BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

In the Matter of:	**)**	
	)	
Application of Duke Energy Carolinas, LLC	**)**	**Docket No. 2018-319-E**
for Adjustments in Electric Rate Schedules	**)**	
and Tariffs	**)**	

DIRECT TESTIMONY OF

JONATHAN WALLACH

ON BEHALF OF

SOUTH CAROLINA STATE CONFERENCE OF THE NATIONAL ASSOCIATION FOR THE ADVANCEMENT OF COLORED PEOPLE, SOUTH CAROLINA COASTAL CONSERVATION LEAGUE, AND UPSTATE FOREVER

Resource Insight, Inc.

FEBRUARY 26, 2019

Table of Contents

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 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 more than 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 South Carolina State Conference of the National Association for the Advancement of Colored People ("SC NAACP"), the South Carolina Coastal Conservation League ("CCL"), and Upstate Forever.

Q: Are you sponsoring any exhibits?

A: Yes. I am sponsoring the following exhibits:

- Exhibit JFW-1: Resume of Jonathan Wallach, Resource Insight, Inc.
- Exhibit JFW-2: Citations to Marginal-Price Elasticity Studies

Q: What is the purpose of your testimony?

A: On November 8, 2018, Duke Energy Carolinas, LLC ("DEC" or "the Company") filed with the Public Service Commission of South Carolina ("Commission") an application and supporting testimony for approval of increased electric rates and charges. My testimony explains why the Commission should reject the Company's proposal to increase the monthly Basic Facilities Charge ("BFC") for residential customers. I respond to the testimony of Company witness Janice Hager regarding the Company's cost of service study ("COSS"), which served as the basis for its proposal to increase the BFC, and the testimony of Company witness Michael J. Pirro regarding DEC's proposed increase in the BFC.

Q: Please summarize your findings and recommendations.

A: The Company has not justified its proposal to more than triple the residential BFC. The Company proposes to increase the residential BFC in order to recover all costs classified as "customer-related" in its cost of service study ("COSS"). However, contrary to long-standing Commission precedent, DEC has classified a portion of the cost of its distribution grid as customer-related in the COSS based on a "minimum-system" analysis.[1] This inherently flawed analysis erroneously classifies some distribution-grid costs—a portion of the cost of poles, wires, conduits, and transformers—as customer-related, even though they are in fact driven by usage and therefore properly classified as "demand-related." The Company's COSS thereby overstates the amount of customer-related costs appropriately recovered through the residential BFC.

Accordingly, the Commission should reject the Company's reliance on a minimum-system analysis to classify distribution-grid costs as customer-related in the COSS. Instead, as has been the practice for the past three decades and consistent with this Commission's directive, DEC should classify all such distribution-grid costs as demand-related. Only the costs incurred by DEC to connect customers to the distribution grid – i.e., the cost of meters, service drops (the line connecting a residence to the grid) and meter-reading, billing, and other customer-service expenses – should be classified as customer-related.

The Company's proposal to recover distribution-grid costs through the residential BFC also runs contrary to established principles for designing cost-based rates since it would inappropriately shift recovery of costs driven by usage from the volumetric energy rate to the fixed BFC. As explained in more detail below, the Company's proposal to recover usage-driven costs through the residential BFC would:

[1] In a 1991 order granting a rate increase to DEC's predecessor, Duke Power Company, the Commission found that "the Minimum System concept should be eliminated from Duke's cost of service study". Order No. 91-1022, Docket No. 91-216-E, 7 (Nov. 18, 1991).

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

Consequently, the Commission should reject the Company's proposal to increase the BFC for residential customers. Instead, consistent with enduring cost-causation and rate-design principles and in order to protect low-income customers from undue harm, I recommend that the BFC for the residential rate classes be increased from current levels by the same percentage as the revenue increase (if any) ultimately authorized by the Commission in this proceeding for those classes.

Q: How is the rest of your testimony organized?

A: In Section II, I describe the Company's proposal for increasing the residential BFC. In Section III, I discuss how the Company's COSS misclassifies demand-related distribution-grid costs as customer-related. In Section IV, I explain how DEC's proposal to increase the residential BFC violates long-standing principles of cost-based rate design. In Section V, I discuss how DEC's proposal would give rise to unreasonable cost subsidization within the residential class. In Section VI, I discuss how the Company's proposal would dampen energy price signals. Finally, I provide my conclusions and recommendations in Section VII.

II. DEC's Proposal to Increase the Residential BFC

Q: What is the Basic Facilities Charge?

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

Q: What is the Company's proposal with respect to the BFC for residential customers?

A: For residential customers taking standard service under Schedules RS, RE, ES, or ESA, DEC proposes to more than triple the BFC from $8.29 to $28.00 per customer per month. For residential customers taking time-of-use service under Schedule RT, DEC proposes to nearly triple the BFC from $9.93 to $27.08 per customer per month.[2]

Q: What is the basis for the Company's proposal to increase the residential BFC?

A: According to Company witness Pirro, DEC proposes to increase the residential BFC in order to recover the residential classes' share of the costs classified as customer-related in the Company's COSS.[3]

Q: Does the Company's COSS provide a reasonable basis for increasing the residential BFC?

---

[2] Pirro Direct Exhibit No. 6, attached to *Direct Testimony of Michael J. Pirro for Duke Energy Carolinas, LLC*, Docket No. 2018-319-E (November 8, 2018) [hereinafter "Pirro Direct"]. Standard residential service is provided under Schedule RS. Schedule RE is applicable to residential customers who use electricity for all major end-uses. Schedule ES is applicable to residential customers whose homes meet Energy Star standards. Schedule ESA is applicable to residential customers who use electricity for all major end-uses and whose homes meet Energy Star standards.

[3] Pirro Direct, 15.

A: No. As discussed below in Section III, the Company's COSS erroneously classifies some distribution costs as customer-related and therefore overstates the amount of customer-related costs that are eligible for recovery through the residential BFC.

Q: What is the purpose of the Company's COSS?

A: The purpose of the COSS is to allocate the Company's total revenue requirement to the various rate classes in a manner that reasonably reflects each class's contribution to that revenue requirement.

Q: Please describe how the total revenue requirement is allocated to rate classes in the Company's COSS.

A: In order to allocate the total revenue requirement to rate classes, the COSS first separates that total into production, transmission, distribution, and customer cost 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: Please describe how costs are classified in the Company's COSS.

A: The Company classifies the costs of meters, service drops, and customer services as customer-related in the COSS. As I discuss below in Section III, these are the only categories of costs that are properly classified as customer-related.

In addition, the Company relies on a "minimum-system" analysis to classify some distribution-grid costs – a portion of pole, conductor, conduit, and line-transformer costs – as customer-related. As discussed in Section III, the minimum-system classification methodology is fundamentally flawed and incorrectly classifies distribution-grid costs as customer-related.

The remaining portion of pole, conductor, conduit, and line-transformer costs not classified as customer-related are instead classified as demand-related in the COSS, along with all production and transmission plant and fixed operations and maintenance ("O&M") costs. Finally, fuel and variable O&M costs are classified as energy-related.

Q: Please describe how the Company uses the minimum-system analysis to classify some pole, conductor, conduit, and line-transformer costs as customer-related.

A: The Company's minimum-system analysis attempts to estimate the cost to install the same amount of poles, conductors, conduit, and line transformers as are currently on the distribution system, assuming that each piece of distribution equipment is sized to meet minimal load.[4] In other words, the Company's minimum-system analysis attempts to estimate the cost to replicate the configuration of the existing distribution grid using "minimum-size" equipment.

The Company's COSS classifies the cost of this hypothetical minimum-size distribution grid as customer-related. The difference between the test-year cost of the distribution grid and the estimated cost of the hypothetical minimum-size distribution grid is classified as demand-related in the Company's COSS.

