Before the Maryland Public Service Commission

Case No. 9610

Prepared Direct Testimony of

Frank Lacey

On Behalf of the

Energy Supplier Coalition

September 10, 2019

LIST OF ISSUES AND MAJOR CONCLUSIONS

BGE has not fully allocated its costs to provide standard offer service to the Administrative Adjustment component of the Administrative Charge and is using revenues collected through distribution rates to subsidize standard offer service.

In allocating costs to standard offer service, BGE has departed from the National Association of Regulatory Utility Commissioners' principles of cost allocation, its own Cost Allocation Manual and sound utility ratemaking practices.

When standard offer service rates do not reflect the full costs of providing service, consumers are receiving inaccurate information and unable to make meaningful comparisons when shopping for electricity supply.

Mr. Peterson's analysis should be adopted by this Commission such that the SOS price offered by BGE is more accurately reflective of the utilities true cost to provide SOS service. This will benefit consumers and the energy markets generally. Adopting these recommendations within the framework of the existing Administrative Adjustment mechanism will ensure that BGE collects fully its revenue requirement regardless of customer migration.

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Frank Lacey. My business address is 3 Traylor Drive, West Chester, PA 19382.

Q. BY WHOM ARE YOU EMPLOYED AND ON WHOSE BEHALF, ARE YOU TESTIFYING?

A. I am an independent consultant submitting this testimony on behalf of the Energy Supplier Coalition ("Coalition"). The Coalition is a group of competitive retail electric and natural gas suppliers comprised of NRG Energy, Inc., Direct Energy Services, LLC, Vistra Energy Corp. and Interstate Gas Supply, Inc. d/b/a IGS Energy. The members of the Coalition serve retail customers in Maryland, including in the BGE service territory. In addition to supplying energy commodities, these companies offer advanced energy management services including innovative retail energy products, demand response, energy efficiency, renewable energy, distributed energy resources and other products and services.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. As a consultant, I provide policy- and market-related consulting services to advanced energy management companies and end-use customers. I have worked in the electric power industry for approximately 25 years, beginning immediately after earning my graduate degree. I have worked on major industry restructuring issues including generation asset divestiture, with a specialization in environmental asset valuation; stranded cost valuations; transmission restructuring including the development of Independent System Operators ("ISOs") and Regional Transmission Organization ("RTOs") and other independent transmission entities; the development of retail energy markets; and the development of demand response markets. Early in my career, I was employed as a consultant to industry participants, first by Putnam, Hayes & Bartlett, Inc. and then by Arthur Andersen Business Consulting. Within the industry, I have worked for Strategic Energy, a retail electricity supplier, Direct Energy, a retail energy supplier that acquired Strategic Energy in 2008, and most recently, Comverge, Inc. and CPower, two demand response companies that shared a common owner and provided services to residential and to commercial & industrial ("C&I") customers, respectively. I created Electric Advisors Consulting LLC in 2015. I hold a Bachelor of Science degree in Transportation and Logistics from the University of Maryland and a Master of Science in Industrial Administration with concentrations in finance and environmental management from the Tepper School of Business at Carnegie Mellon University. My resume is provided as Exhibit FPL-1.

Q. HAVE YOU EVER TESTIFIED BEFORE THE MARYLAND PUBLIC SERVICE COMMISSION OR ANY OTHER UTILITY REGULATORY AGENCY?

A. Yes. I have testified before the Maryland Public Service Commission ("Commission" or "PSC"). I have also testified numerous times before other state regulatory agencies, legislatures, and twice as a technical conference witness at the Federal Energy Regulatory Commission ("FERC"). I recently filed an expert report on energy matters in the Superior Court of New Jersey in Bergen County. I have provided expert testimony before the utility commissions in New York, Pennsylvania, Ohio, New Jersey, Massachusetts, Illinois, Delaware, Rhode Island, Virginia, Utah and California. I have presented oral testimony in less formal proceedings before this Commission and those in Pennsylvania, Delaware and Texas. I have presented legislative testimony in New York, Maryland, Pennsylvania, Delaware, Michigan, California and Texas. I have also spoken at numerous trade shows, conferences and other industry and corporate events as an expert on electricity market issues. A detailed listing of my prior testimony is contained in Exhibit FPL-2.

Q. WHAT IS YOUR EXPERIENCE RELATED TO THE ALLOCATION OF COSTS TO STANDARD OFFER SERVICE?

A. I have written two articles on this topic and have testified about this issue in three prior cases. In January 2019, my article "Default Service Pricing Has Been Wrong All Along – Allows Utilities to Maintain Dominance in Markets" was published in Public Utilities Fortnightly.[1] This article is attached as Exhibit FPL-3. The second article, "Default Service Pricing – The Flaw and the Fix: Current pricing practices allow utilities to maintain market dominance in deregulated markets" was more academic in nature and was published in the Electricity

[1] Frank Lacey, Default Service Pricing Has Been Wrong All Along – Allows Utilities to Maintain Dominance in Markets, Public Utilities Fortnightly, January 2019, Pages 40-44.

Journal in April 2019.[2] That article, attached as Exhibit FPL-4, described more thoroughly the problem of the discriminatory pricing, addressed some of the market results from the discriminatory pricing and presented a solution that was modeled based on a fully-allocated implementation of the Administrative Adjustment model in place in Maryland. Much of the research and analyses from those two articles is incorporated in this testimony.

Q. WHAT IS THE ENERGY SUPPLIER COALITION'S INTEREST IN THIS PROCEEDING?

A. The Coalition companies operate competitive retail electric and gas supply businesses in Maryland. With these businesses, the Coalition members compete directly with BGE's standard offer service ("SOS") for electricity and its standard offer supply service for natural gas ("SOSS"). SOS is available to customers who do not purchase their electricity from competitive suppliers in the market.[3] The Coalition's interest in this proceeding is to ensure that BGE's rates for SOS reflect the full cost of providing that service, so that customers are able to make more accurate comparisons when shopping for electricity supply.

The focus of the Coalition is on BGE's proposed Administrative Adjustment component of its Administrative Charge, which is part of its SOS rate. Through

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2 Frank Lacey, Default service pricing – The flaw and the fix: Current pricing practices allow utilities to maintain market dominance in deregulated markets, The Electricity Journal, Volume 32, Issue 3, 2019, Pages 4-10.

3 *Severstal Sparrows Point, LLC v. Pub. Serv. Comm'n of Md.*, 194 Md. App. 601, 605 (2010) and Md. Code Ann., Public Utility Article ("PUA") §7-510. SOSS is the same service for natural gas supply. *See In the Matter of the Baltimore Gas and Electric Company's Long-Term Gas Capacity Plan*, Case No. 8950 (September 16, 2005).

my testimony and the testimony of Mr. Chris Peterson, the Coalition shows that BGE has failed to allocate costs to the SOS rate that are incurred to provide that service. Proposing an Administrative Adjustment of 1.00 Mill per kWh, which is equal to only one-tenth of one cent per kWh, BGE has omitted major cost categories and significantly understated other cost allocations. For example, BGE has not allocated administrative and general expenses to SOS, including costs of information technology ("IT") and human resources ("HR") and other costs that the Commission has previously ordered it to include in SOS. Further, BGE has failed to fully allocate costs from the accounting, regulatory and legal functions required to support SOS.

Because BGE has included many of its costs of providing SOS in its distribution rates, distribution customers are subsidizing SOS service and all shopping customers are over-paying distribution rates. The subsidy results in an SOS rate that is too low and unfairly biases customers toward standard offer services, and a distribution rate that is above what a cost-based rate should be. When costs of providing SOS, which are currently embedded in distribution rates, are properly recovered through the SOS rate, distribution customers will no longer be subsidizing SOS. The elimination of this subsidy will improve the retail market, thereby giving customers more competitive supply options.

Q. HOW DOES THE COALITION PROPOSE TO CORRECT THIS PROBLEM?

A. The Coalition is seeking to utilize the current Administrative Charge and Administrative Adjustment mechanism for its intended purpose, and to fully and equitably allocate the costs that are currently classified as distribution costs but are clearly used in the provision of SOS. Using this mechanism, Mr. Peterson's testimony calculates the allocation to the Administrative Adjustment for the residential customer class to be $114,299,607, as compared to BGE's proposed allocation of $9,564,533. An appropriate allocation, which removes costs that are currently embedded in distribution rates and recovers them instead from SOS rates, will result in rates for both distribution service and SOS that are just and reasonable. Deploying the allocation through the currently effective Administrative Charge and Adjustment mechanisms will ensure that BGE is fully – and not over – collecting its distribution costs. More importantly, it will result in SOS prices that more accurately reflect the cost of providing that service.

Q. IS IT IMPORTANT TO HAVE SOS PRICES THAT MORE ACCURATELY REFLECT THE COST OF PROVIDING SOS?

A. Yes, for several reasons. The Commission and various stakeholders, through many actions, encourage customers to make comparisons of competitive offers to the SOS rates. BGE, for example, includes the SOS rates and information about when the SOS rate will change on its customers' bills. In fact, BGE titles this section of its bill the "BGE Supply Price Comparison." I have included BGE's sample bill, presented on its website, which shows this "comparison" language as

Exhibit FPL-5. BGE also informs customers on its website that customers "can use [the SOS price] to compare prices among electric suppliers."[4] As the Commission, BGE and others are positioning SOS as the baseline product against which competitive offers should be compared, it is essential for the SOS price to be accurate and reflective of its true costs.[5] Notwithstanding the drive to compare competitive offers to the SOS price, all utility products should be charged at cost, including a full allocation of costs. With a proper allocation of costs to SOS, customers will be able to make much more informed choices about their energy consumption and about competitive energy options.

SOS should not be subsidized by distribution customers. By proposing a rate for SOS that is reflective of the true cost to offer and provide that service to customers, the Coalition seeks to remove these SOS subsidies from the distribution business. Properly allocating costs to SOS will also empower customers with more accurate pricing information, enabling them to make better informed competitive energy market choices. When SOS pricing reflects the costs to provide this service, competitors are able to offer competitive prices. By contrast, the current allocation of costs to SOS and the allocation of costs

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[4] See: https://www.bge.com/MyAccount/MyBillUsage/Documents/NewBill_websitePDF_10_10.pdf

[5] I do not condone the concept of SOS being any type of pricing comparison or baseline against which competitive supply products should be compared. SOS is procured for discreet periods of time, at discreet dates and as it is priced today, reflects what is essentially a pass-through of wholesale market prices. Suppliers' products have different attributes, different benefits, different terms and are procured and offered on dates that are different from SOS.

proposed by Mr. Manuel in this proceeding will result in SOS pricing that harms the competitive market, harms customers and results in an over-consumption of energy.

II. SUMMARY AND CONCLUSIONS

Q. HAVE YOU READ BGE'S RATE CASE FILING AND SUPPORTING TESTIMONY?

A. I have.

Q. COULD YOU PLEASE SUMMARIZE THE FILING AND YOUR CONCLUSIONS?

A. Yes. BGE has filed what would be classified as a traditional utility rate case, seeking an increase in base distribution rates for its gas and electricity distribution businesses. As a result of Commission Order No. 87891 in Case No. 9221, BGE was to set the Administrative Adjustment to $0.00 per kWh until they "set[] forth the Company's expenses attributed to SOS service, distribution service, or both operations" in this rate proceeding.[6] As directed, this rate proceeding includes an unbundling of a portion of SOS-related costs and an allocation of some indirect costs to SOS. I take no position on the overall revenue requirement submitted by BGE in this proceeding. However, I find that BGE's unbundling of the SOS-related costs is inadequate and drastically understates the true cost of operating the SOS business and inappropriately includes these costs in its distribution rates.

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[6] Order 87891, p. 26.

I conclude based on my review of the filing that if the rates proposed by BGE are adopted as presented, BGE would be allocating too many costs to its distribution businesses and failing to allocate costs appropriately to the SOS business, rendering both SOS and distribution rates unjust and unreasonable. If BGE's proposal is approved, BGE would be over-collecting its distribution costs, most notably from customers who have chosen a competitive supplier, and under-collecting costs related to serve SOS customers. As I will explain in my testimony, the current SOS structure provides a "natural business incentive"[7] for BGE to maintain the status quo of serving the vast majority of residential customers on SOS so that it can reap excess returns derived from SOS. Without an accurate SOS rate, consumers are deprived of an opportunity to meaningfully compare offers in the competitive market with the SOS rate charged by BGE. This result is harmful to customers, to energy suppliers and to the long-term success of Maryland's competitive energy policy and environmental goals.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. My testimony supports the analyses presented by Mr. Peterson and will show that BGE has not followed long-standing traditional cost allocation methodologies in determining the costs that should be allocated to the Administrative Adjustment and as a result has allocated too few costs to the Administrative Charge, including the Administrative Adjustment component. BGE has proposed an allocation to

[7] NARUC Guidelines for Cost Allocations and Affiliate Transactions, Section D, p. 3.

the Administrative Adjustment of 1.00 mills per kWh to each of the SOS customer groupings (Residential, Type I, Type II and HPS). Mr. Peterson's analysis shows that the allocations to the Administrative Adjustment should be 11.82 mills per kWh to residential customers and 21.06 mills per kWh to each of the C&I rate classes. Mr. Peterson included an alternative calculation that mirrored BGE's approach to assigning the allocated costs based on a per-kWh basis. That alternative calculation results in the Administrative Adjustment being 13.89 mills per kWh for all customer classes.

In reaching my conclusions, I have adopted Mr. Peterson's direct testimony and exhibits regarding the proper computation of BGE's Administrative Adjustment for SOS. My testimony will show that his recommended allocations are consistent with National Association of Regulatory Utility Commissioners ("NARUC") principles of cost allocation, with BGE's Cost Allocation Manual and with sound utility ratemaking practices. Mr. Peterson will further explain that appropriate cost allocations are consistent with sound business accounting practices. I will detail the financial incentive that might encourage BGE management to maintain the status quo, which ironically, is an incentive that NARUC and BGE both suggest would be eliminated with proper cost allocations. Finally, I will discuss the applicability of the allocation principles discussed in this testimony to BGE's natural gas business.

I will further show that the cost allocation flaws identified by Mr. Peterson can be corrected within the current SOS framework and that it can be corrected in a manner that does not either increase or decrease the base revenues that BGE will receive after this proceeding. Moreover, our cost reallocation will not increase costs to customers in aggregate, and it will facilitate the type of robust competition envisioned when the Maryland Legislature opened this market to competitive forces.

III. PROCEDURAL BACKGROUND AND LEGAL FRAMEWORK

Q. DOES THE PUBLIC UTILITIES ARTICLE OF THE MARYLAND CODE ("PUA") IMPOSE REQUIREMENTS ON THE COMMISSION IN ADMINISTERING THE LAW REGARDING ELECTRIC INDUSTRY RESTRUCTURING?

A. Yes. Counsel advises that through the Electric Customer Choice and Competition Act of 1999 ("Competition Act"),[8] the Commission is obligated to administer the law in a manner that is consistent with the express legislative goals of establishing customer choice, creating a competitive retail market and providing economic benefits for all customer classes.[9] The Competition Act further requires the Commission to ensure that utilities do not give "undue or unreasonable preference in favor of the electric company's own electricity supply" or engage in "practices that could result in noncompetitive electricity prices to customers."[10] Additionally, the Commission has an obligation to monitor the markets to ensure that they are not being adversely affected by anticompetitive conduct.[11] Finally,

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[8] Md. Code Ann., PU, §§ 7-501 through 7-518.
[9] Md. Code Ann., PU, § 7-504.
[10] Md. Code Ann., PU, § 7-505(b)(2).
[11] Md. Code Ann., PU, § 7-514(a)(2).

the Commission is required to adopt regulations or issue orders to protect suppliers from anticompetitive practices and to ensure that customers receive "adequate and accurate" information enabling them to "make informed choices regarding the purchase of any electric services."[12]

Q. DOES THE PUA CONTAIN ANY REQUIREMENTS RELATED TO PRICING OF SOS?

A. Yes. I am aware from counsel that § 7-510(c)(3)(ii)(2) of the PUA requires that SOS be provided at "a market price that permits recovery of the verifiable, prudently incurred costs to procure or produce the electricity plus a reasonable return."[13] This language establishes a "market price" standard for the provision of SOS.

Q. WHAT IS THE HISTORY OF BGE'S ADMINISTRATIVE CHARGE?

A. The history of the Administrative Charge in the BGE service territory is long and described well in the Procedural History section of PSC Order No. 87891 issued in Case No. 9221.[14] As explained in Order No. 87891, the Commission approved a settlement agreement in Case No. 8908 in 2003 ("Phase I Settlement"), which extended SOS and established a wholesale competitive procurement methodology to implement utility-provided SOS.[15] The Administrative Charge was adopted as part of the SOS price at that time and consisted of a utility return component, an

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12 Md. Code Ann., PU, § 7-507(e).

13 Md. Code Ann., PU, § 7-510(c)(3)(ii)(2).

14 *In the Matter of a Request by Baltimore Gas and Electric Company for Recovery of Standard Offer Service Related Cash Working Capital Revenue Requirement*, Case No. 9221 (Order No. 87891 issued November 17, 2016).

15 *Re Competitive Selection of Electricity Supplier/Standard Offer Service*, Case No. 8908, Order No. 78400, 94 MD PSC 113 (2003).

incremental cost component, uncollectibles and an Administrative Adjustment component.[16] In approving the Phase I Settlement, the Commission found that the SOS prices, as structured to include the Administrative Charge, would allow the retailers' prices to be competitive with the utility's SOS prices and that the Administrative Adjustment component of the Administrative Charge would stimulate Maryland's retail electric market.[17]

Q. WHAT WAS THE PURPOSE OF CASE NO. 9221 YOU REFERENCED ABOVE?

A. Case No. 9221 arose from a November 2009 filing by BGE to modify the cash working capital component of its Administrative Charge for SOS. In assigning this matter to the Commission's Public Utility Law Judge ("PULJ"), the Commission expanded the scope of the proceeding to permit a full investigation of all components of the residential and non-residential SOS Administrative Charge.[18] As a result, the Administrative Charge, including the Administrative Adjustment component, were at issue in that proceeding.

