BEFORE THE PUBLIC SERVICE COMMISSION OF WEST VIRGINIA

IN THE MATTER OF	**)**	
APPALACHIAN POWER COMPANY	**)**	**Case No. 18-0646-E-42T**
AND WHEELING POWER COMPANY	**)**	

DIRECT TESTIMONY OF

JONATHAN F. WALLACH

ON BEHALF OF THE

CONSUMER ADVOCATE DIVISION

Resource Insight, Inc.

October 9, 2018

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I. Introduction and Summary

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

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

Q: Please summarize your professional experience.

A: I have worked as a consultant to the electric power industry since 1981. 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 the firm's founding in 1990.

Over the past four decades, I have advised and testified on behalf of clients on a wide range of economic, planning, and policy issues relating to the regulation of electric utilities, including: electric-utility restructuring; wholesale-power market design and operations; transmission pricing and policy; market-price forecasting; market valuation of generating assets and purchase contracts; power-procurement strategies; risk assessment and mitigation; integrated resource planning; mergers and acquisitions; cost allocation and rate design; and energy-efficiency program design and planning.

My resume is attached as Exhibit JFW-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have sponsored expert testimony in 90 state, provincial, and federal proceedings in the U.S. and Canada. I include a detailed list of my previous testimony in Exhibit JFW-1.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Consumer Advocate Division (CAD).

Q: Are you sponsoring any exhibits to your testimony?

A: Yes. I am sponsoring the following exhibits:

- Exhibit JFW-1: Resume of Jonathan Wallach, Resource Insight, Inc.
- Exhibit JFW-2: Residential Minimum Connection Cost
- Exhibit JFW-3: Citations to Marginal-Price Elasticity Studies
- Exhibit JFW-4: Companies' response to Request RD-1 of CAD's third set of requests for information
- Exhibit JFW-5: Companies' response to Request 1-2 of Kroger's first set of requests for information

Q: What is the purpose of your testimony?

A: On May 9, 2018, Appalachian Power Company and Wheeling Power Company (collectively, "the Companies") filed with the Public Service Commission ("the Commission") an application (including supporting direct testimony) to increase electric rates. My testimony addresses the methods used in the Companies' class cost of service study (CCOSS) to allocate 2017 test year revenue requirements, as described in direct testimony by Companies witness Katherine I. Walsh. In addition, my testimony responds to direct testimony by Companies witness Alex E. Vaughn regarding the Companies' proposals to: (1) eliminate the alleged subsidy paid by the LCP, IP, and Special Contracts customer classes; (2) increase the residential basic service charge (BSC) from $8 to $12 per monthly bill; and (3) maintain a declining-block rate structure for residential energy rates.[1] My testimony on

[1] I address the Companies' proposals regarding the basic service charge and energy rates for customers taking standard service under Tariff Schedule RS. I do not address the Companies' proposals regarding the basic service charge or energy rates for time-of-day customers taking service under Tariff Schedule RS-TOD.

the proposed subsidy mitigation reflects consideration of the impact of the Joint Stipulation and Agreement for Settlement regarding the Tax Cuts and Jobs Act of 2017 ("TCJA Settlement"), filed on August 23, 2018 in General Investigation No. 236.1.

Q: Please summarize your findings and recommendations with regard to the Companies' proposal for allocating the requested revenue increase.

A: It would not be appropriate to rely on the results of the Companies' CCOSS as the basis for allocating the requested revenue increase since the CCOSS does not allocate costs to customer classes in a manner that reasonably reflects each class's responsibility for such costs. Instead, the Commission should consider the results of a CCOSS that corrects the misallocations in the Companies' CCOSS.

In addition, it would be appropriate to consider the revenue-impact and subsidy-mitigation provisions of the TCJA settlement when determining the allocation of test-year revenue requirements to customer classes.

Based on the various considerations, and in order not to overburden any one customer class and provide for a fair revenue allocation, I recommend that the revenue increase for any customer class be capped at the approved system-average percentage increase plus 150 basis points.

Q: Please summarize your findings and recommendations with regard to Companies' proposal to increase the residential BSC.

A: The Companies' proposal runs contrary to long-standing principles for designing cost-based rates since it would inappropriately shift recovery of load-related costs from the volumetric energy rate to the fixed basic service charge. As explained in more detail below, the Companies' proposal to recover load-related costs through the residential BSC would:

- Lead to subsidization of high-usage residential customers' costs by low-usage customers, and thereby inequitably increase bills for the Companies' low-usage residential customers.
- Dampen price signals to consumers for controlling their bills through conservation or investments in energy efficiency or distributed renewable generation.

In Case No. 14-1152-E-42T, the Commission rejected the Companies' proposal to increase the residential BSC on the basis of a calculation of the fixed cost to serve a residential customer, stating that:

> The Commission will not abandon its practice of determining the basic service charge based on costs related to meters, services and billing.[2]

In this proceeding, the Companies again propose to increase the residential BSC on the basis of a calculation of the fixed cost to serve a residential customer. Consequently, the Commission should again reject the Companies' proposal to increase the residential BSC. Instead, based on a calculation of the "costs related to meters, services and billing", I recommend that the residential BSC be maintained at its current rate of $8 per residential customer per month.

Q: Please summarize your findings and recommendations with regard to the design of residential energy rates.

A: The Companies' proposal to maintain the existing differential between the rates for the first and second energy blocks would inappropriately shift recovery of base (i.e., non-ENEC) costs from the second to the first block. Instead, if the Commission approves the Companies' request for a third

[2] *Commission Order*, Case Nos. 14-1152-E-42T and 14-1151-E-D, 103 (May 26, 2015).

winter block rate at a discount to the second block rate, then I recommend that the charge for the first energy block be set at a rate that recovers 45% of approved residential base energy revenues.

Q: How is the rest of your testimony organized?

A: In Section II, I discuss how the Companies' CCOSS overstates the cost to serve residential customers. In Section III, I discuss how the Companies' proposal for allocating the requested revenue increase would unfairly burden the residential class. In Section IV, I explain how the Companies' proposal to increase the residential BSC runs contrary to Commission practice and violates long-standing principles of cost-based rate design. In addition, I discuss in Section IV how the Company's proposal for the residential BSC would give rise to unreasonable cost subsidization within the residential class, and would dampen energy price signals. Finally, I describe in Section V my recommended structure for residential energy rates.

II. Class Cost of Service Study

Q: Please describe the Companies' requested revenue increase.