---

[4] *Direct Testimony of Janice Hager for Duke Energy Carolinas, LLC*, Docket No. 2018-319-E, 14 (November 8, 2018) [Hereinafter "Hager Direct"].

Q: Is there another method that utilities typically use to classify distribution costs?

A: Yes. Under the Basic Customer method, only the costs of meters, service drops, and customer services are classified as customer-related and all other distribution costs are classified as demand-related.

Q: Does DEC propose to recover all of the costs classified as customer-related in its COSS through the residential BFC?

A: Yes. Based on the minimum-system approach, the Company's COSS estimates a customer-related cost of $28.00 per residential customer taking standard service and $27.08 per residential customer taking time-of-use service. The Company proposes to collect these amounts through the BFC for standard-service and time-of-use residential customers, respectively.[5]

III. DEC's COSS Misclassifies Distribution Costs

Q: Is the Company's proposal to classify distribution costs based on a minimum-system analysis a break from past practice?

A: Yes. As far as I am aware, DEC has been relying on the Basic Customer method to classify distribution costs as demand-related ever since the Commission ordered the Company to stop relying on the minimum-system classification method in 1991.

Q: Has DEC explained why it decided in this proceeding to not comply with the Commission's 1991 directive and instead to start relying on the minimum-system classification method?

[5] Pirro Direct Exhibit No. 6.

A: No. Instead, Company witness Hager opines that continued reliance on the Basic Customer method would yield cost classifications that are "counter to cost causation principles."[6]

Q: Do you agree with Ms. Hager's contention that the Basic Customer method produces cost classifications that are inconsistent with cost-causation principles?

A: No. To the contrary, it is the minimum-system classification approach adopted by DEC in this proceeding which classifies distribution costs inconsistently with cost-causation principles.

Q: Why are minimum-system classifications inconsistent with cost-causation?

A: The minimum-system method suffers from a number of fundamental flaws which lead to classifications that are contrary to cost-causation principles.

For one, the minimum-system approach implausibly assumes that a utility would incur costs to build a distribution grid to serve customers that have no load. As noted in a study by the Regulatory Assistance Project:

> … the threshold assumption is that there is some portion of the system whose costs are unrelated to demand (or to energy for that matter). From one perspective, this notion has a certain intuitive appeal — these are the lowest costs that must be incurred before any or some minimal amount of power can be delivered — but from another viewpoint it seems absurd, since in the absence of any demand no such system would be built at all.[7]

---

[6] Hager Direct, 15.

[7] Frederick Weston, *Charging for Distribution Utility Services: Issues in Rate Design*, Regulatory Assistance Project, 31 (December, 2000), available at https://www.raponline.org/wp-content/uploads/2016/05/rap-weston-chargingfordistributionutilityservices-2000-12.pdf.

For another, the minimum-system approach erroneously assumes that the minimum system would consist of the same number of units (e.g., number of poles, feet of conductors) as the actual system. In reality, load levels help determine the number of units, as well as their size. Minimum-system analyses ignore the effect of loads on the number of units installed, or the type of equipment installed, classifying some costs as customer-related even though they are really driven by demand.

Finally, the minimum-system method fails to account for the fact that even the minimum-size equipment currently installed on the system has some amount of load-carrying capability. Consequently, some portion of the cost for this minimum-size equipment should be classified as demand-related. However, under the minimum-system method, that demand-related portion of the cost of the minimum-sized equipment is instead misclassified as customer-related.[8]

Q: What is the magnitude of misclassified cost under the Company's minimum-system classification?

A: I estimate that about $71 million of the distribution-grid costs allocated to the residential rate classes in the COSS have been misclassified as customer-related under the Company's minimum-system method.

Q: How did you derive your estimate of misclassified cost?

A: In response to a data request, DEC provided the unit cost results from its COSS and from a cost of service study that classifies distribution costs using the Basic Customer method.[9] These results show that the Company's

[8] George J. Sterzinger, "The Customer Charge and Problems of Double Allocation of Costs", *Public Utilities Fortnightly*, (July 2, 1981).

[9] DEC response to Vote Solar Data Request No. 1-20.

COSS classifies about $165 million of residential revenue requirements as customer-related, while the revised cost of service study based on the Basic Customer method classifies about $94 million of residential revenue requirements as customer-related. The $71 million difference between these two results represents demand-related distribution-grid costs that have been misclassified as customer-related under the Company's minimum-system classification method.

Q: How would these misclassified costs be recovered under the Company's proposal for the residential BFC?

A: As noted in Section II, DEC proposes to recover through the residential BFC all costs that the Company's COSS classified as customer-related (and allocated to the residential classes). Thus, the proposed residential BFC would recover not just costs that are truly customer-related but also those distribution-grid costs that are erroneously classified as customer-related in the Company's COSS.

Q: What do you recommend with regard to the Company's proposal to rely on the minimum-system method to classify distribution costs in its cost of service study?

A: The Commission should reject the Company's use of the minimum-system method to classify distribution-grid costs. Instead, DEC should be directed to continue the long-standing practice adopted by the Commission in 1991 of classifying distribution costs in cost of service studies using the Basic Customer method.

IV. DEC's Proposed Increase to the Residential BFC Violates Principles of Cost-Based Rate Design

Q: How did DEC use the results of its COSS in the design of proposed rates for the residential rate classes?

A: As discussed above in Section II, the Company proposes to set the residential BFC at the rate that would recover the residential classes' share of costs classified as customer-related with the minimum-system method in the COSS. The Company further proposes to set the energy charge for each residential rate class at the rate that would recover the difference between each class's share of requested total revenues and the revenues collected from that class through the proposed BFC.

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 share costs fairly and to encourage economically efficient usage of utility resources. Accordingly, fixed customer charges should reflect the fact that each customer contributes equally to certain types of 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 at different levels. If usage-driven costs are inappropriately collected through fixed customer charges, then customers will have reduced incentives to control their bills through conservation or investments in energy efficiency or distributed renewable generation.[10]

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

A: In order to provide cost-based price signals, volumetric energy rates should be set at levels that recover those categories of costs that are driven by customer usage over the long run. This includes plant, fuel, and O&M costs for the production, transmission, and distribution functions, along with certain customer-service costs that tend to vary with usage, such as uncollectible costs.[11]

In other words, volumetric energy rates should reflect long-run marginal costs. As James Bonbright concluded in his seminal text *Principles of Public Utility Rates*:

> … 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.[12]

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

---

[10] 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.

[11] Uncollectible costs are the billed amounts not recovered from customers as a result of those customers' non-payment of all or a portion of their monthly bills.

[12] James C. Bonbright, *Principles of Public Utility Rates*. Columbia University Press, 348-336 (1961), available at media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf.

> … 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 [short-run marginal cost] ….[13]

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

A: In contrast to the volumetric energy rate, the fixed customer charge should reflect the cost to connect a customer who uses very little (or even zero) energy to the distribution grid. Such "customer connection costs" are limited to the costs of a meter and service drop (including plant and maintenance) and meter-reading, billing, and other customer-service expenses.

Q: What is the basis for your opinion regarding which costs are appropriately recovered through the fixed customer charge?

A: My opinion is based on established and enduring rate-design principles. For example, Bonbright explains 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.[14]

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

---

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

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

> The purpose of … the service 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.[15]

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

> 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.[16]

Q: Is the Company's proposal for the residential BFC consistent with these long-standing principles of cost-based rate design?

A: No. Contrary to these principles, DEC proposes to recover through the residential BFC not just customer connection costs – i.e., the costs for meters, service drops, and customer services – but also the costs allocated to the residential class under the COSS for: (1) Advanced Metering Infrastructure ("AMI meters"); (2) uncollectible costs; and (3) customer-related distribution-grid plant.

---

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

[16] 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/.

Q: Would it be reasonable to recover AMI meter costs through the residential BFC, as DEC proposes?

