**BEFORE THE PUBLIC SERVICE COMMISSION**

**OF THE STATE OF GEORGIA**

**In the Matter of )**

**Georgia Power Company’s ) Docket No. 42516**

**2019 Base Rate Case )**

**DIRECT TESTIMONY OF JUSTIN R. BARNES ON BEHALF OF GEORGIA INTERFAITH POWER & LIGHT, SOUTHFACE ENERGY INSTITUTE, AND VOTE SOLAR**

**OCTOBER 17, 2019**

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# I. INTRODUCTION

### Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A. Justin R. Barnes. My business address is 1155 Kildaire Farm Rd., Suite 202, Cary, North Carolina, 27511. My current position is Director of Research with EQ Research LLC.

### Q. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A. I am submitting testimony on behalf of Georgia Interfaith Power & Light (“GIPL”), Southface Energy Institute (“Southface”), and Vote Solar (“VS”).

### Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE Georgia Public Service Commission (“the Commission”)?

A. No.

### Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND OCCUPATIONAL BACKGROUND.

A. I obtained a Bachelor of Science in Geography from the University of Oklahoma in Norman in 2003 and a Master of Science in Environmental Policy from Michigan Technological University in 2006. I was employed at the North Carolina Solar Center at N.C. State University for more than five years as a Policy Analyst and Senior Policy Analyst.[[1]](#footnote-1) During that time I worked on the *Database of State Incentives for Renewables and Efficiency (“DSIRE”)* project, and several other projects related to state renewable energy and energy efficiency policy. I joined EQ Research in 2013 as a Senior Analyst and became the Director of Research in 2015. In my current position, I coordinate and contribute to EQ Research’s various research projects for clients, assist in the oversight of EQ Research’s electric industry regulatory and general rate case tracking services, and perform customized research and analysis to fulfill client requests.

### Q. Please Summarize your Relevant experience as relates to this proceeding.

A. My professional career has been spent researching and analyzing numerous aspects of federal and state energy policy, spanning more than a decade. Throughout that time I have reviewed and evaluated trends in regulatory policy, including trends in rate design and utility regulation. For example, as part of my current duties overseeing EQ Research’s general rate case tracking service, I have reviewed dozens of general rate case applications, including the methods used by different utilities to develop cost of service studies and different rate designs, as well as the decisions made by regulators in those proceedings.

I have submitted testimony before utility regulatory commissions in Colorado, Hawaii, New Hampshire, New York, North Carolina, Oklahoma, South Carolina, Texas, and Utah, as well as the City Council of New Orleans, on various issues related to clean energy policy, rate design, and cost of service.[[2]](#footnote-2) These individual regulatory proceedings have involved a mix of general rate cases and other types of contested cases. My *curriculum vitae* is attached as Exhibit JRB-1. It contains summaries of the subject matter I have addressed in each of these proceedings.

### Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses the proposals made by the Georgia Power Company (“GPC” or “the Company”) to increase its residential basic service charge (“BSC” or “fixed charge”) and revise the residential BSC from a monthly charge to a daily charge.

### Q. What are your Recommendations to the Commission on GPC’s residential BSC Proposals?

A. I recommend that the Commission reject both the Company’s proposed BSC increase and the proposed shift from a monthly BSC to a daily BSC. Instead, I recommend that the Commission adopt a residential BSC of no more than $9.46/month, the amount that I have determined to be consistent with the Company’s residential customer-related costs, with an adjustment to reflect the principle of gradualism in ratemaking.

I also recommend that the Commission not accept the Company’s classification of a portion of distribution costs as customer-related for the purpose of cost allocation or rate design. Should the Commission decline to fully reject this aspect of the Company’s cost of service study, I recommend that it direct the Company to make changes to its methodology for identifying customer-related distribution costs to correct errors that I have identified.

# II. Proposed residential BSC Increase

## A. Summary of GPC’s Proposal

### Q. Please summarize the Company’s proposal for Setting the residential BSC.

A. The Company proposes to increase the stated residential BSC from the current rate of $10.00/month to $17.95/month. The proposal, in the context of the Company’s proposed three-year alternative rate plan (“ARP”), would phase the increase in over three years, starting at $14.90 in 2020 and rising to $16.95 in 2021 and $17.95 in 2022.[[3]](#footnote-3) In practice, because GPC employs a series of percentage-based bill riders, the effective residential BSC is higher. The current effective rate is roughly $12.75/month but would increase to $23.69/month under the proposed test year rates. Thus the nominal proposed increase is $7.95/month, while the effective proposed increase would be $10.94/month. Throughout my testimony I use the term “nominal” to refer to the tariffed residential BSC and the term “effective” to refer to the BSC as grossed up by percentage-based riders.

### Q. How is the Company’s proposed residential BSC derived?

A. The Company starts with the customer-related unit costs from its cost of service study, calculated at $24.36/month.[[4]](#footnote-4) I discuss how GPC arrives at this amount for customer-related costs in more detail later in my testimony, but observe here that GPC’s classification of a significant portion of the distribution system shared by multiple customers as customer-related is a prominent factor in the result. By “shared distribution system,” I am referring to infrastructure logged in FERC Accounts 364-368 pertaining to poles, overhead and underground conductors, underground conduit, and line transformers.

GPC presents the customer-related costs reduced for the revenue associated with several percentage-based riders as $20.87/month.[[5]](#footnote-5) The phased-in proposal increases the residential BSC in an amount sufficient to collect 80% of the annual increase under the ARP in 2020 and 2021, reaching a cap of $17.95/month in 2022.[[6]](#footnote-6)

### Q. You mention the percentage-based riders and their IMPACT on the effective monthly fixed charge that customers pay. Please clarify whether you are objecting to the design of those riders.

A. I mention the effects of those riders to illustrate the actual fixed charge amount that residential customers currently pay, or would pay under the Company’s proposals. I observe that these riders recover costs for environmental compliance (ECCR rider), nuclear construction (NCCR rider), demand-side management programs (DSM rider), and municipal franchise fees (MFF rider). None of the costs associated with these riders vary directly with the number of customers GPC serves. I am not objecting to the design of these riders per se, but the additive effect they have on the residential BSC should be considered when establishing a reasonable charge that is based on customer-related costs.

In particular, the ECCR rider and the NCCR rider are relatively large and both have already contributed to non-trivial increases in the effective residential BSC since GPC’s 2013 rate case. Based on the Company’s tariff compliance filings for the 2013 rate case and the present rider amounts, these riders have collectively resulted in BSC “creep” amounting to $0.375/month since March 2014. The Company has proposed a further increase in the ECCR rider in this proceeding that would increase the effective residential BSC by an additional $0.26/month in the first year of the ARP, or $0.41/month under proposed test year rates, even if the residential fixed charge remains at its present amount of $10.00/month.

## B. Good Ratemaking Policy and GPC’s Proposal

### Q. Please summarize the elements of good ratemaking practice.

A. Good ratemaking is an exercise in balancing a suite of goals. The oft-cited work of Dr. James Bonbright offers valuable guidance on the criteria that should be used in the development of a sound rate structure. Dr. Bonbright’s original work published in 1961 listed a set of eight ratemaking principles to consider. A 1988 re-issuance contains two additions and somewhat more descriptive language. The full text of the 1988 principles is as follows:[[7]](#footnote-7)

*Revenue-related attributes:*

1. Effectiveness in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality and safety.
2. Revenue stability and predictability, with a minimum of unexpected changes seriously adverse to utility companies.
3. Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers and with a sense of historical continuity. (Compare “The best tax is an old tax.”)

