BEFORE THE

GEORGIA PUBLIC SERVICE COMMISSION

In the Matter of:	)	
GEORGIA POWER COMPANY'S	)	DOCKET NO. 42516
2019 RATE CASE	)	

JOINT DIRECT TESTIMONY

AND EXHIBITS

OF

JAMIE BARBER
GEORGE BROWN
BENJAMIN DEITCHMAN
STAN FARYNIARZ

ON BEHALF OF THE

GEORGIA PUBLIC SERVICE COMMISSION
PUBLIC INTEREST ADVOCACY STAFF

OCTOBER 17, 2019

I. INTRODUCTION

Q. MS. BARBER, PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is Jamie Barber, and I am the Energy Efficiency and Renewable Energy Manager for the Georgia Public Service Commission ("Commission"). My business address is 244 Washington Street, S.W. Atlanta, GA 30334.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My educational background and work experience are provided in my resume, which is attached as Staff Exhibit BBDF-1.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

Yes. I testified in each of the 1998 through 2009 United Cities Gas Company (now known as Atmos Energy Corporation) Gas Supply Plan Proceedings. I have also testified in Docket No. 10270, GPSC Determination of Lack of Market Constraints on Atlanta Gas Light Company's Commodity Sales; Docket No. 11114, Rule Nisi Against United Gas Management of Georgia, Inc.; Docket No. 14311, Earnings Review to Establish Just and Reasonable Rates for Atlanta Gas Light Company; Docket No. 15296 Service Quality Standards for Certified Marketers and Regulated Provider; Docket No. 18638- Atlanta Gas Light Company's 2004/2005 Rate Case; Docket No. 20298 Atmos Energy Corporation's 2005 Rate Case; Docket No. 27163 Atmos Energy Corporation's 2008

Rate Case; Docket No. 30442 Atmos Energy's 2010 Rate Case; Docket No. 36498 Georgia Power Company's 2013 IRP Filing; Docket No. 36499 Georgia Power Company's 2013 Demand Side Program Certification; Docket No. 37854, Georgia Power Company's Application for the Certification of the Power Purchase Agreements for Wind Resources from the Blue Canyon II and Blue Canyon VI Wind Farms; Docket No. 38877, Georgia Power Company's Application for the Certification of the 2015 and 2016 Advanced Solar Initiative Prime Power Purchase Agreements and Request for Approval of the 2015 Advanced Solar Initiative Power Purchase Agreements, Docket No. 36989 Georgia Power Company's 2013 Rate Case, Docket No. 40161 Georgia Power Company's 2016 IRP Filing, 40162 Georgia Power Company's 2016 Demand Side Program Certification, Docket No. 41596, Georgia Power Company's Application for the Certification of the 2018/2019 Renewable Energy Development Initiative Utility Scale Power Purchase Agreements, Docket No. 41734, Georgia Power Company's Application for the Certification of the 2018/2019 Renewable Energy Development Initiative Utility Scale Power Purchase Agreements for the Commercial and Industrial Program, Docket No. 42310 Georgia Power Company's 2019 IRP Filing, and Docket No. 42311 Georgia Power Company's Application for the Certification, Decertification, and Amended Demand Side Plan.

Q. **MR. BROWN, PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.**

A. I am George Brown. I am an Electric Unit Utilities Analyst at the Georgia Public Service Commission. My business address is 244 Washington Street, S.W., Atlanta, GA 30334.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND, AND WORK EXPERIENCE.

A. I have a Bachelor of Science in Banking and Finance from Troy University. I previously served as Program Director, Finance for the Sustainable Energy Fund in Allentown Pennsylvania. I have also worked as a Public Utility Analyst at the Alabama Public Service Commission. My background and work experience are provided in Staff Exhibit BBDF-2.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No.

Q. DR. DEITCHMAN, PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. I am Benjamin Deitchman. I am an Electric Unit Utilities Analyst at the Georgia Public Service Commission. My business address is 244 Washington Street, S.W., Atlanta, GA 30334.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND, AND WORK EXPERIENCE.

A. I hold a PhD in Public Policy from the Georgia Institute of Technology, a Master of Public Administration degree from the George Washington University, and a Bachelor of Arts in History from the Johns Hopkins University. I previously served on the faculties of Liberal Arts and Business at the Rochester Institute of Technology and as the Regional

Program Coordinator for the National Association of State Energy Officials. My background and work experience are provided in Staff Exhibit BBDF-3.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No.