A: No. Recovering AMI costs through the residential BFC would be inconsistent with cost-causation principles. The National Association of Regulatory Utility Commissioners describes cost causation as "an attempt to determine what, or who, is causing costs to be incurred by the utility."[17] In this case, the "what" causing DEC to make discretionary investments in AMI meters is the expectation that such investments would provide benefits to customers, and the "who" are the customers who would share in these benefits as a result of the Company's AMI investments. Thus, in the case of AMI meters, cost-causation requires that customers contribute toward recovery of AMI costs in proportion to their share of the AMI benefits.

Within the residential class, high-usage, more-sophisticated energy consumers will likely reap greater benefits than lower-usage customers from AMI technologies and services.[18] In which case, it would be consistent with cost-causation principles for larger users to contribute a greater share toward recovery of AMI costs than smaller users. However, each customer regardless of usage would contribute the same amount to recovery of AMI costs if such costs were recovered through the residential BFC. Thus,

---

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

[18] For a description of the expected customer benefits from the Company's investment in AMI meters, see *Direct Testimony of Donald Schneider, Jr. for Duke Energy Carolinas, LLC*, Docket No. 2018-319-E (November 8, 2018).

recovering AMI costs through the residential BFC, as proposed by DEC, would be contrary to cost-causation principles.[19]

Q: Why is the Company's proposal to recover uncollectible costs inconsistent with cost-based rate design?

A: Uncollectible costs tend to vary with revenues and thus with usage. Thus, as discussed above, such costs are appropriately recovered through the volumetric energy rate.

Q: How does DEC estimate the customer-related distribution-grid cost per residential customer proposed for recovery through the residential BFC?

A: As discussed in Section II, DEC relies on the results of its minimum-system analysis to estimate the "customer-related" distribution-grid cost per residential customer. Specifically, as discussed in Section III, the Company's COSS allocates to the residential rate classes in total about $71 million of pole, conductor, conduit, and line-transformer costs that were erroneously classified as customer-related using a minimum-system analysis. Dividing by the number of residential bills yields a "customer-related" distribution-grid cost of $11.97 per residential customer.[20]

---

[19] In addition, the Company's proposal to recover AMI meter costs through the residential BFC would effectively double-count the cost to meter a new customer since the proposed BFC would recover both the cost of AMI meters and the cost of the legacy meters replaced by AMI meters.

[20] Calculated based on data provided in the Company's responses to Vote Solar Data Request Nos. 1-20 and 1-28.

Q: Why would it be unreasonable for DEC to recover costs through the residential BFC that were classified as "customer-related" using a minimum-system analysis?

A: As discussed in Section III, the $71 million of distribution-grid costs that DEC proposes to recover through the residential BFC are actually demand-related costs that have been misclassified as customer-related in the Company's minimum-system analysis. Recovering such demand-related costs through the residential BFC would be contrary to long-standing principles of cost-based rate design.

Even if the results of the Company's minimum-system analysis were accepted for *cost-allocation* purposes, such results should not be used for *rate-design* purposes. Minimum-system analyses overstate the minimum cost *per customer* because they assume that a minimum system carrying minimal load would have the same amount of distribution equipment (e.g., the same number of poles, the same length of conductor) as would a distribution system designed to carry actual distribution load. In other words, the minimum-system method assumes that each piece of distribution equipment would serve the same number of customers on average, regardless of whether the customers are average-sized (as for the actual system) or have minimal demand (as for the hypothetical minimum-size system.)

This is not a realistic assumption, since even a minimally sized piece of distribution equipment should be able to serve more minimal-usage customers than the number of average-usage customers served by an average-sized piece of distribution equipment. Consequently, the true distribution-grid cost to serve a customer with minimal usage is likely to be less than that derived using a minimum-system analysis. Indeed, since the minimum-system method attempts to estimate the distribution-grid cost incurred regardless of usage – i.e., the cost to serve load approaching zero – the true minimum distribution-grid cost per customer is zero since distribution equipment that carries zero load can serve an infinite number of customers with zero load.

Q: Once the excess costs from the minimum-system approach have been removed, what is the resulting cost to connect a residential customer to the distribution grid?

A: As shown in Table 1 below, I estimate that $12.55 per residential customer per month would recover the truly customer-related costs of meters, service drops, and customer services allocated to both the standard-service and time-of-use rate classes.

Q: How did you derive your estimate of the cost to connect a residential customer to the distribution grid?

A: In response to a data request, DEC provided the unit cost results from a cost of service study that classifies distribution costs using the Basic Customer method.[21] These results show an allocation to the residential rate classes of about $94.3 million in customer-related costs. I then adjusted this total in order to remove AMI and uncollectible costs for the reasons discussed above. In addition, I reduce this total to correct for an erroneous classification of overhead line maintenance costs as customer-related.[22]

---

[21] DEC response to Vote Solar Data Request No. 1-20.

[22] The revised COSS based on the Basic Customer method classifies about 32% of the overhead line maintenance expense allocated to the residential classes as customer-related. This is the only cost of service study based on the Basic Customer method that I can recall reviewing during my career that classified *any* overhead line maintenance expense as customer-related.

Dividing the net amount of $73.9 million by the number of residential bills yields a connection cost per residential customer of $12.55 per month.

Table 1: Derivation of the Cost to Connect a Residential Customer

	Residential Cost	Residential Bills	Cost per Bill
Customer-Related Cost	$94,303,956	5,890,613	$16.01
Less			
AMI Deferral Amortization	$(10,633,476)	5,890,613	$(1.81)
Uncollectible Expense	$(1,939,128)	5,890,613	$(0.33)
OH Line Maintenance	$(7,791,038)	5,890,613	$(1.32)
Total	$73,940,315		$12.55

Q: What accounts for the $15.45 difference between your $12.55 estimate of the residential connection cost and the $28.00 residential BFC proposed by DEC?

A: The $15.45 difference between my $12.55 estimate of the cost to connect a residential customer and the $28.00 BFC proposed by DEC represents load-related costs that would be inappropriately recovered through the fixed customer charge under the Company's proposal.[23]

Q: Why should the Commission be concerned about the Company's proposal to recover $15.45 in load-related costs through the BFC?

A: As I discuss in the following sections, this shift in recovery of load-related costs from the volumetric energy rate to the fixed customer charge would give rise to cost subsidization within the residential class and would

[23] Although DEC proposes a BFC of $27.08 for Schedule RT customers and $28.00 for all other residential customers, the average rate (weighted by number of customers) across all residential customers is still $28.00 because there are so few Schedule RT customers.

dampen energy price signals to consumers for controlling their bills through conservation, energy efficiency, or distributed renewable generation.

V. DEC's Proposal to Increase the Residential BFC Would Lead to Intra-Class Cost Subsidization

Q: How would the Company's proposal to increase the residential BFC cause subsidization within the residential class?

A: As discussed above, DEC's proposal to increase the residential BFC would shift recovery of load-related costs from the volumetric energy rate to the fixed customer charge. Such costs are driven by residential load and are therefore appropriately recovered from each residential customer in proportion to their contribution to class load. To the extent that load-related costs are recovered through the fixed customer charge rather than through the volumetric energy rate, residential customers with below-average usage would bear a disproportionate share of load-related costs and consequently subsidize customers with above-average usage. In other words, a residential customer with below-average usage would pay more, and a residential customer with above average-usage would pay less, than their fair share of such costs.

Q: What is the extent of the intra-class subsidization under the Company's proposal for the residential BFC?