A: The Companies are requesting that electric base rates be increased on average by 8.53% in order to recover an expected revenue deficiency of about $114.6 million in the 2017 test year.[3] Of the total $114.6 million requested revenue

[3] Paragraph 17 of the TCJA Settlement stipulates that certain provisions of the settlement will reduce the Companies' revenue request in this proceeding by about $17 million. The Companies have not yet filed for an adjustment to the requested revenue increase. However, according to the Companies' response to Request RD-1 of the CAD's third set of requests for information, the Companies' intend to reduce the requested revenue increase by $17.8 million. This adjustment would reduce the requested increase to 7.2% of test-year revenues at current

increase, the Companies propose to allocate about $69.7 million to residential customers. This amount represents a 12.3% increase over residential test-year revenues under current rates.[4]

Q: What is the basis for the Companies' proposed allocation of the requested revenue increase to the residential class?

A: According to Companies witness Vaughn, the Companies' CCOSS served as the basis for the Companies' revenue allocation proposal:

> One key objective of ratemaking is to design rates such that they reflect as closely as possible the actual costs of serving customers. To fully meet this objective would require that the rates of return for all customer classes be equalized. The class cost of service ("CCOS") study prepared by Company witness Walsh provides the information needed to evaluate customer class's rate of return.[5]

Q: What is the purpose of a class cost of service study?

A: The primary purpose of a class cost of service study is to allocate a utility's total revenue requirements to individual customer classes in a manner that reasonably reflects each class's responsibility for such revenue requirements. In other words, the primary purpose of a class cost of service study is to attribute costs to customer classes based on how those classes cause such costs to be incurred.

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rates. The Companies' response to Request RD-1 of the CAD's third set of requests for information is attached hereto as Exhibit JFW-4.

[4] Company Exhibit AEV-D1. The Companies use the term "going level revenues" to refer to test-year revenues under current rates.

[5] *Direct Testimony of Alex E. Vaughn on behalf of Appalachian Power Company and Wheeling Power Company*, Company Exhibit AEV-D, Case No. 18-0646-E-42T, 8 (June 11, 2018) [hereinafter "Vaughn Direct"].

Q: Please describe how the Companies' CCOSS allocates total-system revenue requirements to customer classes.

A: In order to allocate costs to customer classes, the CCOSS first separates total costs into production, transmission, distribution, and customer functions. Costs in each function are then classified as energy-, demand-, or customer-related based on whether costs are considered to be "caused" by energy sales, peak demand, or the number of customers, respectively. Finally, costs classified as either energy-, demand-, or customer-related are allocated to customer classes in proportion to each class's contribution to total-system energy sales, peak demand, or number of customers, respectively.

Q: Does the Companies' CCOSS reasonably allocate test-year revenue requirements?

A: No. The Companies' CCOSS does not allocate costs to customer classes in a manner that reasonably reflects each class's responsibility for such costs. In particular, the CCOSS allocates more production plant costs to customer classes with low load factors than is appropriate.[6]

Q: How does the Companies' CCOSS over-allocate production plant costs to the customer classes with low load factors?

A: The Companies' CCOSS inappropriately classifies all production plant costs as demand-related, as if such costs were incurred solely for the purposes of meeting system reliability requirements, and not at all for the purposes of minimizing the cost of meeting energy requirements. This classification approach is inconsistent with investment decision-making under typical generation expansion planning practices, where plant investment choices are

[6] Load factor is defined as the ratio of average demand to peak demand, where average demand is annual energy requirements divided by 8760 (i.e., the number of hours in a year).

driven by both reliability and energy requirements. As explained in NARUC's *Electric Utility Cost Allocation Manual*:

> Cost causation is a phrase referring to an attempt to determine what, or who, is causing costs to be incurred by the utility. For the generation function, cost causation attempts to determine what influences a utility's production plant investment decisions. Cost causation considers: (1) that utilities add capacity to meet critical system planning reliability criteria such as loss of load probability, loss of load hours, reserve margin, or expected unserved energy; and (2) that the utility's energy load or load duration curve is a major indicator of the type of plant needed. The type of plant installed determines the cost of the additional capacity. This approach is well represented among the energy weighting methods of cost allocation.[7]

From a cost-causation perspective, investments in peaking plant are appropriately classified as demand-related, since peaking units would be the least-cost option for meeting an increase in peak demand and planning reserve requirements. On the other hand, baseload or intermediate plant costs *in excess of peaking plant costs* (so-called "capitalized energy" costs) should be classified as energy-related, since these incremental costs are incurred to minimize the total cost of meeting an increase in energy requirements.

The Companies' CCOSS misclassifies these capitalized energy costs as demand-related. As a result, the Companies' CCOSS over-allocates capitalized energy costs to the residential class and under-allocates such costs to the industrial classes since the residential class has a lower load factor than the industrial classes.[8]

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[7] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, 38-39 (January, 1992).

[8] A customer class with a low load factor (relative to other classes) will be allocated a greater percentage of demand-related costs than that of energy-related costs because that class's

Q: Is there a classification method that would classify the Companies' production plant costs in a manner that reasonably reflects cost causation?

A: Yes. The Equivalent Peaker classification method classifies production plant costs in a manner that reasonably reflects investment decision-making under typical generation expansion planning practices. According to the *Electric Utility Cost Allocation Manual*:

> Equivalent peaker methods are based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the <u>need</u> for additional generating capacity and the most cost-effective <u>type</u> of capacity to be added.…
>
> The premises of this and other peaker methods are: (1) that increases in peak demand require the addition of peaking capacity only; and (2) that utilities incur the costs of more expensive intermediate and baseload units because of the additional energy loads they must serve. Thus, the cost of peaking capacity can properly be regarded as peak demand-related and classified as demand-related in the cost of service study. The difference between the utility's total cost for production plant and the cost of peaking capacity is caused by the energy loads to be served by the utility and is classified as energy-related in the cost of service study.[9]

Q: Have you reclassified the Companies' production plant costs using the Equivalent Peaker method?

A: Yes. For this analysis, I estimated the demand- and energy-related portions of the Companies' production plant costs based on data provided in the Companies' FERC Form 1 reports for 2017. Based on the FERC Form 1 data

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percentage contribution to total system demand is larger than its contribution to total system energy requirement.

