STATE OF MARYLAND

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of the Application of Potomac	**)**	
Electric Power Company for Authority to	**)**	**Case No. 9092**
Revise Its Rates and Charges for Electric	**)**	
Service and for Certain Rate Design Changes	**)**	

DIRECT TESTIMONY OF

JONATHAN WALLACH

ON BEHALF OF

THE OFFICE OF PEOPLE'S COUNSEL

Resource Insight, Inc.

MARCH 7, 2007

TABLE OF CONTENTS

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: 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 November 17, 2006, Potomac Electric Power Company ("PEPCo"; "the Company") filed an application for an increase in its distribution rates, along with supporting testimony. This testimony addresses three aspects of the Company's filing: (1) the proposal to implement a Bill Stabilization Adjustment

("BSA") mechanism; (2) the Class of Business Embedded Cost Allocation Study; and (3) the proposed residential rate design. These three elements are supported in the direct testimony by Company witnesses Mark E. Browning, J. Reed Bumgarner, and John Chamberlin.

The Company's filing is based on a test year that consists of six months of actual data and six months of projected data. On February 9, 2007, the Company amended portions of its filing to reflect a test year with twelve months of actual data. The Company did not update its Cost Allocation Study or its tariff filing to reflect twelve months of actual data. Nor did PEPCo file any supplemental testimony supporting the portions of the filing it did amend. As such, my findings and recommendations with regard to cost allocation and rate design are preliminary in nature and subject to change once the Company files an amended Cost Allocation Study and any associated revisions to its proposed residential rate design.

People's Counsel is also sponsoring testimony by Mr. David Effron regarding revenue requirements and Mr. Charles King regarding rate of return.

Q: Please summarize your preliminary recommendations.

A: Based on my assessment of the Company's filing using a six-month actual, six-month projected test year, my preliminary recommendations are as follows:

- The Commission should approve the implementation of a Bill Stabilization Adjustment mechanism with two modifications, as described below in Section II. However, approval should be conditioned on the Company implementing a comprehensive, cost-effective portfolio of residential Demand Side Management ("DSM") programs, and on establishment of a program to monitor service quality and certain other changes in customer characteristics and economic conditions relevant to the BSA. In addition, as recommended by OPC witness Mr. King, the Company's authorized rate of return should be adjusted downward to reflect the significant reduction in risk to the Company from implementation of the BSA.

- The Company's proposal for a demand-elasticity adjustment as an alternative to the BSA should be rejected.
- The Commission should reject the Company's proposal for allocating to the residential class the revenue increase ultimately approved by the Commission. Moreover, the Commission should reject the Company's Cost Allocation Study as a reasonable basis for that allocation. Instead, the revenue increase should be allocated pro rata across all classes.
- The Company's proposal to increase the R and R-TM customer charges by 50% and 24%, respectively, should be rejected. Instead, customer and energy charges should be increased in proportion to the overall revenue increase allocated to the residential class.
- The Company's proposal to reduce the summer-winter differential in energy charges should be rejected as lacking a reasonable cost basis.

II. Bill Stabilization Adjustment

Q: Please describe the Company' proposal for a BSA mechanism.

A: According to Dr. Browning, the Bill Stabilization Adjustment mechanism will decouple recovery of test-year revenues from actual sales during the rate effective period. The BSA is designed such that the Company collects only an amount of revenue per customer approved by the Commission for the test year. If actual revenue per customer is more or less than the approved test-year amount, the difference is credited or recovered from customers at a later time.

The BSA would be calculated quarterly and for each rate class separately as the difference between the class's actual and target revenues for the quarter. Subject to a 10% capping mechanism and revenue reconciliation, the calculated BSA would be applied to rates in the next quarter.

Q: What is the Company's rationale for the BSA?

A: The Company claims that the BSA would:

- Provide revenue stability for the Company, especially during periods of extreme weather.
- Reduce the Company's risk and cost of equity.
- Reduce the Company's disincentive to promote DSM.
- Provide an alternative to the demand elasticity adjustment proposed by the Company.
- Provide bill stability for customers, especially during periods of extreme weather.
- Correct for the "mismatch between the underlying cost and the rates intended to recover those costs."[1]

Q: Are these arguments valid?