A: As explained above, the $15.45 difference between the $12.55 residential connection cost and the $28.00 residential BFC proposed by the Company represents load-related costs that DEC would inappropriately recover from each residential customer every month through a fixed charge on the customer's bill. The Company estimates about 5.9 million residential bills in the test year.[24] This means that $91.0 million of load-related costs would be recovered annually through the residential BFC under the Company's proposal.[25]

If the load-related costs recovered through the residential BFC under the Company's proposal were instead 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 6.2 million megawatt-hours.[26] Therefore, if the $91.0 million of load-related costs continued to be recovered through the volumetric energy rate rather than through the residential BFC, they would be charged at a rate of 1.47 cents per kilowatt-hour ("¢/kWh").[27] In this case, a residential customer with below-average monthly usage of 500 kWh would contribute about $88 per year toward recovery of the $91.0 million of load-related costs while a customer with above-average monthly usage of 1,500 kWh would contribute about $264 per year.[28] Thus, the 1,500 kWh customer would contribute three times more than the 500 kWh customer, in

[24] The number of residential bills in the test year is provided in the Company's response to Vote Solar Data Request No. 1-28.

[25] The $91.0 million result is derived by taking the product of the annual number of residential bills (5.9 million) and the amount of the proposed residential BFC in excess of residential connection cost ($15.45 per bill).

[26] Residential sales for the test year are provided in the Company's response to Vote Solar Data Request No. 1-28.

[27] The 1.47¢/kWh result is derived by dividing $91.0 million by residential sales of 6.2 million megawatt-hours.

[28] Based on data provided in the Company's response to Vote Solar Data Request No. 1-28, I estimate monthly usage of 1,054 kWh for an average residential customer.

direct proportion to their usage and consistent with accepted principles of cost-causation.

In contrast, under the Company's proposal to recover $91.0 million of load-related costs through the residential BFC, each residential customer would contribute about $185 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 Company's proposal while an above-average 1,500 kWh customer would pay only 70% of their fair share.

Q: Would subsidization of high-usage residential customers by low-usage customers be eliminated if the residential BFC were set at your estimate of the cost to connect a residential customer?

A: No. Even with the residential BFC set at my estimate of residential connection cost, low-usage customers would likely continue to subsidize high-usage customers' costs because customer charges and energy rates are priced at the cost to serve an average-usage customer. For example, Schedule RS customers who reduce their on-peak (and overall) usage with energy efficiency or rooftop solar generation pay the same energy rate as larger, peakier customers even though the latter customers may impose more generation costs per kWh of usage than the former due to their proportionately greater on-peak usage. Likewise, lower-usage customers in an apartment building will typically share a service drop, whereas higher-usage single-family homes will typically be connected with their own service drop. Yet, the lower-usage apartment resident will contribute the same amount toward recovery of service-drop costs as the higher-usage single-family customer even though the cost of a service drop per customer is lower for the former than for the latter customer. In both of these cases, any differences in the cost to serve smaller and larger customers are socialized across the residential class, resulting in subsidization of high-usage customers by low-usage customers.

VI. DEC's Proposal to Increase the Residential BFC Would Dampen Energy Price Signals

Q: Would the Company's proposal to increase the residential BFC send appropriate price signals?

A: No. As discussed in Section IV, DEC proposes to set the residential BFC at a rate that greatly exceeds the cost to connect a residential customer to the distribution grid. The amount in excess of residential connection costs represents load-related costs that are more appropriately recovered in the volumetric energy rate. However, under the Company's proposal, this excess over the cost to connect a residential customer would instead be inappropriately recovered through the fixed customer charge. This shift in the recovery of load-related costs from the volumetric energy rate to the fixed customer 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 BFC 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 BFC, the lower the volumetric energy rate, and vice versa. As shown below in Table 2, with the BFC set at $28.00, DEC proposes an average energy rate of 10.02¢/kWh in order to recover the requested allocation of total revenue requirements to Schedule RS customers.[29] If, instead, the BFC were set at my $12.55 estimate of the cost to connect a residential customer, I estimate that the average energy rate for Schedule RS customers would have to be increased to 11.56¢/kWh to recover the same allocated revenue requirement.[30]

Table 2: Schedule RS Energy Rates with Connection-Cost and DEC's Proposed BFC (¢/kWh)

	Rate With Connection-Cost BFC	Rate With DEC's Proposed BFC	Rate Difference	% Difference
First 1000 kWh	11.36	9.85	(1.51)	-13.3%
Over 1000 kWh	12.11	10.50	(1.61)	-13.3%
Average	11.56	10.02	(1.53)	-13.3%

For the average Schedule RS customer with a monthly usage of 1,007 kWh, the price signal would be provided by the volumetric rate for the second energy block (applicable to monthly usage in excess of 1,000 kWh).[31] As shown in Table 2, DEC proposes a rate for the second energy block of 10.50¢/kWh. With the BFC set at $12.55, I estimate an energy rate for the second block of 12.11¢/kWh. In other words, DEC is proposing a rate for the second energy block that is 1.61¢/kWh, or about 13%, less than what the rate would be if the Schedule RS BFC were set at the cost to connect a residential customer. Thus, the Company's proposal for the

[29] Provided in the Company's response to Vote Solar Data Request No. 1-28.

[30] For the purposes of this calculation, I assume the same inclining-block rate structure for the block volumetric energy rates as proposed by DEC.

[31] My estimate of the monthly usage of an average Schedule RS customer is derived from data provided in the Company's response to Vote Solar Data Request No. 1-28.

Schedule RS BFC would dampen the price signal provided by the volumetric energy rate by about 13%.

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

A: Since the volumetric energy rate under the Company's proposal for the residential BFC would be lower than the volumetric energy rate with a residential BFC of $12.55, I would expect residential customers to consume more energy with the Company's proposed BFC than they would with a BFC set at the cost to connect a residential customer. The magnitude of the increase in energy consumption would depend on: (1) the extent to which the volumetric energy rate with the Company's proposed residential BFC is lower than the volumetric energy rate with the BFC set at residential connection cost; 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 typically 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 2004 review of 36 articles on residential electricity demand published between 1971 and 2000 reported that, 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.[32]

Studies of electric price response typically examine the change in usage as a function of changes in the marginal rate paid by the customer.[33] Table 3 below lists the results of seven studies of marginal-price elasticity over the last forty years.[34]

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 a marginal-price elasticity of –0.3 – that is, a 0.3% decrease in consumption for every 1% increase in price – would be a reasonable mid-range estimate of the impact over a few years.

---

[32] Espey and Espey (2004). Specifically, the review reported 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. The full citation for this study is provided in Exhibit JFW-2.

[33] For the average Schedule RS customer with a monthly usage of 1,007 kWh, that would be the rate for the second energy block (applicable to monthly usage in excess of 1,000 kWh).

[34] The citations for these studies are provided in Exhibit JFW-2.

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

A: As discussed above, if the Schedule RS BFC were increased as proposed by DEC, the rate for the second energy block would be about 13% less than what the volumetric rate would be if the BFC were set at residential connection cost. Assuming an elasticity of –0.3, this 13% reduction in the volumetric energy rate would result in an increase in energy consumption of about 4% for the average Schedule RS customer. This means that all else being equal, Schedule RS load after a few years with the $28.00 BFC proposed by DEC would be expected to be about 4% higher than it would have been if the BFC had been set at the cost to connect a residential customer.

VII. Conclusions and Recommendations

Q: What do you conclude with respect to the Company's use of the minimum-system method to classify distribution-grid costs in its COSS?

A: The Commission should reject the Company's reliance on a minimum-system analysis to classify distribution-grid costs in the COSS. This inherently flawed analysis erroneously classifies some distribution-grid costs – a portion of the cost of poles, wires, conduits, and transformers – as customer-related, even though they are in fact driven by usage and therefore properly classified as demand-related. The Company's COSS thereby overstates the amount of customer-related costs appropriately recovered through the residential BFC.

Instead, as has been the practice for the past three decades, DEC should classify all such distribution-grid costs as demand-related. Only the costs incurred by DEC to connect customers to the distribution grid – i.e., the cost of meters, service drops, and meter-reading, billing, and other customer-service expenses – should be classified as customer-related.

Q: What do you conclude with respect to the Company's proposal to increase the residential BFC?