[9] *Electric Utility Cost Allocation Manual*, 52-53.

for 2017, I calculated the demand-related portion of total plant costs for the Companies' generation portfolio as the sum of: (1) total plant cost for the Ceredo gas turbines; (2) total plant cost for the Smith Mountain pumped-storage plant; and (3) the demand-related portion of total plant cost for the rest of the portfolio.[10] I calculated the demand-related portion of total plant cost for the rest of the portfolio as the product of: (1) total plant cost for the rest of the portfolio; and (2) the ratio of the average plant cost per kilowatt of plant capacity for the Ceredo gas turbines to the average plant cost per kilowatt for the rest of the portfolio. Using this approach, I estimate that 40% of the Company's production plant costs are demand-related and about 60% are energy-related.

Q: How would this reclassification affect the allocation of the requested revenue increase to customer classes?

A: I modified the Companies' CCOSS to reflect my estimate of a 40%/60% demand/energy split under an Equivalent Peaker classification.[11] As indicated in Table 1, such a reclassification would dramatically reduce both the current subsidy for the residential class and the residential allocation of the revenue increase required to achieve the Companies' requested rate of return (ROR).

[10] Thus, for this analysis, I classified 100% of the Smith Mountain plant costs as demand-related.

[11] More precisely, I modified the electronic spreadsheet version of the Companies' CCOSS (WV_CCOS_TYE_2017__-__EXTERNAL_WORKING_COPY.xlsx), as provided in the Companies' response to Request 1-2(d) of Kroger's first set of requests for information. This response is attached hereto as Exhibit JFW-5.

Table 1: Results of Companies' and Modified Class Cost of Service Studies

	Revenue Increase at Equalized ROR		Current Subsidy	
	Companies' CCOSS	**Modified CCOSS**	**Companies' CCOSS**	**Modified CCOSS**
RS	97,752,213	69,248,273	40,080,949	15,495,904
SWS	1,357,884	1,016,568	494,558	200,168
SGS	122,099	173,509	(1,837,537)	(1,793,195)
GS	8,400,302	10,367,062	(11,848,689)	(10,152,331)
LCP	5,724,867	22,097,982	(16,901,705)	(2,779,665)
IP	(481,772)	3,761,945	(3,852,035)	(191,770)
Sp. Contracts	70,666	5,374,814	(4,561,052)	13,849
SS	2,871,233	2,355,550	458,877	14,094
OL	(932,838)	109,563	(1,510,503)	(611,418)
SL	(296,565)	82,825	(522,864)	(195,635)

Q: What do you recommend with respect to the Companies' CCOSS?

A: In Case No. 14-1152-E-42T, the Commission denied the Companies' request for approval of its cost of service study, noting that:

> The Commission is also aware that a COSS is, to some extent, based on the judgment of the preparer and is subject to different methodologies and interpretations….
>
> Because of the changing nature of the cost of service for each customer classification, the Commission does not normally approve a specific COSS or even a specific methodology. The cost allocations can and do vary from case to case, and the Commission has historically employed the concept of gradualism to move toward the results of the COSS to avoid over-correction in the current case.[12]

[12] *Commission Order,* Case Nos. 14-1152-E-42T and 14-1151-E-D, 99 (May 26, 2015).

As discussed above, the specific methodologies employed in the Companies' CCOSS in this proceeding appear to overstate the cost to serve the residential class. Consequently, it would be appropriate for the Commission to consider the results from my modification of the Companies' CCOSS when allocating the approved revenue increase.

III. Revenue Allocation

Q: Please describe the Companies' proposal for allocating the requested revenue increase to customer classes.

A: Based on the results of the Companies' CCOSS, the Companies propose to eliminate the current subsidy provided by the industrial customer classes (LCP, IP, and Special Contracts) and thereby move these classes to full cost of service. The Companies further propose to recover the current industrial subsidy from other customer classes in a manner that provides for an equal percentage increase in test-year revenues under current rates.[13]

Specifically, the Companies' CCOSS indicates that the industrial classes are currently providing a subsidy of about $25.3 million. The Companies propose to eliminate this subsidy amount by increasing revenues for all other classes by 12.3%. For the residential class, a 12.3% revenue increase would reduce the Companies' estimate of the current subsidy of $40.1 million by $12.0 million, or about 30.1%.[14]

Q: Would the Companies' proposal provide for a fair allocation of the requested revenue increase?

[13] Vaughn Direct, 9.

[14] Company Exhibit AEV-D1.

A: No. According to the results of my modified CCOSS, the Companies' proposal would not provide for a gradual transition to cost of service. As shown in Table 1 above, my modified CCOSS indicates a current subsidy of $15.5 million for the residential class. Consequently, the Companies' proposal to mitigate the residential subsidy by $12.0 million would amount to a substantial 78% reduction in the current subsidy and an abrupt transition to cost of service.

Moreover, the Companies' proposal fails to account for the impacts of the proposed TCJA Settlement on the current residential subsidy. Specifically, the proposed TCJA Settlement effectively provides for a $9.8 million reduction to the current residential subsidy (via the "50% Industrial Subsidy Adjustment"), to be funded out the residential class's share of the Unprotected Excess AFDIT.[15] When combined with the TCJA Settlement mitigation funded by the residential class, the Companies' proposed subsidy mitigation would amount (for one year) to a 55% reduction to the current subsidy to the residential class and a 126% reduction to the current subsidy provided by the industrial classes, as estimated in the Companies' CCOSS.[16] In other words, when combined with the mitigation provided by the residential class under the proposed TCJA Settlement, the Companies' proposed revenue allocation would result in industrial rates that are below cost of service.

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[15] TCJA Settlement, Exhibit A.

[16] The combination of the $9.8 million subsidy mitigation in the proposed TCJA Settlement and the $12.0 million mitigation proposed by the Companies would amount to 141% of the current residential subsidy under my modified CCOSS.

Most critically, the Companies' proposed revenue allocation would result in an excessive and overly burdensome bill increase of about 16% for the average residential customer.[17] Such an increase seems particularly unfair in light of the fact that industrial customers will, for the most part, see minimal bill increases or even bill decreases under the Companies' proposal.

Q: How should the requested revenue increase be allocated to customer classes?

A: In light of the magnitude of the requested revenue increase and the subsidy-mitigation impacts of the proposed TCJA Settlement, I recommend that the revenue increase for any customer class be capped at the system-average percentage increase plus 150 basis points. For example, at the Companies' requested increase of 8.53%, my recommendation would be to cap the revenue increase for any class at 10.03% of test-year revenues at current rates.

IV. Residential Basic Service Charge

A. The Companies' Proposal for the Residential Basic Service Charge

Q: What is the residential basic service charge?