Q. WHAT WAS THE OUTCOME OF THE CASE NO. 9221 PROCEEDING?

A. The Commission decided to keep the Administrative Adjustment component of the SOS Administrative Charge, and described it as being intended to "unbundle those incremental costs for SOS that are weaved into BGE's distribution rates while also keeping the Company's SOS prices competitive with retail energy

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[16] Order No. 78400, pp. 8-9.
[17] Order No. 78400, p. 85.
[18] Order No. 87891, p. 4.

suppliers' costs and prices."[19] Recognizing its statutory duty to "establish customer choice" and to "create a competitive retail" market, the Commission characterized the Administrative Adjustment as serving as a "proxy for A&G costs retail suppliers must include in their rates, which for the utility are embedded in BGE's distribution rates."[20]

The Commission specifically identified costs that are not being recovered through BGE's Administrative Charge such as costs for billing, call center operations, staffing for human resources and legal services.[21] The Commission further recognized that the effect of intermingling incremental costs from SOS service with distribution service is that distribution customers subsidize the price of SOS.[22] The Commission appropriately observed that this result prevents retailers from competing on "a level playing field given the fact that they pay those incremental costs and factor them into their prices, while electricity companies integrate those incremental expenses for SOS in their distribution rates."[23] The Commission further determined that elimination of the Administrative Adjustment would "cause BGE distribution customers to subsidize costs for BGE

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19 Order No. 87891, p. 22.
20 Order No. 87891, pp. 21-22; See also Order No. 78710, p. 14; Md. Code Ann., PU, § 7-505(b)(10).
21 Order No. 87891, p. 22.
22 Order No. 87891, p. 22.
23 Order No. 87891, p. 23.

customers who receive SOS services" and place retailers "on an uneven playing field relative to BGE." [24]

Q. DID THE COMMISSION DETERMINE THE LEVEL OF THE ADMINISTRATIVE ADJUSTMENT?

A. Despite the Commission's clear understanding of the need to ensure that the SOS price reflects all of the costs that are incurred to provide that service, and its firm commitment to taking steps that are necessary to ensure the creation of a competitive retail market, the Commission set the Administrative Adjustment at zero. The Commission took this route because it was "unable to glean what a reasonably precise Administrative Adjustment should be at this present time."[25]

However, to rectify this situation going forward, the Commission determined that the "issue of the precise amount of the Administrative Adjustment Component should be taken up in connection with BGE's next general rate case, in which a cost of service study should be presented to reflect more precisely which costs should be properly allocated in distribution rates and which costs should be properly allocated to SOS prices."[26]

Q. HAVE OTHER PARTIES SUPPORTED THE ADMINISTRATIVE CHARGE AND THE ADMINISTRATIVE ADJUSTMENT IN THE PAST?

A. Yes. Most notably Commission staff has supported this retail pricing mechanism because it was based on the principle that customers who use SOS should pay

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24 Order No. 87891, p. 24.
25 Order No. 87891, p. 24.
26 Order No. 87891, pp. 24-25.

their full cost, and that customers receiving electricity from a supplier should not subsidize SOS through distribution rates.[27] Staff has also described it as fostering competition "by allowing suppliers to compete against a full-cost market-priced service provided by utilities."[28] Similarly, the Office of People's Counsel ("OPC") described the Administrative Adjustment component as providing "various measures for reducing potential entry barriers for competitive retail suppliers."[29] Likewise, BGE has characterized the Administrative Adjustment as promoting the creation of a competitive market.[30] Finally, the Retail Energy Supply Association ("RESA") has contended that the Administrative Adjustment is necessary to comply with the market price standard set forth in the Competition Act.[31]

Q. WHAT IS THE SIGNIFICANCE OF THIS HISTORY OF THE ADMINISTRATIVE CHARGE, AND SPECIFICALLY WITH THE ADMINISTRATIVE ADJUSTMENT?

A. The history of the evolution of the Administrative Charge, and particularly the Administrative Adjustment, is significant for several reasons. First, the background of this issue demonstrates that the Commission has repeatedly acknowledged its statutory duties to establish customer choice and create a competitive retail market. Second, it shows that the Commission has long recognized the importance of ensuring the proper allocation of costs between

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[27] Order No. 78400, p. 18.
[28] Order No. 78400, p. 18.
[29] Order No. 78400, pp. 25-26.
[30] Order No. 87891, pp. 8-9.
[31] Order No. 87891, p. 10.

distribution service and SOS, so as to avoid cross-subsidization and to create a more level playing field for energy suppliers to compete for the utility's supply customers. Third, it is clear from the history surrounding this issue that Commission Staff has advocated views that are similar to those expressed by RESA in prior proceedings and to that being set forth by the Coalition here. Fourth, this discussion has revealed that the issue is finally ripe for a Commission determination and that in order to meaningfully address the problem of improper cost allocations, the Commission needs information showing "more precisely which costs should be properly allocated" to SOS rates.[32]

Q. HAS BGE PRESENTED SUCH INFORMATION IN THIS PROCEEDING?

A. BGE has presented a proposed allocation of costs to the Administrative Charge. However, that presentation is inadequate. In short, the cost of any resource that is consumed by BGE in the provision of standard offer services should be directly assigned or properly allocated to those services. This testimony, coupled with that of Mr. Peterson, will provide a much "more precise" allocation of costs to the Administrative Charge than was presented by BGE in this proceeding. To provide an order of magnitude, BGE proposes to allocate just over $9.5 million of costs to the Administrative Adjustment for the residential class ($12.3 million overall), whereas Mr. Peterson has calculated the proper allocation amount to be approximately $114 million to the residential class ($173 million overall).

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[32] Order No. 87891, p. 25.

Q. COULD YOU PLEASE EXPLAIN BRIEFLY THE DIFFERENCE BETWEEN ASSIGNING AND ALLOCATING COSTS AND HOW THEY RELATED TO THE COSTS AT ISSUE IN THIS PROCEEDING?

A. Yes. Costs can generally be divided into two categories – direct and indirect. Direct costs are assigned. Indirect costs are allocated. Direct costs should be "assigned" to the business unit that incurs the cost. For example, in the provision of standard offer services, cash working capital is a direct cost. The costs of that working capital should be assigned to standard offer service. A simple test to determine if a cost is a direct cost is to evaluate whether or not it would go away if the product or service goes away. In my example, BGE's need for working capital needed to effectively manage supply procurement would be eliminated if it were no longer providing standard offer services. Indirect costs, by contrast, are those costs that are incurred for more than one purpose. A very obvious example of an indirect cost incurred in the provision of standard offer services is Administrative and General Costs. This cost category is broad and includes items ranging from office supplies to executive salaries. These resources are certainly utilized in the provision of SOS. If SOS went away, BGE would still be consuming office supplies and executive salaries. Therefore, Administrative and General expenses are shared or "indirect" costs that must be allocated to the businesses for which it provides services.

IV. THE APPROPRIATE ALLOCATION

Q. WHAT IMPACT WILL THE ALLOCATION YOU ESPOUSE HAVE ON STANDARD OFFER RATES?

A. Per Mr. Peterson's analyses, the immediate impact to standard offer rates will be an adjustment of 11.82 mills per kWh for residential customers and 21.06 mills per kWh for business customers. Translated to cents, the SOS rate for residential customers would increase by 1.18 cents per kWh, while the SOS rate for business customers would increase by 2.11 cents for kWh.

Q. HOW WAS THIS AMOUNT CALCULATED?

A. Mr. Peterson initially defined the pool of resources that should be allocated to standard offer services. The total bucket of resources that should be allocated, in part, to SOS is: $538 million (versus the $43.8 million identified by Mr. Manuel). Mr. Peterson then performed an analysis to show that approximately 32% of that bucket should be allocated to SOS resulting in an allocation of $173 million to be spread over 12.5 million MWH. This results in an Administrative Adjustment component of the Administrative Charge of 11.82 mills per kWh for residential customers and 21.06 mills per kWh for business customers. When that money is collected by BGE, it is refunded to all of its distribution customers, exactly the way it is today, resulting in no net increase in costs to customers and no net increase in revenue to BGE.

Q. WHAT IS THE SIGNIFICANCE OF A ONE CENT INCREASE PER KWH IN THE PRICE FOR SOS?

A. BGE's price for SOS, which is currently 6.558 cents per kWh for the residential customer class, is understated by approximately 18 percent. That kind of price differential is fundamentally misleading to consumers evaluating offers from suppliers, and it deprives them of the information that is needed to compare prices and services on a fair and accurate basis. This is significant given the Competition Act's directive for the Commission to ensure that customers receive "adequate and accurate" information enabling them to "make informed choices regarding the purchase of any electric services."[33] As consumers shop for generation supply, they are constantly reminded of the price. When the SOS rate is understated by 18 percent, consumers cannot meaningfully compare it to offers in the market. In short, BGE's SOS customers are not being provided adequate information that is needed to enable them to make informed choices regarding the purchase of electricity.

Q. WHAT HAPPENS IF AND WHEN MORE CUSTOMERS MIGRATE TO COMPETITIVE SUPPLY?

A. The bucket of costs that is allocated to SOS will always stay the same (until base rates change). However, the allocation percentages to SOS will be lower if customers migrate to competitive supply because many of the allocators are based on the revenue split between the SOS and distribution businesses and will change periodically. For example, if a $75,000 cost was allocated based on the split of revenues between SOS and electric distribution, the allocation might be 50% to each line of business on day 1, resulting in $37,500 moving to SOS costs. If at the first true-up, half of the customers had migrated to competitive supply, the revenue-based allocation to standard offer service might only be 33%, so the period 2 allocation of that $75,000 cost would be only $25,000 instead of the

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[33] Md. Code Ann., PU, § 7-507(e).

$37,500 in period 1. The following table shows that as Customers migrate to competitive supply, the allocation of costs to SOS will decrease.

Allocations to SOS Decrease with Customer Migration				
Cost Pool	Distribution Revenue	SOS Revenue	Allocation %	$ Allocated to SOS
a	b	c	d	e
			d = c/(b+c)	e = a*d
75,000	100,000,000	100,000,000	0.50	37,500
75,000	100,000,000	50,000,000	0.33	25,000

The Administrative Adjustment can be adjusted as frequently as desired. The Commission currently has slated three adjustments per year. As long as the adjustments come with customer true-ups to account for mid-month meter readings and other technical details, customers will always be paying and BGE will always be collecting its full revenue requirement and nothing more.

Q. HAS THE COMMISSION APPROVED PERIODIC ADJUSTMENTS TO THE ADMINISTRATIVE CHARGE?

A. Yes. In fact, in Order No. 87891, the Commission addressed the issue of moving from a fixed Administrative Charge to one that is adjusted periodically, stating,

> "We find, as did the Chief Judge, that the change in the recovery of the Incremental Cost Component for Residential SOS to actual costs is reasonable and ensures that BGE neither over-collects or under-collects its SOS-related incremental costs over any length of time. The change to actual incremental costs from a fixed rate is also consistent with our decision in the PEPCO/DPL Settlement Order."[34]

[34] Order No. 87891, p. 12.

The same logic should apply to the indirect costs associated with providing SOS. Timely adjustments to the Administrative Adjustment will ensure that BGE neither over- or under-collects its revenue requirement.

V. FUNDAMENTAL MARKET FLAWS

Q. WHY IS COST ALLOCATION IMPORTANT?

A. An appropriate allocation of costs to different business lines, in any business, is important so that management can understand the true cost to produce and deliver a product and then make decisions about the product including proper pricing. In a market where costs are regulated and are generally to be provided "at cost," allocation takes on a new level of importance because of the possibility of a regulated business subsidizing another business unit. NARUC has recognized that "utilities have a natural business incentive to shift costs from non-regulated competitive operations to regulated monopoly operations…"[35] and has issued cost allocation guidance (discussed below) to prevent such subsidization.

Q. WHAT HAPPENS IF COST ALLOCATION IS NOT DONE CORRECTLY?

A. It leads to market flaws – not just in energy markets, but in any market. For example, if a company failed to allocate costs properly to one of its business lines, it could potentially cause severe financial harm to the business or possibly lead the business into bankruptcy.

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[35] NARUC Guidelines for Cost Allocations and Affiliate Transactions, Section D, p. 3.

Q. DOES AN IMPROPER ALLOCATION OF COSTS TO SOS HARM CONSUMERS?

A. Yes. It harms consumers who choose competitive electricity options and those who are taking SOS.

Q. COULD YOU PLEASE EXPLAIN THIS IN MORE DETAIL?

A. Yes. Under the current Maryland retail energy market structure, utility costs are recovered from the prices for two distinct products – distribution and energy (or standard offer service rates). Without an appropriate allocation of costs between the two retail products, the energy products will be priced below the market value for those products. This harms consumers who have chosen an electricity supplier because they are subsidizing, through distribution rates, the provision of SOS to customers who do not choose competitive options. It also harms consumers on SOS because it prevents them from being able to make a fair comparison to alternatives that may in fact offer real value to these customers, and it obscures the appropriate price signal, potentially resulting in over-consumption. Because of the subsidized SOS prices, consumers on SOS do not get the price signal to conserve or manage their electricity consumption, and they do not have reliable information that would enable them to value other options appropriately. Given the Commission's obligations under the Competition Act to establish customer choice, create a competitive market and provide economic benefits for all customer classes, it is not acceptable to allow BGE to charge artificially low SOS rates.

This flawed allocation approach also creates a market where a utility can hold a significant anti-competitive pricing advantage on the services that are supposed to be “competitive.” As recognized by NARUC, a “natural business incentive” exists to shift costs from the competitive customers to the captive customers. In the case of BGE, that natural incentive is driven by, among other things, the return component received for providing SOS. This incentive that harms customers and the markets is the exact incentive that NARUC was trying to prevent when it wrote its Guidelines for Cost Allocations and Affiliate Transactions. In view of the Commission’s statutory duties to ensure that utilities do not give undue preference in favor of their supply and or engage in practices that could not result in noncompetitive SOS rates, it is essential that steps be taken in this proceeding to rectify BGE’s cost allocations.[36]

Q. DOES THIS PRICING DISORDER CAUSE ANY OTHER PROBLEMS?

A. Yes. When the utility’s SOS price fails to capture all costs, consumers are unable to make meaningful comparisons between the price being charged by the utility for electricity and offers that are available from suppliers in the market, which in turn drives competition, innovation and value-added services out of the market. In short, consumers are deprived of the opportunity to receive accurate pricing information to which they are entitled under the Competition Act.[37] Artificially low SOS rates are anti-competitive because they make it more difficult for

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[36] Md. Code Ann., PU, § 7-505(b)(2).

[37] Md. Code Ann., PU, § 7-507(e).

suppliers in the market to compete for retail customers since they need to charge prices that reflect all of the costs of supplying electricity while BGE provides a heavily-subsidized SOS product.

Q. IF BGE ALLOCATES MORE COSTS TO SOS, WOULDN'T IT BE POSSIBLE THAT BGE WOULD FIND ITSELF IN A POSITION WHERE IT WOULD BE UNDER-COLLECTING ITS DISTRIBUTION COSTS IF THOSE CUSTOMERS MIGRATED TO COMPETITIVE SUPPLY SERVICE?

A. No. The Maryland competitive energy markets have Administrative Charge and Administrative Adjustment mechanisms which are already used to collect some costs associated with standard offer service products. Deploying these mechanisms appropriately will facilitate a more efficient market and a full collection of distribution revenues for BGE regardless of customer shopping levels.

Q. IS A FULL ALLOCATION OF COSTS TO THE ADMINISTRATIVE CHARGE AN EFFECTIVE MARKET OUTCOME?

A. Yes. Under today's market rules, the utility's costs to provide SOS are nearly fully recovered in distribution rates. The Administrative Charge is then added to the standard offer costs and collected from all standard offer customers. The Administrative Charge recovers some direct costs and includes an Administrative Adjustment which collects some of BGE's indirect costs. The money collected from the Administrative Adjustment is then refunded to all distribution customers so that the utility does not over-collect its distribution revenue requirement. This exact mechanism should be used going forward.

Once this solution is implemented, customers will see the full distribution rate approved in this rate proceeding. SOS customers would see an Administrative Charge which will be higher than the Administrative Charge proposed by BGE in this proceeding due to an increase in the Administrative Adjustment component. The Administrative Adjustment funds would be collected and then would be credited back to all distribution customers. Under this approach BGE would be made whole financially regardless of customer migration to competitive suppliers. Customers, on net, will be paying what they would be paying in the absence of the allocation and will also be exposed to the appropriate rates for standard offer service and distribution service, allowing them to make better informed choices about their energy procurement. All else being equal, changing how costs are allocated does not increase the utility's total revenues. It only moves money into different buckets, and when done properly, those buckets will reflect the true cost of providing utility services – in this case, standard offer services and distribution services. For consumers, they will be empowered to make meaningful comparisons between the price being charged by the utility for electricity and offers that are available from suppliers in the market, which in turn drives competition, innovation and value-added services into market, further benefitting consumers.

VI. COST ALLOCATION PRINCIPLES

Q. HOW SHOULD BGE ALLOCATE COSTS TO THE ADMINISTRATIVE CHARGE?

A. BGE should allocate the appropriate amount of costs to its SOS using a fully-allocated cost approach based on standard accounting principles, as detailed in Mr. Peterson's testimony. If a resource is used in the delivery of standard offer products, the costs of those resources should be allocated, in some manner, to those products. In addition to standard accounting principles, several energy industry sources suggest that a full allocation of costs to standard offer products is appropriate. Most notably, guidance from NARUC suggests that all utility products should be priced using fully allocated cost principles. BGE's own cost allocation manual suggests the same. General utility rate-making, including the distribution rates being sought in this proceeding, are fundamentally premised on an appropriate allocation of costs to certain products and services. Finally, general sound business, management and pricing practices require a full and appropriate allocation of costs to all products and services. For purposes of this proceeding, properly allocating the costs to SOS is the only way to ensure compliance with the market price standard that is established by the Competition Act.[38]

<u>NARUC STANDARDS FOR COST ALLOCATION</u>

Q. WHERE HAS NARUC OPINED ON COST ALLOCATION?

A. NARUC has written on cost allocation at least twice. In 1992, NARUC published its "Electric Utility Cost Allocation Manual" ("NARUC CAM"), which is an

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[38] Md. Code Ann., PU, § 7-510(c)(3)(ii)(2) (SOS is to be provided at a "market price that permits recovery of the verifiable, prudently incurred costs to procure or produce the electricity plus a reasonable return").

almost 200-page tome on cost allocation in utility rate making. NARUC also published "Guidelines for Cost Allocation and Affiliate Transactions" ("Guidelines"). The NARUC CAM, dating back over 25 years, is still available on the NARUC website.[39]

According to all regulatory and accounting guidance, an appropriate allocation of costs should be made to standard offer service to account for the costs required to provide the service. The NARUC CAM states:

> "While opinions vary on the appropriate methodologies to be used to perform cost studies, few analysts seriously question the standard that service should be provided at cost. Non-cost concepts and principles often modify the cost of service standard, but it remains the primary criterion for the reasonableness of rates. The cost principle applies not only to the overall level of rates, but to the rates set for individual services, classes of customers, and segments of the utility's business. Cost studies are therefore used by regulators for the following purposes:
>
> - To attribute costs to different categories of customers based on how those customers cause costs to be incurred.
> - To determine how costs will be recovered from customers within each customer class.
> - To calculate costs of individual types of service based on the costs each service requires the utility to expend.
> - To determine the revenue requirement for the monopoly services offered by a utility operating in both monopoly and competitive markets.
> - To separate costs between different regulatory jurisdictions."[40] (emphasis added).