Q. MR. FARYNIARZ, PLEASE STATE YOUR NAMES AND BUSINESS ADDRESS.

A. My name is Stan Faryniarz. I work for Daymark Energy Advisors ("Daymark"), headquartered at 370 Main Street, Ste 325, Worcester, Massachusetts 01608.

Q. MR. FARYNIARZ WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND?

A. I am a Principal Consultant at Daymark Energy Advisors. I serve as an energy economist and power supply planning and management specialist with 33 years of experience in areas including electric utility cost of service and rates, power supply procurement and management, wholesale and retail power transactions, power project financial analysis and due diligence, asset and utility valuations, and integrated resource planning and analysis.

In addition to being a load forecasting specialist, directing Integrated Resource Planning studies, advising large commercial and industrial customer as well as small utilities on electric power and natural gas portfolio management my experience includes the preparation or review of dozens of electric and water utility allocated cost of service and rate design studies, rate unbundling studies, and rate path projection studies, for or involving utilities in Maine, New Hampshire, Pennsylvania, Rhode Island, Utah and Vermont.

Q. MR. FARYNIARZ, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No, but other Daymark experts have, including on matters involving, as in this case, Georgia Power Company.

My resume, with selected allocated cost of service, rate design and other ratemaking experience, is provided in Staff Exhibit BBDF-4.

I have testified as a ratemaking expert before regulatory authorities in Maine, New Hampshire, Pennsylvania, Rhode Island, Utah and Vermont. A list of selected expert witness appearances is provided in Staff Exhibit BBDF-4.

Q. WHAT IS THE PURPOSE OF STAFF'S TESTIMONY IN THIS PROCEEDING?

A. The Georgia Public Service Commission's Public Interest Advocacy Staff ("Staff") evaluated the accuracy and reasonableness of Georgia Power Company's ("Georgia Power" or "Company") retail class cost of service study, proposed distribution of revenues by class, rate design, and other tariff issues. The purpose of our testimony, therefore, is to comment on Georgia Power's proposals on these issues and to present our findings and recommendations.

Q. PLEASE EXPLAIN THE ISSUES THAT EACH PANEL WITNESS WILL BE RESPONSIBLE FOR ADDRESSING.

A. Mr. Faryniarz will address the Company's allocated cost of service study ("ACOSS"), the ratemaking principles it relied upon, the rate modernization foundation for the Company's rate design proposals, basic (customer) service charges, proposed phase-in of new rates, effect on low-use residential customers, Georgia Power's residential Rate R design, time-of-use rates and a number of related policy matters attending all of these items.

Ms. Barber will address the Company's request for approval of proposed revisions to the Simple Solar, Renewable and Nonrenewable Resources ("RNR"), Residential Demand Side Management ("DSM") and Commercial tariffs. Ms. Barber will also address the Company's request to add Section G: Customer Generation to the Company's Rules and Regulations and Staff's recommendation that the Company continue to explore providing residential customers access to hourly usage data.

Dr. Deitchman will address the policy implications of the proposed changes for customers.

Mr. Brown will address Staff's concerns with the Flat-5 tariff, Pay By Day and Budget Billing options.

Q. WILL STAFF BE OFFERING ANY CHARACTERIZATIONS OR CRITIQUES OF THE COMPANY'S COST ALLOCATION OR RATE DESIGN PROPOSALS?

A. Yes. However, our testimony does not address every cost allocation and rate design proposal or characterization made by Company witnesses Mssrs. Vogt, Legg and Dr. Faruqui. Furthermore, on issues where Staff does not comment on or critique what the Company did or proposed, it should not be implied that Staff tacitly endorse the

Company's position. In other words, silence on an issue should not be necessarily taken as acceptance of the Company's proposals.

II. ALLOCATED COST OF SERVICE STUDY ("ACOSS")

A. General ACOSS Review

Q. PLEASE BRIEFLY EXPLAIN THE PURPOSE OF AN ALLOCATED COST OF SERVICE STUDY AND HOW IT IS USED IN DEVELOPING RATES.

A. The following is excerpted from the Docket No. 36989 testimony of Glenn Watkins and Jamie Barber in the Georgia Power Company 2013 rate case:

"Generally, there are two types of cost of service studies used in public utility ratemaking: marginal cost studies and embedded, or fully allocated, cost studies. Consistent with the practices of this Commission, Georgia Power has utilized a traditional embedded cost of service study for purposes of establishing the overall revenue requirement in this case, as well as for class cost of service purposes.