*Cost-related Attributes:*

1. Static efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
   1. in the control of the total amounts of service supplied by the company;
   2. in the control of the relative uses of alternative types of service (on peak versus off peak service, or higher quality versus lower quality service).
2. Reflection of all of the present and future private and social costs and benefits occasioned by a service’s provision (i.e., all internalities and externalities)
3. Fairness of the specific rates in the apportionment of total costs of service among the different ratepayers so as to avoid arbitrariness and capriciousness and to attain equity in three dimensions: (1) horizontal (i.e., equals treated equally); (2) vertical (i.e., unequals treated unequally); and (3) anonymous (i.e., no ratepayer’s demands can be diverted away uneconomically from an incumbent by a potential entrant).
4. Avoidance of “undue discrimination” in rate relationships so as to be, if possible, compensatory (i.e., subsidy free with no intercustomer burdens).
5. Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns.

*Practical-related Attributes:*

1. The related, “practical” attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.

The principles themselves are generally non-controversial. However, it is typically recognized that they are sometimes in conflict with one another and present a need for subjective judgments as to interpretation (e.g., the practical meaning of “stability”) and the relative weighting each aspect should carry. The need to achieve a balance is generally acknowledged but disagreements will almost always arise as to what that balance should look like.

### Q. How do these principles relate To the Company’s Cost of service study?

A. The principle role of the cost of service study is to serve Objective #6, which is reflected as the concept of cost causation. A cost of service study addresses other ratemaking aspects to some degree, such as economic efficiency and revenue sufficiency, but for the most part, its target is correct cost apportionment rather than design of rates themselves.

While cost of service studies present outputs that are superficially precise, in practice those results depend greatly on numerous assumptions. A cost of service study presents one version of cost causation and an alternative set of equally well-supported and justifiable judgments could produce very different results. In other words, cost of service studies provide guidance for cost allocation but are not determinative, and do not address many other ratemaking objectives from either the perspective of cost allocation or the specific design of rates.

### Q. How do these principles relate to rate Design, such as the proper setting of the residential BSC?

A. All of Bonbright’s principles are relevant to rate design in one way or another on both a broad level associated with overall rate structure and in the context of specific elements of rate structure such as the residential BSC.

### Q. Does Georgia Power’s residential BSC proposal achieve a good balance of sound ratemaking objectives?

A. No. The Company’s proposal uses its cost of service study in a deterministic fashion, a purpose for which it is ill-suited, and effectively ignores objectives of gradualism, economic efficiency, customer acceptability, and fairness. For instance, as I describe later in my testimony, the Company’s proposal does not reflect gradualism as practiced throughout the country in authorizing reasonable residential fixed charges. I note here that Commission staff raised similar concerns in the Company’s 2013 rate case, noting that GPC’s proposal for a $10.00/month residential BSC would result in a 33% increase in the charge over four years considering that the charge had already increased from $7.50/month to $9.00/month in the 2010 rate case.[[8]](#footnote-8)

Furthermore, the Company’s proposal is punitive to low usage customers generally, subjecting them to much larger bill increases than high usage customers on a percentage basis, an effect that is particularly harsh on low-income customers because they tend to have lower usage than the average customer. I present data supporting these assertions later in my testimony. Finally, it promotes wasteful use of service by discouraging energy efficiency and customer self-generation. With respect to this last issue, the proposal also conflicts with the Commission’s official policy recognizing energy efficiency as a priority resource.[[9]](#footnote-9)

### Q. Since you observed that interpretation of ratemaking principles can be subjective, how can the Commission evaluate whether the Company’s proposal reflects gradualism?

A. A national perspective on residential fixed charges and adopted increases provides an objective measure of how gradualism and consideration of other rate principles occurs in practice. Common statistical measures such as means and medians allow the identification of what is “typical”, accounting for the subjectivity involved and the fact that costs and other factors differ from utility to utility.

**Q. HOW DOES THE COMPANY’S PROPOSED RESIDENTIAL BASIC SERVICE CHARGE COMPARE TO THAT APPROVED BY REGULATORS IN OTHER STATES?**

A. The proposed residential BSC is highly atypical. The proposed charge would result in a nominal basic service charge that ranks 12th among a list of 172 investor-owned utilities (“IOUs”). The effective basic service charge as grossed up by percentage-based bill riders would rank 3rd. The amount of the nominal increase would be the largest adopted for any IOU during the last several years while the effective increase after rider gross ups would be still higher.

### Q. PLEASE SUMMARIZE the results of the research YOU conducted to support this ASSERTION.

A. Table 1 below presents comparisons between current fixed monthly charge averages among IOUs nationally and GPC’s current rate ($10.00/month) as well as proposed nominal rate ($17.95/month) and effective rate ($23.69). Table 2 presents comparisons of *increases* approved in rate cases filed during the last five years relative to the Company’s proposed nominal increase of $7.95/month and the effective increase of $10.94/month after gross-up for riders.

Table 1: National Comparison of Fixed Charges

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Basis of Comparison** | **Fixed Charge ($)** | **GPC Above Nominal ($)** | **GPC Above Effective ($)** | | **GPC Above Nominal (%)** | | **GPC Above Effective (%)** | |
| National Average Fixed Charge | $10.52 | $7.43 | $13.16 | | 70.6% | | 125.2% | |
| National Median Fixed Charge | $10.00 | $7.95 | $13.69 | | 79.5% | | 136.9% | |
|  |  |  | |  | |  | |
| GPC Proposed Nominal | $17.95 |  | |  | |  | |  | |
| GPC Proposed Effective | $23.69 |  | |  | |  | |  | |
| GPC Current Nominal | $10.00 |  | |  | |  | |  | |
| GPC Current Effective | $12.75 |  | |  | |  | |  | |

Table 2: National Average Fixed Charge Increases

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Basis of Comparison** | **Fixed Charge ($)** | **GPC Above Nominal ($)** | **GPC Above Effective ($)** | **GPC Above Nominal (%)** | **GPC Above Effective (%)** |
| National Average Increase ($) | $1.91 | $6.04 | $9.02 | 316.3% | 472.9% |
| National Median Increase ($) | $0.50 | $7.45 | $10.43 | 1490.0% | 2088.0% |
| National Average Increase (%) | 17.5% |  |  | 62.0% | 68.3% |
| National Median Increase (%) | 5.3% |  |  | 74.2% | 80.5% |
|  |  |  |  |  |  |
| GPC Nominal Increase ($) | $7.95 |  |  |  |  |
| GPC Effective Increase ($) | $10.94 |  |  |  |  |
| GPC Nominal Increase (%) | 79.5% |  |  |  |  |
| GPC Effective Increase (%) | 85.7% |  |  |  |  |

As shown in Tables 1 and 2, GPC’s proposed residential BSC is far outside the norm as reflected in both the monetary and percentage amounts by which it departs from national average and median charge amounts as well as adopted increases. For instance, the nominal fixed charge would be more than 70% higher than the national average and 80% higher than the national median and the proposed nominal increase is more than three times the average monetary increase and nearly 15 times the median increase. The effective rate and effective increase amounts depart even further from national norms.

### Q. Please describe the research you conducted to develop the data underlying these results?

A. I conducted a review of current residential customer charges for 172 IOUs in 49 states and the District of Columbia.[[10]](#footnote-10) The utilities in this survey encompass all major IOUs and nearly all smaller IOUs in each state, thus the survey presents a comprehensive national picture of residential fixed charges. I also conducted a review of adopted increases in residential customer charges for IOU general rate case applications filed since July 2014. A total of 190 general rate cases are represented in this sample, though the total number of utilities is lower because several utilities had multiple rate cases during this time frame. Consequently, the sample of adopted increases reflects these utilities more than once. Both datasets are current as of September 2019.

### Q. are the fixed charges imposed by electric MEMbership cooperatives in georgia a good point of comparison for evaluating the Company’s residential BSC?

