.

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.

Maryland PSC Case No. 8994, Delmarva Power & Light recovery of generation-related uncollectibles; Maryland Office of People's Counsel. Direct, March 2004; Supplemental April 2004.

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, October 2005.

Inefficiencies and risks associated with use of administratively determined demand curve. Effect of proposed Reliability Pricing Model on capacity costs.

Mitigation of BGE July 1, 2006 Residential Bills

Summer Generation Rate / kWh $0.1150
Winter Generation Rate / kWh $0.0950

		Use Data		Generation & Transmission Rates ($/kWh)			Typical Bill			
		MWHs	Median Use	Gen. Freeze	Post-Gen. Freeze	Trans-mission	Freeze	Post Freeze	$ Inc	% inc
JUN	2006	1,161,933	1029	0.05759	0.05759	0.00370	$ 99.11	$ 99.11	$ -	0.0%
JUL	2006	1,431,865	1268	0.05759	0.11500	0.00370	$ 120.28	$ 193.05	$ 72.77	60.5%
AUG	2006	1,436,944	1218	0.05759	0.11500	0.00370	$ 115.86	$ 185.77	$ 69.91	60.3%
SEP	2006	1,153,379	994	0.05759	0.11500	0.00370	$ 96.06	$ 153.15	$ 57.09	59.4%
OCT	2006	912,064	854	0.03961	0.09500	0.00370	$ 68.21	$ 115.49	$ 47.28	69.3%
NOV	2006	897,196	890	0.03961	0.09500	0.00370	$ 70.76	$ 120.04	$ 49.28	69.6%
DEC	2006	1,223,538	1150	0.03961	0.09500	0.00370	$ 89.18	$ 152.89	$ 63.71	71.4%
JAN	2007	1,359,697	1281	0.03961	0.09500	0.00370	$ 98.45	$ 169.42	$ 70.97	72.1%
FEB	2007	1,162,152	1085	0.03961	0.09500	0.00370	$ 84.61	$ 144.73	$ 60.12	71.1%
MAR	2007	1,204,168	1052	0.03961	0.09500	0.00370	$ 82.24	$ 140.51	$ 58.27	70.8%
APR	2007	812,979	779	0.03961	0.09500	0.00370	$ 62.95	$ 106.10	$ 43.15	68.6%
MAY	2007	818,733	809	0.03961	0.09500	0.00370	$ 65.05	$ 109.85	$ 44.80	68.9%
JUN	2007	1,161,933	1029	0.05759	0.11500	0.00370	$ 99.11	$ 158.18	$ 59.07	59.6%
JUL	2007	1,431,865	1268	0.05759	0.11500	0.00370	$ 120.28	$ 193.05	$ 72.77	60.5%
AUG	2007	1,436,944	1218	0.05759	0.11500	0.00370	$ 115.86	$ 185.77	$ 69.91	60.3%
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MAR	2008	1,204,168	1052	0.03961	0.09500	0.00370	$ 82.24	$ 140.51	$ 58.27	70.8%
APR	2008	812,979	779	0.03961	0.09500	0.00370	$ 62.95	$ 106.10	$ 43.15	68.6%
MAY	2008	818,733	809	0.03961	0.09500	0.00370	$ 65.05	$ 109.85	$ 44.80	68.9%
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JUL	2008	1,431,865	1268	0.05759	0.11500	0.00370	$ 120.28	$ 193.05	$ 72.77	60.5%
AUG	2008	1,436,944	1218	0.05759	0.11500	0.00370	$ 115.86	$ 185.77	$ 69.91	60.3%
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DEC	2008	1,223,538	1150	0.03961	0.09500	0.00370	$ 89.18	$ 152.89	$ 63.71	71.4%
JAN	2009	1,359,697	1281	0.03961	0.09500	0.00370	$ 98.45	$ 169.42	$ 70.97	72.1%
FEB	2009	1,162,152	1085	0.03961	0.09500	0.00370	$ 84.61	$ 144.73	$ 60.12	71.1%
MAR	2009	1,204,168	1052	0.03961	0.09500	0.00370	$ 82.24	$ 140.51	$ 58.27	70.8%
APR	2009	812,979	779	0.03961	0.09500	0.00370	$ 62.95	$ 106.10	$ 43.15	68.6%
MAY	2009	818,733	809	0.03961	0.09500	0.00370	$ 65.05	$ 109.85	$ 44.80	68.9%