Embedded class cost of service studies are also referred to as fully allocated cost studies because the majority of a public utility's plant investment and expense is incurred to serve all customers in a joint manner. Accordingly, most costs cannot be specifically attributed to a particular customer or group of customers. To the extent that certain costs can be specifically attributed to a particular customer or group of customers, these costs are directly assigned to that customer or group in the CCOSS. Most of the costs are jointly incurred to serve all or most customers; therefore, they must be allocated across specific customers or customer rate classes.

It is generally accepted that to the extent possible, joint costs should be allocated to customer classes based on the concept of cost causation. That is, costs are allocated to *customer classes based on analyses that measure the causes of the incurrence of costs to the utility. Although the cost analyst strives to abide by this concept to the greatest extent practical, some categories of costs, such as corporate overhead costs, cannot be attributed to specific exogenous measures or factors, and must be subjectively assigned or allocated to customer rate classes. With regard to those costs in which cost causation can be attributed, there is often disagreement among cost of service experts on what is an appropriate cost causation measure or factor; e.g., peak demand, energy usage, number of customers, etc."*

Q. PLEASE LIST THE FACTORS THAT ARE MOST IMPORTANT IN PREPARATION OF A RATE CASE QUALITY ACOSS.

A. The primary consideration is to apportion cost responsibility on the basis of *cost causation*. Put another way, electric and other utility rates should be "cost reflective," as Company witnesses have termed it, meaning they should include those costs incurred when, and provide a "price signal" to customers about the cost of, consuming an additional kWh of electricity.

There can be differing viewpoints on the specific factors that drive utility costs by function (i.e. generation, transmission, distribution and customer service), how they should be classified (i.e. as demand, energy or customer service-related), and how they should be allocated to customer classes. Further, regardless of whether and when there is agreement among cost analysts on the foregoing, formation of an effective price signal in rates can generate additional disagreements.

While there are numerous cost allocation and rate design principles to guide the cost analyst,[1] decisions which are not entirely data-driven need to be made based on a combination of judgement and ratemaking best practices.

Consistent with its positions in prior Georgia Power rate cases, Staff recommends that the Georgia Public Service Commission consider the Company's ACOSS results only as a guide, and one of a number of considerations in assigning revenue responsibility to and rates for customer classes when cost causation factors cannot be perfectly developed for every single utility cost.

Q. GEORGIA POWER COMPANY WITNESS LAWRENCE J. VOGT HAS CATEGORIZED THE MAJOR DRIVERS IN DEVELOPING COSTS IN AN ALLOCATED COST OF SERVICE STUDY AS DEMAND, ENERGY, AND CUSTOMER-RELATED. ARE THESE THE SAME AS THE COST CAUSATIVE FACTORS THAT YOU DESCRIBED ABOVE?

A. Yes, that is the primary way to classify utility costs and is endorsed by NARUC and Bonbright.

Q. DOES MR. VOGT'S TESTIMONY SUFFICIENTLY EXPLAIN HOW THESE MAJOR DRIVERS WERE DEVELOPED AND USED IN THE COMPANY ACOSS?

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[1] For example, the National Association of Regulatory Utility Commissioners (NARUC) *Electric Utility Cost Allocation Manual,* January 1992, and Bonbright, Danielsen & Kamerschen, *Principles of Public Utility Rates,* 2nd Edition, 1988. These ratemaking guides will be referred to elsewhere in this testimony.

A. Yes, considered alongside certain critiques of the allocation methodology contained in this testimony, the Commission should have a reasonable record for findings on major cost assignments and allocations. Mr. Vogt's testimony provides a good explanation of the major cost causation factors utilized in the Company's ACOSS, as well as how these factors were developed.

Q. DID THE COMPANY'S ACOSS FORM A REASONABLE BASIS UPON WHICH TO FUNCTIONALIZE, CLASSIFY AND ALLOCATE COSTS TO ITS CUSTOMER CLASSES?

A. While we did not try to replicate the Company's model, nor did we conduct a full review of the accounts and every allocator string included therein, the resulting cost breakouts appear to be reasonable.

Q. WHAT COST ALLOCATION METHODOLOGIES DID MR. VOGT UTILIZE WITHIN HIS RECOMMENDED ACOSS FOR GENERATION AND TRANSMISSION COSTS?