A. No. It is an apples-to-oranges comparison. GPC’s comparison, such as the one that appears in Legg Direct Exhibit LTL-3, ignores the fact the electric membership cooperatives (EMCs or cooperatives) generally have higher fixed charges than IOUs in the same state. For instance, in South Carolina the average fixed charge among electric cooperatives is $21.16 while the fixed monthly charges of the regulated IOUs in South Carolina are $11.96, $11.78, and $9.00 for Duke Energy Carolinas, Duke Energy Progress, and Dominion South Carolina, respectively.[[11]](#footnote-11) Stated differently, the average cooperative fixed charge in South Carolina is 94% higher than the average IOU fixed charge of $10.91/month.

As I have previously described, GPC’s current effective residential BSC is $12.75/month. This is actually closer to the Georgia EMC average of $23.17/month than is the case for South Carolina’s IOUs and cooperatives, as the Georgia EMC premium over the effective GPC rate is only 82%.

### q. For what reasons might the residential FIXED CHARGES Of ELECTRIC cooperatives typically be higher than those of IOUs?

A. Electric cooperatives differ from regulated IOUs in many ways that may influence rate structure. Among those differences are the following:

* Cooperatives tend to have more rural service territories and fewer customers, which may cause some customer-related costs such as meter reading and billing to be higher than those with a larger customer base and more urbanized territory.
* The cooperative customer mix tends to be heavily weighted towards residential customers, which makes residential revenue stability of greater concern.
* Unlike the Company, EMCs in Georgia are not subject to integrated resource planning requirements and the Commission’s determination that energy efficiency should be prioritized as a resource.
* Ratemaking among cooperatives is frequently opaque and may suffer from inadequate review of the cost of service studies that form the basis for determining fixed charges.

### Q. what would be a better benchmark for evaluating GPC’s proposed residential BSC?

A. The rates charged by other IOUs, as well as the pattern of increases in those rates, provide a better comparison. Furthermore, since the Commission has determined that the Company should pursue energy efficiency as a priority resource, a subset of IOUs in states that also prioritize energy efficiency is appropriate.

### Q. Please explain How fixed charges relate to Consumer incentives for Energy Efficiency.

A. Increasing fixed charges while also attempting to produce higher levels of energy efficiency savings is like driving with one foot on the gas and one foot on the brakes. Fixed charges cannot be avoided by reducing energy consumption or demand for electricity. If one assumes the same total revenue requirement for a class of customers, a rate design weighted towards fixed charges produces less of a customer incentive to pursue energy efficiency because collecting a larger amount of revenue via fixed charges lowers the amount to be collected from other charges. That produces lower rates for those other charges, reducing the amount of cost savings that a customer can achieve by modifying their energy usage patterns or making investments in more efficient equipment. The magnitude of the effect is determined by consumer sensitivity to price changes, which is typically referred to as price elasticity.

### Q. Please Further explain the concept OF price elasticity and how it relates to energy efficiency.

A. Price elasticity, for electricity or any other product or service, measures how changes in price influence the purchasing behavior of consumers. The definition used by the Electric Power Research Institute (“EPRI”) in the context of electricity states “price elasticity of demand is a measure of how price changes influence electricity use.”[[12]](#footnote-12) I believe that this is a reasonable definition for the term.

Price elasticity is typically reflected as a fraction or ratio, most often a negative number (*e.g.*, -0.5). A negative elasticity number indicates that increases in price are associated with declining consumption or use. Conversely, it indicates that decreases in price produce greater consumption or use. Not surprisingly, most products or services, including electricity, exhibit negative price elasticity. A hypothetical elasticity of -0.5 indicates that a 10% increase in price produces a 5% decrease in consumption. Likewise, it indicates that a 10% reduction in electricity prices would produce a 5% increase in consumption.

Price elasticity can also be differentiated by the time horizon being considered. Short-run price elasticity tends to be lower than long-run price elasticity because, over longer time horizons, consumers become aware of more alternatives and those alternatives become more attractive. For example, replacing an aging appliance with a more efficient model is more attractive than replacing a new one.

Therefore, when fixed charges cause a reduction in the volumetric rates that a customer would otherwise pay, they cause an increase in electricity consumption relative to what it would be with a lower fixed charge and higher volumetric rate. This effect increases over time because electricity demand is more elastic in the long run than the short run.

### Q. How does this effect translate to decisions on setting fixed charges?

A. IOUs in states that place a high priority on energy efficiency tend to have lower residential fixed charges because regulators recognize that potential customer savings are a critical element to consumer behavior and consumer investments in energy efficiency. Implicit in this recognition is consideration of the fact that lower customer savings through avoided electricity costs may necessitate higher incentives in order to achieve the same results (*i.e.,* higher program costs).

### q. How does the Company’s proposed residential BSC compare to those chargeD by IOUs in states where Energy efficiency is prioritized as a Resource?

A. The Company’s proposed charge is well in excess of those authorized in states that place a high priority on energy efficiency. Table 3 shows the average and median fixed charges for states ranked highly by the American Council for an Energy-Efficient Economy (“ACEEE”). The states were selected based on ACEEE’s 2019 Energy Efficiency Scorecard rankings for utility sector energy efficiency policies.[[13]](#footnote-13) Each IOU in those states was selected for the table.

Table 3: Fixed Charges in Highly Ranked EE States

|  |  |  |
| --- | --- | --- |
| **ACEEE State Rank** | **Average Charge** | **Median Charge** |
| **Top 5** | $6.13 | $6.56 |
| **Top 10** | $9.50 | $8.00 |
| **Top 15** | $9.85 | $9.00 |
| **Top 20** | $10.78 | $10.68 |
| **Top 25** | $10.01 | $9.00 |

GPC’s current nominal residential BSC is comparable to the higher end of the scale, though the current effective residential BSC is well above the amounts for utilities in states lower in the rankings. The proposed increase in the residential BSC would place GPC even further out of step.

### Q. How would GPC’s residential BSC Proposal be expected to affect residential ELECTRICITY consumption?

A. Based on a -0.3 short-run (1-5 years) price elasticity value reported by EPRI from a survey of relevant literature,[[14]](#footnote-14) the Company’s proposal would cause residential sales to increase by 2.12% if the calculation is based on the nominal fixed charge increase, or 2.83% if based on the effective fixed charge increase. This equates to an annual sales increase of roughly 558,000 MWh at the lower end and 746,000 MWh at the upper end. These amounts exceed the roughly 394,000 MWh in system-wide savings produced by the Company’s energy efficiency programs in 2018.[[15]](#footnote-15)

The Company’s proposal would effectively undo more than a year’s worth of savings achieved by energy efficiency programs by a healthy margin even when only considering short-run elasticity. EPRI reports a long-run elasticity range of -0.7 to -1.4 with a mean value of -0.9. Thus in the long run the lost savings could be several times higher.

### Q. How would the Company’s residential BSC proposal affect customers with different levels of electricity usage?

A. The average electricity usage for a customer class establishes an indifference benchmark defining whether a customer in that class prefers fixed charges or volumetric charges from a cost standpoint. Assuming a set amount of revenue is being collected, customers with lower-than-average levels of electricity usage are adversely affected by fixed charge increases while those with higher-than-average usage are made better off.

The Company presented some limited information displaying this effect in Exhibit LTL-4 for the 2020 ARP rate year, with a $14.90/month residential BSC. I present the results of the Company’s analysis in Table 3 in terms of the percentage bill increase for customers with different levels of usage.

Table 4: Customer Bill Impacts by Usage Tranche

|  |  |  |
| --- | --- | --- |
| **Customer Type** | **Monthly Use (kWh)** | **% Bill Inc.** |
| Low | 673 | 10.07% |
| Typical | 1,000 | 7.93% |
| High | 1,837 | 5.87% |

What this limited analysis does not clearly show is that the further a customer is from the average, the greater the adverse impact (or benefit) will be. Additionally, Georgia Power’s analysis only reflects changes in 2020 under the proposed ARP, which does not reflect the full amount of the fixed charge increase that GPC proposes. Table 5 presents an expanded view using a larger set of breakpoints. The middle column shows bill impacts at test period rates, which include the full amount of the proposed increase in the residential BSC to $17.95/month. The column furthest to the right shows the distribution of bill impacts if the residential BSC remained at $10.00/month and the volumetric rates were increased by a uniform amount sufficient to raise the same overall revenue. While I understand the GPC has proposed to continue the ARP framework, I use the test period rates because they are known in reference to a $17.95/month residential BSC. The breakpoints were selected to illustrate the relative bill impacts on the lowest usage customers and the highest usage customers in particular without making the table unmanageably large.