A: In part. The BSA would provide revenue stability for the Company, reduce the Company's risk and cost of capital, reduce the Company's financial disincentive to promote DSM (and its incentive to maximize sales), and eliminate the justification for the demand-elasticity adjustment. These effects will benefit ratepayers only if the reduced cost of capital is reflected in rates, the Company implements a significant DSM program, and the Commission rejects the demand-elasticity adjustment proposed in the Company's filing.

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[1] *Direct Testimony of John Chamberlin*, Case No. 9092, November 17, 2006, p. 6.

With regard to the impact of the BSA on bill volatility, the Company overstates the extent to which the BSA would provide bill stability for individual customers. In addition, the Company's arguments regarding alignment of underlying costs and rate design are reasonable solely from the Company's narrow perspective of short-term revenue recovery, but are not valid in terms of long-term cost causation and price signals. Both of these issues are discussed below.

Q: Is the BSA a departure from traditional ratemaking for electric companies?

A: Yes. The BSA represents a significant departure from traditional cost-of-service regulation in that it guarantees that the Company will receive the level of revenues authorized by the Commission during the rate-setting process. As is clear from the Company's proposal in this case, the BSA provides a stable and guaranteed stream of revenue, without regard to the usual risk of declining revenues caused by weather, economic downturns or conservation measures undertaken by customers. According to Mr. King, the mitigation of business risk with a BSA warrants a significant reduction to the Company's return on equity.

Q: Does OPC agree with the Company's quantification of the effect of the BSA on the cost of equity?

A: No. Mr. King concludes that the Company's proposed reduction of 25 basis points is understated, and recommends a reduction in return on equity of 81 basis points.

Q: In what ways are the Company's claims regarding the effectiveness of the BSA in stabilizing customer bills overstated?

A: The BSA will likely provide greater stability in the average annual bills for the residential class. However, the BSA would not provide stability to individual customers' monthly bills. Distribution bills would still vary from month to month, and might well vary more with the BSA than without, as the over-collection (and high bills) in one quarter results in a refund (and hence lower-than-expected bills) in the next quarter. In addition, individual customer monthly bills would not be stabilized as much as total residential monthly revenues. For example, high bills in a cold winter (paid primarily by space-heating customers) would result in a BSA refund in the spring, with the refund spread more evenly among all residential customers.

Q: What are the limitations of the Company's claim regarding the mismatch between underlying costs and the rates intended to recover those costs ?

A: The Company's discussion of the BSA and the recovery of "fixed" costs is narrowly focused on the issue of short-term cost recovery, to the exclusion of consideration of issues of cost causation and appropriate price signals.

In terms of utility cost-recovery, most distribution costs are fixed in the short term. The revenue requirements associated with debt service and maintenance for a given set of lines and transformers in any year does not vary much with load or sales in that year.[2] Thus, recovery of distribution costs in volumetric charges results in revenue instability and financial risk. As I noted above, these are valid justifications for a BSA.

In terms of rate design, price signals, and cost causation, on the other hand, most distribution costs are not "fixed." Increased loading of existing lines, conduit, transformers, substations, and other distribution equipment reduces the lives of that equipment and requires the installation of more and larger

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[2]Higher loads, especially in the summer, are likely to result in failure of more transformers and underground lines, so current costs vary with current load to some extent. This is probably a small effect, compared to total distribution costs and the variation in distribution revenues with seasonal weather.

equipment. Higher loads may even require more poles and towers, to carry additional primary circuits, and higher poles and towers, to allow for higher distribution voltages. In general, energy charges better reflect the causation of these costs than fixed customer charges, and hence provide the better price signal.

Q: What do you recommend with regard to implementation of the BSA?

A: I recommend implementation of a modified version of the BSA. Specifically, the timing of BSA recovery should be corrected to better achieve the goals of bill stabilization and better matching of over-collections with refunds and under-collections with surcharges. In addition, the 10% cap on BSA recovery should be reduced to 5%, with Commission approval required for deferrals in excess of the 5% threshold.

Moreover, approval of the BSA, as modified, should be tied to implementation of a comprehensive, cost-effective portfolio of DSM programs; monitoring and reporting on service quality and changes in customer characteristics and economic conditions relevant to the BSA; and rejection of the Company's proposal for a demand-elasticity adjustment.

Q: How should the timing of BSA recovery be modified?