A. Virtually every electric utility ACOSS employs numerous techniques in order to allocate (or assign) specific rate base and operating income and cost accounts to the various rate classes. These various techniques, or methodologies, are usually referred to within the context of the four major functions of a vertically-integrated electric utility's business: Generation (G), Transmission (T), Distribution (D) and Customer Service (C).

With regard to Generation-related fixed costs, Mr. Vogt recommends the use of the 12-month Coincident Peak ("12-CP") method. With regard to high voltage (bulk power) transmission-related costs, Mr. Vogt uses a blended approach that considers both 12-CP as well as the four highest monthly coincident peak demands ("4-CP"). Specifically, Mr. Vogt's blended high voltage Transmission method utilizes a weighting of 20% 12-CP and 80% 4-CP. Lower voltage facility accounts are allocated based on either the 4-CP or class Non-Coincident Peak ("NCP") methods.[2]

Q. ARE THESE REASONABLE ALLOCATION APPROACHES FOR SPREADING FIXED GENERATION AND TRANSMISSION COSTS?

A. For the most part, yes. As Mr. Vogt notes in his testimony, the 12-CP allocation methodology has long been used by Georgia Power and appears to have been at least tacitly accepted by the Commission.[3]

However, as discussed in Section IV of this testimony, certain winter reliability concerns appear not to have affected these allocation approaches, and given those concerns it is somewhat surprising to see the Company continue to focus on spreading so much of its generation and transmission system fixed costs either exclusively to summer peak demands or over peak demands in all months, with little resulting emphasis on winter-driven costs that even the Company acknowledges are increasing.[4]

Q. WHAT ABOUT DISTRIBUTION COSTS?

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[2] Coincident peak demands are defined as class loads at the same time (coincidental) to system peak loads; i.e., they are measured at the same point in time. Class Non-Coincident Peak demands are defined as the maximum demand for each individual class regardless of when each occurs; i.e., class maximum demands are not necessarily coincident with the system peak or one another for that matter.

[3] Refer to Vogt prefiled direct testimony, p. 16, lines 6-9.
[4] Refer to Legg oral testimony at hearing, transcript p. 801, lines 6-8.

A. Generally speaking, distribution costs were spread based on either a 4-CP or non-coincident peak demand allocator.

With regard to distribution-related costs, Mr. Vogt has utilized an approach that *classifies* some costs partially on the basis of peak demand and partially on the basis of number of customers.

However, as we will discuss below, Mr. Vogt has utilized a Minimum Distribution System methodology in 2019, as the Company did in 2013, with the 2019 analysis allocating significantly more distribution costs to customer service in this case.

B. Minimum Distribution System Methodology

Q. PLEASE PROVIDE AN OVERVIEW OF THE MINIMUM DISTRIBUTION SYSTEM ("MDS") METHODOLOGY.

A. As mentioned above the allocated cost of service study goes through many steps to *functionalize, classify* and then *allocate* costs among the different customer classes. The MDS is a technique used by the Company as part of the second of these steps, classification.

As indicated by its name, the MDS is used to determine a portion of the costs in the distribution system that Georgia Power views as caused by the need to serve customers, separate from the demand they place on the system for electricity. The costs we are discussing in the MDS are portions of equipment unit costs, not separate FERC accounts in the ACOSS model. The MDS concept implies certain costs would be incurred such as a transformer with a "0" kVA rating simply for purposes of "readiness to serve" the customer, before any demand is placed on the system by said customer. These costs are calculated using a regression analysis known as the zero-intercept method separately on various equipment unit costs (dependent variable), driven by variance in capacity value of said equipment (independent variable). The equipment functionalized this way by the Company includes reclosers, sectionalizers, fused contacts, single-phase transformers, three-phase padmount transformers, overhead conductors, underground conductors, and distribution poles.

This technique, as described in Mr. Vogt's testimony, is used to classify a portion of this equipment cost to the customer service function, with the rest classified as distribution demand cost.

Q. DOES THE USE OF THIS TECHNIQUE RESULT IN AN ASSIGNMENT OF COSTS THAT VARY DIRECTLY WITH THE NUMBER OF CUSTOMERS?

A. No. The use of this technique merely serves to find a theoretical breakpoint between equipment costs required for meeting distribution system demands, and a fixed, "readiness to serve" cost for that equipment. If a single customer is added or dropped from the Georgia Power system, none of these equipment costs change on the margin. For this reason, it is merely loading Georgia Power customers with another system fixed cost.