Table 5: Bill Impacts at Test Period Rates

|  |  |  |
| --- | --- | --- |
| **Average Monthly Usage (kWh)** | **Bill Impact (%) at Test Period Rates** | **Bill Impact (%) With $10 BSC** |
| 100 | 44.80% | 3.65% |
| 200 | 29.05% | 3.69% |
| 300 | 20.72% | 3.71% |
| 400 | 15.57% | 3.72% |
| 500 | 12.08% | 3.73% |
| 673 | 7.75% | 3.47% |
| 800 | 5.44% | 3.17% |
| 1,000 | 3.15% | 2.99% |
| 1,200 | 1.59% | 2.86% |
| 1,500 | -0.14% | 2.54% |
| 1,837 | -1.30% | 2.46% |
| 2,000 | -1.72% | 2.42% |
| 2,500 | -2.68% | 2.35% |

As shown in Table 5, the Company’s test period rates proposal would result in extraordinary bill increases to the lowest usage customers, at more than 20% or more for customers with monthly usage of 300 kWh or less, while the highest usage customers would actually see bill reductions. By contrast, a $10.00/month residential BSC produces much more evenly distributed bill impacts across the customer usage spectrum.

### Q. Would the Company’s residential BSC Proposal disproportionately impact Low-Income customers?

A. Yes. The Company states that it does not collect income data directly from customers, but it was able to provide data mapping usage to income level based on a third-party dataset.[[16]](#footnote-16) This data shows that low-income customers, defined in this case as customers with annual household incomes of $20,000 or less, tend to use less energy on average than the average residential customer. As a consequence, a disproportionate percentage of those customers are made worse off by fixed charges relative to volumetric charges that raise the same amount of revenue.

More specifically, 2013 usage data show that low-income customers averaged 11,477 kWh of consumption annually while the average residential customer used 12,789 kWh annually. Stated another way, low-income customers averaged about 10% less than the broader residential population as a whole. This actually understates the difference between low-income customers and those with annual incomes above $20,000 because low-income customers are a part of the full population. Their relatively lower usage lowers the average for the entire class.[[17]](#footnote-17)

Another way to evaluate the impacts on low-income customers is to look at the percentage of low-income customers that fall below the “indifference” threshold established by class average usage. Based on the same data used to generate the low-income and total residential population averages, 64.3% of low-income customers had usage below the indifference threshold and are therefore made worse off by fixed charges relative to volumetric charges. This is significantly higher than the percentage for the residential population as a whole, which is 57.4%. Furthermore, of customers with incomes above $20,000 annually, only 56% had annual usage below the indifference threshold.

This is the very definition of disproportionate impact. First, a larger percentage of low-income customers are averse to fixed charge increases than other customers. Second, greater percentages of low-income customers are on the lowest end of the usage spectrum – the end that experiences the greatest adverse effect. For instance, in the 2013 data a reference breakpoint of 9,000 kWh of annual usage (750 kWh/month) captures 41.9% of low-income customers while it only captures 33.3% of other customers. Likewise a breakpoint of 6,000 kWh of annual usage (500 kWh/month) captures 22% of low-income customers, while it only captures 16.3% of other customers.

Table 6 below is a variation on Table 5. It shows percentage bill impacts based on usage, but also shows where low-income customers fall relative to the breakpoints based on a July 2017-June 2018 dataset provided by the Company.[[18]](#footnote-18)

Table 6: Distribution of Rate Impacts on Low-Income Customers

|  |  |  |  |
| --- | --- | --- | --- |
| **Average Month Usage (kWh)** | **Cumulative % of Low-Income Customers Below** | **Bill Impact (%) at Test Period Rates** | **Bill Impact (%) With $10 BSC** |
| 100 | 1.81% | 44.80% | 3.65% |
| 200 | 3.72% | 29.05% | 3.69% |
| 300 | 6.62% | 20.72% | 3.71% |
| 400 | 11.20% | 15.57% | 3.72% |
| 500 | 17.32% | 12.08% | 3.73% |
| 673 | 30.36% | 7.75% | 3.47% |
| 800 | 40.49% | 5.44% | 3.17% |
| 1,000 | 55.55% | 3.15% | 2.99% |
| 1,200 | 68.42% | 1.59% | 2.86% |
| 1,500 | 82.52% | -0.14% | 2.54% |
| 1,837 | 91.57% | -1.30% | 2.46% |
| 2,000 | 94.19% | -1.72% | 2.42% |
| 2,500 | 97.72% | -2.68% | 2.35% |

Roughly 55.6% of low-income customers fall below the Company’s “average” customer benchmark of 1,000 kWh per month, which defines the approximate indifference threshold to fixed charges.[[19]](#footnote-19) Moreover, 17.3% of low-income customers average less than 500 kWh of usage monthly and would experience bill increases greater than 12%. The bill impact for those same customers under a $10.00/month BSC scenario is substantially lower, at 3.73%.

## C. Customer-Related Costs, Cost of Service, and Fixed Charges

### q. How does the Company arrive at the $24.36/month amount for residential customer-related Costs?

A. The Company’s calculated customer-related unit cost is the aggregate of:

* Customer-specific costs such as meters, service drops, billing, and collections.
* A portion of costs associated with the shared distribution system, under which a percentage of costs associated with plant investment and operation and management (“O&M”) expenses for poles, conductors, and line transformers are considered customer-related. The plant portion is comprised of FERC Accounts 364-368.
* A portion of general and administrative plant and O&M expenses, which receive a customer-related component based on dynamic allocators tied to other cost categories (e.g., total revenue, total net distribution plant).

Allocators for expenses generally follow the associated plant, such that line transformer O&M expenses are assigned the same customer-related percentage as the underlying plant.

### Q. How does the Company determine the portion of the shared distribution System that should be considered Customer-related?

A. Company Witness Vogt calls the underlying conceptual framework the Minimum Distribution System (“MDS”), which he goes on to describe as representing the portion of the system necessary to serve customers “independent of customers’ load requirements.” [[20]](#footnote-20) The Company uses a zero-intercept analysis, sometimes also referred to as a minimum-intercept analysis, to determine the customer-related portion.[[21]](#footnote-21)

A zero-intercept analysis involves a regression analysis to determine the relationship between equipment cost and equipment size. This is used to plot a curve that intercepts the Y-axis at a point that, in theory, represents the cost of equipment with a zero “size”. In other words, it is supposed to represent the cost of a piece of equipment that cannot support any demand. From here, this cost is applied across all plant in the applicable account to show the cost of a system composed entirely of equipment that is not capable of supporting any demand.[[22]](#footnote-22) The demand-related portion of the distribution system is defined as the remainder after customer-related costs have been subtracted from the total.

### q. How does the Company justify the classification of some portions of the shared distribution system as customer-related?

A. Company Witness Vogt relies on the fact that what he refers to as the “MDS Methodology” is described in the National Association of Regulatory Utility Commissioners (“NARUC”) Electric Utility Allocation Manual (“NARUC Manual”). He also states that the method is “commonly used” by other utilities, citing several examples, and states that the Company has used a MDS analysis in its cost of service studies for decades.[[23]](#footnote-23)

### Q. Is the Company’s method reasonable for the purpose of cost allocation or Rate Design?

A. No. For the reasons I discuss at length in this section of my testimony, the Commission should not rely on the Company’s classification of customer-related costs for the purposes of cost allocation or rate design. Should the Commission accept the MDS concept for the purpose of cost allocation, it should not utilize the resulting customer-related unit cost as the basis for rate design. Furthermore, for the purpose of cost allocation it should direct GPC to cure the deficiencies I identify in the Company’s analysis.