A: The Company's proposal would inappropriately shift load-related costs from the volumetric energy rate to the fixed customer charge, dampen price signals to consumers for reducing energy usage, disproportionately and inequitably increase bills for the Company's smallest residential customers, and result in subsidization of larger residential customers' costs by customers with below-average usage. Accordingly, the Commission should reject the Company's proposal to increase the BFC for residential customers.

Q: Should the residential BFC be set at your estimate of the cost to connect a residential customer to the distribution grid?

A: No. In direct testimony also filed in this proceeding on behalf of SC NAACP, CCL, and Upstate Forever, John Howat finds that low-income customers would be disproportionately harmed by an increase in the residential BFC. In order to mitigate this harm, I recommend that the BFC for the residential rate classes be increased from current levels by the same percentage as the revenue increase (if any) ultimately authorized by the Commission in this proceeding for those classes. With my recommended approach, the percentage impact on customer bills from the authorized revenue increase would be essentially uniform across all usage levels.

By way of example, if the Commission were to approve the Company's request for a 12.3% increase in Schedule RS revenues, the Schedule RS BFC would be increased by 12.3% under my recommended approach. In this example, a Schedule RS customer's bill would increase by essentially the same percentage regardless of whether that customer's usage was below-average, average, or above-average.

Q: Does this conclude your direct testimony?

A: Yes.

STATE OF SOUTH CAROLINA

BEFORE THE PUBLIC SERVICE COMMISSION

DOCKET NO. 2018-319-E

I certify that the following persons have been served with one (1) copy of Direct Testimony of Jonathan Wallach by electronic mail and/or U.S. First Class Mail at the addresses set forth below:

Becky Dover
Carri Grube-Lybarker
SC Department of Consumer Affairs
bdover@scconsumer.gov
clybarker@scconsumer.gov

Bess J. DuRant
Sowell & DuRant, LLC
1325 Park Street, Suite 100
Columbia, SC 29201
bdurant@sowelldurant.com

Carrie M. Harris
Stephanie U. Eaton
Spilman Thomas & Battle, PLLC
110 Oakwood Drive, Suite 500
Winston-Salem, NC
charris@spilmanlaw.com
sroberts@spilmanlaw.com

Derick P. Williamson
Spilman Thomas & Battle, PLLC
1100 Bent Creek Blvd., Suite 101
Mechanicsburg, PA 17050
dwilliamson@spilmanlaw.com

Heather Shirley Smith
Duke Energy Progress, LLC
40 W. Broad Street, Suite 690
Greenville, SC 29601
Heather.smith@duke-energy.com

Frank R. Ellerbe, III
Robinson, McFadden & Moore, P.C.
PO Box 944
Columbia, SC 29202
fellerbe@robinsongray.com

John Burnett
Duke Energy Business Services, LLC
550 South Tryon Street
Charlotte, NC 28202
John.burnett@duke-energy.com

Molly McIntosh Jagannathan
Troutmas Sanders LLP
301 South College Street, Suite 3400
Charlotte, NC 28202
Molly.jagannathan@troutman.com

Richard L. Whitt
Austin & Rogers, P.A.
508 Hampton Street, Suite 300
Columbia, SC 29201
rlwhitt@austinrogerspa.com

Scott Elliott
Elliott & Elliott, P.A.
1508 Lady Street
Columbia, SC 29201
selliott@elliottlaw.us

Robert Guild
314 Pall Mall
Columbia, SC 29201
bguild@mindspring.com

Thadeus B. Culley
Vote Solar
1911 Ephesus Church Road
Chapel Hill, NC 27517
thad@votesolar.org

Alexander G. Shissias
The Shissias Law Firm, LLC
1727 Hampton Street
Columbia, SC 29201
alex@shissiaslawfirm.com

Len Anthony
Law Office of Len Anthony
812 Schloss Street
Wrightsville Beach, NC 28480
len.anthony1@gmail.com

Jeffery M Nelson
C. Lessie Hammonds
Jenny R. Pittman
Steven W. Hamm
Office of Regulatory Staff
1401 Main Street, Suite 900
Columbia, SC 29201
jnelson@ors.sc.gov
lhammonds@ors.sc.gov
jpittman@ors.sc.gov
sham@ors.sc.gov

Hasala Dharmawardena
145 Cochran Road, Unit 4
Clemson, SC 29631
hasala@ieee.org

This the 26th day of February, 2019.

s/ Stinson Ferguson

Qualifications of

JONATHAN F. WALLACH

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

SUMMARY OF PROFESSIONAL EXPERIENCE

1990–Present	**Vice President, Resource Insight, Inc.** Provides research, technical assistance, and expert testimony on electric- and gas-utility planning, economics, regulation, and restructuring. Designs and assesses resource-planning strategies for regulated and competitive markets, including estimation of market prices and utility-plant stranded investment; negotiates restructuring strategies and implementation plans; assists in procurement of retail power supply.
1989–90	**Senior Analyst, Komanoff Energy Associates.** Conducted comprehensive cost-benefit assessments of electric-utility power-supply and demand-side conservation resources, economic and financial analyses of independent power facilities, and analyses of utility-system excess capacity and reliability. Provided expert testimony on statistical analysis of U.S. nuclear plant operating costs and performance. Co-wrote *The Power Analyst*, software developed under contract to the New York Energy Research and Development Authority for screening the economic and financial performance of non-utility power projects.
1987–88	**Independent Consultant.** Provided consulting services for Komanoff Energy Associates (New York, New York), Schlissel Engineering Associates (Belmont, Massachusetts), and Energy Systems Research Group (Boston, Massachusetts).
1981–86	**Research Associate, Energy Systems Research Group.** Performed analyses of electric utility power supply planning scenarios. Involved in analysis and design of electric and water utility conservation programs. Developed statistical analysis of U.S. nuclear plant operating costs and performance.

EDUCATION

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

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

PUBLICATIONS

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

“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.

“The Future of Utility Resource Planning: Delivering Energy Efficiency through Distribution Utilities” (with Paul Chernick), *1996 Summer Study on Energy Efficiency in Buildings* 7(7.47–7.55). Washington: American Council for an Energy-Efficient Economy, 1996.

“Retrofit Economics 201: Correcting Common Errors in Demand-Side-Management Cost-Benefit Analysis” (with John Plunkett and Rachael Brailove). In proceedings of “Energy Modeling: Adapting to the New Competitive Operating Environment,” conference sponsored by the Institute for Gas Technology in Atlanta in April of 1995. Des Plaines, Ill.: IGT, 1995.

“The Transfer Loss is All Transfer, No Loss” (with Paul Chernick), *Electricity Journal* 6:6 (July, 1993).

“Benefit-Cost Ratios Ignore Interclass Equity” (with Paul Chernick et al.), *DSM Quarterly*, Spring 1992.

“Consider Plant Heat Rate Fluctuations,” *Independent Energy*, July/August 1991.

“Demand-Side Bidding: A Viable Least-Cost Resource Strategy” (with Paul Chernick and John Plunkett), *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

“New Tools on the Block: Evaluating Non-Utility Supply Opportunities With *The Power Analyst*, (with John Plunkett), *Proceedings of the Fourth National Conference on Microcomputer Applications in Energy*, April 1990.

REPORTS

“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.

“Peak-Shaving–Demand-Response Analysis: Load Shifting by Residential Customers” (with Brian Tracey). 2003. Barnstable, Mass.: Cape Light Compact.

“Electricity Market Design: Incentives for Efficient Bidding; Opportunities for Gaming.” 2002. Silver Spring, Maryland: National Association of State Consumer Advocates.

“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.

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

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

“Preliminary Comments of the City of New York on Con Edison’s Generation Divestiture Plan and Petition.” 1998. Filed by the City of New York in PSC Case No. 96-E-0897.

“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.

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

“Protest and Request for Hearing of Maryland Office of People’s Counsel.” 1997. Filed by the Maryland Office of People’s Counsel in PSC Docket Nos. EC97-46-000, ER97-4050-000, and ER97-4051-000.