A: Under the Company's BSA proposal, one quarter's charge or credit is recovered in the succeeding quarter's adjustment—in particular, the weather-related fluctuation in loads that occurs largely in the summer and winter are recovered in fall and spring bills. The high bills in a cold winter would be paid primarily by space-heating customers, but would result in a BSA refund in the spring that flows predominantly to non-heating customers. This outcome – collection of excess revenues from one sub-class and refund to another – is inequitable and undermines the bill-stabilization goals of the BSA.

To avoid this problem, the quarterly adjustments can be lagged one year, so that excess revenues from a cold winter are refunded to customers the following winter, and excess revenues from a hot summer are refunded the following summer.

Q: How should the cap on BSA recovery be modified?

A: Under some circumstances (e.g., high generation prices, an economic slowdown), a 10% increase in distribution rates may be excessive. The Commission should direct the Company to seek Commission approval prior to instituting BSA recovery in excess of 5% of base distribution rates in any quarter.

Q: How should the BSA be tied to implementation of a comprehensive, cost-effective DSM portfolio?

A: Since a major benefit of the BSA is its effect in reducing utility resistance to energy efficiency, approval of the BSA should be conditioned on implementation of a comprehensive, aggressive DSM package. The Commission should require that the Company file program designs and implementation plans for a least-cost portfolio of DSM programs within 90 days of the start of the rate effective period. The Commission should also condition the continued operation of the BSA on the continued implementation of a comprehensive DSM portfolio.

Q: Why should approval of the BSA result in rejection of the Company's proposal for a demand-elasticity adjustment?

A: The Company proposes the demand-elasticity adjustment as an alternative to the BSA. If the Commission approves the Company's BSA proposal, this adjustment is unnecessary.

Q: What types of monitoring and reporting should be required in connection with the BSA?

A: I recommend three monitoring activities. By protecting Company revenues from falling sales, the BSA may allow the Company to stretch out the interval between distribution rate cases, creating a perverse incentive to increase earnings by skimping on service quality. The Commission should therefore require the Company to monitor and report to the Commission and OPC changes in service quality from the time of BSA implementation.

Second, the proposed BSA varies the target revenue for each class in proportion to the number of customers in the class. That mechanism is reasonable, so long as the size of new customers is not very different from the size of existing customers, and the number of large master-metered multi-family and commercial buildings converted to multiple small customers (increasing the customer number and hence the revenue target, but not distribution costs) is not significant. To ensure that these conditions apply, and to provide the opportunity to modify the BSA, the Company should be required to monitor the size of new customers in each class and the number of conversions from master-metered to multi-metered buildings, and to report to the Commission and OPC if conditions change significantly.

Third, the Company should monitor economic conditions. If an economic downturn were to reduce sales and revenues, the BSA would increase rates, exacerbating the effect on already stressed households, businesses and local governments. The Commission should be prepared to modify the BSA, either on its own or at the request of a party, if those conditions occur.

III. Cost Allocation

Q: What is the purpose of the cost-allocation process?

A: The cost allocation process assigns the Company's total Maryland-jurisdictional revenue requirement to the various customer and rate classes. The process is generally driven by some concept of fairness. It is a generally accepted principle that allocation based on cost causation results in an equitable sharing of costs.

Q: What were the results of PEPCo's Cost Allocation Study?

A: The Company calculates that for the 12 months ending September 30, 2006, the residential rates R and R-TM were paying returns of 0.72% and -1.21%, respectively, compared to the Company's average rate of return of 4.82%.[3]

Q: On which portions of the cost-allocation process do you have comments?

A: I have comments on the allocation of the proposed revenue increase (which is based in part of the Cost Allocation Study), and on three aspects of the Cost Allocation Study itself. I will discuss each of these in turn.

A. Allocation of Revenue Increase

Q: How does the Company propose to use its Cost Allocation Study to allocate its requested rate increase among rate classes?

A: According to Mr. Bumgarner, the Company proposes to bring class rates of return closer to the Company average by allocating the requested 16.844% revenue increase in two steps. PEPCo proposes to increase all rates halfway to the requested rate of return, and then to increase the initial General Service classes' return by a constant factor to meet the Company's overall requested

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[3] *Direct Testimony of J. Reed Bumgarner*, Case No. 9092, November 17, 2006, Exhibit PEPCO_JRB-1, page 1.

return. Under PEPCo's proposal, Rate R receives an 18.107% increase and Rate R-TM receives a 25.314% increase.[4]

Q: Do you recommend any changes to the Company's proposal for allocating its overall revenue request to the residential class?