### Q. How do you respond to Witness Vogt’s reference to the NARUC Manual In justifying the Company’s use of the mDS Method?

A. There are two details of critical importance that Witness Vogt omits to mention regarding the NARUC Manual. First, the NARUC Manual as indicated by its title, addresses only cost allocation. It does not purport to address rate design based on the results of embedded cost studies. Second, the NARUC Manual refers to the zero-intercept method, which it terms the minimum-intercept method, as *one* method of classifying distribution costs, but it does not endorse any method in particular—as conceded by Company Witness Vogt on cross examination (Tr. at 629:9-10).[[24]](#footnote-24) The preface expressly states, regarding the overall objectives of the document, as follows:

The writing style should be non-judgmental, not advocating any one particular method, but trying to include all currently used methods with pros and cons.[[25]](#footnote-25)

Furthermore, the document includes statements advising readers of methodological concerns present with the Zero-Intercept Method and highlighting that the issue of distribution cost classification is in no way settled:

The minimum-intercept method can sometimes produce statistically unreliable results.[[26]](#footnote-26)

The major issue in establishing the marginal cost of the distribution system is the determination of *what costs, if any, should be classified as customer related*, rather than demand and energy related. *The issue is a carry-over of the unresolved argument in embedded cost studies* with the added query of whether the distribution costs usually identified as customer related are, in fact, marginal.[[27]](#footnote-27)

### Q. Please further explain the “unresolved argument” regarding the classification of distribution costs.

A. The concept of a Minimum Distribution System, or MDS, is based on the premise that customers will pay to connect to the grid even if they do not intend to use any electricity. What the concept ignores is that a customer that has no demand for electricity would have no need to be connected to the distribution system in the first place. In other words, a zero- or minimum-demand customer of the type represented by the zero-intercept method or other MDS variants simply does not exist, which leads many analysts to conclude that distribution costs are caused by demand and customer density, not by the mere presence of a customer.

On a deeper level, taken to its furthest extent, the premise underlying the MDS concept effectively assumes that any distribution cost not proven to fall into another category must be customer-related. Dr. James Bonbright discusses this line of thinking in his seminal work *Principles in Public Utility Rates*. Dr. Bonbright acknowledges that one could devise a so-called minimum system, but dismisses the notion that the costs of that system are customer-related, referring to them as “unallocable”.

What this last-named cost imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). *Indeed, if the company’s entire service area stays fixed, an increase in the number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system* ….

But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs ... while it is also denied a place among the customer costs ... to which cost function does it then belong? The only defensible answer, in my opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs .... But the fully-distributed cost analyst dare not avail himself of this solution, since they are prisoners of his own assumption that “the sum of the parts is equal to the whole.” *He is therefore under impelling pressure to fudge his cost apportionments by using the category of customer costs as a dumping ground for costs that he cannot plausibly impute to any of their other cost categories*.[[28]](#footnote-28)

### Q. what are the implicatons of the hypothetical minimum distribution system having the ability to support non-zero customer loads?

A. It causes demand to be double-counted. A given class receives an allocation based on the minimum system on a per-customer basis, but because that minimum system has some level of load-carrying capability, it contains demand-related costs. That same class is then allocated the remaining distribution costs based on their full demands. This tends to have disproportionately large impacts on residential classes because those classes typically have the largest number of customers, and are allocated a comparatively larger amount of customer-related costs.

Witness Vogt’s Zero-Intercept Method purports to address this issue by identifying a theoretical no-load system cost. However, in practice the results of such an analysis are highly dependent on the accompanying assumptions (e.g., equipment sizes used in the regression analysis) and as the NARUC Manual notes, the method is vulnerable to producing statistically unreliable results. Later in my testimony, I discuss several specific shortcomings of the Company’s methodology that speak to its unreliability even if one accepts the MDS concept.

### Q. Can you point to any practical examples that speak to the unreasonableness of the MDS Framework?

A. Yes. One easily understood example is for a customer with multiple meters, which is common for agricultural customers. In addition to the multiple meters, such a customer may have multiple service drops and possibly cause additional billing expenses (e.g., separate bills). That customer still takes service from the same delivery infrastructure that would exist if only a single meter was present, yet the customer pays multiple BSCs, effectively paying twice for the same service rather than only the incremental costs associated with a second meter and service drop.

At a larger scale, consider a town with 100 small customers served by a single primary line, relative to a load of equivalent size comprised of one or two large customers that is also served by an identical primary line. The small customers that comprise one load center end up paying 50 or 100 times the amounts paid by the one or two large customers for identical infrastructure. The same scenario is present for customers in multi-family housing. For instance, an industrial building that transitions to multi-unit housing may use the same delivery infrastructure that was already present for the industrial load (i.e., cause no additional costs) but the residents would pay many multiples of the “connection” charge levied on the former industrial customer.

### Q. Should the Commission accept Witness Vogt’s assertion that the MDS is “Commonly Used” by other utilities as evidence that it is broadly endorsed as the correct approach to distibution cost classification?

A. No. The notion that any portion of shared distribution plant should be classified as customer-related has been rejected in numerous states throughout the country. In fact, upon its publication the NARUC Manual was criticized for failing to adequately represent the commonly accepted Basic Customer Method of classifying customer-related costs. The Basic Customer Method classifies all elements of the shared distribution system as demand-related and limits the customer-related classification to meters, service drops, meter reading, and billing.

Earlier drafts of the NARUC Manual and related discussions included the Basic Customer Method in addition to MDS methodologies as a method for defining customer-related costs. The Basic Customer Method was apparently removed from the final version, eliciting concerns by least one state regulatory agency. Exhibit JRB-2 contains a letter from the Washington Utilities and Transportation Commission (“UTC”) voicing the UTC’s concerns about the omission of the Basic Customer Method from the NARUC Manual. Among other things, the letter notes that UTC staff believes it to be the most common approach taken by regulators throughout the country, citing Arizona, Iowa, and Illinois as states that have explicitly rejected the MDS framework.

### Q. Have other states also rejected the use of a MDS Framework in cost of service studies or for establishing customer charges?

A. Yes. In 2015 legislators in Connecticut directed the Public Utilities Regulatory Authority (“PURA”) to utilize the Basic Customer Method for the purpose of establishing a maximum residential customer charge.[[29]](#footnote-29) Likewise, in 2018 regulators in Colorado directed Black Hills Energy to eliminate the Minimum-Intercept Method entirely from its cost of service study in the utility’s most recent general rate case.[[30]](#footnote-30) Other states where the MDS concept has been expressly rejected for use in cost allocation or for the purpose of establishing customer charges include South Carolina[[31]](#footnote-31), Texas[[32]](#footnote-32), and California[[33]](#footnote-33). Finally, based on cost of service studies that I have reviewed, I am also aware that the MDS concept is not employed in cost of service studies by Public Service New Mexico, Rocky Mountain Power in Utah, the Appalachian Power Company in West Virginia, Pepco or Baltimore Gas & Electric in Maryland, Entergy New Orleans, and Entergy Arkansas.

### Q. Are there instances where the MDS Concept is used as part of cost of service evaluation but not for the purpose of BSCs?

A. Yes. Unit costs derived from a cost of service study are not typically translated directly to rates. As I have previously observed, this stems in part from a general acceptance that cost of service studies are best viewed as a guide rather than as a determinant of rates. Embedded cost studies in particular are more useful for determining the amount of revenue to be collected, not how to collect it. This is because marginal costs, rather than embedded costs, are the proper basis for developing economically efficient price signals. Furthermore, embedded cost studies do not account for the negative public policy impacts of the result. These negative impacts most notably include the departure from economic efficiency in rates and the dilution of customer incentives to use less energy and thereby contribute to producing long-term system cost savings.