“Restructuring the Electric Utilities of Maryland: Protecting and Advancing Consumer Interests” (with Paul Chernick, Susan Geller, John Plunkett, Roger Colton, Peter Bradford, Bruce Biewald, and David Wise). 1997. Baltimore, Maryland: Maryland Office of People's Counsel.

"Comments of the New Hampshire Office of Consumer Advocate on Restructuring New Hampshire's Electric-Utility Industry" (with Bruce Biewald and Paul Chernick). 1996. Concord, N.H.: NH OCA.

"Estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities" (with Paul Chernick, Susan Geller, Rachel Brailove, and Adam Auster). 1996. On behalf of the Massachusetts Attorney General (Boston).

"Report on Entergy's 1995 Integrated Resource Plan." 1996. On behalf of the Alliance for Affordable Energy (New Orleans).

"Preliminary Review of Entergy's 1995 Integrated Resource Plan." 1995. On behalf of the Alliance for Affordable Energy (New Orleans).

"Comments on NOPSI and LP&L's Motion to Modify Certain DSM Programs." 1995. On behalf of the Alliance for Affordable Energy (New Orleans).

"Demand-Side Management Technical Market Potential Progress Report." 1993. On behalf of the Legal Environmental Assistance Foundation (Tallahassee)

"Technical Information." 1993. Appendix to "Energy Efficiency Down to Details: A Response to the Director General of Electricity Supply's Request for Comments on Energy Efficiency Performance Standards" (UK). On behalf of the Foundation for International Environmental Law and Development and the Conservation Law Foundation (Boston).

"Integrating Demand Management into Utility Resource Planning: An Overview." 1993. Vol. 1 of "From Here to Efficiency: Securing Demand-Management Resources" (with Paul Chernick and John Plunkett). Harrisburg, Pa.:Pennsylvania Energy Office

"Making Efficient Markets." 1993. Vol. 2 of "From Here to Efficiency: Securing Demand-Management Resources" (with Paul Chernick and John Plunkett). Harrisburg, Pa.: Pennsylvania Energy Office.

"Analysis Findings, Conclusions, and Recommendations." 1992. Vol. 1 of "Correcting the Imbalance of Power: Report on Integrated Resource Planning for Ontario Hydro" (with Paul Chernick and John Plunkett).

"Demand-Management Programs: Targets and Strategies." 1992. Vol. 1 of "Building Ontario Hydro's Conservation Power Plant" (with John Plunkett, James Peters, and Blair Hamilton).

"Review of the Elizabethtown Gas Company's 1992 DSM Plan and the Demand-Side Management Rules" (with Paul Chernick, John Plunkett, James Peters, Susan Geller, Blair Hamilton, and Andrew Shapiro). 1992. Report to the New Jersey Department of Public Advocate.

"Comments of Public Interest Intervenors on the 1993–1994 Annual and Long-Range Demand-Side Management and Integrated Resource Plans of New York Electric Utilities" (with Ken Keating et al.) 1992.

“Review of Jersey Central Power & Light’s 1992 DSM Plan and the Demand-Side Management Rules” (with Paul Chernick et al.). 1992. Report to the New Jersey Department of Public Advocate.

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

“Initial Review of Ontario Hydro’s Demand-Supply Plan Update” (with David Argue et al.). 1992.

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

“Comments on the 1991–1992 Annual and Long Range Demand-Side-Management Plans of the Major Electric Utilities” (with John Plunkett et al.). Filed in NY PSC Case No. 28223 in re New York utilities’ DSM plans. 1990.

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

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

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

“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.

“Cost-Benefit Analysis of the Cancellation of Commonwealth Edison Company’s Braidwood Nuclear Generating Station.” 1984. ESRG Study No. 83-87.

“The Economics of Seabrook 1 from the Perspective of the Three Maine Co-owners.” 1984. ESRG Study No. 84-38.

“An Evaluation of the Testimony and Exhibit (RCB-2) of Dr. Robert C. Bushnell Concerning the Capital Cost of Fermi 2.” 1984. ESRG Study No. 84-30.

“Electric Rate Consequences of Cancellation of the Midland Nuclear Power Plant.” 1984. ESRG Study No. 83-81.

“Power Planning in Kentucky: Assessing Issues and Choices—Project Summary Report to the Public Service Commission.” 1984. ESRG Study No. 83-51.

“Electric Rate Consequences of Retiring the Robinson 2 Nuclear Plant.” 1984. ESRG Study No. 83-10.

“Power Planning in Kentucky: Assessing Issues and Choices—Conservation as a Planning Option.” 1983. ESRG Study No. 83-51/TR III.

"Electricity and Gas Savings from Expanded Public Service Electric and Gas Company Conservation Programs." 1983. ESRG Study No. 82-43/2.

"Long Island Without the Shoreham Power Plant: Electricity Cost and System Planning Consequences; Summary of Findings." 1983. ESRG Study No. 83-14S.

"Long Island Without the Shoreham Power Plant: Electricity Cost and System Planning Consequences; Technical Report B—Shoreham Operations and Costs." 1983. ESRG Study No. 83-14B.

"Customer Programs to Moderate Demand Growth on the Arizona Public Service Company System: Identifying Additional Cost-Effective Program Options." 1982. ESRG Study No. 82-14C.

"The Economics of Alternative Space and Water Heating Systems in New Construction in the Jersey Central Power and Light Service Area, A Report to the Public Advocate." 1982. ESRG Study No. 82-31.

"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.

"Utility Promotion of Residential Customer Conservation, A Report to Massachusetts Public Interest Research Group." 1981. ESRG Study No. 81-47

PRESENTATIONS

"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.

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

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

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

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

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

Support of proposed comprehensive restructuring settlement agreement

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

Support of proposed comprehensive restructuring settlement agreement

Maryland PSC Case No. 8797, comprehensive restructuring agreement for Potomac Edison Company, Maryland Office of People's Counsel. October 1999.

Support of proposed comprehensive restructuring settlement agreement

Connecticut DPUC Docket No. 99-03-35, United Illuminating standard offer, Connecticut Office of Consumer Counsel. November 1999.

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

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

Evaluation of innovative rate proposal by PJM transmission owners.

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

Reasonableness of proposed fees for electricity-supplier services.

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

Costs and benefits to ratepayers. Assessment of public interest.

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

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

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

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

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

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

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

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

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

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

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

Reasonableness and risks of resource-procurement plan.

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

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

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

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

FERC Dockets Nos. ER05-1410-000 & EL05-148-000, proposed market-clearing mechanism for capacity markets in PJM; Coalition of Consumers for Reliability, 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 **Maryland 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.

Maryland 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.

Maryland 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.

Maryland PSC Case No. 9064, default service for residential and small commercial customers; Maryland Office of People's Counsel, Rebuttal Testimony, September 2006.

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

FERC Dockets Nos. ER05-1410-000 & EL05-148-000, proposed market-clearing mechanism for capacity markets in PJM; Maryland Office of the People's Counsel, Supplemental Affidavit October 2006.

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

Maryland 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.

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

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

2007 **Maryland PSC** Case No. 9091, rate-stabilization and market-transition plan for the Potomac Edison Company; Maryland Office of People's Counsel, Direct Testimony, March 2007.

Rate-stabilization plan.

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

Cost allocation and rate design. Revenue decoupling mechanism.

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

Cost allocation and rate design. Revenue decoupling mechanism.

Maryland PSC Case No. 9099, rate-stabilization plan for Baltimore Gas & Electric; Maryland Office of People's Counsel, Direct, March 2007; Surrebuttal April 2007.

Review of standard-offer-service-procurement plan. Rate stabilization plan.

Connecticut DPUC Docket No. 07-04-24, review of capacity contracts under Energy Independence Act; Connecticut Office of Consumer Counsel, Joint Direct Testimony June 2007.