These observations are especially prescient given the date of the NARUC CAM – January 1992. At that point in time NARUC was envisioning an allocation of

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[39] See: https://pubs.naruc.org/pub.cfm?id=53A20BE2-2354-D714-5109-3999CB7043CE

[40] NARUC, Electric Utility Cost Accounting Manual, January 1992, found at *http://pubs.naruc.org/pub/53A3986F-2354-D714-51BD-23412BCFEDFD*

costs of monopoly services offered by a utility operating in both monopoly and competitive markets. Notably, the NARUC CAM expressly identifies "segments of the utility's business."[41] In other words, it is appropriate to allocate costs to each business segment, even if it is not a separate business unit with profits and/or losses attached to it. Despite the foresight from NARUC, this guidance has been ignored by utilities, including BGE, in the provision of standard offer service. Even though the NARUC CAM likely did not envision standard offer services as they are being provided today, the allocation principles hold true from an accounting perspective and from a regulatory rate making perspective and should be applied to SOS rate making.[42]

Q. DO NARUC'S GUIDELINES ALSO APPLY TO ALLOCATION OF COSTS TO STANDARD OFFER SERVICE?

A. Yes. The Guidelines include a set of cost allocation principles that are directly relevant to pricing standard offer services. According to NARUC, the principles should be applied "whenever products or services are provided between a regulated utility and its non-regulated affiliate or division."[43] Under its first identified principle, direct costs "should be collected and classified on a direct basis for each asset, service or product provided."[44] The set of direct costs that should be charged to standard offer service include, but is not limited to, the cost of credit, the cost of wholesale market departments, the costs of procurement,

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41 *Id.*
42 Lacey, Electricity Journal, p. 7.
43 NARUC, http://pubs.naruc.org/pub/539BF2CD-2354-D714-51C4-0D70A5A95C65
44 *Id.*, Section B.1.

working capital, bad debt, the cost of communicating standard offer issues, and the cost of any other regulatory requirements imposed on SOS providers.

NARUC's second principle addresses indirect costs, which are costs for resources that are used for multiple products, services or other. This principle states that "[t]he general method for charging indirect costs should be on a fully allocated cost basis."[45] The resources deployed to provide standard offer service are vast and include executives' salaries and benefits, rents and other office space expenses, regulatory cost, billing and customer care costs and others. To meet NARUC's "fully allocated cost basis" principle, the costs for all resources that are utilized in the provision of standard offer service must be included in bucket of costs allocated to the Administrative Charge or the Administrative Adjustment component.

The principles of cost allocation should apply to all utility products and services. The NARUC CAM states exactly that fact: "The cost principle applies not only to the overall level of rates, but to the rates set for individual services, classes of customers, and segments of the utility's business." More importantly, the Guidelines state: "The allocation methods should apply to the regulated entity's affiliates in order to prevent subsidization from, and ensure equitable cost sharing

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[45] *Id.*, Section B.2 (emphasis added).

among the regulated entity and its affiliates, and vice versa."[46] These principles are directly applicable to pricing standard offer service.

Q. ARE BGE'S STANDARD OFFER BUSINESSES "AFFILIATES" OF BGE?

A. Technically, they are not affiliate organizations. Standard offer services are services provided by BGE (the distribution utility). However, I have incorporated NARUC's Guidelines into this testimony because BGE's SOS business acts like an affiliate in the market. SOS is a market-based service being offered in a competitive market. As detailed in Mr. Peterson's and my testimony, BGE's current SOS rates, as well as the rates being proposed by BGE do not reflect all costs of providing SOS and those rates have become the benchmark against which competitive market energy prices are compared. NARUC very specifically states that the objective of its Guidelines is to "lessen the possibility of subsidization in order to protect monopoly ratepayers and to help establish and <u>preserve competition in the electric generation and the electric and gas supply markets</u>."[47] (emphasis added) In fact, to ensure the competitiveness of markets, NARUC states that generally, "the price for services, products and the use of assets provided by a regulated entity to its non-regulated affiliates should be at the <u>higher of</u> fully allocated costs or prevailing market prices."[48] (emphasis added). Despite this strong guidance from NARUC on allocation of costs to competitive

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[46] *Id.*, Section B.4.
[47] *Id.*, Section D.
[48] *Id.*, Section D.1.

services, BGE is allocating significantly too few costs to SOS. NARUC's guidance and objectives have been ignored for nearly two decades and this is harming the competitiveness of energy markets in Maryland, especially for residential and small commercial customers. Not fully allocating indirect costs to standard offer products provides BGE with a significant pricing advantage in the market that significantly impacts the competitive retail markets – as evidenced by BGE's proposed SOS rates being understated by 18% per the analyses by Mr. Peterson and me. While the standard offer businesses are not technically affiliates of BGE, they should be treated as such for cost allocation purposes because of the unique nature of the services they provide.

Q. ARE SOS PRICES REGULATED BY THE COMMISSION?

A. They are not regulated in a manner that one would consider "traditional rate regulation." The Commission oversees a competitive energy procurement process that yields a "market-based" rate for consumers who choose to take standard offer products. BGE then adds to the market-based energy component, costs for transmission and other pass-through expenses, applicable taxes and an Administrative Charge. The Commission has full regulatory authority over components to be included in the Administrative Charge.

Q. DO YOU BELIEVE THAT MR. PETERSON'S ANALYSIS OF COSTS AND ALLOCATION OF COSTS IS CONSISTENT WITH THE PRINCIPLES ARTICULATED BY NARUC IN THE NARUC CAM AND GUIDELINES?

A. Yes.

<u>BGE'S COST ALLOCATION STANDARDS</u>

Q. HAVE YOU READ BGE'S COST ALLOCATION MANUAL?

A. I have read the public version of a document entitled "BGE Cost Allocation and Transfer Pricing Manual" ("BGE CAM") that was filed with this Commission on May 14, 2019, in accordance with the Code of Maryland Regulations 20.40.02.07B. This document was referenced in Section Twelve of BGE's Application for Adjustments to Electric and Gas Base Rates and other Tariff Revisions, filed in this proceeding.

Q. DOES THE BGE CAM REFERENCE ALLOCATIONS TO STANDARD OFFER SERVICE?

A. It does not specifically reference allocations to SOS. I reference it, however, because the very opening sentence of the document, in a section titled "Purpose" states: "It is important that costs incurred by Baltimore Gas and Electric Company (BGE or the Company) to support utility and non-utility affiliates be clearly identified and charged to those affiliates to avoid any inadvertent subsidization of those businesses." This shows clearly that BGE understands the importance of not subsidizing business that are competing in the markets. That purpose is the fundamental reason for allocating costs appropriately to standard offer service.

Q. DOES BGE DESCRIBE ITS COST ALLOCATION PHILOSOPHY IN ITS COST ALLOCATION MANUAL?

A. It does. It states: "Cost allocations into and out of BGE are premised on the use of a fully distributed cost allocation methodology. A fully distributed cost allocation is premised on the concept of distributing all costs to business activities, either through direct charges or allocations, based on a consistent method of determining cost causation from period to period so that reasonable cost attribution occurs. Under a fully distributed cost allocation, all direct and indirect expenses such as labor, materials, and other related expenses are included in the cost of the various business activities performed."

Q. DOES BGE APPLY ITS OWN COST ALLOCATION PHILOSOPHY TO THE COSTS OF PROVIDING STANDARD OFFER SERVICE?

A. No. It does not.

Q. HAS BGE REASONABLY ALLOCATED COSTS TO STANDARD OFFER SERVICE?

A. No. Mr. Manuel stated that "the Company prepared a cost of service study of its own costs that could reasonably be allocated to SOS."[49] I disagree. As demonstrated by Mr. Peterson, identifying all costs incurred to provide SOS to include in the Administrative Adjustment should be accomplished through the application of widely accepted accounting principles.

Q. WHY DID BGE UNDERTAKE THE ALLOCATION OF COSTS TO THE ADMINISTRATIVE ADJUSTMENT IN THIS RATE PROCEEDING?

A. In Order No. 87891, the Commission ordered that the Administrative Adjustment be set to $0.00 until this rate proceeding, stating "the precise amount of the Administrative Adjustment Component should be taken up in connection with BGE's next general rate case, in which a cost of service study should be presented

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[49] Direct Testimony of Jason M. B. Manuel, p. 30.

to reflect more precisely which costs should be properly allocated in distribution rates and which costs should be properly allocated to SOS prices."[50]

Q. HAS BGE PROPOSED AN ALLOCATION OF ANY COSTS THAT YOU BELIEVE SHOULD NOT BE INCLUDED IN THE ADMINISTRATIVE ADJUSTMENT?

A. No. All of the costs presented by BGE in its analysis rightfully belong in the Administrative Adjustment, but BGE has overlooked many other costs that should also be included.

Q. DOES BGE UNDERSTAND THE PURPOSE OF THE ADMINISTRATIVE ADJUSTMENT?

A. Yes. Mr. Manuel understands generally, stating the "purpose of the Administrative Adjustment is to better align BGE's total SOS price with the electric supply market price, thus, 'leveling the playing field' between the Company and alternative suppliers."[51] In fact, this Commission, in Order No. 87891, recognized the exact purpose of the Administrative Adjustment stating:

> The Administrative Adjustment Component was meant to unbundle those incremental costs for SOS that are weaved into BGE's distribution rates while also keeping the Company's SOS priced competitive with retail energy suppliers' costs and prices.[52]

Q. HOW DOES MR. MANUEL CHARACTERIZE THE ADMINISTRATIVE ADJUSTMENT?

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50 Order 87891, pp. 24-25.
51 Direct Testimony of Jason M. B. Manuel, p. 30.
52 Order No. 87891, p. 22.

A. Mr. Manuel characterizes the Administrative Adjustment as representing a "proxy for certain costs incurred by third-party electric suppliers to provide electric supply to their customers but are not otherwise included in SOS rates."[53]

Q. DO YOU HAVE ANY RESPONSE TO THAT CHARACTERIZATION?

A. Yes. I understand that the Commission has viewed the Administrative Adjustment as serving a proxy for indirect costs that suppliers need to include in their prices but that are embedded in BGE's distribution rates.[54] While that notion certainly supports the inclusion of additional indirect costs in BGE's SOS prices, it is important to note that the focus of the Coalition is not on suppliers' costs. Rather, the best way to level the playing field is quite simple and is premised in traditional rate-making practices. The SOS should be priced utilizing a fully-allocated cost methodology. This simple premise is rooted in decades of utility rate-making policy.

Q. DOES BGE HAVE AN INCENTIVE TO UNDER-ALLOCATE COSTS TO STANDARD OFFER SERVICES?

A. Yes. As identified in the Guidelines, NARUC observed that utilities have a "natural business incentive" to include costs of competitive service in regulated rates. BGE has a strong "natural business incentive" to shift costs to the distribution company in order to keep standard offer rates below cost. Part of the Administrative Charge proposed by BGE in this proceeding is a "return" to BGE shareholders for the provision of SOS. BGE earns between $0.00045 and

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53 Direct Testimony of Jason M. B. Manuel, p. 30.
54 Order No. 87891, p. 22.

$0.00072 per kWh[55] ($0.45 and $0.72 per MWh) of standard offer service provided. The variation is customer class dependent. If BGE can keep its costs below what its competitors are charging, then it can continue to earn risk-free returns on the provision of SOS. BGE based its allocation to the Administrative Adjustment on the assumption it would serve 12,462,742 MWH of electricity to SOS customers. That would allow them it collect almost $8.3 million in incremental returns. Again, NARUC's Guidelines acknowledge that utilities "have a natural business incentive to shift costs…"[56] As shown in the following Table, this is a perfect example of the "natural business incentive" for BGE to shift costs and the wrongful shifting of costs to distribution should be corrected in this proceeding.

Incentive to Keep SOS Price Below Market

Rate Class	Return Component ($/MWH)	MWH Sold	Total Return
Residential	$ 0.72	9,671,588	$ 6,963,543
Type I	0.48	892,899	428,592
Type II	0.47	1,766,538	830,273
Hourly	0.45	131,717	59,273
Total			**$ 8,281,680**

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55 See: Commission's Letter Order accepting proposed changes to Rider 1, Case No. 9056/9064, ML #226130, August 21, 2019, and Baltimore Gas and Electric Company - Supplement 631 to P.S.C. Md. E-6, Company proposal to make revisions to the Residential Type I and Type II SOS Market-Priced Service Transmission and Administrative Charges under Rider 1. Effective: August 1, 2019, ML #225894 for return component breakdown. See Workpapers of Mr. Manuel for MWH sold by rate classification.

56 NARUC Guidelines, Section D, p. 3.

GENERAL UTILITY PRICING PRACTICES

Q. WHAT PRINCIPLES TYPICALLY GUIDE GENERAL UTILITY RATEMAKING PRACTICES?

A. There are several, but most frequently, the so-called "Bonbright Principles" are utilized. James Bonbright was a finance professor at Columbia University and published in 1961 the "Principles of Public Utility Rates", which is to this day, considered by most, to be the seminal writing on public utility rates.

Q. DID DR. BONBRIGHT DEFINE RATEMAKING PRINCIPLES IN HIS BOOK?

A. Yes.

Q. COULD YOU PLEASE SUMMARIZE SOME OF THOSE PRINCIPLES?

A. Yes. They are the typical principles cited in most rate proceedings or discussions about regulated rate making. In fact, Ms. Fiery cites to the Bonbright principles in her testimony when saying "An effective rate design incorporates the principles of cost causation, intergenerational equity, price signaling, reasonableness, gradualism, and both inter-class and intra-class equity. These are documented by experts within the area of utility ratemaking and are principles employed by this Commission in prior base rate case proceedings as well as by numerous other commissions around the country."[57]

Q. DOES BGE APPLY ALL OF THE BONBRIGHT PRINCIPLES IN ITS RATE DESIGN PROPOSALS?

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[57] Direct Testimony of Lynn Fiery, pp. 4-5.

A. It does not. Dr. Bonbright articulated one principle that is not often cited in rate proceedings, but it very applicable in this proceeding. Dr. Bonbright articulated a principle that a competitive price should be the norm of regulation. He stated specifically that:

> "Regulation, it is said, is to be a substitute for competition. Hence, its objective should be to compel a regulated enterprise, despite its possession of complete or partial monopoly, to charge rates approximating those which it would charge if free from regulation but subject to the market forces of competition. In short, regulation should be not only a substitute for competition, but a closely imitative substitute."[58]

Perhaps this principle is not frequently cited because competition does not typically come into play when discussing distribution rates or even energy rates in the vertically integrated, regulated states. However, it is directly applicable to this proceeding.

Q. PLEASE EXPLAIN.

A. Neither BGE's proposed distribution rates nor its standard offer rates are designed as if they are subject to the market forces of competition. Instead, its rates appear to be designed to capture the "natural business incentive" articulated in NARUC's Guidelines, by subsidizing the competitive product with services from the regulated entity, with a captive customer base and a guaranteed collection of rates. BGE's SOS rates are priced at a level that is under-market and the corresponding

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[58] Bonbright, James C. "Competitive Price as a Norm of Rate Regulation." *Principles of Public Utility Rates*, Columbia University Press, 1961, pp. 93–93.

distribution rates, which are not competitive, are priced above what a fair-market price would yield.

Q. ARE MR. PETERSON'S ANALYSES OF COSTS AND PROPOSED ALLOCATIONS OF COSTS CONSISTENT WITH THE RATE-MAKING PRINCIPLES ESTABLISHED BY DR. BONBRIGHT?

A. Yes. His analysis adheres to all the Bonbright principles adopted by BGE in its rate presentation, and additionally, incorporates the principle that regulation should yield a rate that is "closely imitative" of a market price.

SOUND BUSINESS ACCOUNTING AND PRICING PRACTICES

Q. IS IT COMMON BUSINESS PRACTICE TO ALLOCATE COSTS TO DIFFERENT BUSINESS UNITS AND SEGMENTS?

A. It is common and prudent business practice to allocate an appropriate amount of costs to any business or business unit so that management can better understand the practical implications of running that line of business. According to the Corporate Finance Institute, "Cost allocation is an important process for a business because if costs are misallocated, the business might make wrong decisions to overprice/underprice a product or invest unnecessary resources in non-profitable products."[59] Mr. Peterson discusses the appropriateness of cost allocation in more detail in his testimony.

Allocation of costs to different businesses or business units is not a novel concept in utility ratemaking. Utilities, including BGE in this rate proceeding, allocate

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[59] See: https://corporatefinanceinstitute.com/resources/knowledge/finance/cost-structure/

indirect expenses to varying business units and cost centers on a regular basis. In fact, this rate case is premised almost entirely on allocating indirect costs to certain customers and customer classes. Mr. Manuel's first line of testimony after his introductory section is: "The primary objective of an embedded cost of service study is to present a reasonable representation of the cost allocation and revenue responsibility of the Company's costs during the study period amongst its customer classes, based upon the principles of cost causation and revenue responsibility."[60]

My testimony does not take issue with his allocations to any customer classes. However, Mr. Manuel falls short in the next step of the required allocations, sending just a small fraction of the actual indirect costs incurred by the standard offer business to that service. The failure to allocate an appropriate level of costs to SOS will continue to result in anti-competitive pricing structure for SOS, and rates for distribution customers that are not just and reasonable. Mr. Peterson and I have identified the set of costs that are incurred in the provision of SOS and Mr. Peterson has calculated the set of costs that should be allocated to the Administrative Adjustment.

VII. THE ADMINISTRATIVE CHARGE AND ADJUSTMENT MECHANISM

Q. ARE YOU FAMILIAR WITH THE CURRENT ADMINISTRATIVE CHARGE AND ADMINISTRATIVE ADJUSTMENT MECHANISMS

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[60] Direct Testimony of Jason M. B. Manuel, p. 4.

THAT ARE APPLIED TO STANDARD OFFER SERVICE RATES IN MARYLAND?

A. I am.

Q. HOW DID THE ADMINISTRATIVE CHARGE AND ADJUSTMENT MECHANISMS COME INTO EXISTENCE IN THE MARYLAND ENERGY MARKETS?

A. The Administrative Charge was a feature embedded in the 2003 Phase I Settlement, discussed above. Under the terms of the Phase I Settlement, the retail price to residential customers was to include the price of energy solicited through an auction process, transmission and other PJM-related costs, an Administrative Charge and taxes. The Administrative Charge was comprised of a return for retention by the utilities' shareholders, a payment for incremental costs of supplying residential service, such as working capital, a payment for uncollectible expenses and the remainder, which was classified as the Administrative Adjustment, which was refunded to all distribution rate payers.