The upshot is that even if a utility includes a MDS assumption in its cost of service study, it would be highly unusual for regulators to set residential BSCs at the customer unit cost indicated by that study. Were that the case, the national picture of residential BSCs I presented previously would look much different. Instead, those actual charges stem from decisions balancing the competing objectives of ratemaking and, in many cases, the use of the Basic Customer Method to arrive at reasonable BSCs. Research conducted for NARUC concluded that the Basic Customer Method is in fact the most common method, observing that it is the general approach used in more than thirty states.[[34]](#footnote-34)

### Q. Has a distinction between the use of the MDS in the Company’s cost of Service study and its use in rate design been raised in the past in Georgia?

A. Yes. In the Company’s 2013 rate case Commission staff accepted the Company’s allocation of distribution costs as reasonable.[[35]](#footnote-35) At the same time, Commission staff proposed setting the residential BSC based on the Basic Customer Method, which was referred to as the Direct Customer Cost method. This is reflected in the following testimony by staff in the 2013 rate case:

Customer costs should only reflect those costs that are required to connect a new customer and maintain that customer’s account. The approach that I use and which is widely-used in the industry is often referred to as a “Direct Customer Cost” analysis.[[36]](#footnote-36)

Staff’s derivation of the residential BSC included only meter and services plant, O&M costs for meters and customer installations, meter reading, and customer accounts and collections, plus a small adder for uncollectables.[[37]](#footnote-37) Such a derivation is akin to the “marginal cost” of adding new customers and consequently providing an economically efficient price signal to customers.

## D. GPC’s Zero-Intercept Study

### Q. Are there any differences in the Company’s Minimum system Study relative to its 2013 Rate Case?

A. I do not possess a copy of the Company’s 2013 zero-intercept study, or its equivalent. However, I have reviewed the results that the analysis produces in terms of the percentage of shared distribution plant classified as customer-related has increased dramatically. These amounts can be calculated from the cost of service study outputs, though the cost of service study outputs do not show how those customer-related percentage amounts were determined.

The 2019 study produces a 46.9% customer-related component in aggregate for FERC Accounts 364-368.[[38]](#footnote-38) The 2013 study produced a customer-related percentage of 26.5%.[[39]](#footnote-39) On the individual FERC account level, the customer-related percentage for FERC Account 365 pertaining to overhead conductors increased from 31.2% to 56.5%, while FERC Account 368 pertaining to line transformers increased from 24.7% to 90.2%. The large increase in the customer-related percentage is almost exclusively attributable to secondary level line transformers, which went from 26% to 99% customer-related.[[40]](#footnote-40)

### Q. Does the Company offer any Explanation for why the 2013 results differ so greatly from the 2019 results?

A. For the line transformer component Company Witness Vogt stated that the large increase is associated with differences in cost escalators used for pad-mounted secondary line transformers rather than any change in methodology (Tr. at 637: 6-21 and 640:20-24). His explanation is somewhat jumbled, but based on how cost escalators are used in the Company’s analysis, he seems to be saying that GPC’s costs for pad-mounted transformers escalated at a higher rate than the Handy Whitman index, which is used to trend GPC’s historic booked costs for pad-mounted transformers to current construction costs.

### Q. Does Witness Vogt’s explanation make sense?

A. It could, but only if GPC’s costs for pad-mounted line transformers have increased dramatically while industry-wide costs have not. The Handy Whitman index produces a multiplier of 1.1172 for pad-mounted line transformers, meaning that booked costs for this equipment are multiplied by that amount to produce a current construction cost.[[41]](#footnote-41) This “current” cost is the denominator in determining the customer-related percentage. The numerator is the zero-intercept cost multiplied by the number of pad-mounted line transformers.

The only way for the customer-related percentage of pad-mounted line transformers to increase by a large amount is if the zero-intercept cost also increased by a large amount. It would have to be several times higher in 2019 than 2013 to produce such a result. The problem with accepting this possibility is that the Handy Whitman index tells a much different story. It tells us that industry costs for pad-mounted line transformers have only increased by 11.72% not by several times.

In fact, if one applies the Handy Whitman escalator to the Company’s actual booked costs for different sizes of line transformers, the resulting “current” costs are in many cases much lower than those used to derive the zero-intercept and in some cases well below the zero-intercept itself. For instance, for single-phase pad-mounted line transformers, the Company’s zero-intercept amount is $3,653.40 and the cost for a 25 KVA line transformer used in this portion of the analysis is $4,405.[[42]](#footnote-42) Yet, the Company’s plant investment report shows an average actual cost of $1,182 for 25 KVA single-phase pad-mounted line transformers, which translates to $1,321 after applying the Handy Whitman escalator.[[43]](#footnote-43)

### Q. How Specifically does this affect the Company’s customer-related percentage for secondary Line transformers?

A. The Company’s analysis produces customer-related percentages of 219.3% and 199.3% for single-phase and three-phase transformers, respectively. This means that the Company’s zero-intercept study indicates that there is more than twice as much customer-related plant for pad-mounted line transformers *as there is total pad-mounted line transformer plant on the entire GPC system*. The manner in which these amounts are translated to dollar amounts of total customer-related plant allows these overages to effectively offset much lower customer-related percentages for overhead transformers, leading to the roughly 99% customer-related figure for secondary line transformers.

This anomaly is the kind of “statistically unreliable” result that the NARUC Manual identifies as possible under the zero-intercept method.[[44]](#footnote-44) Yet rather than reviewing the underlying data and assumptions to identify the reasons for the anomaly as the NARUC Manual recommends, the Company simply accepted it and allowed it to flow through to the results of the study.

### Q. Have you identified any issues with the Company’s methodology with respect to Overhead conductors in FERC Account 365?

A. Yes. For FERC Account 365 the Company hard-wired a large portion of the plant account composed of accessory equipment such as reclosers, switches, fuses, etc. (i.e., not the conductors themselves) as 100% customer-related. I cannot say whether this is a methodological change, but the Company’s method is inconsistent with the guidance provided in the NARUC Manual for addressing accessory equipment. The NARUC Manual expressly specifies that the customer-related portion of this type of equipment be assigned based on the results of the analysis for conductors.[[45]](#footnote-45) In this case the customer-related portion would be 43.9% rather than the 100% amount used by GPC. The NARUC Manual’s treatment is logical because the accessory equipment would not exist but for the existence of the conductors themselves. This is similar to how cost of service studies address O&M expenses, where expenses follow the associated plant. If the Company wishes to rely on the NARUC Manual to justify its cost allocation method, it should also adhere to the associated instructions for implementing the analysis.

### q. Are either of these methods appropriate for conducting a minimum intercept study?

A. No. I emphasize that I do not support the classification of any shared distribution plant as customer-related. Moreover, even if the way the Company conducted its analysis has not changed relative to its 2013 analysis, both aspects are unsound and produce unreliable results. Should the Commission accept the underlying MDS conceptual framework, it should not accept these specific elements of the Company’s methodology. With respect to secondary line transformers, the Company’s method produces physically impossible results. Clearly, a component of the system cannot be more than 100% customer-related. Furthermore, the end result, where 99% of secondary line transformer costs are deemed customer-related, implies that: (1) the secondary line transformers that serve virtually all of the load on the Company’s system in fact have no load-serving capability, and (2) that customer loads are not a driver of transformer sizing. Neither implication is true in practice.