Assessment of proposed capacity contracts.

Maryland PSC Case No. 9117, residential and small-commercial standard-offer service; Maryland Office of People's Counsel. Direct and Reply, September 2007; Supplemental Reply, November 2007; Additional Reply, December 2007; presentation, December 2008.

Benefits of long-term planning and procurement. Proposed aggregation of customers.

Maryland PSC Case No. 9117, Phase II, residential and small-commercial standard-offer service; Maryland Office of People's Counsel. Direct, October 2007.

Energy efficiency as part of standard-offer-service planning and procurement. Procurement of generation or long-term contracts to meet reliability needs.

2008 **Connecticut DPUC 08-01-01**, peaking generation projects; Connecticut Office of Consumer Counsel. Direct (with Paul Chernick), April 2008.

Assessment of proposed peaking projects. Valuation of peaking capacity. Modeling of energy margin, forward reserves, other project benefits.

Ontario EB-2007-0707, Ontario Power Authority integrated system plan; Green Energy Coalition, Penimba Institute, and Ontario Sustainable Energy Association. Evidence (with Paul Chernick and Richard Mazzini), August 2008.

Critique of integrated system plan. Resource cost and characteristics; finance cost. Development of least-cost green-energy portfolio.

2009 **Maryland PSC** Case No. 9192, Delmarva Power & Lights rates; Maryland Office of People's Counsel. Direct, August 2009; Rebuttal, Surrebuttal, September 2009.

Cost allocation and rate design.

Wisconsin PSC Docket No. 6630-CE-302, Glacier Hills Wind Park certificate; Citizens Utility Board of Wisconsin. Direct and Surrebuttal, October 2009.

Reasonableness of proposed wind facility.

PUC of Ohio Case No 09-906-EL-SSO, standard-service-offer bidding for three Ohio electric companies; Office of the Ohio Consumers' Counsel. Direct, December 2009.

Design of auctions for SSO power supply. Implications of migration of FirstEnergy from MISO to PJM.

2010 **PUC of Ohio** Case No 10-388-EL-SSO, standard-service offer for three Ohio electric companies; Office of the Ohio Consumers' Counsel. Direct, July 2010.

Design of auctions for SSO power supply.

Maryland PSC Case No. 9232, Potomac Electric Power Co. administrative charge for standard-offer service; Maryland Office of People's Counsel. Reply, Rebuttal, August 2010.

Proposed rates for components of the Administrative Charge for residential standard-offer service.

Maryland PSC Case No. 9226, Delmarva Power & Light administrative charge for standard-offer service; Maryland Office of People's Counsel. Reply, Rebuttal, August 2010.

Proposed rates for components of the Administrative Charge for residential standard-offer service.

Maryland PSC Case No. 9221, Baltimore Gas & Electric cost recovery; Maryland Office of People's Counsel. Reply, August 2010; Rebuttal, September 2010; Surrebuttal, November 2010

Proposed rates for components of the Administrative Charge for residential standard-offer service.

Wisconsin PSC Docket No. 3270-UR-117, Madison Gas & Electric gas and electric rates; Citizens Utility Board of Wisconsin. Direct, Rebuttal, Surrebuttal, September 2010.

Standby rate design. Treatment of uneconomic dispatch costs.

Nova Scotia UARB Case No. NSUARB P-887(2), fuel-adjustment mechanism; Nova Scotia Consumer Advocate. Direct, September 2010.

Effectiveness of fuel-adjustment incentive mechanism.

Manitoba PUB, Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystems. Direct, December 2010.

Assessment of drought-related financial risk.

2011 **Mass. DPU 10-170,** NStar–Northeast Utilities merger; Cape Light Compact. Direct, May 2011.

Merger and competitive markets. Competitively neutral recovery of utility investments in new generation.

Mass. DPU 11-5, -6, -7, NStar wind contracts; Cape Light Compact. Direct, May 2011.

Assessment of utility proposal for recovery of contract costs.

Wisc. PSC Docket No. 4220-UR-117, electric and gas rates of Northern States Power: Citizens Utility Board of Wisconsin. Direct, Rebuttals (2) October 2011; Surrebuttal, Oral Sur-Surrebutal November 2011;

Cost allocation and rate design. Allocation of DOE settlement payment.

Wisc. PSC Docket No. 6680-FR-104, fuel-cost-related rate adjustments for Wisconsin Power and Light Company: Citizens Utility Board of Wisconsin. Direct, October 2011; Rebuttal, Surrebuttal, November 2011

Costs to comply with Cross State Air Pollution Rule.

2012 **Maryland PSC** Case No. 9149, Maryland IOUs' development of RFPs for new generation; Maryland Office of People's Counsel. March 2012.

Failure of demand-response provider to perform per contract. Estimation of cost to ratepayers.

PUCO Case Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-AAM, 11-350-EL-AAM, transition to competitive markets for Columbus Southern Power Company and Ohio Power Company; Ohio Consumers' Counsel. May 2012

Structure of auctions, credits, and capacity pricing as part of transition to competitive electricity markets.

Wisconsin PSC Docket No. 3270-UR-118, Madison Gas & Electric rates, Wisconsin Citizens Utility Board. Direct, August 2012; Rebuttal, September 2012.

Cost allocation and rate design (electric).

Wisconsin PSC Docket No. 05-UR-106, We Energies rates, Wisconsin Citizens Utility Board. Direct, Rebuttal, September 2012.

Cost allocation and rate design (electric).

Wisconsin PSC Docket No. 4220-UR-118, Northern States Power rates, Wisconsin Citizens Utility Board. Direct, Rebuttal, October 2012; Surrebuttal, November 2012.

Recovery of environmental remediation costs at a manufactured gas plant. Cost allocation and rate design.

2013 **Corporation Commission of Oklahoma** Cause No. PUD 201200054, Public Service Company of Oklahoma environmental compliance and cost recovery, Sierra Club. Direct, January 2013; rebuttal, February 2013; surrebuttal, March 2013.

Economic evaluation of alternative environmental-compliance plans. Effects of energy efficiency and renewable resources on cost and risk.

Maryland PSC Case No. 9324, Starion Energy marketing, Maryland Office of People's Counsel. September 2013.

Estimation of retail costs of electricity supply.

Wisconsin PSC Docket No. 6690-UR-122, Wisconsin Public Service Corporation gas and electric rates, Wisconsin Citizens Utility Board. Direct, August 2013; Rebuttal, Surrebuttal September 2013.

Cost allocation and rate design; rate-stabilization mechanism.

Wisconsin PSC Docket No. 4220-UR-119, Northern States Power Company gas and electric rates, Wisconsin Citizens Utility Board. Direct, Rebuttal, Surrebuttal, October 2013.

Cost allocation and rate design.

Michigan PSC Case No. U-17429, Consumers Energy Company approval for new gas plant, Natural Resources Defense Council. Corrected Direct, October 2013.

Need for new capacity. Economic assessment of alternative resource options.

2014 **Maryland PSC** Case Nos. 9226 & 9232, administrative charge for standard-offer service; Maryland Office of People's Counsel. Reply, April 2014; surrebuttal, May 2014.

Proposed rates for components of the Administrative Charge for residential standard-offer service.

Conn. PURA Docket No. 13-07-18, rules for retail electricity markets; Office of Consumer Counsel. Direct, April 2014.

Estimation of retail costs of power supply for residential standard-offer service.

PUC Ohio Case Nos. 13-2385-EL-SSO, 13-2386-EL-AAM; Ohio Power Company standard-offer service; Office of the Ohio Consumers' Counsel. Direct, May 2014.

Allocation of distribution-rider costs.

Wisc. PSC Docket No. 6690-UR-123, Wisconsin Public Service Corporation electric and gas rates; Citizens Utility Board of Wisconsin. Direct, Rebuttal, August 2014; Surrebuttal, September 2014.

Cost allocation and rate design.