Q. WHAT ARE YOUR OTHER CONCERNS ABOUT THE USE OF THIS METHODOLOGY?

A. The primary concern is that the MDS methodology seeks to assign something more akin to a long-term marginal cost[5] to serve a theoretical customer, directly to a charge that each of its actual customers must pay now. The costs classified as customer-related are not actual incremental costs. Put another way, there are no zero-kVA overhead line transformers to purchase with the addition of a new customer, and is doubtful that there are any in the inventory at Georgia Power Company.[6]

Q. IS THIS MDS TECHNIQUE ENDORSED BY NARUC?

A. The NARUC *Electric Utility Cost Allocation Manual* discusses this method, and another approach designed to do the same classification of plant called the Minimum-System method, but we would not characterize the discussion of either as an endorsement.[7]

Importantly, the NARUC Manual does in fact place an emphasis on classifying customer related costs on the basis of how well they vary directly with the number of customers on the utility system.

Q. THE COMPANY RELIES SUBSTANTIALLY ON RATEMAKING PRINCIPLES ESPOUSED BY BONBRIGHT.[8] IS THE MDS TECHNIQUE ENDORSED BY BONBRIGHT?

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[5] Even though *embedded* costs are used to develop it.

[6] See Vogt prefiled direct testimony pp. 10-11.

[7] See for example, NARUC Electric Utility Cost Allocation Manual, January 1992, p. 92, "Some utilities assign distribution to customer-related expenses" or p. 95 "The minimum intercept method can sometimes produce statistically unreliable results."

A. No. Bonbright takes the position that only costs that vary directly with the number of customers should be allocated to customer service and included in a customer charge. For instance, minimum-sized distribution costs',

"inclusion among the customer costs is defended on the ground that, since they vary directly with the <u>area</u> of the distribution system (or else with the lengths of the distribution lines, depending on the type of distribution system), they therefore vary directly with the number of customers. Alternatively, they are calculated by the zero-intercept method whereby regression equations are run relating cost to various sizes of equipment and eventually solving for the cost of a zero-sized system.

What this last-named cost imputation overlooks, of course, is the <u>very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system</u> (emphasis added) ... Thus, 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 ..."

Bonbright goes on to note that "<u>the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to us clearly indefensible</u> (emphasis added).[9]

Q. DOES STAFF HAVE ANY ADDITIONAL PRACTICAL CONCERNS WITH THE USE OF THE MDS METHOD BY THE COMPANY?

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[8] Refer to Faruqui prefiled direct testimony pp. 5-6.
[9] Bonbright, Danielsen & Kamerschen, *Principles of Public Utility Rates,* 2nd Edition, 1988, pp. 493-494 (emphasis added).

A. Yes. Relying on such a theoretical concept as the MDS, based on a statistical relationship between the unit cost of, and size of various pieces of secondary distribution system equipment, is not consistent with the other cost accounting the Company does in its ACOSS. The costs identified by MDS may deviate significantly as compared to actual costs that are accumulating for actual equipment in their respective FERC accounts.

A good example of this was discussed in the hearings by Mr. Vogt under cross examination.[10] Mr. Vogt discussed how much cost allocation based on customer count can change for a specific type of equipment. Mr. Vogt further testified that, for instance, line transformers cost had changed dramatically from the 2013 Georgia Power Class Cost of Service Study (CCOSS) to the 2019 CCOSS. Mr. Vogt verified that the MDS zero-intercept methodology was used in both cases employing essentially the same math.[11]

In 2013, the customer allocated costs for the line transformers was $342 million out of the total line transformer account of $1.31 billion, or approximately 26%. Mr. Vogt verified that the same methodology used in the CCOSS for this 2019 case, reflecting the same FERC accounts resulted in customer allocated costs for line transformers, of $1.396 billion, out of the total line transformer costs of $1.413 billion - or almost 99%. In our view, this demonstrates the instability and almost arbitrary results a theoretical methodology such as MDS can yield.

[10] Transcript P. 633 Line 2 through P. 641 Line 4
[11] Transcript P. 641 Line 1

Q. WHAT ARE THE MONTHLY CUSTOMER COSTS THAT THE COMPANY STUDY HAS CALCULATED FOR THE DOMESTIC CUSTOMER GROUP?

A. Mr. Vogt's testimony identifies that the monthly customer costs for the Domestic Group are $20.87.[12]

Q. HAS MR. VOGT IDENTIFIED HOW MUCH OF THAT $20.87 REPRESENTS COSTS DETERMINED THROUGH THE MDS?

A. No, he has not. Therefore, Daymark Energy Advisors oversaw preparation of an analysis to isolate the MDS component. Based on the Company's response to Staff's data request[13] and the Company's ACOSS model, we estimate that close to $8 of the $20.87, are costs that emanate from the use of the MDS.