### Q. Do you have any other concerns about the information the Company presents in its Zero-intercept study?

A. Yes. The Company stated that the results are reproducible using the data inputs provided as part of the study. However, it is not immediately clear how this could be done because certain foundational values, the costs for differently sized equipment used to perform the statistical regression, are hard coded into the associated spreadsheet. In other words the zero-intercept costs themselves that underpin the analysis do not appear to be reproducible through any readily ascertainable means based on the accompanying accounting data. This prevents a complete evaluation of the Company’s method, including the reasons why it produces such aberrant results for pad-mounted line transformers.

### Q. What Changes do you recommend be made to the Company’s zero-intercept analysis if the Commission accepts the MDS framework?

A. First, the Company’s zero-intercept study should be modified to utilize the methodology for accessory conductor plant in FERC Account 365 described in the NARUC Manual. This would reduce the customer-related portion of FERC Account 365 from 56.5% to 43.9%. Second, the study should be modified to exclude the erroneous results associated with pad-mounted transformers in FERC Account 368. I recommend that customer-related plant for secondary level pad-mounted line transformers be recalculated based on the results for secondary level overhead line transformers. This produces customer-related percentages of 45.4% for all secondary single-phase transformers and 4.4% for all secondary three-phase transformers.

## E. A Reasonable Residential BSC

### Q. What approach do you recommend the Commission use for determining a reasonable residential BSC?

A. I recommend that the Commission use the Basic Customer Method because it reliably avoids any double-counting of demand, is far simpler to execute, is not vulnerable to being biased by subjective assumptions, and is more broadly accepted as an appropriate mechanism. Furthermore, it reduces the downstream effects that classifying any portion of shared distribution system has on other dynamic allocators that derive in part from how distribution plant is classified. This avoids rendering the customer costs category “a dumping ground” for unallocable costs that Dr. Bonbright cautions against.

### Q. What result does the basic Customer Method analysis produce for the residential BSC?

A. The Basic Customer Method produces a monthly residential customer cost of $8.92/month. This value is based on the same framework used by Commission staff in the Company’s 2013 rate case, updated to reflect the current cost of service study, the Company’s requested weighted average cost of capital (7.93%), and the current effective tax rate (25.47%). This compares favorably with the current nominal residential BSC of $10.00/month, and the effective charge of $12.75/month as grossed-up by percentage-based riders at their current amounts, or $13.02/month if the rider gross-up assumes the rider amounts the Company has requested in this case. The $8.92/month customer-related cost I have calculated would gross up to $11.62/month at the Company’s proposed percentage-based surcharges.

### Q. What is your recommendation for a reasonable residential BSC?

A. I recommend that the residential BSC be reduced to $9.46/month, the midpoint between the current nominal residential BSC and amount arrived at using the Basic Customer Method. This would produce an effective customer charge of roughly $12.35/month after gross-up for the Company’s proposed percentage-based rider surcharges. I use the midpoint between the current residential BSC and Basic Customer Method derived amount in the interest of gradualism, though a residential BSC of $8.92/month or even lower would also be reasonable in light of the Commission’s policy of prioritizing energy efficiency as a resource. The incrementally larger reduction would be minimally disruptive to residential customers given the relatively small amount.

I further recommend that should the Commission use an approach different than the Basic Customer Method for determining the residential BSC, it should consider the additive effect that the Company’s percentage-based riders have on the effective rate of the residential BSC that customers pay. Those riders already inflate the effective charge by a considerable amount, and further increases would result in BSC “creep” driven by costs that are not directly related to the number of customers GPC serves.

# III. Daily BSC for Residential Customers

### Q. Why does the Company propose to transition its current monthly residential BSC to A daily charge?

A. Company Witness Legg states that a daily charge would make the BSC reflected in customer bills “more accurate and simpler for the customer to understand.”[[46]](#footnote-46) This is the extent of the Company’s justification for proposed change.

### Q. Does the Company propose to convert the BSCs for other classess of customers to daily charges?

A. No. This aspect of the Company’s proposal is confined to residential rates.

### Q. Does the Company offer an explanation for confining the proposed change to residential customers?

A. No. One would think that the same rationale would apply to rates for other customers, but the Company does not elaborate on why it makes this proposal specifically for only the residential class.

### q. do you agree With Witness Legg’s contentions that the change results in more accurate and easier to understand bills for residential customers?

A. No. As to the accuracy of customer bills, the current system does not produce any long-term inaccuracies so there is little opportunity for improvement. Long billing periods followed by short billing periods, or vice versa, even out any potential inaccuracies in short order. Furthermore, the costs of issuing a customer bill and accepting payment accrue on a per-billing-period basis anyway, which the current system accurately reflects.

As to simplicity and understandability, it is hard to see how the change would support either for several reasons. First, a single amount that does not change from billing period to billing period is inherently *simpler* because a customer does not need to know the number of days in their billing period to calculate it. A daily charge simply makes the amount seem smaller to the customer, obscuring the amount that the charge will represent on each bill. This is the common marketing strategy often seen in advertising statements along the lines of “for less than a dollar a day….”

Second, customers are accustomed to the current denomination of the charge as a per-billing-period amount, which is in fact how fixed charges are denominated by the vast majority of other IOUs. In other words, the current nature of the charge is understood by GPC’s residential customers, and would also be understood by new customers that move from the service territories of other utilities.

### Q. Do you forEsee any negative consequences from converting the BSC to a daily Charge?

A. Yes. A daily BSC would unavoidably make customer bills more volatile from month to month. The Company notes that currently bills can be generated for a service period from 25 to 36 days without being pro-rated.[[47]](#footnote-47) It is reasonable to expect that the length of a billing period will be correlated with billed usage. If one assumes an average duration of 30.5 days (*i.e.,* the midpoint between 25 and 36) and uniform monthly use, a customer’s bill would be up to 18% higher or lower at the upper and lower ends of the permitted billing period durations. The difference between a shorter than average billing period followed by a longer than average billing period would, of course, be larger. A daily BSC exacerbates this volatility.

### Q. What are your recommendations to the Commission on the Company’s daily residential BSC Proposal?

A. The Commission should deny the Company’s request because such a change is unnecessary for producing accurate bills, would adversely impact customers’ understanding of their bills, and would exacerbate bill volatility from month to month. Furthermore, the Company’s proposal to apply the change only to residential rates is unsupported by its stated rationale and, without such a justification, the proposal is discriminatory on its face.

# IV. Conclusion

### Q. Please summarize your REcommendations on the Company’s proposed residential BSC and the reasons for those reCommendations.

A. I recommend that the Commission adopt a residential BSC of $9.46/month and consider lowering it even further to $8.92/month in consideration of the Commission’s designation of energy efficiency as a priority resource.[[48]](#footnote-48) The amount I recommend is consistent with the Basic Customer Method of calculating reasonable residential fixed charges, which is the most common method used by regulators throughout the country. My recommendation is also consistent with generally accepted ratemaking principles and would help mitigate the effects that the rate increase would have on low usage and low-income customers, who would experience disproportionate bill increases under a high fixed charge rate design. Finally, my recommendation is consistent with the Commission’s policies regarding energy efficiency. It would avoid considerable increases in residential energy consumption that could be expected to occur as a result of the Company’s proposal, which would effectively undo more than a year’s worth of savings produced by the Company’s energy efficiency programs.

I recommend that the Commission reject the Company’s proposal to modify the residential BSC from a monthly charge to a daily charge because it would exacerbate customer bill volatility from month to month and, contrary to the Company’s assertions, would actually make the charge less understandable to a typical customer.

### Q. Please summarize your recommendations on the use of the MDS method of deriving customer-related costs and the reasons for those recommendations.

A. I recommend that the MDS assumption be removed from the Company’s cost of service study because its use tends to overcharge customers in highly populated rate classes. This occurs because a so-called minimum system has an ability to serve demand, which should be viewed as a demand-related cost, and the methods used to extract these demand-related costs and isolate the customer-related component, such as the Company’s Zero-Intercept study, are not reliable.