Q. DID THE ADMINISTRATIVE CHARGE RESULT IN A REDUCTION IN DISTRIBUTION REVENUES FOR THE UTILITIES UNDER THE PHASE I SETTLEMENT?

A. No. The Phase I Settlement stated clearly that the Administrative Charge and Administrative Adjustment "shall not be interpreted as requiring a single-issue distribution rate reduction, and any change in distribution rates shall be based on normal ratemaking reviews of overall costs and revenues allocated to the distribution portion of rates."[61]

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[61] Phase I Settlement, Section 12.c, p. 10.

Q. ARE THE ADMINISTRATIVE CHARGE AND ADMINISTRATIVE ADJUSTMENT MECHANISMS STILL OPERATIONAL TODAY?

A. They are.

Q. COULD THOSE MECHANISMS BE UTILIZED TO IMPLEMENT AN APPROPRIATE COST ALLOCATION MECHANISM THAT WOULD KEEP BOTH BGE AND THE CUSTOMERS WHOLE FINANCIALLY?

Yes. In fact, Order No. 87891 continued the operation of the Administrative Charge and Administrative Adjustment in the BGE service territory and addressed the individual components correctly. In Order 87891, the Commission rejected the Chief Judge's recommendation (Proposed Order II) to eliminate the Administrative Adjustment component. In doing so, it stated:

> "The Administrative Adjustment serves as a proxy for A&G costs retail suppliers must include in their rates, which for the utility are embedded in BGE's Distribution rates. More directly, it placed into SOS costs – costs that retail suppliers bear and report on FERC reporting forms – that are not fully represented by the incremental costs recovered in the Administrative Charge, such as: costs for billing, marketing and advertisement for customers acquisition; call center operations; product and price formation; hedging supply commitment; electronic data information; PJM membership fees; staffing for human resources and policy and legal services. The Administrative Adjustment Component was meant to unbundle those incremental costs for SOS that are weaved into BGE's distribution rates while also keeping the Company's SOS priced competitive with retail energy suppliers' costs and prices."[62]

Recognizing the importance of the Administrative Adjustment in Order No. 87891, the Commission cited Staff witness VanderHeyden's testimony about the appropriateness of the Administrative Adjustment stating:

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[62] Order No. 87891, p. 22 (internal references omitted).

> "…it is typical regulatory practice to divide common costs in proportion to the portions that separate types of service or customer classes impose on the total costs. SOS and distribution service provide separate services, so it is appropriate that both services share a portion of the costs to provide utility service. The Administrative Adjustment does not reflect an artificial increase in SOS costs, but continues the means to approximate the proper allocation of customer costs that are incurred by the utility but are currently fully recovered through base rates. In order to provide a market-based price, inclusive of the costs typically borne by retail suppliers, there must be an Administrative Adjustment Component."[63]

Q. DO YOU SUPPORT THE CONTINUED IMPLEMENTATION OF THE ADMINISTRATIVE CHARGE AND ADMINISTRATIVE ADJUSTMENT MECHANISMS?

A. In general, I am fully supportive of these mechanisms, but the allocations of the administrative costs should be based on the data presented in this rate proceeding. The Administrative Charge should be broken out to account for BGE's direct and indirect costs. The Administrative Charge currently captures some of BGE's direct costs but it significantly understates the indirect costs. Therefore, it does not, but should, reflect all the costs that BGE incurs in providing standard offer services. The majority of those costs have always been embedded in distribution rates. The Administrative Charge and Administrative Adjustment mechanisms are the proper channels to ensure that BGE's rates reflect the true cost to serve its customers objective and that it is made whole financially.

Q. COULD YOU EXPLAIN HOW THE ADMINISTRATIVE CHARGE AND ADMINISTRATIVE ADJUSTMENT MECHANISMS COMBINE TO ENSURE THAT BGE IS MADE WHOLE FINANCIALLY?

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[63] Order No. 87891, p. 23.

A. Yes. The Administrative Charge is generally made up of two types of costs. The first is the direct costs associated with providing SOS. These costs include working capital, bad debt and a return to shareholders. The direct costs of providing SOS are not included in distribution rates because they are not in any way related to distribution service. The other category of costs is indirect costs, or shared costs, of resources that serve both the distribution business and SOS. A portion of the indirect costs is allocated to the Administrative Adjustment component of the Administrative Charge. However, in making this allocation, costs are not removed from the distribution business. As BGE collects SOS revenues from customers, including the Administrative Adjustment, it is temporarily "over-collecting". However, it then credits all of the Administrative Adjustment collections back to distribution customers. Without the crediting mechanism, BGE would over-collect every month. The mechanism already adopted in Maryland, if implemented properly, will deliver a more accurate and fair rate for energy to customers and ensure BGE is made whole as customers migrate back and forth from SOS.

Q. WHAT HAPPENS IF THE ADMINISTRATIVE CHARGE, INCLUDING THE ADMINISTRATIVE ADJUSTMENT, ARE TOO LOW?

A. In Order 89871, the Commission (quoting BGE witness Pino) stated, "[w]thout the Administrative Adjustment Component, SOS service would have an unfair pricing advantage over retail suppliers and Maryland's competitive retail market would not continue to be robust."[64] While the Adjustment remains in place, the charges allocated to it are too few and the SOS rate charged to customers is artificially low. The utility pricing advantage mentioned by Mr. Pino exists today. Mr. Manuel has allocated only a small portion of the indirect costs incurred in offering standard offer services.

SCOPE OF THE ADMINISTRATIVE CHARGE

Q. HAS BGE APPLIED AN APPROPRIATE SCOPE OF COSTS TO ITS PROPOSED ADMINISTRATIVE ADJUSTMENT?

It has not. As explained by Mr. Peterson, BGE has materially understated the amount of costs that it incurs in the provision of standard offer service.[65] . Notably, BGE did not include many of the cost items detailed in Order No. 87891, such as staffing for human resources, marketing and advertisement, product and price formation, electronic data information, or PJM membership fees. Its allocation for regulatory and legal services was unrealistically low. Similarly, its call center allocations were also unjustifiably low.

Q. WHAT IS THE MAGNITUDE OF COSTS THAT BGE IS ALLOCATING TO THE ADMINISTRATIVE ADJUSTMENT?

A. BGE has proposed that approximately $12.3 million be allocated to the Administrative Adjustment for all customer classes.

Q. WHAT IS THE SIZE OF BGE'S SOS BUSINESS?

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[64] Order No. 87891, p. 23.
[65] The details of this understatement of costs are set forth in UHY Exhibit CP-2.

A. According to BGE witness Manuel's work papers, BGE's SOS business accounted for approximately $1 billion in revenue in 2018.

Q. IS IT REASONABLE TO BELIEVE THAT A $1 BILLION BUSINESS COULD OPERATE WITH ONLY THE COSTS THAT BGE ALLOCATED TO IT?

No. By way of simple example, BGE's allocation to the Administrative Adjustment included only costs for the billing system, credit and collections, the call center, regulatory, accounting and legal expenses. It is simply not feasible to run and manage a nearly $1 billion business with only those resources. BGE did not include any IT expenses, any expenses for computer equipment, communications, rent or insurance or any expenses for executive time. For accounting, it included only the equivalent of approximately 11% of one full-time accounting employee (one-ninth of one FTE) when approximately 46%, or close to $1 billion, of BGE's revenues are derived from SOS and must be "accounted" for.

Q. DOES ORDER NO. 87891 REFLECT THE TOTAL SCOPE OF COSTS THAT SHOULD BE INCLUDED IN THE ADMINISTRATIVE CHARGE AND ADMINISTRATIVE ADJUSTMENT?

A. It does not. BGE should allocate a portion of all of the resources that it uses in the provision of standard offer service to those rates. Order No. 87891 acknowledged that it was not meant to be comprehensive, identifying costs "<u>such as</u>: costs for billing, marketing and advertisement for customer acquisition; call center operations; product and price formation; hedging supply commitments; electronic data information; PJM membership fees; staffing for human resources;

and policy and legal services." The "such as" language clearly indicates that the Commission recognized that others, not on the list, should be included in the allocation. Some items in addition to those included in Order No. 87891 include executive salaries, credit and finance personnel, accounting, accounts payable and accounts receivable personnel, rents and mortgages, insurance, and others. The list of incremental costs, as computed by Mr. Peterson, which should be allocated to SOS is provided in the following table:

Summary of Reallocations / Additions to the Administrative Adjustment

	Administrative Adjustment	Total Cost Pool	Allocation Factor	Total Cost Allocated to SOS
1	Call Center	$ 15,123,798	26.54%	$ 4,013,555
2	Regulatory	2,419,738	45.60%	1,103,401
3	Legal	2,729,642	45.60%	1,244,717
4	Customer Accounts Expenses	40,570,150	45.60%	18,499,988
5	Customer Service & Info Expenses	3,624,588	45.60%	1,652,812
6	Administrative & General Expenses	129,355,958	45.60%	58,986,317
7	Depreciation and Amortization	318,429,337	24.42%	77,766,494
8	Allowed Return on Working Capital	2,070,509	10.99%	227,492
9	**Total**	**$ 514,323,720**	**31.79%**	**$ 163,494,776**

Q. IS THE LIST OF COSTS THAT YOU AND MR. PETERSON ARE SUGGESTING BE ALLOCATED TO SOS A COMPREHENSIVE LIST OF COSTS THAT SHOULD BE ALLOCATED?

A. Unfortunately, I am not able to say that it is the definitive list of costs that should be allocated to SOS. The data presented in this proceeding reflect hundreds of millions of dollars of expenses in a relatively few line items on excel spreadsheets. The bucket of costs identified in this testimony reflects the next step in the evolution of the electricity market in Maryland. The pool of costs that should be allocated to SOS should be dynamic. Businesses change, markets will change, and technologies will change. Once the concept of a full allocation of costs to SOS is adopted, the Commission should also implement a process that would have stakeholders convene periodically to address market changes and other utility costs that should be allocated to SOS.

Q. HOW DID YOU DETERMINE WHAT LINE ITEMS TO INCLUDE IN THE ALLOCATION OF COSTS TO THE ADMINISTRATIVE CHARGE AND ADMINISTRATIVE ADJUSTMENT?

A. One very practical way to determine if a charge should be allocated to the Administrative Adjustment is to ask the question if the resource would be used or the if the costs would be incurred by a company providing standard offer service without the support of any other entity, including the electric utility. If the answer is yes, then some or all of that resource cost should be applied to the Administrative Charge or Administrative Adjustment.

BGE should collect all of its direct costs – costs that would go away if it did not provide standard offer services – from the Administrative Charge. Those costs include, at a minimum, working capital, bad debt expense and the return component. The Administrative Charge should also be used to collect other direct costs such as the costs for the wholesale supply team, the team that conducts SOS auctions, standard offer-related bill inserts and any other costs of complying with Commission Orders related to the provision of standard offer services.

BGE should also collect an appropriate allocation of indirect costs – costs or resources that are shared between the standard offer businesses and other business functions – from standard offer rates. For example, if the billing department was housed in an office that BGE rents, then a portion of the rent (and of the office furniture and equipment) should be allocated to the Administrative Adjustment. Again, if a product or service utilizes any asset or resource, then a portion (or all) of the cost of that asset or resource should be allocated to the product or service utilizing the resource.

Q. YOU HAVE INCLUDED COSTS FOR DEMAND RESPONSE AND ENERGY EFFICIENCY PROGRAMS IN YOUR ALLOCATION OF COSTS TO STANDARD OFFER SERVICES. CAN YOU EXPLAIN WHY?

A. Yes. First, if you look at BGE as offering two services – distribution and a competitive energy service – demand response and energy efficiency fit more appropriately into the competitive energy services box. After all, competitive energy providers offer demand response and energy efficiency services. It could be argued that these costs should be 100% assigned to the standard offer business. At a minimum, it is a shared cost, if it can provide benefits to customers of both services.

Mr. Case testified that "BGE's portfolio of programs realized over 738,000 MWh of annualized electric energy savings and natural gas savings were over 5.6 million therms."[66] Those energy savings come from standard offer customers, as well as competitive supply customers. BGE is, in essence, offering competitive market services to its customers and competitive supply customers. So, to the

[66] Direct Testimony of Mark D. Case, p. 8.

extent BGE's competitive services business is standard offer, it must allocate these costs there.

Finally, at a bare minimum, it is not reasonable by any measure to view these services as 100% related to the distribution business. Applying the same question to distribution as was suggested above for standard offer service – what costs would you incur if you ran the distribution business in isolation? – nowhere would costs for demand response and energy efficiency show up. Therefore, these services must be considered related to SOS and at some level, their costs must be allocated to SOS.

Q. COULD YOU PLEASE EXPLAIN HOW OR WHY THE COSTS OUTLINED BY MR. PETERSON ARE USED IN THE PROVISION OF STANDARD OFFER SERVICES?

These categories of costs have been specifically identified based on the descriptions of the accounts in FERC uniform system of accounts or because of BGE's own description of cost elements within the pools, as follows:

- Customer Accounts expenses are captured in FERC Accounts 901 -905 and are intended to cover expenses related to operations of the customer care center, including supervision, meter reading, collections and account management, postage, bank fees and other expenses related to customer care. Many of these costs are driven, at least in part, by the provision of SOS.[67]
- Customer Service & Information includes costs that are captured in FERC Accounts 906 – 910 and are intended to capture miscellaneous customer

[67] See FERC Uniform System of Accounts, https://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&SID=054f2bfd518f9926aac4b73489f11c67&rgn=div5&view=text&node=18:1.0.1.3.34&idno=18.

items such as efficient use of equipment, customer education, printing, postage, and other miscellaneous expenses.[68]

- A&G costs are captured in FERC Accounts 920 – 931 and capture costs for administrative salaries, office supplies, consulting costs, accountants and auditors, insurance, pensions and benefits, regulatory commission expenses and office rents.[69]
- Depreciation & Amortization costs are captured in FERC Account 403.[70] Only a small percentage of BGE's annual depreciation expense has been allocated to SOS and that allocation included depreciation on items such as office furniture and fixtures.
- Working Capital is captured in FERC Account 130. BGE has directly assigned the costs of working capital associated with the procurement of SOS directly to the Administrative Charge. However, the additional allocation of the cost of working capital is based on other working capital line items presented by BGE in this proceeding for items such as salaries, benefits, the PSC fee and other taxes. These costs arise in part from the operation of SOS.

VIII. ALTERNATIVE CALCULATION

Q. HAS MR. PETERSON PERFORMED ANY ALTERNATIVE CALCULATIONS THAT YOU BELIEVE ARE WORTHY OF THE COMMISSION'S CONSIDERATION?

A. Yes. I asked Mr. Peterson to perform a calculation that distributed the costs allocated to the SOS pool equally across all rate classes. In other words, I asked him to calculate what the Administrative Adjustment would be if the SOS costs were assigned to SOS based on MWH instead of based on the allocations embedded in BGE's ECOSS models.

Q. WHY DID YOU MAKE THAT REQUEST?

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[68] *Id.*
[69] *Id.*
[70] *Id.*

A. I asked him to make this calculation because BGE, after it determined its allocation of costs to the Administrative Charge, also assigned these costs to customer groupings (residential, Type I, Type II, HPS) on a per MWH basis. The net impact of assigning costs in this manner is that all customers will see the same Administrative Adjustment in its rates.

Q. WHAT ARE THE RESULTS OF THAT ALTERNATIVE CALCULATION?

If costs are assigned to each customer class based on MWH, then the SOS Administrative Adjustment would be 13.89 mills per kWh for all customers. Mr. Peterson provides that calculation in his testimony.

IX.APPLICABILITY TO SOSS

Q. YOUR TESTIMONY HAS REFERENCED SOS, SOSS AND GENERIC STANDARD OFFER SERVICES. HOWEVER, THE ANALYSIS PRESENTED IS FOCUSED ONLY ON THE SOS ELECTRIC BUSINESS. WOULD IT BE APPROPRIATE FOR BGE TO IMPLEMENT THE EXACT SAME TYPE OF ANALYSIS AND ADJUSTMENT MECHANISMS FOR THE GAS BUSINESS?

A. Yes, it would. The same types and magnitudes of costs would be applicable to the SOSS business. The NARUC cost allocation principles are also applicable to gas businesses. BGE utilizes an Administrative Charge tool in the delivery of SOSS, but it does not include an “Adjustment” mechanism that refunds costs back to distribution ratepayers. The Commission should mandate that BGE implement a system that collects both direct and an allocation of all indirect costs incurred in the delivery of SOSS and refund those indirect costs back to its gas distribution ratepayers.

Q. IS IT IMPORTANT THAT THE ALLOCATIONS TO SOSS BE DETERMINED IN A RATE PROCEEDING?

A. No. As discussed above, these allocations do not change base distribution revenue requirements or rates in any way. They move some costs to the standard offer service, but those costs are also recovered in distribution rates and the "over-collection" is then refunded to the customers. With strong guidance from the Commission about the costs that should be allocated to the Administrative Adjustment, the allocations to the SOSS business can be determined in a stakeholder process. The value of hearing this issue on the electric side in this rate proceeding is that it reveals with a high degree of certainty the costs that are utilized in the provision of SOS. The lessons learned can easily be transferred to SOSS and to other SOS businesses across the state without disrupting rates or revenue requirements.

X.SUMMARY

Q. COULD YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A. My testimony supports the analyses presented by Mr. Peterson and has shown that BGE has not followed long-standing traditional rate-making procedures in determining the costs that should be allocated to the Administrative Adjustment and as a result has allocated too few costs to the Administrative Charge, including the Administrative Adjustment component. BGE has proposed an allocation to the Administrative Adjustment of 1.00 mills per kWh to each of the SOS customer groupings (Residential, Type I, Type II and HPS). Mr. Peterson's analysis shows that the allocations to the Administrative Adjustment should be 11.82 mills per kWh to residential customers and 21.06 mills per kWh to each of the C&I rate classes. An alternative approach that levelizes the Administrative Adjustment across all rate classifications results in the Administrative Adjustment being 13.89 mills per kWh for all customer classes.

In reaching my conclusions, I adopted Mr. Peterson's direct testimony and exhibits regarding the proper computation of BGE's Administrative Adjustment for SOS. His recommended allocations are consistent with National Association of Regulatory Utility Commissioners ("NARUC") principles of cost allocation, with BGE's Cost Allocation Manual and with sound utility ratemaking practices. Mr. Peterson testified that appropriate cost allocations are consistent with sound business accounting practices. BGE has a meaningful financial incentive that might encourage it to maintain the status quo, which ironically, is an incentive that NARUC and BGE both suggest could be eliminated with proper cost allocations.