Q. DOES STAFF THINK THAT THE ACOSS SHOULD BE REVISED BY ELIMINATING THE MDS?

A. Yes, Georgia Power should remove the allocation of the MDS costs to customer service If the ACOSS is to be used as a basis for determination of the monthly basic service charge. Alternatively, Georgia Power should strip out the MDS effects on the monthly basic service charge it proposes.

III. BASIC CUSTOMER SERVICE CHARGE

Q. WHAT IS THE BASIC SERVICE CHARGE?

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[12] Georgia Power response to STF-PIA-DEA 2-14 Attachment 2-14

[13] Georgia Power response to STF-PIA 7-22.

A. The Basic Service Charge is the Company's fixed monthly charge for customer service, which each customer in each rate class must pay regardless of their level of consumption. In this proceeding, Georgia Power is proposing to have the Basic Service Charge pro-rated by the number of days in the actual billing period defined by days between meter-reads. Regardless of the billing determinant period (for an average month, or approximately 30 days in a billing cycle), it is still essentially a fixed monthly fee for being a Georgia Power customer. With this rate case, the Company proposes to raise the charge for domestic customers from the current level of $10/month to $17.95/month.

Q. WHAT IS THE PHASE IN PERIOD PROPOSED BY THE COMPANY?

A. The Company proposes a 3-year phase in, but under an accelerated schedule. For Domestic customers almost half of the increase ($4.90, or 49% of the increase) would be in the first year 2020, another $2.90 or 29% of the total increase would come in 2021, and the remaining $1 in year 3. Other customers, including those in the General Service and Small Power & Light classes, would see a doubling of their customer charge all in the first year.

Q. WHAT IMPACT WILL SUCH A DRASTIC INCREASE HAVE ON CUSTOMER BILLS?

A. The Company suggests these changes will not impact what it defines as low, typical and high use average consumption customers by more than between $8 - $13/month, because it also made other rate adjustments.

However, low use customers will be hardest hit, because of the fact that the fixed Basic Service Charge represents a significant portion of their overall bill. Under cross examination, Dr. Faruqui states that very small customers will see a higher bill and goes on to explain how the arithmetic is such that there will be quite an impact on these customers. (Transcript Day 2, Faruqui, pp. 707-708.).

Our bill impact analysis for ARP rate years 1 and 3, show that a domestic customer using only 200 kWh per month will see an average monthly bill increase of $6.54, or 20%. A 500 kWh per month General Service or Small Power & Light customer using 1000 kWh per month will experience average monthly bill increases of $14.43, or 14.38%, and $35.04, or 14.36%, respectively, all in one year.

Q. YOU NOTED EARLIER THAT THE COMPANY HAS RELIED SIGNIFICANTLY ON RATEMAKING PRINCIPLES ESPOUSED BY BONBRIGHT, ET AL. IS GRADUALISM IN RATE ADJUSTMENTS ONE SUCH PRINCIPLE?

A. Yes.

Q. IN YOUR OPINION, IS A 49% INCREASE IN A FIXED CHARGE FOR DOMESTIC CUSTOMERS AND A 100% INCREASE FOR OTHERS, ALL IN ONE YEAR, IN ALIGNMENT OF THE PRINCIPLE OF GRADUALISM?

A. No. Regardless of what the Commission decides is an appropriate basic service charge, to the extent it would increase significantly as a fraction of the bill for certain low use customers including domestic residential customers, we propose that any multi-year phase-in reflect an even dollar increase over a period of up to 3 years, as opposed to the accelerated schedule proposed by the Company.

A related ratemaking principle to gradualism, is customer bill stability. A more evenly-distributed increase would achieve a greater level of stability in customer bills from year to year

Q. DOES STAFF SUPPORT THE COMPANY'S PROPOSAL TO PRORATE THE BASIC SERVICE CHARGE ON A DAILY BASIS FOR ALL RESIDENTIAL CUSTOMERS?

A. No. Staff does not believe that the Company has sufficiently explained why this complicating change is necessary and recommends continuing the standard practice of 12 evenly monthly payments for customers who pay monthly bills. Customers who pay rent or for subscription services on a monthly basis are familiar with the fact that they may pay the same amount for 31 days in January as they might for a 28 day February and accept the simplifying payment structure. The Company already prorates a daily charge for PrePay customers and that should continue to be incorporated into that particular tariff's billing structure.