A: Yes. Rate R and R-TM revenues should be increased by the same percentage as that for the Company's overall revenue target. The Company has not adequately supported its proposed allocation of the overall revenue increase. Specifically, the Cost Allocation Study on which they are based appears to overstate the residential class's share of costs. If that is the case, then the extent to which the residential classes are under-earning, and the increase necessary to bring these classes halfway to average rate of return, would be less than indicated by the Company's Cost Allocation Study.

Any reduction to the Company's requested revenue increase should be applied evenly across rate classes. In addition, the Commission should require the Company to correct its Cost Allocation Study, to address the problems described in the following section of my testimony.

B. Evaluation of PEPCo's Cost Allocation Study

Q: How does PEPCo allocate distribution plant?

A: As discussed by Dr. Browning, the Cost Allocation Study allocates plant as follows:

- Subtransmission is allocated on an average-and-excess allocator driven by class contribution to the system peaks in the four summer months.

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[4] Bumgarner Direct, Exhibit PEPCO_(JRB)-1, p. 2.

- Primary distribution is assigned on the basis of class non-coincident annual peak demand ("NCAP"), that is, the class's maximum load.
- Services are allocated on sum of maximum customer demands ("MCD"), i.e., the sum of each customer's individual annual maximum demand, whenever it occurs.
- Line transformers are allocated to secondary customers based on a simple average of NCAP and MCD, to recognize that some transformers serve more than one customer.
- Secondary lines (overhead and underground) are assigned on MCD.

Q: Do these allocators reasonably reflect cost causation?

A: No. I have identified a number of problems with the Company's allocation decisions that are likely to overstate the allocation of costs to the residential class:

- The allocation of transformers based on a simple average of MCD and NCAP may understate the diversity of load on these facilities.
- The allocation of secondary lines on MCD understates the diversity of load on these facilities.
- PEPCo's allocation of services based on MCD (which assumes zero diversity in their loads) does not account for the sharing by many residential customers of a single service line to a multi-family building.

All of these problems arise as a result of the Company's apparent understatement of residential load diversity in its specification of residential allocators. By understating diversity, the Company likely overstates the residential-class contribution to distribution costs and thus over-allocates such costs to the residential class.

Q: How does load diversity affect the sizing of transmission and distribution ("T&D") plant?

A: The diversity of demand among a group of customers results in a group peak demand that is lower than the sum of customers' individual maximum demands. In other words, since customers reach their individual peak demands on different days and hours, their loads at the single hour when a distribution facility reaches its peak will be less than the sum of the individual customers' maximum demands. In general, utilities size T&D plant to meet the group peak, not the sum of customers' individual maximum demands.[5]

The load diversity on a given piece of distribution equipment, a transformer, or a length of line, depends upon the number and type of customers served by that equipment. The farther downstream the distribution equipment, the fewer the customers served, and the lower the load diversity.

Load diversity is frequently reported as a coincidence factor, the ratio of the peak of a group of customers to the sum of their maximum demands. In other words, the coincidence factor measures the percentage of the customers' maximum demand that occurs at the hour of the group peak.

Q: Do PEPCo demand allocators reflect load diversity on distribution plant?

A: Yes. For example, at the primary level, PEPCo's analysis assumes a Rate R load coincidence factor of 44% when it assigns this plant based on the NCAP factor. In other words, it assumes that the peak of a group of Rate R customers is 44% of the sum of their maximum annual demands. At the farthest end of the T&D

[5]In response to OPC Data Request No. 7, Question No. 15, the Company indicates that it sizes line transformers to diversified load. And in response to OPC Data Request No. 10, Question No. 6, PEPCo indicates that it sizes substations to meet diversified feeder loads. Copies of these and all other responses cited herein are attached.

system, at the service drop, PEPCo assumes no diversity of load (or a coincidence factor of 100%) when it allocates this plant according to the sum of individual customers' maximum demands. The diversity reflected in PEPCo's demand allocators is shown in the following table of coincidence factors:

Allocator	Total Maryland	R	R-TM	GS Low Volt	MGT Low Volt	GT Low Volt	Street Light
Class NCAP	51%	44%	47%	57%	67%	72%	75%
50/50 NCAP–MCD	76%	72%	73%	78%	84%	86%	88%
Class MCD	100%	100%	100%	100%	100%	100%	100%

Source: Volume III of Cost Allocation Study, p. 74.