A: The residential BSC is a fixed fee charged to each residential customer on their monthly bill regardless of the customer's energy usage during that month.

Q: What is the Companies' proposal with respect to the monthly basic service charge for residential customers?

[17] Companies Exhibit AEV-D4.

A: The Companies propose to increase the residential BSC from $8 to $12 per customer per month.[18] The proposed $4 increase represents a 50% increase over the current residential BSC.

Q: What is the Companies' rationale for increasing the residential BSC?

A: Company witness Vaughn contends that the Company's proposal would shift recovery of allegedly "fixed" distribution costs from the volumetric energy rate to the fixed basic service charge and thereby reduce intra-class subsidies:

> These fixed distribution costs, or at least a larger portion of them, should be recovered in the basic service charge since they do not vary with usage and are instead solely the costs associated with connecting a customer to the distribution system and maintaining that connection. The current basic service charge is too low relative to the fixed cost of providing electric service creating intra-class subsidies between customers.[19]

Q: To which distribution costs is Mr. Vaughn referring when he discusses the "fixed costs of providing electric service"?

A: Mr. Vaughn considers the costs of secondary poles, conductors, transformers, services, and meters to be "fixed".[20]

Q: Do the Companies propose to recover all allegedly fixed distribution costs through the residential BSC?

A: No. Mr. Vaughn estimates that the residential BSC would need to increase to about $39 per month to recover these allegedly fixed distribution costs.[21] Based on Mr. Vaughn's analysis, I estimate that the $12 residential BSC

[18] Vaughn Direct, 13.

[19] *Id.*

[20] Company Exhibit AEV-D3.

[21] *Id.*

proposed by the Companies' would effectively recover 100% of the Mr. Vaughn's estimate of meter and service costs and 24% of his estimate of secondary pole, conductor, and transformer costs.

Q: Does Mr. Vaughn offer any other rationale for increasing the residential BSC?

A: Yes. Mr. Vaughn contends that increasing the residential BSC would reduce spikes in monthly bills.[22] However, customer concerns regarding monthly bill volatility could be addressed simply by encouraging those customers to sign up for budget billing under the Companies' Average Monthly Payment Plan and by offering cost-effective energy efficiency programs targeting weather-related loads. In any event, customers experiencing financial hardship from periodically high bills—who tend to be lower-income consumers—would not likely find reprieve in an overall rate hike that smooths out billing periods by way of raising each of their monthly bills to varying degrees. In other words, consistently higher monthly bills are not made more palatable to vulnerable households simply because those bills are more uniform in their costliness.

B. The Companies' Proposal for the Residential BSC Violates Principles of Cost-Based Rate Design and is Contrary to Commission Practice

Q: What are the relevant considerations in designing cost-based rates for residential customers?

A: The primary challenge in rate design is to reflect the costs that customers impose on the system, both to encourage them to use utility resources responsibly and to share costs fairly. Accordingly, fixed basic service charges

[22] Vaughn Direct, 15-16.

should reflect the fact that each customer contributes equally to certain types of costs (e.g., meter costs) regardless of that customer's energy usage. Volumetric energy rates, on the other hand, recognize that customers of different sizes and load profiles contribute to other types of costs (e.g., generation plant costs) at different levels. If usage-driven costs are inappropriately collected through fixed basic service charges, then customers will have reduced incentives to control their bills through conservation or investments in energy efficiency or distributed renewable generation.[23]

Q: Given these considerations, what categories of costs are appropriately recovered through the volumetric energy rate?

A: In order to provide efficient price signals, volumetric energy rates should be set at levels that recover those categories of costs that tend to increase with customer usage over the long run, including plant, fuel, and O&M costs for the production, transmission, and distribution functions. In other words, volumetric energy rates should reflect long-run marginal costs.

As James Bonbright explains in his seminal text *Principles of Public Utility Rates*:

[23] National Association of Regulatory Utility Commissioners, *Distributed Energy Resources Rate Design and Compensation*, 118 (November 2016), available at https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0.

> In view of the above-noted importance attached to existing utility rates as indicators of rates to be charged over a somewhat extended period in the future, one may argue with much force that the cost relationships to which rates should be adjusted are not those highly volatile relationships reflected by short-run marginal costs but rather those relatively stable relationships represented by long-run marginal costs. The advantages of the relatively stable and predictable rates in permitting consumers to make more rational long-run provisions for the use of utility services may well more than offset the admitted advantages of the more flexible rates that would be required in order to promote the best available use of the existing capacity of a utility plant.[24]

> I conclude this chapter with the opinion, which would probably represent the majority position among economists, that, as setting a general basis of minimum public utility rates and of rate relationships, the more significant marginal or incremental costs are those of a relatively long-run variety – of a variety which treats even capital costs or "capacity costs" as variable costs.[25]

Almost three decades later, Alfred Kahn affirmed Bonbright's opinion in his *The Economics of Regulation*:

> … the practically achievable benchmark for efficient pricing is more likely to be a type of average long-run incremental cost, computed for a large, expected incremental block of sales, instead of SRMC [short-run marginal cost] ….[26]

Q: Which costs are appropriately recovered through the fixed basic service charge?

A: In contrast to the volumetric energy rate, the fixed basic service charge is intended to reflect the cost to connect to the distribution system a customer

[24] James C. Bonbright, *Principles of Public Utility Rates*. Columbia University Press, 334 (1961), available at media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf.

[25] *Id.*, 336.

[26] Alfred E. Kahn, *The Economics of Regulation*, The MIT Press, 85 (1988).

who uses very little or zero energy. Such "minimum connection costs" are generally limited to plant and maintenance costs for a service drop and meter, along with meter-reading, billing, and other customer-service expenses. As Bonbright explains:

> But this twofold distinction [between demand and energy in rate design] overlooks the fact that a material part of the operating and capital costs of utility business is more directly and more closely related to the number of customers than to energy consumption on the one hand or maximum kilowatt demand on the other hand. The most obvious examples of these so-called customer costs are the expenses associated with metering and billing.[27]

In their *Public Utility Economics*, economists Paul Garfield and Wallace Lovejoy also describe which costs are truly customer-related and therefore appropriately recovered through the fixed basic service charge:

> The purpose of both the service charge and the minimum charge is to cover at least some of the costs incurred by the utility whether or not the customer uses energy in a particular month. For small customers under the block meter-rate schedule, a charge of this kind is intended to cover the expenses relating to meter service and maintenance, meter reading, accounting and collecting, return on the investment in meters and the service lines connecting the customer's premises to the distribution system, and others. Such expenses as these represent as a minimum the "readiness-to-serve" expenses incurred by the utility on behalf of each customer.[28]

More recently, Severin Borenstein restated these principles for designing cost-based fixed basic service charges as follows:

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[27] Bonbright, *op. cit.*, 311.