The Administrative Adjustment, if implemented correctly, will resolve the pricing/allocation anomalies and will do so in a manner that does not either increase or decrease the base revenues that BGE will receive after this proceeding, in a manner that does not increase costs to customers in aggregate and in a manner that will facilitate the type of robust competition envisioned when the Maryland Legislature opened this market to competitive forces.

The principles and methodologies used by Mr. Peterson and me are directly applicable to the SOSS business and can be implemented outside of a rate proceeding.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

EXHIBIT FPL-1

Frank Lacey

3 Traylor Drive
West Chester, PA 19382
724-413-0849
frank@eacpower.com
www.linkedin.com/in/fplaceyelectricityleadership

Summary

Recognized energy market consultant and executive known for implementing innovative regulatory, business and operational strategies to capitalize on emerging energy market products, technologies and services. Success in achieving business growth through regulatory strategy. Strong knowledge of retail energy and utility operations, regional electric and gas markets and strategies, market trends and national energy policy. Success in bringing cross-functional teams together to achieve superior results to capitalize on non-traditional business opportunities.

Board of Directors positions: Smart Electric Power Alliance (finance committee) (2015-2018); Association for Demand Response and Smart Grid (finance chair) (2011-2015); Advanced Energy Management Alliance (Chairman) (2012-Present); ERCOT (finance committee) (2002-2004); Electric Power Supply Association (2002-2004).

Experience

Electric Advisors Consulting 2015-Present
Founder and President

As an independent consultant, advise senior business leadership on developing business and operational strategies to advance legislative, regulatory and market design changes in the energy industry. Advise and assist entities on facilitating legislative, regulatory and market changes to accommodate evolving business strategies and advise clients on technologies and operational changes required to successfully adapt to regulatory mandates.

Comverge, Inc./CPower Corporation 2011-2015
Senior Vice President, Regulatory and Market Strategy

Within a PE-owned demand response and energy services firm that was separated into two companies, served on both companies' executive teams, developing and implementing corporate and regulatory growth strategies. Conducted M&A analyses and due diligence. Developed market entry plans and complex communications approaches for entities embroiled in a US Supreme Court litigation with a combined $150 million in revenue at risk.

Direct Energy 2006 - 2011
Director, Complex Transactions (2008-2011)

For a multi-billion dollar retail electric and gas company, led team consisting of four direct reports and eight cross-functional leaders, facilitating incremental gross margin sales in excess of $100 million from non-standard product requests.

Director, Government and Regulatory Affairs (2006-2008)

Managed regulatory strategy and regulatory risk in Mid-Atlantic region of US, participating in multiple rate proceedings and regulatory initiatives, securing greater than $90 million in shareholder value through reduced credit and collateral exposure and increased sales.

Starlight Energy 2004 - 2006
President

Led the development of business plan and pro formas for venture seeking $20 million in equity financing and other financial relationships. Successes included securing $100 million credit relationship and working capital financing to enable launch of competitive electricity markets retail supply company.

Strategic Energy 2001- 2004
Director, Regulatory Affairs

Served on the Leadership team of start-up company, managing a regulatory group that grew to 15 people. Managed the development of regulatory strategy, the oversight of regulatory risk and the attainment of desired regulatory results, advocating for market design structures in emerging electricity markets across 16 states and the federal government, ultimately resulting in sale of business valued at $780 million.

Arthur Andersen 1998 - 2001
Senior Manager

Responsibility for development and growth of Andersen's transmission restructuring business in Eastern half of US market, achieving annual consulting sales in excess of $3 million.

Putnam, Hayes and Bartlett, Inc 1995 - 1998
Associate Consultant

Financial analyst in firm's energy practice with expertise in asset valuation, including stranded costs, power plants and environmental assets.

Education

Carnegie Mellon University, Tepper School of Business
MSIA/MBA with concentrations in finance, entrepreneurship and environmental management

University of Maryland
B.S. in Transportation and Logistics

Programs for Life
Certified Leadership Development Trainer

EXHIBIT FPL-2

Prepared Direct Testimony of Frank Lacey On Behalf of Strategic Energy, LLC, before the Public Utilities Commission of the State of California in the matter of the *Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060*. Docket No. R. 02-01-011. June 6, 2002.

Prepared Rebuttal Testimony of Frank Lacey On Behalf of Strategic Energy, LLC before the Public Utilities Commission of the State of California in the matter of the *Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060*. Docket No. R. 02-01-011. June 20, 2002

Cross Examination testimony of On Behalf of Strategic Energy, LLC before the Public Utilities Commission of the State of California in the matter of the *Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060*. Docket No. R. 02-01-011. July 2002.

Prepared Testimony of Frank Lacey on the subject of truing up the CERS Fee On Behalf of Strategic Energy, LLC before the Public Utilities Commission Of the State Of California in the matter of the *Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060*. Docket No. R. 02-01-011. March 19, 2003

Prepared Direct Testimony of Frank Lacey on behalf of Strategic Energy L.L.C. before the Pennsylvania Public Utility Commission in the matter *Pennsylvania Public Utility Commission, et al. v.Duquesne Light Company*, Docket Nos. R-00038092, R-00038092C0001 and R-00038092C0002. January 2003.

Prepared Rebuttal Testimony of Frank Lacey on behalf of Strategic Energy L.L. C. Before the Pennsylvania Public Utility Commission in the matter *Pennsylvania Public Utility Commission, et al. v. Duquesne Light Company* Docket Nos. R-00038092, R-00038092C0001 and R-00038092C0002. February 2003.

Prepared Supplemental Testimony of Frank Lacey on behalf of Strategic Energy L.L.C. before the Pennsylvania Public Utility Commission in the matter *Pennsylvania Public Utility Commission, et al. v. Duquesne Light Company* Docket Nos. R-00038092, R-00038092C0001, R-00038092C0002. November 2003

Cross Examination testimony of Frank Lacey on behalf of Strategic Energy L.L.C. before the Pennsylvania Public Utility Commission in the matter *Pennsylvania Public Utility Commission, et al. v. Duquesne Light Company* Docket Nos. R-00038092, R-00038092C0001, R-00038092C0002. July 1, 2003.

Prepared Direct Testimony of Frank Lacey submitted on behalf of Strategic Energy L.L.C. and Dominion Retail, Inc. before the Public Utilities Commission of Ohio in the matters of the *Continuation of the Rate Freeze and Extension of the Market Development Period for The Dayton Power and Light Company* Case No. 02-2779-EL-ATA and the *Application of The Dayton Power and Light Company for Certain Accounting Authority Pursuant to Section 4905.13, Ohio Revised Code* Case No. 02-2879-EL-AAM. May 19, 2003.

Prepared Supplemental Testimony of Frank Lacey submitted on behalf of Strategic Energy L.L.C. and Dominion Retail, Inc. before the Public Utilities Commission of Ohio in the matters of the *Continuation of the Rate Freeze and Extension of the Market Development Period for The Dayton Power and Light Company* Case No. 02-2779-EL-ATA and the *Application of The Dayton Power and Light Company for Certain Accounting Authority Pursuant to Section 4905.13, Ohio Revised Code* Case No. 02-2879-EL-AAM. June 12, 2003.

Deposition Testimony of Frank Lacey submitted on behalf of Strategic Energy L.L.C. and Dominion Retail, Inc. before the Public Utilities Commission of Ohio in the matters of the *Continuation of the Rate Freeze and Extension of the Market Development Period for The Dayton Power and Light Company* Case No. 02-2779-EL-ATA and the *Application of The Dayton Power and Light Company for Certain Accounting Authority Pursuant to Section 4905.13, Ohio Revised Code* Case No. 02-2879-EL-AAM. May 2003 and June 2003.

Cross Examination testimony of Frank Lacey on behalf of Strategic Energy L.L.C. and Dominion Retail, Inc. before the Public Utilities Commission of Ohio in the matters of the *Continuation of the Rate Freeze and Extension of the Market Development Period for The Dayton Power and Light Company* Case No. 02-2779-EL-ATA and the *Application of The Dayton Power and Light Company for Certain Accounting Authority Pursuant to Section 4905.13, Ohio Revised Code* Case No. 02-2879-EL-AAM. June 2003.

Oral Testimony of Frank Lacey before the Standing Committee on Energy of the New York State Assembly on the issue of Ensuring a Reliable Supply of Electricity to the People of New York, Chairman Paul D Tonko, presiding. March 6, 2003

Prepared Direct Testimony of Frank Lacey on behalf of Strategic Energy, L.L.C. before the Pennsylvania Public Utility Commission in the matter of the *Petition of Duquesne Light Company for Approval of Plan for Post-Transition Period Provider of Last Resort Service.* Docket No. P-00032071. February 2004.

Prepared Rebuttal Testimony of Frank Lacey on behalf of Strategic Energy, L.L.C. before the Pennsylvania Public Utility Commission in the matter of the *Petition of Duquesne Light Company for Approval of Plan for Post-Transition Period Provider of Last Resort Service.* Docket No. P-00032071. February 2004.

Cross Examination testimony of Frank Lacey on behalf of Strategic Energy, L.L.C. before the Pennsylvania Public Utility Commission in the matter of the *Petition of Duquesne Light Company for Approval of Plan for Post-Transition Period Provider of Last Resort Service.* Docket No. P-00032071. April 1, 2004.

Oral Testimony of Frank Lacey at the *POLR Roundtable* before the Pennsylvania Public Utility Commission re: Optimal Future POLR Design models. May 3, 2004.

Prepared Direct Testimony of Frank Lacey on behalf of Strategic Energy, L.L.C. and Mid-American Energy Company before the Public Utilities Commission of Ohio in the matters of *The Application of the Cincinnati Gas & Electric Company to Modify its Non-Residential Generation Rates to Provide for Market-Based Standard Service Offer Pricing and to Establish a Pilot Alternative Competitively-Bid Service Rate Option Subsequent to Market Development Period*, Case No. 03-93-EL-ATA, *The Application of the Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Certain Costs Associated with the Midwest ISO*, Case No. 03-2079-EL-AAM, and *The Application of the Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Capital investment in its Electric Transmission and Distribution System and to Establish a Capital Investment Reliability Rider to be Effective After the Market Development Period*, Case Nos. 03-2080-EL-AAM and 03-2080-EL-ATA. May 6, 2003.

Deposition of Frank Lacey in the matters of *The Application of the Cincinnati Gas & Electric Company to Modify its Non-Residential Generation Rates to Provide for Market-Based Standard Service Offer Pricing and to Establish a Pilot Alternative Competitively-Bid Service Rate Option Subsequent to Market Development Period*, Case No. 03-93-EL-ATA, *The Application of the Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Certain Costs Associated with the Midwest ISO*, Case No. 03-2079-EL-AAM, and *The Application of the Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Capital investment in its Electric Transmission and Distribution System and to Establish a Capital Investment Reliability Rider to be Effective After the Market Development Period*, Case Nos. 03-2080-EL-AAM and 03-2080-EL-ATA. May 2003.

Cross Examination Testimony of Frank Lacey on behalf of Strategic Energy, L.L.C. and Mid-American Energy Company before the Public Utilities Commission of Ohio in the matters of *The Application of the Cincinnati Gas & Electric Company to Modify its Non-Residential Generation Rates to Provide for Market-Based Standard Service Offer Pricing and to Establish a Pilot Alternative Competitively-Bid Service Rate Option Subsequent to Market Development Period*, Case No. 03-93-EL-ATA, *The Application of the Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Certain Costs Associated with the Midwest ISO*, Case

No. 03-2079-EL-AAM, and *The Application of the Cincinnati Gas & Electric Company for Authority to Modify Current Accounting Procedures for Capital investment in its Electric Transmission and Distribution System and to Establish a Capital Investment Reliability Rider to be Effective After the Market Development Period*, Case Nos. 03-2080-EL-AAM and 03-2080-EL-ATA. May 18, 2003.

Oral Testimony of Frank Lacey before the Michigan Senate Committee on Technology and Energy on the subject of revision to Public Act 141, the Michigan Electricity Choice and Restructuring Act, Chairman Bruce Patterson, Presiding. May 19, 2004.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Maryland Senate Finance Committee on Senate Bill 561 on the subject of communications between electric companies and suppliers to enhance the development of competitive electric markets, Chairman Thomas Middleton, Presiding. March 7, 2006.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Maryland Senate Finance Committee on Senate Bills 814, 1048, 1051 and 1078 on the subject of retail electricity market design, Chairman Thomas Middleton, Presiding. March 14, 2006.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Maryland House of Delegates Economic Matters Committee on House Bills 1334, 1654 and 1712 on the subject of retail electricity market design, Chairman Dereck Davis, Presiding. March 14, 2006.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utility Commission in the Matter of *Petition of Direct Energy Services, LLC for Emergency Order*, Docket No. P-00062205, April 11, 2006.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utility Commission in the Matter of *Policies to Mitigate Potential Electricity Price Increases*, Docket No. M-00061957, June 22, 2006.

Prepared Direct Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of *Duquesne Light Company Base Rate Case*, Docket No. R-00061346, July 7, 2006. (Case Settled)

Prepared Rebuttal Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of *Duquesne Light Company Base Rate Case*, Docket No. R-00061346, August 2, 2006. (Case Settled)

Prepared Surrebuttal Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of *Duquesne Light Company Base Rate Case*, Docket No. R-00061346, August 16, 2006. (Case Settled)

Prepared Direct Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of _Petition of PPL Electric Utilities Corporation for Approval of Competitive Bridge Plan_, Docket No. P-00062227, November 15, 2006.

Prepared Rebuttal Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of _Petition of PPL Electric Utilities Corporation for Approval of Competitive Bridge Plan_, Docket No. P-00062227, December 6, 2006.

Prepared Surrebuttal Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of _Petition of PPL Electric Utilities Corporation for Approval of Competitive Bridge Plan_, Docket No. P-00062227, December 15, 2006.

Oral Rejoinder Testimony and Cross-examination of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of _Petition of PPL Electric Utilities Corporation for Approval of Competitive Bridge Plan_, Docket No. P-00062227, December 15, 2006.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania House of Representatives, Consumer Affairs Committee, Honorable Joseph Preston Jr., Chairman, March 15, 2007.

Prepared Direct Testimony of Frank Lacey on behalf of Direct Energy Services, LLC and the Retail Energy Supply Association before the Pennsylvania Public Utilities Commission in the Matter of _Petition of Duquesne Light Company for Approval of Default Service Plan for the Period January 1, 2008 through December 31, 2010_, Docket No. P-00072247, March 29, 2007. (case settled)

Prepared Rebuttal Testimony of Frank Lacey on behalf of Direct Energy Services, LLC and the Retail Energy Supply Association before the Pennsylvania Public Utilities Commission in the Matter of _Petition of Duquesne Light Company for Approval of Default Service Plan for the Period January 1, 2008 through December 31, 2010_, Docket No. P-00072247, April 12, 2007. (case settled)

Prepared Surrebuttal Testimony of Frank Lacey on behalf of Direct Energy Services, LLC and the Retail Energy Supply Association before the Pennsylvania Public Utilities Commission in the Matter of _Petition of Duquesne Light Company for Approval of Default Service Plan for the Period January 1, 2008 through December 31, 2010_, Docket No. P-00072247, April 20, 2007. (case settled)

Prepared Direct Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of *Petition of Pike County Light & Power Company for Expedited Approval of its Default Service Implementation Plan, Docket No.* P-00072245, March 28, 2007.

Prepared Rebuttal Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of *Petition of Pike County Light & Power Company for Expedited Approval of its Default Service Implementation Plan, Docket No.* P-00072245, April 11, 2007.

Oral Surrebuttal Testimony and Cross-examination Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania Public Utilities Commission in the Matter of *Petition of Pike County Light & Power Company for Expedited Approval of its Default Service Implementation Plan, Docket No.* P-00072245, April 19, 2007.

Prepared Direct Testimony of Frank Lacey on behalf of Direct Energy Services, LLC, before the Maryland Public Service Commission *In the Matter of the Commission's Investigation of Investor-owned Electric Companies' Standard Offer Service for Residential and Small Commercial Customers in Maryland*, Case No. 9117, September 14, 2007.

Prepared Reply Testimony of Frank Lacey on behalf of Direct Energy Services, LLC, before the Maryland Public Service Commission *In the Matter of the Commission's Investigation of Investor-owned Electric Companies' Standard Offer Service for Residential and Small Commercial Customers in Maryland*, Case No. 9117, September 28, 2007.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC, before the Maryland Public Service Commission *In the Matter of the Commission's Investigation of Investor-owned Electric Companies' Standard Offer Service for Residential and Small Commercial Customers in Maryland*, Case No. 9117, October 2007.

Oral Testimony of Frank Lacey on behalf of Direct Energy Services, LLC before the Pennsylvania House of Representatives Republican Policy Committee, Honorable Michael Turzai, Chairman, March 17, 2008.

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EXHIBIT FPL-3

Default Service Pricing Has Been Wrong All Along

Allows Utilities to Maintain Dominance in Markets

By Frank Lacey, Electric Advisors Consulting

Default service prices have been wrong for two decades.

Most of the states that have implemented competition in electric and gas sales have employed a Provider of Last Resort, POLR, or default service to supply electricity to customers who do not select an alternative provider. Yet the utilities allocate few to no "costs to serve customers" to default service rates.

This practice has allowed the incumbent utilities to price default service below market rates. And it has allowed them to maintain unregulated monopoly-like power and dominant market positions in the energy markets in their respective service territories.

The failure to allocate costs appropriately to a utility business unit is in direct conflict with cost allocation guidance from the National Association of Regulatory Utility Commissioners, NARUC. Until the default service pricing distortion is corrected, utility default service providers will continue to hold an anti-competitive pricing advantage in the provision of retail electricity service.[1] Regulators should act to correct this major market flaw.

Default Service Rates Artificially Low

Several states have deregulated or restructured their energy markets to allow consumers to choose their own electric and or gas supplier. With few notable exceptions, the deregulation models adopted in these states called for the incumbent utility to become the POLR or default service provider.[2]

While initially envisioned to serve a small number of customers who needed a "last resort" provider, the market rules incorporated into most restructured markets placed all customers on last resort service at the inception of retail competition, making it more of a "default" service.

Because an appropriate amount of costs are not allocated to default service, customers are reluctant to leave their incumbent utility. They are receiving electricity that is subsidized by distribution rates.

The default service pricing subsidy provides the incumbent utilities with what are effectively unregulated monopolies. Default service customers are not being charged an amount that is reflective of the cost to serve them.