Q: Why does understating the load diversity overstate the residential class's share of costs?

A: There tends to be more load diversity on the distribution equipment serving small customers, because each piece of equipment typically can serve more small customers than large customers. For example, according to PEPCo's 1985 underground residential distribution guidelines, a 167 kVA transformer can serve 41 residential customers using gas heat and 3½ hp air conditioning, with a total non-coincident demand of 492 kVA.[6] But that same transformer could only serve a single commercial customer with a demand of around 167 kVA. There is no diversity in the large-customer load on the transformer, while the diversity of the residential loads reduces the peak on the transformer by 66% compared to the individual customer peaks. The greater the number of customers on a particular component, the greater the variation in loads and load shapes (that is, load diversity), the lower the contribution per customer to the group peak, and the lower the cost per customer.

[6] *Underground Residential Distribution: Loading & Cable Parameters* (DR OPC-RD-1-36, Attachment A provided in Case No. 8466), Tables III and IX.

Q: Has the Company provided any load diversity studies to support its specification of allocators?

A: No. In response to a request for load diversity studies, PEPCo merely refers to demand data from which the diversity factors implicit in the allocators can be derived, as shown in the table above.[7]

Q: Are there other PEPCo planning documents, other than the 1985 distribution guidelines, that assume greater load diversity than the Cost Allocation Study?

A: Yes. In its recent District of Columbia Marginal Distribution Cost Study, PEPCo assumes that load-related secondary plant costs are driven by NCAP.[8]

1. Line Transformers

Q: What is the Company's rationale for using the 50/50 average of NCAP and the MCD to allocate transformers?

A: The Company's rationale is provided in response to OPC Data Request No. 7, Question No. 15:

> Line transformers are allocated using the average of the diversified non-coincident peaks and the undiversified sum of customer maximum demands which recognizes that a transformer may serve multiple customers so that diversity of loads will impact the sizing of the transformer, while some transformers serve only a single customer so no load diversity is considered in sizing the transformer.

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[7]Response to OPC Data Request No. 7, Question No. 13.

[8]This study was provided in response to OPC Data Request No. 7, Question No. 35.

Q: Has PEPCo provided the data necessary to evaluate its assumption of a 50/50 weighting, with its implied coincidence factor of 72%?

A: No. But in the absence of adequate information from the Company, I have prepared an illustrative calculation using PEPCo's overall average of customers per transformer and the Company's estimates of residential load coincidence by number of houses and end use included in its 1985 distribution guidelines. This calculation illustrates how the 50/50 weighting may understate diversity on line transformers.

There were 74,248 transformers in PEPCo's Maryland jurisdiction as of February 20, 2007 and 510,518 secondary customers in the 2006 test year, for an average of seven customers per transformer.[9] The number of residential customers per transformer is probably greater than seven, since many large customers will have one or more dedicated transformers.

Assuming seven residential customers per transformer, PEPCo's underground residential distribution guidelines show significantly less than 72% load coincidence for all but the largest electric air conditioning and-heating customers, even when all the customers on the transformer are assumed to have the same air conditioning or heating equipment. Based on Table III of PEPCo's guidelines, as indicated in the following table, a group of seven houses each with 2½ hp air conditioning, for example, would have a coincidence factor of 0.47:

	Air Conditioning (hp)								
	None	*1½*	*2*	*2½*	*3*	*3½*	*4*	*5*	*7½*
1 House	7	9	10	11	11	12	13	15	19
7 Houses diversified kVa	23	26	30	36	40	45	50	61	88
Coincidence Factor	47%	41%	43%	47%	52%	54%	55%	58%	66%

[9] Response to OPC Data Request No. 10, Question No. 18 and Section V.A, Attachment C of filing, 2006 Class of Business Study Unadjusted Workpapers, page 77.

Likewise, as shown in the following table, based on Table IV of PEPCo's guidelines, a group of seven houses each with 12.5 kW of electric heating, would have a coincidence factor of 57%:

	Electric Furnace (kW)							
	5	*7.5*	*10*	*12.5*	*15*	*20*	*25*	*30*
1 House	10	15	14	17	18	22	27	31
7 Houses diversified kVa	42	52	59	68	74	105	122	168
Coincidence Factor	60%	50%	60%	57%	59%	68%	65%	77%

If diversity among different types of residential customers were also taken into account, the load coincidence factors would be even lower. A single transformer may serve some homes with electric heat that peak in the winter, and some with fossil heat that peak in the summer.