Wisc. PSC Docket No. 05-UR-107, We Energy biennial review of electric and gas costs and rates; Citizens Utility Board of Wisconsin. Direct, August 2014; Rebuttal, Surrebuttal September 2014.

Cost allocation and rate design.

Wisc. PSC Docket No. 3270-UR-120, Madison Gas and Electric Co. electric and gas rates; Citizens Utility Board of Wisconsin. Direct, Rebuttal, September 2014.

Cost allocation and rate design.

Nova Scotia UARB Case No. NSUARB P-887(6), Nova Scotia Power fuel-adjustment mechanism; Nova Scotia Consumer Advocate. Evidence, December 2014.

Allocation of fuel-adjustment costs.

2015 **Maryland PSC** Case No. 9221, Baltimore Gas & Electric cost recovery; Maryland Office of People's Counsel. Second Reply, June 2015; Second Rebuttal, July 2015.

Proposed rates for components of the Administrative Charge for residential standard-offer service.

Wisconsin PSC Docket No. 6690-UR-124, Wisconsin Public Service Corporation electric and gas rates; Citizens Utility Board of Wisconsin. Direct, Rebuttal, September 2015; Surrebuttal, October 2015.

Cost allocation and rate design.

Wisconsin PSC Docket No. 4220-UR-121, Northern States Power Company gas and electric rates; Citizens Utility Board of Wisconsin. Direct, Rebuttal, Surrebuttal, October 2015.

Cost allocation and rate design.

Maryland PSC Cases Nos. 9226 & 9232, administrative charge for standard-offer service; Maryland Office of People's Counsel. Third Reply, September 2015; Third Rebuttal, October 2015.

Proposed rates for components of the Administrative Charge for residential standard-offer service.

Nova Scotia UARB Case No. NSUARB P-887(7), Nova Scotia Power fuel-adjustment mechanism; Nova Scotia Consumer Advocate. Evidence, December 2015.

Accounting adjustment for estimated over-earnings. Proposal for modifying procedures for setting the Actual Adjustment.

2016 **Maryland PSC** Case No. 9406, Baltimore Gas & Electric base rate case; Maryland Office of People's Counsel. Direct, February 2016; Rebuttal, March 2016; Surrebuttal, March 2016.

Allocation of Smart Grid costs. Recovery of conduit fees. Rate design.

Nova Scotia UARB Case No. NSUARB P-887(16), Nova Scotia Power 2017-2019 Fuel Stability Plan; Nova Scotia Consumer Advocate. Direct, May 2016; Reply, June 2016.

Base Cost of Fuel forecast. Allocation of Maritime Link capital costs. Fuel cost hedging plan.

Wisconsin PSC Docket No. 3270-UR-121, Madison Gas and Electric Company electric and gas rates; Citizens Utility Board of Wisconsin. Direct, August 2016; Rebuttal, Surrebuttal, September 2016.

Cost allocation and rate design.

Wisconsin PSC Docket No. 6680-UR-120, Wisconsin Power and Light Company electric and gas rates; Citizens Utility Board of Wisconsin. Direct, Rebuttal, Surrebuttal, Sur-surrebuttal, September 2016.

Cost allocation and rate design.

Minnesota PSC Docket No. E002/GR-15-826, Northern States Power Company electric rates; Clean Energy Organizations. Direct, June 2016; Rebuttal, September 2016; Surrebuttal, October 2016.

Cost basis for residential customer charges.

Nova Scotia UARB Case No. NSUARB M07611, Nova Scotia Power 2016 fuel adjustment mechanism audit; Nova Scotia Consumer Advocate. Direct, November 2016.

Sanctions for imprudent fuel-contracting practices.

2017 **Kentucky PSC** Case No. 2016-00370, Kentucky Utilities Company electric rates; Sierra Club. Direct, March 2017.

Cost basis for residential customer charges. Design of residential energy charges.

Kentucky PSC Case No. 2016-00371, Louisville Gas & Electric Company electric rates; Sierra Club. Direct, March 2017.

Cost basis for residential customer charges. Design of residential energy charges.

Massachusetts DPU 17-05, Eversource Energy electric rates; Cape Light Compact. Direct, April 2017; Supplemental Direct, Surrebuttal, August 2017.

Cost Allocation. Cost basis for residential customer charges. Demand charges for net metering customers.

Michigan PSC Case No. U-18255, DTE Electric Company electric rates; Natural Resources Defense Council, Michigan Environmental Council, and Sierra Club. Direct, August 2017.

Cost basis for residential customer charges.

North Carolina NCUC Docket No. E-2, Sub 1142, Duke Energy Progress electric rates; North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy. Direct, October 2017.

Cost basis for residential customer charges.

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.

2018 **North Carolina NCUC** Docket No. E-7, Sub 1146, Duke Energy Carolinas electric rates; North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy. Direct, January 2018.

Cost basis for residential customer charges.

PUC Ohio Case Nos. 15-1830-EL-AIR, 15-1831-EL-AAM, 15-1832-EL-ATA; Dayton Power and Light Company electric rates; Natural Resources Defense Council. Direct, April 2018.

Cost basis for residential customer charges.

Indiana Utility Regulatory Commission Cause No. 45029, Indianapolis Power and Light Company electric rates; Citizens Action Coalition of Indiana, Indiana Coalition for Human Services, Indiana Community Action Association, and Sierra Club. Direct, May 2018.

Cost basis for residential customer charges. Design of residential energy rates.

PUC of Texas Docket No. 48401, Texas-New Mexico Power Company electric rates; Office of Public Utility Counsel. Direct, Cross-Rebuttal, August 2018.

Cost of service study. Allocation of requested revenue increase.

West Virginia PSC Case No. 18-0646, Appalachian Power Company and Wheeling Power Company electric rates; Consumer Advocate Division. Direct, Rebuttal, October 2018.

Cost allocation and rate design.

Works Cited

Acton, Jan, Bridger Mitchell, and Ragnhill Mowill. 1976. "Residential Demand for Electricity in Los Angeles: An Econometric Study of Disaggregate Data" Rand Report R-1899-NSF, Rand Corporation: Santa Monica, Cal., 1976. www.prgs.edu/content/dam/rand/pubs/reports/2008/R1899.pdf.

Barnes, Roberta, Robert Gillingham, and Robert Hagemann. 1981. "The Short-Run Residential Demand for Electricity" *Review of Economics and Statistics* 63(Nov. 1981):4 at 541–552; www.jstor.org/discover/10.2307/1935850

Espey, James, and Molly Espey. 2004. "Turning on the Lights: A Meta-Analysis of Residential Electricity Demand Elasticities" Journal of Agricultural and Applied Economics 36 (1), 65–81.

Henson, Steven. 1984. "Electricity Demand Estimates under Increasing-Block Rates" *Southern Economic Journal* 51(July 1984): 1 at 147–156. www.jstor.org/discover/10.2307/1058328

McFadden, Daniel, Carlos Puig, and Daniel Kirshner. 1977. "Determinants of the Long-Run Demand for Electricity," Proceedings of the Business and Economic Statistics Section, American Statistical Association, 1977at 109–119. eml.berkeley.edu/reprints/mcfadden/7_2.pdf

Orans, Ren, Michael Li, Jenya Kahn-Lang, and Chi-Keung Woo. 2014. "Are Residential Customers Price-Responsive to an Inclining Block Rate? Evidence from British Columbia, Canada" *Electricity Journal* 27(1) 85–92. www.sciencedirect.com/science/article/pii/S1040619013002935

Reiss, Peter, and Matthew White. 2005 "Household Electricity Demand, Revisited" *Review of Economic Studies* 72:853–883. web.stanford.edu/~preiss/demand.pdf

Xcel Energy. 2012. "Impact Analysis of Residential Two Tier, Inverted Block Rates" 11/05/2012. Minneapolis: Xcel Energy. www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=190806.