[28] Paul J. Garfield and Wallace F. Lovejoy, *Public Utility Economics*, Prentice-Hall, Inc., 155-156 (1964).

> When having one more customer on the system raises the utility's costs regardless of how much the customer uses – for instance, for metering, billing, and maintaining the line from the distribution system to the house – then a fixed charge to reflect that additional fixed cost the customer imposes on the system makes perfect economic sense. The idea that each household has to cover its customer-specific fixed costs also has obvious appeal on ground of fairness or equity.[29]

Q: What has been Commission practice with regard to the design of the fixed basic service charge?

A: Consistent with these long-standing principles of cost-based rate design, Commission practice has been to determine the basic service charge "based on costs related to meters, services and billing."[30]

Q: Is the Companies' proposal for the residential BSC consistent with these long-standing principles of cost-based rate design and Commission practice?

A: No. Contrary to these principles and Commission practice, the Companies propose to recover through the residential BSC not just customer-related minimum connection costs – i.e., the costs for meters, service drops, and customer services – but also a portion of the load-related cost of secondary poles, conductors, and transformers. As discussed above in Section IV.A, the $12 residential BSC proposed by the Companies would effectively recover 100% of the Mr. Vaughn's estimate of customer-related meter and service costs and 24% of his estimate of load-related secondary pole, conductor, and transformer costs.

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[29] Severin Borenstein, "What's So Great About Fixed Charges?" (2014), available at https://energyathaas.wordpress.com/2014/11/03/whats-so-great-about-fixed-charges/.

[30] *Commission Order,* Case Nos. 14-1152-E-42T and 14-1151-E-D, 103 (May 26, 2015).

Q: Why do the Companies propose to recover load-related distribution plant costs through the residential BSC?

A: As discussed in Section IV.A, Mr. Vaughn contends that all such load-related costs are "fixed" and therefore appropriately recovered through a fixed basic service charge.

Q: Do you agree that load-related distribution costs are fixed?

A: No. Such costs may appear "fixed" when considered from a short-run accounting perspective, since the revenue requirements associated with debt service and maintenance in any year are unlikely to vary much with load in that year.

However, from the long-run perspective of cost-causation and price efficiency, plant investments are variable with respect to customer usage. The Companies' proposal to shift recovery of such load-related costs from the volumetric energy rate to the fixed basic service charge would drive the energy rate from long-run to short-run marginal cost and thereby dampen price signals for efficient customer behavior.[31]

Q: Have you estimated the minimum cost to connect a residential customer?

A: Yes. As shown in Exhibit JFW-2, I estimate a minimum connection cost of $7.51 per residential customer per month.[32] Consistent with long-standing rate design principles and Commission practice, my estimate of the minimum

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[31] I discuss the impact of the Company's proposal on energy price signals in Section IV.D. I also discuss in Section IV.C how the Companies' proposal would lead to inequitable subsidization of high-usage residential customers' costs by low-usage residential customers.

[32] Cost inputs for each cost account shown in Exhibit JFW-2 are from the Companies' CCOSS. Specifically, each line-item cost is the amount allocated to the residential class for that cost account in the Companies' CCOSS.

connection cost for residential customers includes only those costs which are truly customer-related, i.e., the costs of meters, service drops, and customer services.

Q: What accounts for the $4.49 difference between your $7.51 estimate of minimum connection cost and the $12 residential BSC proposed by the Companies?

A: The $4.49 difference represents load-related secondary pole, conductor, and transformer cost that would be inappropriately recovered through the residential BSC under the Companies' proposal. As discussed below, this shift in recovery of load-related costs from the volumetric energy rate to the fixed basic service charge would give rise to cost subsidization within the residential class and would dampen energy price signals to consumers for controlling their bills through conservation or investments in energy efficiency or distributed renewable generation.

C. The Companies' Proposal for the Residential BSC Would Lead to Intra-Class Cost Subsidization

Q: How would the Companies' proposal to increase the residential BSC cause intra-class subsidization?

A: As noted above, the Companies' proposal to increase the residential BSC would shift recovery of load-related costs from the volumetric energy rate to the fixed basic service charge. Such load-related costs are driven by residential load and are therefore appropriately recovered from residential customers in proportion to their contribution to total load. To the extent that load-related costs are recovered at a fixed rate through the residential BSC rather than at a volumetric rate through the energy charge, residential customers with below-average usage would bear a disproportionate share of load-related costs and consequently subsidize customers with above-average usage. In this case, a residential customer with below-average usage will pay more, and a residential customer with above average-usage will pay less, than their fair share of such costs.

Q: What is the extent of the intra-class subsidization under the Companies' proposal for the residential BSC?

A: As explained in Section IV.B, the $4.49 difference between the minimum connection cost of $7.51 and the $12 residential BSC proposed by the Companies represents load-related distribution costs that would be inappropriately recovered from each residential customer every month through a fixed charge on the customer's bill. The Company estimates about 4.7 million residential bills in the test year.[33] This means that $21.2 million of load-related costs would be recovered annually through the residential BSC under the Companies' proposal.[34]

If the load-related costs recovered through the residential BSC under the Companies' proposal were instead appropriately recovered through the volumetric energy rate, each residential customer would contribute to recovery of these costs in proportion to their usage. The Company estimates residential sales in the test year of about 5.2 million megawatt-hours.[35]

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[33] The number of residential bills in the test year is provided in Attachment 1 (Master_Rate_Design_Workbook.xlsx) to the Companies' response to Request 1-2(e) of Kroger's first set of requests for information. The Companies' response to Kroger Request 1-2(e) is attached hereto as Exhibit JFW-5.

[34] The $21.1 million result is derived by taking the product of the annual number of residential bills (4.7 million) and the amount of the proposed residential BSC in excess of minimum connection cost ($4.49 per bill).

[35] Residential sales for the test year are provided in Attachment 1 (Master_Rate_Design_Workbook.xlsx) to Kroger Data Request 1-2(e).