2. Secondary Lines

Q: What is the Company's explanation for using the MCD to allocate secondary distribution lines?

A: According to PEPCo's response to OPC Data Request No. 7, Question No. 14:

> The Company uses the undiversified sum of customer maximum demands to allocate secondary lines in order to recognize that secondary facilities are sized to serve the maximum demands of customers.

Q: Is this a valid explanation?

A: No. Sizing secondary facilities to serve customer maximum demands would make sense only if every secondary line served only a single customer. This is an unlikely situation, particularly in urban areas, and PEPCo does not claim it to be so.

If secondary lines serve more than one customer, PEPCo's explanation is counter-intuitive. The Company sizes line transformers to meet diversified load. If it were the Company's actual practice to size secondary lines to meet MCD, while sizing transformers to meet a diversified load, then PEPCo would be installing secondary lines with more load-carrying capability than the transformers would be able to handle. In this case, either the distribution system would not reliably carry the load or the Company would be wasting money on excess secondary line capacity.

3. Sharing of Services

Q: Could taking into account the sharing of services in multi-family buildings have a significant effect on the services allocator for the residential class?

A: Yes. Where services are shared, the load on the equipment is less than the sum of individual customer's maximum demand. In other words, load diversity is greater than zero for these multi-family buildings and, in turn, greater than zero on average for the residential class as a whole.

Q: Have you estimated what the impact of shared services would be on the residential services allocator?

A: I am unable to estimate at this time the impact of shared services, since the Company has not provided data on load diversity required for such a calculation. In addition, PEPCo is unable to provide other necessary information, such as the number of customers per service in its Maryland jurisdiction.[10]

However, this impact may be significant, since a substantial portion of housing in PEPCo's service territory is multi-family. According to the 2000 Census of Housing, in Prince George's and Montgomery Counties, 10% of the

[10]Response to OPC Data Request No. 10, Question No. 17.

housing units are multi-family housing with 2 to 9 units, and 23% are multi-family housing with more than 10 units.

Q: Would similar adjustments apply to other classes?

A: No. Other than multi-family residential customers on the residential rate, relatively few customers are likely to share services.[11]

IV. Rate Design

Q: What are your concerns with regard to PEPCo's residential rate design proposals?

A: I have identified two issues with regard to PEPCo's proposed rate design for the residential class. First, the Company's proposal to increase the monthly customer charge by 50% for the R class and by 24% for the R-TM class relies on a Cost Allocation Study that: (1) likely overstates the residential share of total distribution costs; and (2) counts load-related costs as a customer cost. Second, the Company is proposing a reduction to the Rate R summer/winter differential, especially for large residential customers, without any cost justification.

Although not formally incorporated in its proposed rate design, I am also concerned by statements by Company witnesses that imply that load-related distribution costs should be shifted from the volumetric charge to the customer charge, since such costs are fixed in the short term. While such a shift might serve the Company's desire for revenue stability, it is antithetical to the goal of conservation, cost-based rate design, reduction of system costs, and non-

[11] In some cases, small commercial customers in a strip mall or office building will share a service.

disruptive impacts on customer bills. Moreover, if the Commission adopts a BSA, revenue stability should no longer be a matter of concern for the Company.

A. The Customer Charge Proposal

Q: What is PEPCo's proposal with regard to the R and R-TM customer charges?

A: The Company proposes to set the customer charges to half of the Customer Cost derived in the Cost Allocation Study.

Q: Should the results of the Cost Allocation Study be the basis for the proposed increases to the R and R-TM customer charges?

A: No, for the following reasons:

- As I discussed above in Section III, the Cost Allocation Study suffers from a number of problems that likely overstate costs to the residential class.
- The customer charge includes costs that the Company itself allocates as load-related.
- The large increase disproportionately affects small customers' bills. PEPCo's approach would require that the smallest customers (with the least-expensive distribution equipment) pay the average of customer costs attributable to all sizes of residential customers. Using an average cost per customer does not take into account the effect of customer size on cost and results in the subsidy of large customers by small customers within the class.

Q: Which costs typically classified as customer-related in cost of service studies should not be included in the calculation of the customer charge?