Mitigation of BGE July 1, 2006 Residential Bills

Summer Generation Rate / kWh	$0.1150
Winter Generation Rate / kWh	$0.0950

		Mitigation For Typical Bill				Total Deferral and (Recovery)		Credit / (Surcharge)	
		Credit / (Surcharge) per kWh	Typical Bill	Credit or (Charge)	Increase Over Freeze Bill	Monthly (Million)	Total (Million)	Credit / (Surcharge) per kWh	Percent of Post Freeze Generation
JUN	2006	0.000000	$ 99.11	$ -	0%	$ -	$ -	$ -	
JUL	2006	0.020000	$ 167.70	$ 25.35	39%	$ 28.6	$ 28.6	$ 0.02000	17.4%
AUG	2006	0.020000	$ 161.41	$ 24.35	39%	$ 28.9	$ 57.6	$ 0.02000	17.4%
SEP	2006	0.020000	$ 133.26	$ 19.89	39%	$ 23.4	$ 81.0	$ 0.02000	17.4%
OCT	2006	0.020000	$ 98.42	$ 17.07	44%	$ 18.8	$ 99.7	$ 0.02000	21.1%
NOV	2006	0.020000	$ 102.25	$ 17.79	44%	$ 18.6	$ 118.3	$ 0.02000	21.1%
DEC	2006	0.020000	$ 129.88	$ 23.00	46%	$ 25.2	$ 143.5	$ 0.02000	21.1%
JAN	2007	0.020000	$ 143.80	$ 25.63	46%	$ 28.1	$ 171.6	$ 0.02000	21.1%
FEB	2007	0.020000	$ 123.02	$ 21.71	45%	$ 24.3	$ 196.0	$ 0.02000	21.1%
MAR	2007	0.020000	$ 119.47	$ 21.04	45%	$ 25.3	$ 221.3	$ 0.02000	21.1%
APR	2007	0.020000	$ 90.52	$ 15.58	44%	$ 17.7	$ 238.9	$ 0.02000	21.1%
MAY	2007	0.020000	$ 93.67	$ 16.18	44%	$ 17.9	$ 256.8	$ 0.02000	21.1%
JUN	2007	0.000000	$ 158.18	$ -	60%	$ 1.6	$ 258.4	$ -	0.0%
JUL	2007	0.000000	$ 193.05	$ -	61%	$ 1.6	$ 260.1	$ -	0.0%
AUG	2007	0.000000	$ 185.77	$ -	60%	$ 1.6	$ 261.7	$ -	0.0%
SEP	2007	0.000000	$ 153.15	$ -	59%	$ 1.6	$ 263.3	$ -	0.0%
OCT	2007	(0.005000)	$ 119.76	$ (4.27)	76%	$ (2.9)	$ 260.4	$ (0.00500)	-5.3%
NOV	2007	(0.005000)	$ 124.49	$ (4.45)	76%	$ (2.8)	$ 257.6	$ (0.00500)	-5.3%
DEC	2007	(0.005000)	$ 158.64	$ (5.75)	78%	$ (4.5)	$ 253.1	$ (0.00500)	-5.3%
JAN	2008	(0.005000)	$ 175.83	$ (6.41)	79%	$ (5.2)	$ 247.9	$ (0.00500)	-5.3%
FEB	2008	(0.005000)	$ 150.15	$ (5.43)	77%	$ (4.2)	$ 243.6	$ (0.00500)	-5.3%
MAR	2008	(0.005000)	$ 145.77	$ (5.26)	77%	$ (4.5)	$ 239.2	$ (0.00500)	-5.3%
APR	2008	(0.005000)	$ 109.99	$ (3.90)	75%	$ (2.6)	$ 236.6	$ (0.00500)	-5.3%
MAY	2008	(0.005000)	$ 113.89	$ (4.04)	75%	$ (2.6)	$ 234.0	$ (0.00500)	-5.3%
JUN	2008	(0.015000)	$ 173.62	$ (15.43)	75%	$ (16.0)	$ 218.0	$ (0.01500)	-13.0%
JUL	2008	(0.015000)	$ 212.06	$ (19.01)	76%	$ (20.1)	$ 197.9	$ (0.01500)	-13.0%
AUG	2008	(0.015000)	$ 204.03	$ (18.27)	76%	$ (20.3)	$ 177.6	$ (0.01500)	-13.0%
SEP	2008	(0.015000)	$ 168.07	$ (14.92)	75%	$ (16.2)	$ 161.5	$ (0.01500)	-13.0%
OCT	2008	(0.019800)	$ 132.39	$ (16.90)	94%	$ (17.0)	$ 144.4	$ (0.01980)	-20.8%
NOV	2008	(0.019800)	$ 137.65	$ (17.61)	95%	$ (16.9)	$ 127.6	$ (0.01980)	-20.8%
DEC	2008	(0.019800)	$ 175.66	$ (22.77)	97%	$ (23.4)	$ 104.1	$ (0.01980)	-20.8%
JAN	2009	(0.019800)	$ 194.79	$ (25.37)	98%	$ (26.3)	$ 77.9	$ (0.01980)	-20.8%
FEB	2009	(0.019800)	$ 166.22	$ (21.49)	96%	$ (22.5)	$ 55.4	$ (0.01980)	-20.8%
MAR	2009	(0.019800)	$ 161.33	$ (20.83)	96%	$ (23.5)	$ 31.9	$ (0.01980)	-20.8%
APR	2009	(0.019800)	$ 121.52	$ (15.43)	93%	$ (15.9)	$ 16.0	$ (0.01980)	-20.8%
MAY	2009	(0.019800)	$ 125.86	$ (16.01)	93%	$ (16.1)	$ (0.1)	$ (0.01980)	-20.8%