The lack of any meaningful cost allocations to default service allows (requires) the incumbent utilities in restructured states to understate the price of retail electricity. This practice effectively eliminates competitive suppliers from functioning in those markets.

This pricing error leads to numerous market flaws. Distribution rates are too high. Default service rates are too low. Customers are receiving incorrect and inappropriate price signals from their host utilities.

The failure to allocate costs appropriately to a utility business unit is in direct conflict with cost allocation guidance from NARUC.

Customers who have switched to competitive suppliers are subsidizing those who stay on default service. And competitive suppliers are at a distinct pricing disadvantage compared to default service providers, allowing the utility market power to proliferate in retail energy markets.

This pricing incongruity allows utilities to maintain a stronghold over customers in their service territory. It also has given rise to claims about overcharging by competitive suppliers.

Freestanding Default Service Business Couldn't Survive

It is easy to prove the anti-competitive pricing in default service. One only needs to contemplate how long a default service business could operate if it was removed from the distribution company but kept its current cost structure intact. The short answer is that it would survive for only a very short period of time – technically, not even a day.

Default service companies need to issue tens of thousands of invoices every day and then need to process revenues as they come in. But because no costs to serve customers are allocated to default service businesses, there would be no money to pay any employees to perform those functions, nor any other function involved in running a default service business.

The current default service businesses would be bankrupt in a matter of days, or even hours, if they were operated outside of the distribution utilities. Clearly, this is a fundamentally flawed

Frank Lacey has worked in competitive energy markets since their inception as a consultant to utilities navigating restructuring and as a direct market participant once the markets opened. After more than twenty years in the industry, he launched Electric Advisors Consulting, in the fall of 2015. His focus is assisting clients with energy market issues – regulatory, strategic and business. His clients include energy market participants and end-use consumers. He can be reached at frank@eacpower.com.

FIG. 1 **COMPARATIVE ELECTRIC CUSTOMER RATES**

Electric customer rates of switching from utility to competitive retail provider.

		Percentage migration by customer count		
State	Utility	Residential customers	Small and medium customers	Large customers
DC	PEPCO	15.0	32.1	N/A
MD	BGE	23.9	41.0	96.5
	PEPCO	19.8	42.8	87.9
	POT ED	10.8	32.4	90.3
	Delmarva	13.8	35.8	96.9
NJ	ACE	12.8	32.2	87.1
	JCPL	16.6	38.1	83.7
	PSEG	9.7	24.7	81.0
	RECO	6.9	18.4	74.5
PA	Duquesne	29.9	39.9	63.1
	Met-Ed	30.2	45.1	86.3
	PECO	31.0	46.0	91.0
	Penn Elec	26.1	42.2	88.1
	Penn Power	24.2	46.3	100.0
	PPL	41.3	53.7	70.5
	West Penn	24.7	32.8	91.9
NY	Central Hud	13.1	23.1	78.0
	Con Ed	22.8	29.8	91.6
	Nat Grid	16.1	38.5	80.2
	NYSEG	18.6	35.2	66.0
	O & R	33.5	45.9	26.4
	Rochester	16.2	42.0	93.2
Maine	State-wide	14.1	42.6	84.2
Delaware	Delmarva	9.8	32.2	

system and one that conflicts with all traditional rate-making standards.

Cost allocation is a fundamental tenet of utility ratemaking. The principles of cost allocation are fully endorsed by NARUC and should be applied to default service as they are to all other utility rates.

Allocations are required to appropriately assign fixed costs to multiple products or services that drive the costs. The principles of cost allocation are the foundation for nearly every (if not every) utility rate, aside from default service rates.

The NARUC Cost Accounting Manual states:

"While opinions vary on the appropriate methodologies to be used to perform cost studies, few analysts seriously question the standard that *service should be provided at cost.* Non-cost concepts and principles often modify the cost of service standard, but it remains the primary criterion for the reasonableness of rates. The cost principle applies not only to the overall level of rates, but to *the rates set for individual services, classes of customers, and segments of the utility's business.*" Emphasis added.

NARUC has separately published cost allocation principles. The principles should be applied, according to NARUC "whenever products or services are provided between a regulated utility and its non-regulated affiliate or division." NARUC principles apply to default service, a business segment where many services are provided by the distribution company:

"The allocation methods should apply to the regulated entity's affiliates in order to *prevent subsidization* from and ensure equitable cost sharing among the regulated entity and its affiliates, and vice versa." Emphasis added.

NARUC states that the objective of its guidelines is to "lessen the possibility of subsidization in order to *protect monopoly ratepayers and to help establish and preserve competition* in the electric generation and the electric and gas supply markets." Emphasis added.

In fact, to ensure the competitiveness of markets, NARUC states that generally, "the price for services, products and the use of assets provided by a regulated entity to its non-regulated affiliates should be *at the higher of* fully allocated costs or prevailing market prices." Emphasis added.

NARUC's objectives and guidelines have been ignored in pricing default service.

Market Distortions

The default service pricing anomaly has given rise to many market distortions and has resulted in competitive suppliers being cast in a negative light in many jurisdictions. It has caused competitive suppliers to spend millions of dollars in unnecessary marketing costs, regulatory costs and legal and compliance costs.

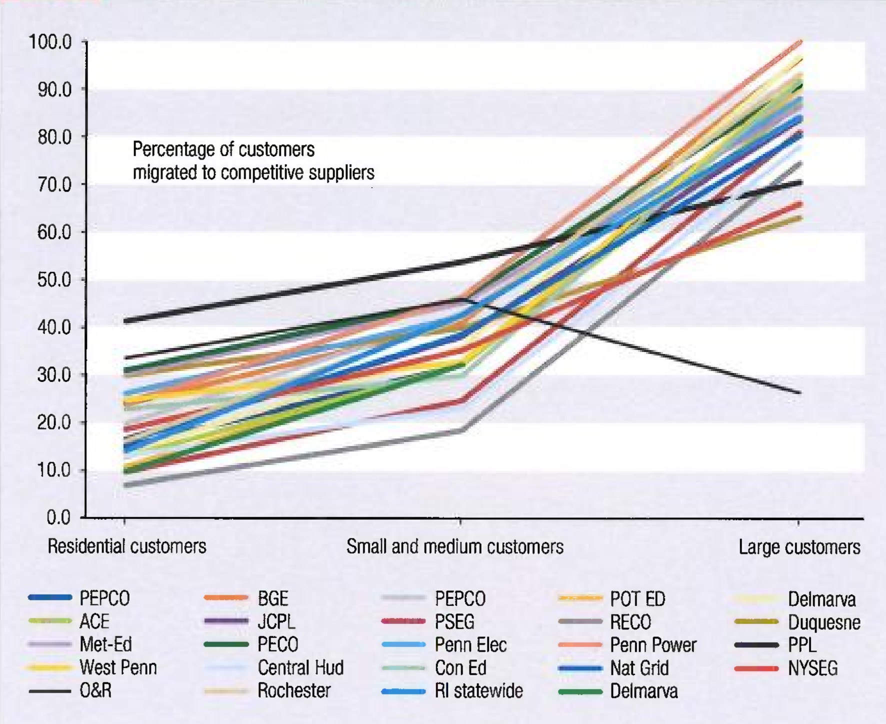
Most important, it has resulted in customer harm from being constrained to the utilities' "no service" products and from the lack of product options that are available in more competitive markets.

Table One details the percentage of customers who have chosen a competitive electric supplier across many of the deregulated electricity markets. Despite two decades of competition and dozens of suppliers vying for customers in every market, the incumbent utility stronghold on the market, especially over residential customers, is painfully clear.

See Figure One.

At the low end, we see single digit migration rates for residential customers to competitive suppliers. The Pennsylvania market shows the most promising residential migration numbers – ranging from the mid-twenty percent range to just over forty percent in PPL's service territory.

FIG. 2 CUSTOMER MIGRATION TRENDS ARE CONSISTENT ACROSS MARKETS



States that have deployed municipal aggregations to facilitate customer migration are not included in this chart because aggregations are simply a regulatory fix that masks the pricing problem in the short-term. Municipal aggregations do not solve the pricing problems over time.

Figure Two shows the same data in graphical form. The utilities all show the same migration trends. Small customers do not migrate away from the utilities while the largest customers participate in the competitive markets at very high penetration levels.[3] See Figure Two.

Artificially Low Default Service Prices Harms Customers

Under an appropriate cost allocation approach, the customers will pay, on net, the same amount every year. Cost allocation does not cause an increase in costs to customers. It only moves costs to different buckets.

Because there is no total cost increase to customers with an appropriate cost allocation, the argument that the customers are better off under the current pricing model is flawed. In fact, because of the inaccurate pricing signal with the current model, customers are harmed in meaningful ways.

Most important, customers are not receiving the appropriate price signal for energy. This results in a potential to over-consume energy provided by default service providers, yielding what could be a higher overall monthly cost to the customer than would otherwise incur if the electricity was priced appropriately.

Customers who have switched to competitive suppliers are subsidizing those who stay on default service.

The distribution subsidy also creates a barrier to evaluating competitive offers. It is impossible for customers to assess fairly a competitive offer when the utility price is artificially low.[4] Because the basic competitive market product would be viewed as uneconomic by the consumers, competitive suppliers are less likely to invest fully in the market, depriving customers of other products and services that the suppliers might be inclined to offer in that market. Foregone products and services include many that might reduce a consumer's consumption overall, benefitting the customers and the environment.

Finally, the distribution subsidy results in a distribution rate that is too high. Customers who have moved away from the utility are forced to pay costs that benefit customers who remain on default service.

Recent Analyses Reveal Subsidies

Substantial analyses seeking to understand the magnitude of the distribution subsidy have been performed in two recent distribution rate cases. The results of those analyses have been presented to utility commissions in Pennsylvania and New

Jersey in the form of expert testimony in those respective cases. These analyses show that the subsidy is significant – a penny or more per kilowatt-hour – as high as fifteen percent of the default service rate.

In PECO's rate proceeding, Pennsylvania Public Utility Commission's docket R-2018-3000164, NRG Energy Company provided an analysis of PECO's distribution rates to determine if any distribution costs were being used to subsidize PECO's default service rates. The analysis showed that the subsidy of PECO's default service by PECO's distribution business amounts to 1.25 cents per kilowatt-hour for residential customers.

If that amount was properly allocated to PECO's default service rates, it would increase those rates by approximately fifteen percent. Of course, if the costs were properly allocated to default service, the corresponding cost components from the distribution rates would decrease by the same amount.

In PSEG's rate proceeding, New Jersey Board of Public Utilities docket ER18010029, I undertook on behalf of Direct Energy, a similar analysis. My analysis showed that the subsidy that PSEG distribution rates were providing to PSEG's default service amounts to 1.0 cents per kilowatt-hour to residential customers. Because PSEG's default service rates are higher than PECO's, an additional 1.0 cents per kWh represents a subsidy of about eight percent to residential default service rates.

In the PSEG rate case, not enough information was provided by the utility to determine the magnitude of costs (working capital, credit, bad debt, etc.) that should be directly assigned to default service. As a matter of conservatism in my analysis, I assumed that those should be only partially allocated.

If direct costs were assigned properly to default service and indirect costs were allocated appropriately, the actual costs to serve default service customers in New Jersey could be in the range of 1.5 cents per kilowatt-hour.

With default service rates ranging from the low single digits to the low teens in cents per kilowatt-hour in markets across the country, and the unallocated funds (or subsidies) ranging from 1.0 to 1.5 cents per kilowatt-hour, this subsidy can be valued anywhere between eight percent and fifty percent of a monthly default service charge. A subsidy of that magnitude, or that scale of utility "discount" severely distorts the market, unfairly advantages the utilities over competitive service providers and harms customers.

Conclusion

Appropriately allocating costs currently paid by distribution customers to default service is a critical next step in creating more competitively neutral energy markets in the United States. This one step will not create the perfect markets, but it will remove a significant anti-competitive pricing advantage held by monopoly utilities.

It will also remove a subsidy that competitive supply customers are forced to pay to benefit default service customers, and it will help create a market that competitive suppliers are more willing to invest in. At the same time, if implemented correctly, it keeps distribution utilities financially whole. It is a win-win-win solution benefitting all market participants.

Endnotes:

1. While this article is focused on electricity markets, the same pricing problems exist in gas markets. The costs to serve customers are not allocated to those customers' rates. Instead, they are charged to distribution customers.
2. Most of the deregulation models deployed in the U.S. are generally very similar. In contrast, Texas electricity customers and Georgia natural gas customers were placed with market participants at the inception of those markets and default service in those markets is truly a "last resort" service, not a "default" or "do nothing" service.
3. The one anomaly revealed in this chart is in the Orange & Rockland Utility in New York. It shows an uncharacteristic low level of customer migration at the large end of the customer spectrum. It is not clear whether this is a data error on the NY PSC website, or if there is a market anomaly in that market that results in the largest customers remaining with the utility.
4. Under no circumstance should any price, including the utilities' default service price, be considered a benchmark price. The default service price is for a specific product with a specific set of parameters associated with it. Additionally, as this article notes, it is heavily subsidized. It comes with a certain level of service and a limited ability for it to be modified in any way to meet customers' needs. Regardless, regulators in many states have mandated rules that require a comparison of all products to the utility default service price. These requirements include for example, a requirement that the default service price be placed on a customer's invoice, even if the customer is being served by another supplier, with a different product. Some have required that all sales interactions include a notice of the utilities' default service price.

EXHIBIT FPL-4

The Electricity Journal 32 (2019) 4–10

Contents lists available at ScienceDirect

The Electricity Journal

journal homepage: www.elsevier.com/locate/tej

Default service pricing – The flaw and the fix
Current pricing practices allow utilities to maintain market dominance in deregulated markets

Frank Lacey

Electric Advisors Consulting, LLC, 3 Traylor Drive, 19382, West Chester, PA, United States

ARTICLE INFO

Keywords:
Default service
Cost allocation
Energy markets
Electric competition
Deregulation
Market power
Market concentration
D-SEAM
Electricity price
Cross-subsidies

ABSTRACT

Utility default service has been priced incorrectly for two decades. Incumbent utilities serving as default service providers for both electricity and gas allocate few to no "costs to serve" to default service rates. The indirect costs not allocated include billing, customer care, enrollments, metering, and other overhead and add up to billions of dollars annually. These costs are paid in distribution rates. The resulting rate for utility-provided default service is a below-market price, allowing the utilities to maintain dominant market positions in the retail markets for residential and small commercial customers. This pricing practice distorts the relevant retail electric and gas markets and harms customers and the markets. NARUC cost allocation guidelines advocate that the cost of utility resources used in the provision of default service should be allocated to that service. This paper presents a Default Service Equalization Adjustment Mechanism ("D-SEAM") that when deployed properly, will provide the default service utilities with a tool to allocate an appropriate amount of costs to default service rates and then adjust that allocation on a monthly basis to ensure the distribution utility is made whole financially as customers migrate off of default service. Without an appropriate allocation of cost to default service, incumbent utilities will maintain a dominant market position in the retail markets for residential and small commercial customers as a result of the significant subsidy provided by the distribution rates. Utilities should adopt, and/or the regulators should compel the adoption of a complete and appropriate allocation of costs to default service. It is only with this allocation that customers will be able to reasonably compare market offerings.

1. Introduction

1.1. Default service prices have been wrong for two decades

Several states have restructured their electricity and/or gas markets to allow for customer choice of energy suppliers. Most of these states have implemented a Provider of Last Resort ("POLR") provider or Default Service provider to provide electricity to customers who do not select an alternative provider. As long as default service remains the benchmark against which other offers are compared[1], it should be priced so that all of the costs incurred to provide default service are included. For it is only in that circumstance when competitive retail energy markets empower customers to meaningfully compare energy offers. Testimony presented in recent rate proceedings for PECO electric distribution utility in Pennsylvania and PSEG's electric and gas distribution utilities in New Jersey reveal the magnitude of the pricing subsidies that are present in those markets. The practice of not allocating costs appropriately to a utility business unit is in direct conflict with cost allocation guidance from the National Association of Regulatory Utility Commissioners ("NARUC"). Until the pricing distortion is corrected, utility default service providers will continue to hold an anti-competitive pricing advantage in the provision of what should be competitive retail electricity service. Regulators should act to correct this major market flaw.

E-mail address: frank@eacpower.com.

[1] For several reasons, including those discussed within this paper, utility-provided default service products and prices should not be a benchmark to compare any competitive service offerings. The default service price is for a very specific product with a very specific set of parameters associated with it. This rate is often reconcilable and reflects a price from a prior point in time in the market. Additionally, as this article notes, default service is heavily subsidized. It comes with a certain level of service and a very limited ability for it to be modified in any way to meet customers' needs. Regardless, regulators in many states have mandated rules that require a comparison of all products to the utility default service price. These requirements include for example, a requirement that the default service price be placed on a customer's invoice, even if the customer is being served by another supplier, with a different product. Some have required that all sales interactions include a notice of the utilities' default service price.

https://doi.org/10.1016/j.tej.2019.02.002

The majority of states that have restructured retail energy markets report statistics on customer migration away from the incumbent utilities. This data shows clearly that the incumbent utilities in restructured states continue to hold strong market dominance in the residential and small commercial markets. For example, after nearly 20 years of competition, the majority of restructured states show migration rates of less than 20% of the residential electricity customers.[2]

The explanations proffered by the so-called "energy experts" all miss the simple truth – the incumbent utilities still hold vast market powers granted to them by their respective regulators. Most notably, the cost of providing default service is nearly fully- (and in some cases fully-) subsidized by the host utility's distribution customers. Yes, customers typically pay the full price for the electrons they receive. Customers, however, are not charged for billing, IT, overhead, or any other costs that should rightfully be allocated to default service. The simple thought experiment to see if appropriate costs are being allocated to the default service business is to imagine what would happen if default service was severed from the utility's distribution business. Under this imaginary scenario, nearly every default service program would be bankrupt in a matter of days, if not hours, if it was removed from the distribution business. This simple example should allow the reader to clearly see that utilities are not allocating adequate costs to default service.

2. Background

Several states within the United States have deregulated or restructured their retail energy markets to allow consumers to choose their own electric and/or gas supplier. While the utilities in these regions continue to maintain monopoly franchise rights over their "pipes and wires" businesses, their electric generation and gas supply businesses are now subject to competitive forces and customer choice of supplier. With few notable exceptions, the deregulation models adopted in these states called for the incumbent utility to become the POLR or default service provider. While initially envisioned to serve a small number of customers who were in need of a "last resort" provider, the market rules incorporated into most restructured markets placed all customers on "last resort" service at the inception of retail competition[3]. Because "last resort" became such an inappropriate phrase for what utility service has become, the name has morphed to "standard offer" or "default service" – the service for customers who fail to choose a competitive alternative. Unfortunately, embedded in this process are default service prices that are heavily subsidized by the host utilities' distribution companies. As a result, default service customers are misled about their retail market options and thus, frequently remain with their incumbent utility.