A: A number of customer-classified costs vary with the size of the customer (in revenues, sales, or demand), and therefore, should be recovered in part through the commodity charge. For example, the service drop for the average small residential customer is likely to be lower than for the average large customer. Large residential customers are likely to be single-family homes, each using a fairly long service drop. Small customers are more likely to share services in multi-family housing or townhouses, or perhaps in row houses with individual, but short, service lines. Other costs that are classified as customer-related will also vary with the customer's use. For example, uncollectible accounts and collection expense are likely to be larger for large customers than for small customers, since the large customers have larger bills to become uncollectible.

Q: Does PEPCo's Cost Allocation Study recognize that customer size affects customer-classified costs?

A: Yes. The Cost Allocation Study allocates service drops on class MCD, recognizing that the cost of services varies with customer loads. Yet, PEPCo includes all service costs in its estimate of customer costs for rate-design purposes. Services constitute a significant portion of the plant cost that PEPCo includes in the customer charge.

Q: What do you recommend with regard to setting of the R and R-TM customer charges?

A: The Company's proposal to increase the customer charge based on the results of its Cost Allocation Study should be denied. Instead, the Commission should direct the Company to increase customer and energy charges for the R and R-

TM rate classes in proportion to the overall revenue increase allocated to each class.

B. Seasonal Differentials

Q: How does the proposed rate design reduce the seasonal differential?

A: The proposal for Rate R reduces the summer energy charge by 5% and nearly eliminates the declining block structure of the winter energy charges by increasing the second block of the winter rate.

Q: What is Company's rationale for reducing the seasonal differential?

A: In response to Staff Data Request No. 4, Question No. 8, PEPCo asserts that:

> Distribution plant is built to serve the maximum demand whenever it occurs. The costs are largely fixed in nature, occurring evenly throughout the year. The method of reducing seasonality, and the magnitude of the proposed reduction, are reasonable and appropriate in the judgment of the witness.

Q: Is this a valid argument for reducing the seasonal differential?

A: No. As I discussed in Section II, distribution costs are only considered fixed and evenly distributed throughout the year from a short-term utility accounting perspective. However, from the perspective of cost causation and rate design, such costs are driven by load and by the timing of peak loads during the year.

Capacity limitations on the PEPCo distribution systems generally occur in the summer. Most of the large and expensive distribution elements—substations and feeders—experience their peak loads in the summer.

The Company's data indicate that 94% of its distribution feeders peak in the summer.[12] Nearly all of PEPCo's substations also peak in the summer. Only 6 out of 60 substations are winter-peaking, accounting for only 433 MW out of a

[12]Response to OPC Data Request No. 7, Question No. 40.

total substation peak of 3644 MW.[13] Since summer capacity for feeders and substations is lower than winter capacity, distribution capacity is even more strongly driven by summer loads.[14] Hence, PEPCo's distribution rates should almost certainly be higher in summer than winter.

Q: Does seasonal rate design reflect generally accepted cost causation principles?

A: Yes. Charging more for summer usage and less for winter and shoulder use may provide customers with more appropriate price signals than rates that are constant over the year. Shifting revenues onto the summer would increase customers' incentive to control summer loads that determine the need for distribution capacity.

In its *Electricity Utility Cost Allocation Manual* (1992, at 143–144), NARUC treats as non-controversial the concept of allocating distribution (and transmission) costs to seasons and time periods. Generally accepted cost-causation principles would *require* higher distribution costs in high-load seasons than in low-load seasons, where feasible.

Q: What about PEPCo's proposal to nearly eliminate the winter declining block structure?

A: This change is more likely to be justified. It is possible that the very large monthly energy bills that reach into the second winter block represent usage that is heavily off-peak (thereby justifying a declining second block), but it is more likely that usage in the second block is mostly heating load on the coldest, highest-load, high-cost winter days. PEPCo should examine its load data to

[13] Response to OPC Data Request No. 7, Question No. 41.

[14] PEPCo acknowledges this seasonal capacity differential in response to OPC Data Request No. 10, Question No. 7.

determine whether elimination of the declining block structure is cost-justified, and, if so, how to modify seasonal charges that eliminates the declining block without reducing the summer-winter differential. In the meantime, PEPCo should apply the class revenue increase to all charges on a pro rata basis.

C. Rate Design and Cost Causation

Q: What statements by the Company give rise to your concern regarding the Company's theory of rate design?

A: The Company has made a number of statements that imply that load-related distribution costs should be shifted from volumetric charges to the customer charge, simply because such costs are fixed in the immediate term.