Therefore, if the $21.2 million of load-related costs continued to be recovered through the volumetric energy rate rather than through the fixed basic service charge, they would be charged at a rate of 0.41 cents per kilowatt-hour ("¢/kWh").[36] At this rate, a residential customer with below-average monthly usage of 500 kWh would contribute about $25 per year toward recovery of the $21.2 million of load-related costs while a customer with above-average monthly usage of 1,500 kWh would contribute about $74 per year.[37] Thus, with continued recovery of load-related costs through the volumetric energy rate, the 1,500 kWh customer would contribute three times more than the 500 kWh customer, in direct proportion to their usage and consistent with accepted principles of cost-causation.

In contrast, under the Companies' proposal to recover $21.2 million of load-related costs through the residential BSC, each residential customer would contribute about $54 per year toward recovery of such costs regardless of that customer's usage. A below-average 500 kWh customer would therefore pay more than double their fair share of these load-related costs under the Companies' proposal while an above-average 1,500 kWh customer would pay only 73% of their fair share.

[36] The 0.14¢/kWh result is derived by dividing $21.2 million by residential sales of 5.2 million megawatt-hours. This calculation assumes that the $21.2 million of load-related costs would be recovered through all residential energy blocks at a uniform rate.

[37] Average residential usage is 1,095 kWh per month. *See* Vaughn Direct, 16.

D. *The Companies' Proposal for the Residential BSC Would Dampen Energy Price Signals*

Q: Would the Companies' proposal to increase the residential BSC send appropriate price signals?

A: No. As discussed above, the Companies propose to set the residential BSC at a rate that exceeds the minimum cost to connect a residential customer. The amount in excess of minimum connection costs represents load-related costs that are more appropriately recovered in the volumetric energy rate. However, under the Companies' proposal, this excess over the minimum connection costs would instead be inappropriately recovered through the fixed basic service charge. This shift in the recovery of load-related costs from the volumetric energy rate to the fixed basic service charge would dampen price signals and discourage economically efficient behavior by residential customers.

Q: To what extent would the Company's proposal to increase the residential BSC dampen price signals provided by the residential volumetric energy rate?

A: With a fixed amount of revenue requirements to be recovered from the residential class, the higher the residential BSC, the lower the volumetric energy rate, and vice versa. As shown in Table 2 below, with the residential BSC set at $12, the Companies' propose an average base (i.e., net of ENEC) energy rate of 7.82¢/kWh in order to recover the proposed allocation of test year revenue requirements to residential customers.[38] If, instead, the residential BSC were set at the cost-based rate of $7.51, I estimate that the

[38] Provided in Attachment 1 (Master_Rate_Design_Workbook.xlsx) to Kroger Data Request 1-2(e).

average base energy rate would have to be increased to 8.23¢/kWh to recover the same allocated revenue requirement.[39]

Table 2: Base Energy Rates with Cost-Based and Companies' Residential BSC (¢/kWh)

	Rate With Cost-Based BSC	Rate With Companies' Proposed BSC	Difference from Cost-Based	% Difference from Cost-Based
First 500 kWh	9.807	9.398	(0.409)	-4.2%
Over 500 kWh	8.598	8.188	(0.410)	-4.8%
Over 1100 kWh (Winter)	2.597	2.188	(0.409)	-15.7%
Average	8.231	7.822	(0.409)	-5.0%

For the average residential customer with a monthly usage of 1,095 kWh, the price signal would be provided by the volumetric energy rate for the second block (applicable to monthly usage in excess of 500 kWh). As shown in Table 2, the Companies propose a base rate for the second energy block of 8.19¢/kWh. With the residential BSC at the cost-based rate of $7.51, I estimate a base rate for the second energy block of 8.60¢/kWh. In other words, the Companies are proposing a base rate for the second energy block that is 0.41¢/kWh, or about 5%, less than what the base rate would be if the residential BSC were set at minimum connection cost.

Including the current ENEC rate of 3.49¢/kWh, the total rate for the second energy block with a residential BSC set at minimum connection cost would be 12.09¢/kWh. If the residential BSC were increased to $12 as proposed by the Companies, then the total rate for the second energy block

[39] For the purposes of this calculation, I assume the same declining-block rate structure for the block volumetric energy rates as proposed by the Companies. However, as discussed in Section V, I do not recommend approval of the Companies' proposed rate discount between the first and second blocks.

would drop by about 3.4% to 11.68¢/kWh. Thus, the Companies' proposal for the residential BSC would dampen the price signal provided by the volumetric energy rate by 3.4%.

Q: How would residential customers likely respond to the reduction in the energy price signal resulting from the Companies' proposal for the residential BSC?

A: Since the volumetric energy rate under the Companies' proposal for the residential BSC would be lower than the volumetric energy rate with the residential BSC set at minimum connection cost, we would expect residential customers to consume more energy with the Companies' proposed BSC than they would with a cost-based BSC. The magnitude of the increase in energy consumption would depend on: (1) the extent to which the volumetric energy rate with the Companies' proposed residential BSC is lower than the volumetric energy rate with a cost-based BSC; and (2) the price elasticity of electricity demand.

Q: What is the price elasticity of electricity demand?

A: Residential customers respond to the price incentives created by the electrical rate structure. Those responses are generally measured as price elasticities, i.e., the ratio of the percentage change in consumption to the percentage change in price. Price elasticities are generally low in the short term and rise over several years, because customers have more options for increasing or reducing energy usage in the medium to long term. For example, a review by Espey and Espey (2004) of 36 articles on residential electricity demand published between 1971 and 2000 reports short-run elasticity estimates of about −0.35 on average across studies and long-run elasticity estimates of about −0.85 on average across studies.[40] In other words, on average across these studies, consumption decreased by 0.35% in the short term and by 0.85% in the long term for every 1% increase in price.

Studies of electric price response typically examine the change in usage as a function of changes in the marginal rate paid by the customer.[41] Table 3 below lists the results of seven studies of marginal-price elasticity over the last forty years.[42]

Table 3: Summary of Marginal-Price Elasticities

Authors	**Date**	**Elasticity Estimates**
Acton, Bridger, and Mowill	1976	−0.35 to −0.7
McFadden, Puig, and Kirshner	1977	−0.25 without electric space heat and −0.52 with space heat
Barnes, Gillingham, and Hageman	1981	−0.55
Henson	1984	–0.27 to –0.30
Reiss and White	2005	−0.39
Xcel Energy Colorado	2012	–0.3 (at years 2 and 3)
Orans et al, on BC Hydro inclining-block rate	2014	–0.13 in 3rd year of phased-in rate

Q: What would be a reasonable estimate of the marginal-price elasticity for changes in the residential volumetric energy rate?