A. Realigning Basic Customer Service Charge and an Appropriate ACOSS

Q. WHAT DOES STAFF RECOMMEND REGARDING THE LEVEL OF THE BASIC CUSTOMER CHARGE INCREASE FOR DOMESTIC CUSTOMERS AND OTHERS?

A. As previously discussed, we recommend that the MDS component of the domestic basic service charge, which was almost $8 ($7.79) of the $20.87/month calculated by the Company, be excluded from the calculation of the charge. The $7.79/month attributable to the MDS would represent about 37% of the total.

Q. WHAT DOES STAFF RECOMMEND REGARDING THE GEORGIA POWER DOMESTIC BASIC SERVICE CHARGE?

A. In general, Staff approves of the Company approach to implementing any indicated increase to the basic service charge at a discount to the calculated charge from the ACOSS, reflecting the principle of gradualism. Recall that in its application, the Company is proposing a domestic basic service charge, once fully implemented, of $17.95/month, which represents a 14% discount to the $20.87/month it calculated.

Staff evaluated 3 options.

Option 1: If the $7.97 MDS component is stripped out of the Company-proposed monthly charge of $17.95, the resulting Basic Customer Charge would reduce back to about $10/month, where it is now.

Option 2: Since the $7.97 MDS component represents about 37% of total cost of customer service as calculated by the Company ($20.87), and if that percentage is stripped out of the Company-proposed monthly charge of $17.95, the resulting Basic Customer Charge would reduce to $11.25/month.

Option 3: If the $7.97 MDS component is stripped out of the Company-calculated monthly charge of $20.87, the resulting Basic Customer Charge would be reduced to $13.08/month.

Staff believes the Company has demonstrated through its ACOSS that some increase in the Basic Service Charge, even without including the MDS component and including <u>only</u> customer service costs that vary directly with the number of customers on its system, is appropriate. After careful consideration of the results of the three options above, Staff finds that Options 2 & 3 represent a reasonable range for the Domestic Basic Service Charge.

Specifically, Staff supports an increase in the Basic Service Charge from the current $10/month to $12/month. We fully expect that if the Company can demonstrate that its incremental costs to serve its next customer are higher than this level, it will have an opportunity to provide evidence to that effect in its next rate case.

Q. SHOULD THIS INCREASE BE PHASED IN?

A. For residential customers, a $2/month increase in the Basic Service Charge, so long as non-customer rates are otherwise limited according to the Company's proposal,[14] and bill impacts are limited to approximately the range for low, typical and high use average customers suggested by the Company of from $8 - $13,[15] could be implemented all in one year. Based on the testimony of Staff witnesses Messrs. Smith and Trokey, the Staff recommends the $12 monthly Basic Service Charge become effective with bills rendered January 2021.

For non-residential customers, particularly smaller commercial customers, an up to three-year, even dollar increase in the customer charge, exclusive of MDS costs, may still be appropriate. The Company should be directed to make such a proposal once it recalculates the customer charge exclusive of the MDS component.

Q. HOW MIGHT CUSTOMERS STILL BENEFIT FROM A LOWER BASIC SERVICE CHARGE, EVEN IF IT REQUIRES HIGHER ENERGY CHARGES TO MEET THE COMPANY'S REVENUE REQUIREMENTS?

A. Staff agrees with the Company's contention that residential rates must allow the Company to collect its revenue requirement, whether that is through the Basic Service Charge, energy charges, or the other elements of the customer bill. We acknowledge that a lower basic service charge would likely result in higher energy charges to align rates to

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[14] Refer to the testimony of Legg, p. 8, lines 20-23.

[15] IBID, p. 9, lines 5-10. This assumes the Company's non-fuel and non-riders' revenue requirement request of 8.8% is approved [Company reply to Staff hearing request 9]. If it is lowered, consistent with the testimony of Staff Witnesses Messrs. Smith and Trokey, rates and bill impacts should be commensurately lower.

recover the revenue requirement, all else being equal.[16] Unlike the Basic Service Charge, however, customers have control of their energy use and can install technologies or utilize other conservation measures, as well as opting for the demand-response rates such as TOU-REO, to manage their non-fixed costs, benefiting themselves and other customers on the Georgia Power system.