Specifically, in response to Staff Data Request No. 2, Question No. 21(a), the Company states that "virtually all distribution costs are fixed in the short term." Dr. Chamberlin also asserts that "[e]lectric distribution costs are largely fixed, and change little in the short run as usage levels change."[15] Dr. Chamberlin then states that:

> … In principle, rate structure changes that collect all of the fixed costs in a fixed charge would best meet the Bonbright standard for alignment of costs and rates. That approach would, however, significantly increase rates for small usage customers.[16]

These statements imply an approach to rate design – recovery of costs that vary with load through fixed customer charges – that is contrary to cost-causation principles.

[15] Chamberlin Direct, pp. 2-3.

[16] Chamberlin Direct, p. 10.

Q: Does James C. Bonbright et al., *Principles of Public Utility Rates* support the recovery of load-related distribution costs in the customer charge?

A: No. Dr. Chamberlin acknowledges that Bonbright does not support "the recovery of load-related distribution costs in the customer charge."[17] As I discuss in Section II, most distribution costs are not fixed (other than in the short-term sense), but instead are load-related.

Q: Does the Company recognize that the need for distribution capacity is driven by load?

A: Yes. In response to OPC Data Request No. 10, Question No. 4, the Company states that:

> … [T]he need for distribution plant capacity is affected by load. Each component on the electric system has a thermal rating which dictates the maximum amount of current that the component can handle safely. As new load is added to the electric system the amount of current passing through each component increases. When the thermal rating of any component is projected to be exceeded, that component must be relieved, either through system rearrangement to shift load to less used components through plant additions that increase capacity or provide new capacity that load can be transferred to.

Q: Are volumetric charges the appropriate basis for recovering residential customers' contribution to load-related distribution costs?

A: Yes. Volumetric charges are appropriate, because energy use on the summer peak and the hours or days before and after the peaks, on periods of high load and high temperatures off the annual system peak, and during other periods of high load increases the catastrophic failure rate and reduces the service life of distribution equipment.

[17] Response to OPC Data Request No. 7, Question No. 26.

Variable energy charges are better at signaling load-related costs than a fixed customer charge that customers cannot avoid. Reducing variable charges will reduce customer control over bills, savings from DSM investments, and therefore incentives for customers to conserve.

Q: Does this conclude your testimony?

A: Yes, at this time.

Exhibit JFW-1

Qualifications of

JONATHAN F. WALLACH

Resource Insight, Inc.
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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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“Best Practices in Market Monitoring: A Survey of Current ISO Activities and Recommendations for Effective Market Monitoring and Mitigation in Wholesale Electricity Markets” (with Paul Peterson, Bruce Biewald, Lucy Johnston, and Etienne Gonin). 2001. Prepared for the Maryland Office of People’s Counsel, Pennsylvania Office of Consumer Advocate, Delaware Division of the Public Advocate, New Jersey Division of the Ratepayer Advocate, Office of the People’s Counsel of the District of Columbia.

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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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"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.

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"Generating Plant Operating Performance Standards Report No. 2: Review of Nuclear Plant Capacity Factor Performance and Projections for the Palo Verde Nuclear Generating Facility." 1985. ESRG Study No. 85-22/2.

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"Electricity Market Design: Incentives for Efficient Bidding, Opportunities for Gaming." NASUCA Northeast Market Seminar, Albany, N.Y., February 2001.

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"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.

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.

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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.

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Reasonableness and risks of resource-procurement plan.

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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.

ATTACHMENT 1

1. Response to OPC Data Request No. 7, Question No. 15.
2. Response to OPC Data Request No. 10, Question No. 6.
3. Response to OPC Data Request No. 7, Question No. 13.
4. Response to OPC Data Request No. 7, Question No. 35.
5. Response to OPC Data Request No. 10, Question No. 18.
6. Response to OPC Data Request No. 7, Question No. 14.
7. Response to OPC Data Request No. 10, Question No. 17.
8. Response to Staff Data Request No. 4, Question No. 8.
9. Response to OPC Data Request No. 7, Question No. 40.
10. Response to OPC Data Request No. 7, Question No. 41.
11. Response to OPC Data Request No. 10, Question No. 7.
12. Response to Staff Data Request No. 2, Question No. 21(a).
13. Response to OPC Data Request No. 7, Question No. 26.
14. Response to OPC Data Request No. 10, Question No. 4.