Some default service providers pass along some direct costs to their customers, such as the cost of credit to procure power in the open market. Some providers pass on no costs at all beyond the direct cost of the energy provided. No incumbent utility default service provider in the US passes along any indirect costs to its default service business. The indirect costs incurred to provide service to default service customers amount to billions of dollars annually and are being paid by distribution customers. This distorts significantly the retail energy markets, providing the incumbent default service provider with a pricing advantage that allows them to maintain market dominance in the residential and small commercial customer segments.

These subsidies are the primary reason that retailers focus on non-price issues and offer many value-added products and services. It is simply not practical to compete with standard offer service on price alone. In short, the default service rates offered to customers by incumbent utilities are artificially low, which leads to numerous market flaws: distribution rates are too high; default service rates are too low; customers are receiving incorrect and inappropriate price signals from their host utilities; consumers are not provided adequate information to make informed energy decisions; and customers who have switched to competitive suppliers are subsidizing those who stay on default service. This pricing incongruity allows the incumbent default service providers to maintain market dominance over customers in their service territories and it also has given rise to bogus claims of "overcharging" by competitive suppliers.

3. Data from recent analyses

Substantial analyses seeking to understand the magnitude of the distribution subsidy have been performed in recent distribution rate cases. The results of those analyses have been presented to Utility Commissions in Pennsylvania and New Jersey in the form of expert testimony in those cases. These analyses show that the subsidy is significant – a penny or more per kilowatt-hour – or more than 10% of the default service rate.

In PECO's rate proceeding (PA PUC Docket No. R-2018-3000164), NRG Energy Company presented an analysis of PECO's distribution rates that showed the subsidy of PECO's default service by PECO's distribution business amounts to 1.25 cents per kilowatt-hour for residential customers.[4]

In PSEG's rate proceeding (NJ BPU Docket No. ER18010029), Frank Lacey (the author of this article), an energy markets consultant and president of Electric Advisors Consulting, undertook on behalf of Direct Energy, a similar analysis that showed the PSEG distribution rates were providing default service subsidies of 1.0 cent per kilowatt-hour to residential customers and 0.67 cents per kWh to C&I customers.[5]

4. Proposed solution

The distribution companies should allocate the portion of costs incurred to operate the default service business to the that business and collect those costs from its customers on the energy portion of those customers' invoices. In order for the distribution company to fully collect its regulated revenue requirement, the distribution companies should also implement crediting, balancing and true-up mechanisms to ensure that it is never over- or under-collecting.

4.1. Cost allocation mechanism

Distribution resources that are used in the functioning of the default service business should be identified. The costs associated with these resources should be quantified as they would be in a rate proceeding. Once the bucket of costs is identified, an appropriate allocation

[2] This paper focuses on competitive electricity markets. The same dynamics discussed in this paper are also present in the competitive gas markets. The distribution companies significantly subsidize the commodity price by failing to allocate costs to serve default service customers. The solutions provided in this paper are applicable to gas distribution companies as well.

[3] A few deregulation models were implemented differently, and customers were immediately placed into the competitive market upon inception of the market. Notably, Texas electricity customers and Georgia natural gas customers were placed with market participants at the inception, or shortly after the inception of those markets.

[4] Direct Testimony of Chris Peterson on Behalf of NRG Energy Company, Pennsylvania Public Utility Commission v. PECO Energy Company, Docket No. R-2018-3000164, June 26, 2018.

[5] Prepared Direct Testimony of Frank Lacey on behalf of Direct Energy and its affiliates before the New Jersey Board of Public Utilities, *In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16, Electric and B.P.U.N.J. No. 16, Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief*, BPU Docket Nos. ER18010029 and GR18010030, OAL Docket No. PUC 01151-18, August 6, 2018.

approach should be applied so that costs to run the default service business are properly attributed to that business.

Based on the numbers presented by PSEG in its recent rate proceeding, approximately $300 million in expenses (out of a total of $900 million) and about $1.3 billion in rate base assets (out of a total of $5.7 billion) were identified as utility resources or costs that were utilized in the provision of default service and as such, these costs should be partially allocated to default service.[6]

The most logical allocator to apportion these shared costs is revenue as the majority of the shared costs are incurred in the revenue or cash management function. These costs include those for the billing system, accounting and finance, metering, and others.

4.2. *True-up mechanism*

If a static, one-time cost allocation is made to default service, as customers migrate to competitive supply, the utility would not be able to collect fully its distribution revenue requirement. In the PSEG rate case, a Default Service Equalization Adjustment Mechanism ("D-SEAM") was proposed to address that shortfall.[7] The D-SEAM does not require a change to the overall distribution revenue requirement or the resulting distribution rates. Instead, the D-SEAM allocation mechanism includes a monthly upward cost adjustment to default service customers and at the same time, it calls for an incremental cost credit to distribution customers, resulting in financial neutrality to the utility. As customers migrate to competitive supply, the D-SEAM collections decrease, but at the same time, so would the distribution credit to customers. The D-SEAM would operate in almost the exact same manner that many decoupling mechanisms are implemented, although calculations and adjustments could be implemented monthly.

As customers migrate away from default service, this ratio of revenues is certain to change, however, the subset of systems, infrastructure and people utilized to support default service will not change. Therefore, only the allocation factor changes with customer migration. The table below shows how the mechanism can be used to keep the utility whole as migration away from default service occurs (Table 1).

As customer migration occurs, the charges and credits change, but the total distribution collections remain constant. Ultimately, if every customer was on a competitive service supply option, there would be no allocations and no credits.

5. Freestanding default service businesses could not survive

To understand the foolishness of the current models, one only needs to contemplate how a default service business could operate if it was removed from the distribution company but kept its current cost structure intact. The short answer s that it would survive for only a very short period of time – technically, not even a day. If nothing else, a default service business needs to process tens of thousands of invoices and payments every day. In reality, the list of utility services utilized in the provision of default service is quite lengthy. Under the current framework, there would be no funds to pay for any of those services. Clearly, this is a fundamentally flawed system.

[6] The rate proceeding did not adequately identify the subset of costs, such as working capital attributable to default service or wholesale procurement costs that should be directly assigned to default service business. As such, those direct costs were included in the analysis as an indirect cost and included in the set of costs that should be allocated to default service. As a result, the final recommendation of a 1.0 cent per kWh allocation to default service is likely understated.

[7] PSEG's default service is called Basic Generation Service or BGS. The equalization adjustment was referred to as "BEAM" in the PSEG rate proceeding.

Table 1
Sample Calculations Showing D-SEAM and D-SEAM Impact on Distribution Revenue Collections.

Time Period	Number of Dist Customers	Average Dist Kwh/cust/month	Total Dist Revenue Requirement ($)	Distribution costs allocable to BGS (30% of all costs)	Retail Choice Customers	Default Service Customers	Revenue-based Allocation Ratio to D-SEAM	Costs Allocated to D-SEAM	D-SEAM per Default Service Customer ($/month)	D-SEAM Credit	D-SEAM Credit per Dist customer ($/month)	Total Distribution Collections ($)
0	1,600,000	577	46,160,000	13,848,000	-	1,600,000	0.50	6,924,000	4.33	6,924,000	4.33	46,160,000
1	1,600,000	577	46,160,000	13,848,000	200,000	1,400,000	0.47	6,462,400	4.62	6,462,400	4.04	46,160,000
2	1,600,000	577	46,160,000	13,848,000	800,000	800,000	0.33	4,616,000	5.77	4,616,000	2.89	46,160,000
3	1,600,000	577	46,160,000	13,848,000	1,000,000	600,000	0.27	3,776,727	6.29	3,776,727	2.36	46,160,000
4	1,600,000	577	46,160,000	13,848,000	1,599,999	1	0.00	0	0.00	0	0.00	46,160,000

6. NARUC principles require allocations to default service

The principles of cost allocation are fully endorsed by NARUC and should be applied to default service as they are to all other utility rates. The principles of cost allocation are the foundation for nearly every (if not every) utility rate, aside from default service rates. The principles of cost accounting are neither new nor novel to utility rate making personnel or regulators who approve rates. Yet despite the long history of cost allocation in the industry, the default service businesses have been allowed to operate since the inception of deregulation without an appropriate allocation of costs to serve default service customers.

The NARUC Cost Accounting Manual states:

"While opinions vary on the appropriate methodologies to be used to perform cost studies, few analysts seriously question the standard that service should be provided at cost. Non-cost concepts and principles often modify the cost of service standard, but it remains the primary criterion for the reasonableness of rates. The cost principle applies not only to the overall level of rates, but to the rates set for individual services, classes of customers, and *segments of the utility's business*. Cost studies are therefore used by regulators for the following purposes:

- To attribute costs to different categories of customers based on how those customers cause costs to be incurred.
- To determine how costs will be recovered from customers within each customer class.
- To calculate costs of individual types of service based on the costs each service requires the utility to expend.
- To determine the revenue requirement for the monopoly services offered by a utility operating in both monopoly and competitive markets.
- To separate costs between different regulatory jurisdictions."[8] (emphasis added).

These observations from NARUC are especially prescient given the date of the Cost Allocation Manual – January 1992. At that point in time NARUC was envisioning an allocation of costs of monopoly services offered by a utility operating in both monopoly and competitive markets. Even though it is likely the NARUC Manual did not envision default service as it is being offered today, the principles hold true from an accounting perspective and from a regulatory rate-making perspective and should be applied to default service.

Notably, NARUC's Manual expressly calls out costs allocated to "segments of the utility's business". In other words, it is appropriate to allocate costs to each business segment, even if it is not a separate business unit with profits and/or losses attached to it. Despite the foresight from NARUC, this guidance has been ignored by utilities in the provision of default service. This manual, dating back over 25 years is still available on the NARUC website.[9]

NARUC has separately published cost allocation principles. The principles should be applied, "whenever products or services are provided between a regulated utility and its non-regulated affiliate or division".[10] Under NARUC's first identified principle, direct costs "should be collected and classified on a direct basis for each asset, service or product provided."[11] The set of direct costs that should be charged to default service include, but is not limited to, the cost of credit, the cost of wholesale market departments, the costs of procurement, working capital, bad debt, the cost of communicating environmental attributes of default service supply (where required), and the cost of other regulatory requirements imposed on default service providers.

NARUC principles further apply to default service stating: "The allocation methods should apply to the regulated entity's affiliates in order to *prevent subsidization from, and ensure equitable cost sharing among the regulated entity and its affiliates*, and vice versa."[12] (Emphasis added.)

NARUC describes that the objective of its guidelines is to "lessen the possibility of subsidization in order to protect monopoly ratepayers and to *help establish and preserve competition in the electric generation and the electric and gas supply markets*."[13] (emphasis added) In fact, to ensure the competitiveness of markets, NARUC states that generally, "the price for services, products and the use of assets provided by a regulated entity to its non-regulated affiliates should be at the *higher of fully allocated costs or prevailing market prices*."[14] (emphasis added) NARUC's cost allocation guidance and objectives have been ignored for two decades and the data shows that the incumbent utilities' monopoly-like stronghold over customers, especially residential and small commercial customers, remains.

7. Default service pricing harms markets

7.1. Default service providers maintain market dominance

The default service pricing anomaly results in a significant subsidy that provides the incumbent utilities default service businesses with anti-competitive pricing power. Default service customers are simply not being charged an amount that is reflective of the cost to serve those customers. The lack of any meaningful cost allocations to default service allows (requires) the incumbent utilities in restructured states to understate the price of retail electricity and eliminates competitive suppliers from functioning effectively in those markets.

In an ironic submission to the New York Public Service Commission, Commission staff offered the results of a Herfindahl–Hirschman Index ("HHI")[15] analysis, while trying to show market power among competitive suppliers. However, what the results actually showed is that each of the New York electricity markets was "highly concentrated" when the analysis included the incumbent utility (with HHI scores above 7000) but was unconcentrated without the incumbent utilities (with HHI scores as low as 420).[16] Rather than showing market power among competitive suppliers, this analysis clearly demonstrates the market dominance of the New York utilities. Commission staff testified further that the 23 largest competitive electric suppliers were serving less than 20% of the New York residential market.[17] That means that on average, the 23 largest competitive electric

[8] NARUC, Electric Utility Cost Accounting Manual, January 1992, found at *http://pubs.naruc.org/pub/53A3986F-2354-D714-51BD-23412BCFEDFD*

[9] See: https://pubs.naruc.org/pub.cfm?id=53A20BE2-2354-D714-5109-3999CB7043CE

[10] NARUC, http://pubs.naruc.org/pub/539BF2CD-2354-D714-51C4-0D70A5A95C65

[11] Ibid, Section B.1.

[12] Ibid, Section B.4.

[13] Ibid, Section D.

[14] Ibid, Section D.1.

[15] According to the US Department of Justice, the HHI is a commonly accepted measure of market concentration. The HHI is calculated by squaring the market share of each firm competing in the market and then summing the resulting numbers. The HHI considers the relative size distribution of the firms in a market. It approaches zero when a market is occupied by a large number of firms of relatively equal size and reaches its maximum of 10,000 points when a market is controlled by a single firm. Agencies generally consider markets in which the HHI is between 1,500 and 2,500 points to be moderately concentrated and consider markets in which the HHI is in excess of 2,500 points to be highly concentrated. *See* U.S. Department of Justice & FTC, *Horizontal Merger Guidelines* § 5.3 (2010).

[16] Prepared Direct Testimony of Joel Andruski, Associate Economist, Office of Market and Regulatory Economics, State of New York, Department of Public Service, *In the Matter of ESCO Track I Proceeding*, Cases 15-M-0127, 12-M-0476 and 98-M-1343, September 2017.

[17] Prepared Direct Testimony of the NY PSC Staff Panel: Bruce E. Alch, Chief, Retail Access and Business Advocacy, Office of Consumer Services; Craig Carroll, Utility Analyst 2, Office of Consumer Services; Peter Lavery, Utility Analyst, Office of Accounting, Audits and Finance; Kristine A. Prylo, Principal Utility Financial Analyst, Office of Accounting, Audits and Finance; David Shahbazian, Utility Auditor II, Office of Accounting, Audits and Finance, State of New York Department of Public Service, *In the Matter of ESCO Track I*

suppliers each hold less than a 1% market share, while one New York utility still holds an 87% share in the residential market in its service territory.

The New York Staff's HHI analysis effectively proves the utilities dominance in New York. The same result would be found in nearly every other deregulated market. The question then is: why do the utilities hold such a dominant position? It is clearly not the lack of interest from competitive suppliers. After all, the New York Staff cites to the "23 largest" suppliers, indicating that there are many more than 23 vying for customers' business. Do customers endear themselves to the utilities in every market? Not likely. Do the utilities offer one better product than the list of all products offered by competitive suppliers? Not likely. Or is the utilities pricing subsidy simply too great for competitive suppliers to overcome? Without performing any formal analysis on these first two questions, the answers seem obvious. The utility pricing advantage brought on by a lack of cost allocation is simply too great for the suppliers to overcome. All energy companies are purchasing power from the same wholesale markets. Utilities simply do not pass on the costs to service their customers. The pricing incongruity could not be more evident.

Because competitive suppliers must include all of their operating costs in their supply prices in addition to the wholesale cost of energy, competitive prices are frequently higher than those of the subsidized default service rates. Instead of regulators fixing the default service pricing, many have instead lobbed allegations of "overcharging" at the competitive suppliers.[18] Regulators and consumer advocates have launched investigations and suggested that residential markets be closed. As a result, competitive suppliers have spent millions of dollars defending their actions and fighting to maintain a presence in the markets.

7.2. Customer migration trends are consistent

The New York customer switching results discussed above are not unique. Table 2 below details the percentage of customers who have chosen a competitive electric supplier across many of the deregulated electricity markets. After two decades of competitive markets, we see a similar pattern of migration rates of customers to competitive suppliers across the restructured markets[19].

The results in Table 2 are not unexpected. In order to compete with default service, a competitive supplier has to either wait for a cycle in the wholesale markets that will allow for a more economic offering than default service, or the supplier has to offer a better, typically more expensive product. It is difficult to compete with the subsidized default service price.

Chart 1 below shows the same data in graphical form. The graph shows that the migration problem is not unique to any one utility jurisdiction. Small customers do not migrate away from the utilities while the largest customers participate in the competitive markets at very high penetration levels[20]. It is not clear whether the outlier in the Large Customer category reflects a data error on the NY PSC website, or if there is a market anomaly that results in the largest customers in that market remaining with the utility.

Table 2
Electric Customer Retail Choice Migration Rates[a].

State	Utility	Percentage of Rate Class Switching By Customer Count: Residential	Small and Medium	Large
DC[b,c]	PEPCO	15.0	32.1	N/A
MD[d]	BGE	23.9	41.0	96.5
	PEPCO	19.8	42.8	87.9
	POTED	10.8	32.4	90.3
	Delmarva	13.8	35.8	96.9
NJ[e]	ACE	12.8	32.2	87.1
	JCPL	16.6	38.1	83.7
	PSEG	9.7	24.7	81.0
	RECO	6.9	18.4	74.5
PA[f]	Duquesne	29.9	39.9	63.1
	Met-Ed	30.2	45.1	86.3
	PECO	31.0	46.0	91.0
	Penn Elec	26.1	42.2	88.1
	Penn Power	24.2	46.3	100.0
	PPL	41.3	53.7	70.5
	West Penn	24.7	32.8	91.9
NY[g]	Central Hud	13.1	23.1	78.0
	Con Ed	22.8	29.8	91.6
	Nat Grid	16.1	38.5	80.2
	NYSEG	18.6	35.2	66.0
	O & R	33.5	45.9	26.4
	Rochester	16.2	42.0	93.2
Maine[h]	State-wide	14.1	42.6	84.2
Delaware[i]	Delmarva	9.8	32.2	

[a]Data in this table gathered from each state's PUC or related website. Each state has differing definitions for C&I customer classes. Data from Ohio, Illinois and Massachusetts are not included in this table because each jurisdiction has engaged in robust community aggregation programs. Rhode Island data is not presented because Rhode Island does not report by rate class, the number of customers not participating in retail choice programs, so percentages by rate class cannot be calculated. Connecticut data is not shown here as its last reported data period is year-end 2014 and it also does not break down enrollment data by rate class.
[b]See: https://dcpsc.org/PSCDC/media/PDFFiles/Electric/electric_sumstats_no_cons.pdf. (Sept. 2018 data).
[c]See: https://dcpsc.org/PSCDC/media/PDFFiles/Electric/electric_sumstats_cons_dmnd.pdf. (Sept. 2018 data).
[d]See: https://www.psc.state.md.us/electricity/electric-choice-monthly-enrollment-reports/. (August 2018 data).
[e]See: https://www.state.nj.us/bpu/pdf/energy/edc07.pdf. (August 2018 data).
[f]See: https://www.papowerswitch.com/sites/default/files/PAPowerSwitch-Stats.pdf. (Sept 2018 data).
[g]See:http://www3.dps.ny.gov/W/PSCWeb.nsf/All/4759ECEE7586F24B85257687006F396E?OpenDocument (December 2017 data).
[h]See: https://www.maine.gov/mpuc/electricity/choosing_supplier/migration_statistics.shtml. (September 2018 data).
[i]See: https://depsc.delaware.gov/electric-regulation/#consumer. (April 2018 data).