A: From Table 3, it appears that –0.3 would be a reasonable mid-range estimate of the impact over a few years.

Q: What would be a reasonable estimate of the effect on energy use from the Company's proposal for the residential BSC?

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[40] The citation for this study is provided in Exhibit JFW-3.

[41] For the average residential customer with a monthly usage of 1,095 kWh, that would be the total rate for the second energy block (applicable to monthly usage in excess of 500 kWh).

[42] The citations for these studies are provided in Exhibit JFW-3.

A: As discussed above, if the residential BSC were increased as proposed by the Companies, the total rate for the second energy block would be about 3.4% less than what the volumetric rate would be if the residential BSC were set at minimum connection cost. Assuming an elasticity of –0.3, this 3.4% reduction in the volumetric energy rate would result in an increase in energy consumption of about 1% for the average residential customer. This means that all else equal, residential load after a few years with a residential BSC as proposed by the Companies would be expected to be about 1% higher than it would have been if the residential BSC had been set at minimum connection cost.

For comparison, I estimate that the Companies' residential energy efficiency programs in 2018 and 2019 will deliver an amount of energy savings equivalent to about 1% of residential energy sales.[43] Thus, the additional consumption induced by the Companies' proposal for the residential BSC would negate two years of energy savings achieved by the Companies' residential energy efficiency programs.

E. Conclusion

Q: What do you conclude with regard to the Companies' proposal to increase the residential BSC to $12?

A: The Companies' proposal runs contrary to Commission practice and to long-standing cost-causation and rate-design principles. The Companies' proposal to increase the residential BSC would inappropriately shift load-related costs from the volumetric energy rate to the fixed basic service charge, dampen

[43] Based on data regarding residential energy efficiency annual gross savings provided in Company Exhibit TCS-D5 in Case No. 17-0401-E-P.

price signals to consumers for reducing energy usage, disproportionately and inequitably increase bills for the Companies' smallest residential customers, and result in subsidization of larger residential customers' costs by customers with below-average usage.

Accordingly, the Commission should reject the Companies' proposal to increase the basic service charge for residential customers. Instead, I recommend that the residential BSC be maintained at its current rate of $8 per residential customer per month.

V. Residential Energy Rates

Q: Please describe the current structure of the Companies' volumetric energy rates for standard-service residential customers.

A: The Companies employ a "declining-block" rate structure for residential volumetric energy rates. This means that a residential customer pays a different volumetric rate for usage up to a certain threshold amount (i.e., a "block" of usage) than for usage that exceeds that threshold, and that the volumetric rate charged for the first block of usage is higher than that for the second block. Thus, with a declining-block rate structure, a residential customer will pay a higher volumetric rate for that portion of monthly usage that falls within the first energy block and a lower volumetric rate for the remaining portion of monthly usage in excess of first-block usage.

Specifically, for a residential customer taking standard service under Tariff Schedule RS, the Companies currently employ two energy blocks: (1) for monthly usage up to 500 kWh; and (2) for monthly usage in excess of 500 kWh. The rate for the first energy block exceeds that for the second energy block by 1.21¢/kWh.

Q: Are the Companies proposing a change to the current structure of the residential energy rates?

A: Yes. The Companies propose to add a third block rate applicable to monthly usage in excess of 1,100 kWh in the winter months.[44] Under this proposed structure, the second block rate would apply to all monthly usage in excess of 500 kWh in the non-winter months or to monthly usage in excess of 500 kWh and up to 1,100 kWh in the winter months. The Companies further propose to maintain the 1.21¢/kWh differential between the first and second block rates and to set the differential between the second and third block rates at 6¢/kWh.

Q: Is it reasonable to maintain the 1.21¢/kWh differential between the first and second block rates with the addition of a third block rate?

A: No. With the current two-block structure and a 1.2¢/kWh differential between the first and second block rates, I estimate that about 44% of test-year base energy revenues would be recovered through the first block and the remaining 56% would be recovered through the second block. Under the Companies' proposal to maintain the 1.2¢/kWh differential between the first and second block rates and to add a third block rate at a 6¢/kWh discount to the second block rate, a portion of the revenue recovery would reasonably be shifted from the second block to the third block. However, the Companies' proposal would also unreasonably shift a portion of the revenue recovery from the second block to the first block, thereby increasing the portion of base energy revenues recovered through the first block from 44% (under the two-block structure) to 48% (under the Companies' proposal).

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[44] Vaughn Direct, 13.

Q: What do you recommend with regard to the design of residential energy rates?

A: If the Commission approves the Companies' request for a third winter block rate at a discount to the second block rate, then the charge for the first energy block should be set at a rate that recovers 45% of approved residential base energy revenues. At the Companies' requested residential base energy revenues and with an $8 residential BSC, my recommended rate design would yield the base energy rates shown in Table 4.

Table 4: Proposed Residential Energy Rates at Requested Revenues (¢/kWh)

	Proposed Rate	**Discount from Prior Block Rate**
First 500 kWh	9.215	
Over 500 kWh	8.917	(0.30)
Over 1100 kWh (Winter Only)	2.918	(6.00)

Q: Does this conclude your direct testimony?

A: Yes.

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.

"The Price is Right: Restructuring Gain from Market Valuation of Utility Generating Assets" (with Paul Chernick), *International Association for Energy Economics Seventeenth Annual North American Conference* (345–352). Cleveland, Ohio: USAEE. 1996.

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"Economic Benefits from Early Retirement of Reid Gardner" (with Paul Chernick) prepared for and filed by the Sierra Club in PUC of Nevada Docket No. 11-08019.

"Green Resource Portfolios: Development, Integration, and Evaluation" (with Paul Chernick and Richard Mazzini) report to the Green Energy Coalition presented as evidence in Ontario EB 2007-0707.

"Risk Analysis of Procurement Strategies for Residential Standard Offer Service" (with Paul Chernick, David White, and Rick Hornby) report to Maryland Office of People's Counsel. 2008. Baltimore: Maryland Office of People's Counsel.

"Integrated Portfolio Management in a Restructured Supply Market" (with Paul Chernick, William Steinhurst, Tim Woolf, Anna Sommers, and Kenji Takahashi). 2006. Columbus, Ohio: Office of the Ohio Consumers' Counsel.

"First Year of SOS Procurement." 2004. Prepared for the Maryland Office of People's Counsel.