Should the Commission accept the general MDS framework as appropriate for cost allocation it should not use the resulting unit costs for the purpose of rate design because they are ill-suited for that purpose, and because doing so in a deterministic fashion would fail to consider the suite of other commonly accepted ratemaking principles. I also recommend that if the MDS method is accepted for any purpose, the Company should be directed to correct its zero-intercept analysis to conform to the NARUC Manual and eliminate the erroneous results the analysis produces for secondary pad-mounted line transformers.

### Q. Does this conclude your testimony?

A. Yes.

1. The North Carolina Solar Center is now known as the North Carolina Clean Energy Technology Center. [↑](#footnote-ref-1)
2. The City Council of New Orleans regulates the rates and operations of Entergy New Orleans in a manner equivalent to state utility regulatory commissions. [↑](#footnote-ref-2)
3. Direct Testimony of Larry T. Legg (“Legg Direct”), Exhibit LTL-1. [↑](#footnote-ref-3)
4. Direct Testimony of Lawrence J. Vogt (“Vogt Direct”), Exhibit LJV-9. [↑](#footnote-ref-4)
5. Legg Direct, Exhibit LTL-1. [↑](#footnote-ref-5)
6. Legg Direct at 8:22-26. [↑](#footnote-ref-6)
7. Bonbright, J. et al., 1988, *Principles of Public Utility Rates (2nd Edition)*. p. 383-384. [↑](#footnote-ref-7)
8. Commission Docket No. 36989. Joint Direct Testimony and Exhibits of Glenn A. Watkins and Jamie C. Barber, October 18, 2013, at 44:1-7. [↑](#footnote-ref-8)
9. Commission Docket No. 31081. Final Order dated July 13, 2010. p. 17. [↑](#footnote-ref-9)
10. Nebraska is the only state not represented in this survey. Nebraska is unique in that it is the only state served entirely by consumer-owned utilities not subject to external rate regulation. [↑](#footnote-ref-10)
11. The South Carolina average is based on the charges for 18 of the 21 electric cooperatives in South Carolina. Three cooperatives do not post their rates online and did not respond to requests for this information. [↑](#footnote-ref-11)
12. Electric Power Research Institute. 2008. *Price Elasticity of Demand for Electricity: A Primer and Synthesis.* epri.com/#/pages/product/1016264/?lang=en. [↑](#footnote-ref-12)
13. ACEEE. 2019 State Energy Efficiency Scorecard. October 1, 2019. Available at: https://aceee.org/research-report/u1908. [↑](#footnote-ref-13)
14. Electric Power Research Institute. 2008. *Price Elasticity of Demand for Electricity: A Primer and Synthesis.* Available at: epri.com/#/pages/product/1016264/?lang=en*.*  [↑](#footnote-ref-14)
15. Commission Docket No. 40162. Georgia Power Certified Demand-Side Management Program, Fourth Quarter 2018 Programs Status Report. February 15, 2019. Available at: http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=175745. [↑](#footnote-ref-15)
16. GPC Resp. to STF-PIA-5-25. [↑](#footnote-ref-16)
17. Based on GPC Response to STF-PIA-5-25, Attachment B. The averages stated are those specified by the Company, using 2013 usage data mapped to the 3rd-party income data. [↑](#footnote-ref-17)
18. The data is sourced from GPC Resp. to STF-PIA-5-25, Attachment A. Note that the percentage of low-income customers in each usage tranche differs from percentages specified in the preceding paragraphs because Table 6 is based on July 2017-June 2018 data while the preceding paragraphs refer to 2013 usage data. [↑](#footnote-ref-18)
19. The indifference threshold is illustrated by the fact that customers with average monthly usage of 1,000 kWh experience roughly the same bill impact under either scenario. [↑](#footnote-ref-19)
20. Vogt Direct at 9:18-20. [↑](#footnote-ref-20)
21. *Id.* at 10:23-24. [↑](#footnote-ref-21)
22. In practice there are typically adjustments made in this calculation to account for accessory plant. Vogt Direct at p. 10-12 describes some of the assumptions used by the Company in more detail. [↑](#footnote-ref-22)
23. Vogt Direct at 13:1-19. [↑](#footnote-ref-23)
24. The NARUC Manual also describes a different method of identifying customer-related distribution plant that is typically referred to as the Minimum Size or Minimum System Method. This specific method should not be confused with the overarching concept that Witness Vogt terms the MDS. [↑](#footnote-ref-24)
25. NARUC Manual. p. ii. [↑](#footnote-ref-25)
26. *Id.* at p. 95. [↑](#footnote-ref-26)
27. *Id.* at p 136 (emphasis added). [↑](#footnote-ref-27)
28. Bonbright, J. *Principles of Public Utility Rates*, 1961. p. 348-349 (emphasis added). [↑](#footnote-ref-28)
29. Connecticut Public Act 15-5, June Special Session*, available at:* https://www.cga.ct.gov/asp/cgabillstatus/CGAbillstatus.asp?selBillType=Bill&bill\_num=1502&which\_year=2015. [↑](#footnote-ref-29)
30. Colorado Public Utilities Commission. Docket No. 17AL-0477E. Decision No. C18-0445. June 15, 2018, *available at*: https://www.dora.state.co.us/pls/efi/efi\_p2\_v2\_demo.show\_document?p\_dms\_document\_id=887641. [↑](#footnote-ref-30)
31. South Carolina Public Service Commission. Docket No. 91-216-E. Order No. 91-1022. p. 7. November 18, 1991. [↑](#footnote-ref-31)
32. Public Utilities Commission of Texas. Docket No. 22344. Order No. 40, p. 6. November 22, 2000. [↑](#footnote-ref-32)
33. California Public Utilities Commission. Docket No. A.16-06-013. Decision No. 17-09-035. p. 33 and 40. September 28, 2017. The decision allows a portion of final line transformer costs consistent with a minimum-sized transformer to be included in a fixed charge. [↑](#footnote-ref-33)
34. F. Weston, et al., *Charges for Distribution Service: Issues in Rate Design*, p. 29, Regulatory Assistance Project (2000), *available at:* http://pubs.naruc.org/pub/536F0210-2354-D714-51CF-037E9E00A724. [↑](#footnote-ref-34)
35. Commission Docket No. 36989. Joint Direct Testimony and Exhibits of Glenn A. Watkins and Jamie C. Barber, October 18, 2013, at 25:16-17. [↑](#footnote-ref-35)
36. *Id.* at 44:10-12. [↑](#footnote-ref-36)
37. *Id.* Exhibit GAW-9. [↑](#footnote-ref-37)
38. GPC Resp. to STF-DEA-1-26a, Attachment, Summary tab. [↑](#footnote-ref-38)
39. GPC Resp. to Hearing Request No. 5. [↑](#footnote-ref-39)
40. Commission Docket No. 36989. June 28, 2013. Direct Testimony of Michael T. O'Sheasy. Exhibit MTO-1. Derived from lines 70-116 of the spreadsheet. [↑](#footnote-ref-40)
41. GPC Resp. to STF-DEA-1-26a, Attachment, Acct368 tab. [↑](#footnote-ref-41)
42. GPC Resp. to STF-DEA-1-26a, Attachment, PwrDeliv tab. [↑](#footnote-ref-42)
43. GPC Resp. to STF-DEA-1-26a, Attachment, Acct368 tab at cell AV272. Derived by dividing plant investment by the number of transformers and applying the Handy Whitman escalator to the result. [↑](#footnote-ref-43)
44. NARUC Manual. p. 95. [↑](#footnote-ref-44)
45. NARUC Manual. p. 93. [↑](#footnote-ref-45)
46. Legg Direct at 10:21-24. [↑](#footnote-ref-46)
47. *Id.* at 10:18-19. [↑](#footnote-ref-47)
48. Commission Docket No. 31081. Final Order dated July 13, 2010. p. 17. [↑](#footnote-ref-48)