7.3. Improper default service pricing harms Consumers

Customers are receiving an artificially low energy-price signal. This incorrect signal results in over-consumption of energy provided by default service providers. Because most residential customers are still on default service, the pricing anomaly results in system-wide over-consumption of electricity, increasing market prices for all consumers. On net, the artificially low price might actually yield what could be higher overall monthly costs to all customers because wholesale prices are impacted by increased consumption levels.

It is also impossible for customers to assess fairly a competitive offer

(footnote continued)
Proceeding, *Cases 15-M-0127, 12-M-0476 and 98-M-1343, September 2017.*

[18] In the aftermath of the Polar Vortex in 2014, a handful of suppliers charged higher prices than were typical in the market at the time. Regulators in some markets determined that certain suppliers acted in bad faith and penalized them. However, the recent analyses presented that allege systemic overcharging have incorrectly and inappropriately compared market-based electricity products to the subsidized default service rates on an apples-to-apples basis.

[19] States that have implemented municipal aggregations programs are not included in Table 2. Municipal aggregations might lead to more robust migration numbers, but they are only a short-term regulatory fix that temporarily masks the distribution subsidy. Municipal aggregations do not solve the pricing incongruity over time.

[20] The research on this paper and in support of the PSEG rate case showed that the subsidy for larger customers is smaller, on a per-kWh basis, than the subsidy for residential customers.

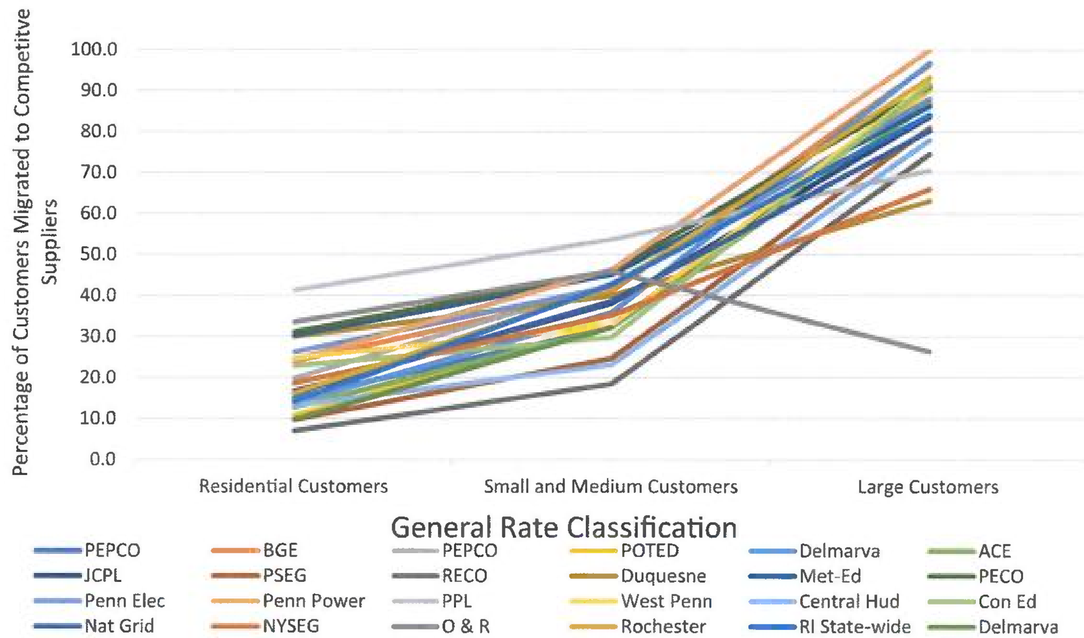


Chart 1. Customer Migration Trends are Consistent Across Markets.

when the utility price is artificially low[21]. Because the basic competitive commodity-only product would be viewed as uneconomic by the consumers, suppliers are less likely to invest fully in the market, depriving customers of other products and services including many that might reduce a consumer's overall consumption, which would benefit the customers and the environment. These products and services are available in the more competitive regions of the country but are not as readily available where the subsidized default service rates stifle competition.

Finally, the distribution subsidy results in a distribution rate that is too high. Customers who have moved away from the utility are forced to pay costs that benefit customers who remain on default service.

The lack of residential and small commercial customer energy savings options, products and services is the result of a failed regulatory paradigm. It is not a reflection of a failed market.

8. Arguments against Cost allocation are flawed

Stakeholders have generally proffered four arguments against allocating indirect retail costs to default service. The typical arguments are:

1) The costs are not avoidable and will be incurred by the distribution business whether or not they provide default service;
2) If costs are allocated to default service, the distribution utility will not be able to recover its full distribution revenue requirement as customers migrate to competitive suppliers;
3) Allocation of costs serves no purpose other than to increase rates on customers so that competitive suppliers can better compete with utility pricing; and
4) Utilities do not earn a profit on the provision of default service, so an allocation of costs is not needed.

All of these arguments are flawed.

8.1. Avoidable versus allocable costs

Simply stated, avoidable costs are direct costs. Fixed costs, which typically serve multiple purposes are considered indirect costs and should be allocated to the businesses which benefit from the resource. Direct or avoidable costs should be directly assigned (not "allocated") to the business unit incurring the costs. The existence of avoidable/direct costs, however, does not mean that allocable/indirect costs don't exist. In order for businesses to properly price products and services, indirect costs must be appropriately allocated to the cost centers benefiting from the incurrence of the costs.

Our economy is replete with examples of businesses that allocate costs to more than one product, service or business unit. But we do not need to look past the rate cases prevalent in the utility industry to see cost allocations implemented. Under the theory of avoidable costs, one could argue that commercial customers shouldn't pay for distribution wires because if the commercial customers left the grid, the utility would still need to have the distribution wires in place to service residential customers. Of course, that argument is foolhardy. The cost of the distribution wires and services related to it are largely fixed costs that benefit all rate classes and are therefore allocated to all rate classes based on cost causation principles. It is inappropriate that utilities do not similarly assign direct costs and allocate an appropriate amount of indirect costs to default service.

8.2. Cost recovery

Utilities have argued against allocations to default service because if costs are allocated to that service and customers move to competitive supply, the utility will not be able to fully recover its allowed rates. This argument assumes a static accounting paradigm. If a utility simply lowered its distribution rate by one cent per kWh and increased default service rates by one cent per kWh, that argument would hold some validity. Further accounting and pricing tools can be developed that would ensure the utility is kept whole. The D-SEAM described above was presented in the PSEG rate case and fully resolves the cost recovery issue.

The cost recovery argument is a red herring. Utility tariffs are chock full of riders, true-ups, monthly adjustments and "make whole" mechanisms. It is clear that a true-up mechanism can be deployed that will

[21] Under no circumstance should any price, including the utilities' default service price, be considered a benchmark price. See fn 1, supra.

ensure that default service customers are seeing a competitive energy price that will also ensure utilities are fully compensated for their revenue requirements.

8.3. Facilitate competition

Stakeholders have argued that any attempt to place cost on default service should be thwarted as the increased default service prices are simply a ploy to allow competitive service providers to compete more effectively on price. This argument is similarly flawed. The lack of allocation of costs is contrary to all rational business accounting practices, is contrary to NARUC guidance on cost allocation and allows utilities to maintain market power in the residential and small commercial customer segments. Incumbent utilities' default service market dominance has been maintained because the cost to serve default service customers is being subsidized inappropriately by distribution rates. No rational or prudent business would price products or services without a full and appropriate allocation of costs included.

Further, if the cost allocation is done correctly, every dollar allocated to default service is similarly deducted from distribution costs. In other words, it is a cost reallocation, not a cost increase. On net, default customers will pay no more for bundled energy (electrons and delivery) than they would pay prior to the reallocation of costs. The premise of competing against "higher rates" is simply a false premise.

8.4. Utility profitability

Some utilities have argued that there is no reason to allocate costs to the default service business because they do not earn a return on the provision of default service. Regardless of the validity of that statement, it is not a reason to justify an allocation approach. A properly run widget manufacturer should allocate costs to profitable and unprofitable lines of business. In the absence of such an allocation, the unprofitable line of business might be viewed as profitable, resulting in decisions that would cause further financial harm to the overall widget company (i.e., lowering the retail price on what are already unprofitable products). These irrational pricing decisions are the exact decisions that the default service utilities have been making (default service prices are too low and distribution rates are too high). If both services were truly competitive, the distribution would be run out of business by its lower-priced competitors and the underpriced default service "successes" would bankrupt the company. However, the utilities are protected from these irrational behaviors by virtue of the distribution monopoly.

The four primary arguments used to support the status quo are weak, at best. A cost allocation mechanism that keeps distribution companies whole as customers migrate on and off of default service could and should be implemented at all utilities that provide default service. The cost allocation implementation should include a comprehensive review of all utility costs inclusive of rate base assets, and all expenses, including executive salaries, legal departments, rate departments, customer service departments and all other employees and expenses. A measurable portion of those costs should be appropriately allocated to default service in accordance with NARUC guidelines and consistent with NARUC policies and objectives.

9. Conclusion

Default service pricing in the majority of the competitive retail energy markets is fundamentally flawed and allows the incumbent utilities to maintain a stronghold over their legacy customers in the residential and small commercial markets. Consistent with NARUC guidance, an appropriate amount of costs to serve default service customers should be allocated to default service rates. This is a critical next step in creating more competitively neutral retail energy markets in the US. This one step will not create the perfect market, but it will remove a significant pricing advantage held by incumbent utilities. It will also remove a subsidy that forces competitive supply customers to pay distribution rates that benefit default service customers, and it will help create a market in which competitive suppliers are more willing to invest. At the same time, if implemented correctly, it keeps distribution utilities financially whole. It is a win-win-win solution benefitting all market participants.

Frank Lacey President and Founding Principal Electric Advisors Consulting, LLC. Mr. Lacey is an experienced energy industry leader who has worked for advanced energy firms or consultancies for 25 years. He has been engaged in transforming the electricity industry throughout his career. His focus has been aligning business strategy with regulatory outcomes – interpreting rules and regulations and modifying strategies to align with those changes or seeking rule changes to align with strategies. Frank launched Electric Advisors Consulting, LLC in 2015. His mission is to help advanced energy companies develop strategies to integrate into existing markets or modify regulations so that the markets will accommodate advanced technologies and business plans.

EXHIBIT FPL-5

A NEW LOOK FOR YOUR BGE BILL.

Organized. Colorful. Easy.

We've made your BGE bill simple and easy to understand thanks to customer feedback.

More organized. Detailed consumption data is easier to find.
More visually appealing. Simple, colorful graphics provide a quick overview.
More concise. Amount due, due date, and usage totals are always prominent.

Let's take a look around.

BGE
An Exelon Company

PAGE ONE

CURRENT CHARGES
- **GREEN** for electric
- **BLUE** for gas

  Tints distinguish between supply and delivery charges
- **DARK GRAY** for taxes and fees
- **GRAY** for other charges and credits (when applicable)

SUPPLIER CONTACT INFORMATION
(if other than BGE)

Refer to the choice ID when choosing an electric or gas supplier

PAYMENT STUB
Send in this portion with your check, or keep for your records when paying by other methods

CONTACT INFORMATION

CUSTOMER INFORMATION

BILL SUMMARY
- Issued date
- Payments received
- Outstanding balance
- Current billing period charges
- Late charge—applied if your bill is not paid by the due date

TOTAL AMOUNT DUE / DUE DATE

ACCOUNT NUMBER

BGE An Exelon Company

CONTACT US BGE.COM
Customer Service: 800.685.0123
800.735.2258 (TTY-TTD)
Correspondence: P.O. Box 1475 Baltimore, MD 21203

BGE ELECTRIC DELIVERY

ELECTRIC SUPPLY
BGE
Electric Choice ID: 0000012345

BGE GAS DELIVERY

GAS SUPPLY
Gas Choice ID: 1234500000

OTHER CHARGES AND CREDITS

See details on page 3

Bill Summary

John Q Customer
123 Anywhere St
Baltimore, MD 21204-0000
Account # 0000000000
Issued Date: June 11, 2016

Previous Balance	$66.99
Payments Received June 2, 2016	-$66.99
BGE Outstanding Balance	$0.00
Electric	$87.32
Gas	$23.11
Other charges and credits (See details)	-$12.50
Total amount due by July 6, 2016	$97.93

Payment received after July 6, 2016 will incur a late charge.

A late payment charge is applied to the unpaid balance of your BGE charges. The charge is up to 1.5% for the first month; additional charges will be assessed on unpaid balances past the first month, not to exceed 5%.

00000-0000-0-X00-x0-0000000 of 0000000-0000000-0000000

BGE An Exelon Company

Return only this portion with your check made payable to BGE. Please write your account number on your check.

Pay your bill online, by phone or by mail.

See reverse side for more info ▸

Account # 0000000000	
Total amount due by Jul 6, 2016	$97.93
Payment Amount $	.

John Q Customer
123 Anywhere St
Baltimore, MD 21204-0000

BGE
P.O. Box 13070
Philadelphia, PA 19101-3070

0000000000000000000000000000000000000000

PAGE TWO

ELECTRIC USAGE PROFILE
Compare your historical electric use

ELECTRIC METER READING DETAILS
- Rate schedule
- Billing period
- Current meter reading details and how much electricity you used

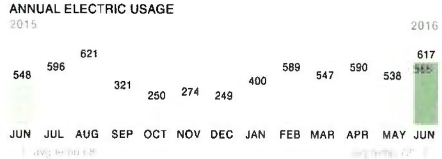
ELECTRIC DETAILS
- Electric supply charges
- Electric delivery charges
- Taxes and fees

BGE SUPPLY PRICE COMPARISON
Shows the price per kilowatt-hour you can use to compare prices among electric suppliers

PAYMENT OPTIONS
Other ways to pay your bill

Electric details

ANNUAL ELECTRIC USAGE



Residential - Schedule R
Billing Period: May 8, 2016 – Jun 9, 2016
Next Scheduled Reading: July 10, 2016 Days Billed: 31

Meter #0000012345 Read on Jun 9

Current Reading 3567 – Previous Reading 2950 = 617 kWh used

ELECTRIC SUPPLY				$55.43
BGE	617 kWh	x	.0898300	55.43
BGE ELECTRIC DELIVERY				$31.06
Customer Charge				7.50
EmPower MD Chg	617 kWh	x	.0048100	2.97
Distribution Chg	617 kWh	x	.0293700	18.12
RSP Chg/Misc Cr	617 kWh	x	.0038200	2.36
Dmd Res Chg/Cr	617 kWh	x	.0000100	.01
ERI Initiative Chg	617 kWh	x	.0001700	.10
TAXES & FEES				$.83
MD Universal Svc Prog				.36
Envir Srchg	617 kWh	x	.0001500	.09
Franchise Tax	617 kWh	x	.0006200	.38
TOTAL				$ 87.32

The RSP Charge on this bill includes a qualified rate stabilization charge of $0.00678 per kWh approved by the Maryland PSC that BGE is collecting as servicer on behalf of RSB BondCo LLC, which owns the qualified rate stabilization charge.

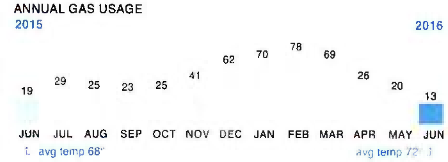
BGE SUPPLY PRICE COMPARISON INFORMATION

The current price for Standard Offer Service (SOS) electricity is 9.342 cents/kWh, effective through May 31, 2017. The price for SOS from June 1 through September 30, 2017, as well as the weighted average price through September 30, 2017, will be set in November 2016.

Federal Tax Identification # 00-0000000

Gas details

ANNUAL GAS USAGE



Residential - Schedule D
Billing Period: May 8, 2016 – Jun 9, 2016
Next Scheduled Reading: July 10, 2016 Days Billed: 31

Meter #1234500000 Read on Jun 9

Current Reading 2962 – Previous Reading 2950 = Units 12 x Therm Factor 1.063 = 13 therms used

GAS SUPPLY				$4.39
BGE	13 therms	x	.3376900	4.39
BGE GAS DELIVERY				$18.67
Customer Charge				13.00
STRIDE Charge				.47
EmPower MD Chg	13 therms	x	.0297000	.39
Distribution Chg	13 therms	x	.3702000	4.81
TAXES & FEES				$.05
Franchise Tax	13 therms	x	.0040200	.05
TOTAL				$23.11

IMPORTANT INFORMATION ABOUT YOUR BILL

- **Moving?** To stop or transfer service, contact BGE at least 3 business days prior to your move date. You are responsible for all service at your present address until you notify us.

Adj Annual Usage Ele 11,740 kWh Gas 712 therms

GAS USAGE PROFILE
Compare your historical gas use

GAS METER READING DETAILS
(shown only if you are supplied with natural gas)
- Rate schedule
- Billing period
- Current meter reading details and how much gas you used

GAS DETAILS
- Gas supply charges
- Gas delivery charges
- Taxes and fees

IMPORTANT INFORMATION
Additional information about your bill

Other ways to pay

Online
BGE.COM

In-person
America's Cash Express**
888.223.2274
Global Express**
800.989.6669

Pay-by-phone
Western Union Speed Pay**
888.232.0088

**Fee applies.

PAGE THREE

OTHER CHARGES AND CREDITS

- Including Smart Energy Rewards® when applicable

Electric and Gas Residential
Account # 0000000000
Issued Date: June 11, 2016

Other charges and credits

SMART ENERGY REWARDS/PEAK REWARDS				-$12.50
Energy Savings Day	kWh Saved		$/kWh	Credits
September 3, 2016	8.3	x	1.25	10.38
			Total	10.38
			Adjusted Total	12.50

Your total has been adjusted to your monthly PeakRewards guarantee of $25.00.
Visit **BGE.COM/SmartEnergyRewards** for energy savings tips.

TOTAL	-$12.50

ADDITIONAL PAGES

SMART ENERGY NEWS

Interesting information and news about BGE programs and services.