“Energy Plan for the City of New York” (with Paul Chernick, Susan Geller, Brian Tracey, Adam Auster, and Peter Lanzalotta). 2003. New York: New York City Economic Development Corporation.

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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.

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

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“Review of the Kentucky-American Water Company Capacity Expansion Program, A Report to the Kentucky Public Service Commission.” 1982. ESRG Study No. 82-45.

“Long Range Forecast of Sierra Pacific Power Company Electric Energy Requirements and Peak Demands, A Report to the Public Service Commission of Nevada.” 1982. ESRG Study No. 81-42B.

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“Office of People’s Counsel Case No. 9117” (with William Fields). Presentation to the Maryland Public Utilities Commission in Case No. 9117, December 2008.

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

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

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

EXPERT TESTIMONY

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

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

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

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

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

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

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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.

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Indiana Utility Regulatory Commission Cause No. 44967, Indiana Michigan Power Company electric rates; Citizens Action Coalition of Indiana, Indiana Coalition for Human Services, Indiana Community Action Association, and Sierra Club. Direct, November 2017.

Cost basis for residential customer charges.

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Estimate of Minimum Cost to Connect a Residential Customer

	Residential Class
Plant in Service	
Services	144,285,630
Meters	18,699,074
Unclassified Customer-Related	5,879,205
	$168,863,909
Reserve for Depreciation	55,290,764
Net Plant in Service	$113,573,145
Return + Tax Rate	8.90%
Return + Income Taxes	$10,103,862
Expenses	
Meter O&M	500,198
Customer Installation	376,533
Cust Acct Supervision	404,992
Meter Reading	1,877,553
Cust Records & Collection	11,106,149
Misc Cust Accounts	44,091
Cust Information & Service	1,493,123
Property Insurance	176,198
Injuries & Damages	406,962
Employee Pensions & Benefits	1,334,920
Depreciation - Services + Meters	7,042,491
Payroll-Related Taxes	464,381
	$25,227,592
Total	$35,331,455
Monthly Bills	4,707,656
Minimum Connection Cost	$7.51

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APPALACHIAN POWER COMPANY &
WHEELING POWER COMPANY
WEST VIRGINIA CASE NO. 18-0646-E-42T
THIRD REQUEST FOR INFORMATION – CAD

Request RD-1

Refer to the Companies' joint stipulation in the TCJA Case No. 236.1. Does the Company intend to file a revised cost of service study and revenue allocation proposal in light of the agreement in paragraph 17 to reduce rate base by $17 million? Please explain one way or the other.

Response RD-1

Paragraph 17 of the Commission approved joint stipulation in the TCJA Case No. 236.1 did not reduce rate base by $17 million; it reduced the base rate case revenue requirement by approximately $17 million.

Supplemental Response RD-1

The CAD has asked the Companies to supplement this response to answer the more general question of whether they intend to file a revised cost of service study and revenue allocation proposal in this case. While a revision to the cost-of-service study filed in this case is not necessary to produce the lower revenue requirement referenced in paragraph 17 of the Commission approved joint stipulation in TCJA Case No. 236.1, it is possible that the Companies might file a revised COS study, and corresponding revenue allocation proposal, in their rebuttal testimony, if necessary given the testimony of the Staff and other parties.

			Total Retail	RS	SGS	GS-SEC	GS-PRI	GS-SUB	GS-TRAN	LCP-SEC
IGCC/CCS										
Allocation Factor	PROD_DEMAND		1.00000000	0.44921787	0.01353629	0.15248662	0.01694355	0.00155683	0.00083564	0.00783891
Amount	$	4,116,531	4,116,531	1,849,219	55,723	627,716	69,749	6,409	3,440	32,269
Storms										
Allocation Factor	TOTOHLINES		1.00000000	0.67089501	0.01824075	0.19106279	0.01558286	-	-	0.00954249
Amount	$	13,710,650	13,710,650	9,198,407	250,093	2,619,595	213,651	-	-	130,834
Total	$	17,827,181	17,827,181	11,047,626	305,815	3,247,311	283,400	6,409	3,440	163,103

	LCP-PRI	LCP-SUB	LCP-TRA	IP-SEC	IP-PRI	IP-SUB	IP-TRA	SWS	SS-Sec	SS-Pri	OL	SL	SC
IGCC/CCS													
Allocation Factor	0.06072828	0.07458766	0.10226910	-	0.00027618	0.00624369	0.03211842	0.00653977	0.01754034	0.00351141	0.00062664	0.00022819	0.05291460
Amount	249,990	307,042	420,994	-	1,137	25,702	132,216	26,921	72,205	14,455	2,580	939	217,825
Storms													
Allocation Factor	0.05523120	-	-	-	0.00025057	-	-	0.01088191	0.02062760	0.00286688	0.00269857	0.00087702	0.00124234
Amount	757,256	-	-	-	3,435	-	-	149,198	282,818	39,307	36,999	12,025	17,033
Total	1,007,245	307,042	420,994	-	4,572	25,702	132,216	176,119	355,023	53,762	39,579	12,964	234,858

APPALACHIAN POWER COMPANY &
WHEELING POWER COMPANY
WEST VIRGINIA CASE NO. 18-0646-E-42T
FIRST REQUEST FOR INFORMATION –
KROGER

Request 1-2

Please provide an electronic version of the company's filing and workpapers in this case. This should include the documents listed in parts a) through e) below. In supplying these materials please remove any passwords or other restrictions that may otherwise be required to open or modify the files:

a) The Company's Application, Testimony and Exhibits in their native electronic formats, i.e., Word, Excel, etc. with working formulas and references included where applicable.

b) All workpapers utilized in the preparation of the Company's filing in this case, preferably in Excel format with all working formulas and links included to the extent practicable.

c) A working copy of the Company's Revenue Requirement model and supporting workpapers in Excel format with working formulas included.

d) A working copy of the Company's Class Cost of Service model and supporting workpapers in Excel format with working formulas included.

e) A working copy of the Company's Rate Design model and all supporting workpapers in Excel format with working formulas included.

Response 1-2

a) See the CD of those Statements and the workpapers provided as part of the Companies' May 9, 2018 filing.

b - e) See Kroger 1-02b, Attachment 1, Kroger 1-02c, Attachments 1 - 6, Kroger 1-02d, Attachments 1 - 7, and Kroger 1-02e, Attachment 1, all on the enclosed CD, for electronic copies of workpapers that underlie the Rule 42 T Statements filed on May 9, 2018.