IV. IRP EMPHASIS ON WINTER RELIABILITY CONCERNS AND RATE DESIGN

Q. PLEASE DESCRIBE WHAT IS MEANT BY WINTER RELIABILITY CONCERNS.

A. Within its 2019 IRP, Georgia Power described changes in its generation resource planning in order to maintain adequate reliability in the winter as a result of growth in winter peak demand. The IRP focuses on the Georgia Power system's vulnerability to a much higher demand for electricity in the winter peak hours if an extreme cold snap occurs as it did relatively recently in 2014 when an extreme polar vortex engulfed much of North America.

A. Winter Reliability Concerns in 2019 IRP

Q. PLEASE SUMMARIZE THE PARTS OF THE IRP THAT GEORGIA POWER DESCRIBES AS THE BASIS FOR ITS RELIABILITY CONCERNS.

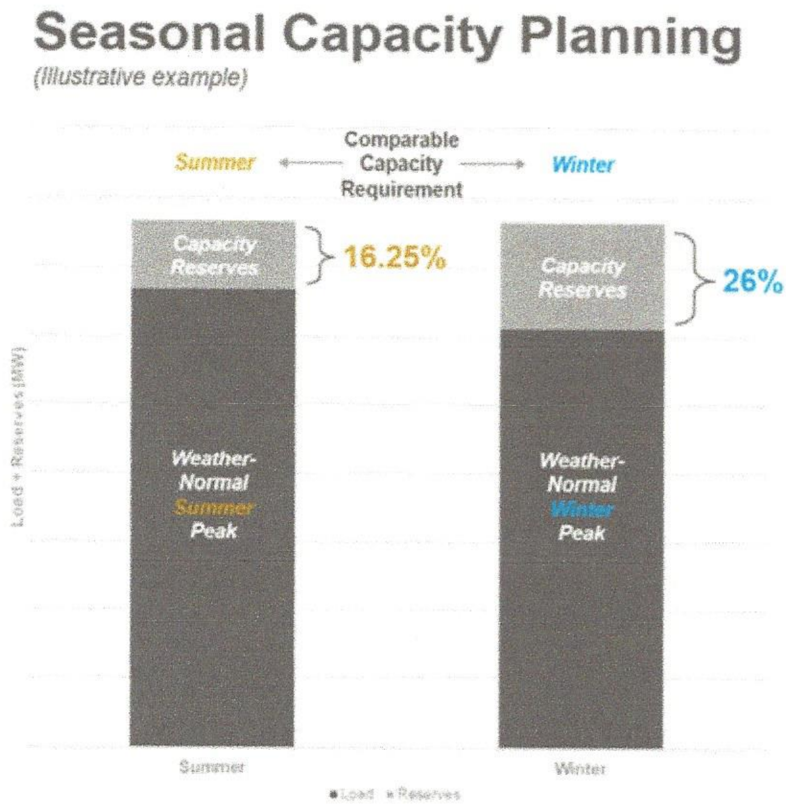
[16] Docket No. 42310 Testimony of Mr. Legg P. 5 Line 26 through P. 7 Line 6.

A. Some of the most straightforward information from Georgia Power, that is available to the public and not trade secret, comes from the testimony offered in the IRP docket from earlier this year.

> "The Company is taking steps to ensure that it can adapt its planning processes to meet the changing demands of the system to reliably meet the energy needs of its customers for the foreseeable future. To ensure proper reliability and economics, the Company evaluates the required amount of resources needed above forecasted peak demand, or reserve margin, prior to each triennial IRP filing to establish a Target Reserve Margin for the System for both the short-term and the long-term planning horizons. Historically, the Company's capacity planning decisions have been driven by a combination of summer peak loads and a corresponding summer-focused Target Reserve Margin. These planning techniques have proven to be successful in supporting reliability while cost-effectively meeting the needs of customers. However, recent operational experiences and forecasted conditions confirm the significant shift in reliability risk from the summer season to the winter season, consistent with the winter reliability drivers first identified in the Reserve Margin Study filed with the 2016 IRP. Due to the continued increases in winter reliability risks, the Company is adopting seasonal planning to better address these winter reliability issues and provide greater visibility into both summer and winter capacity needs rather than limiting reliability decisions to a single season."[17]

The chart below provides an example of how the Summer Target Reserve Margin and the Winter Target Reserve Margin result in a similar level of capacity requirement for Georgia Power in an example year.[18]

[17] Docket No. 42310 Testimony of Messrs. Grubb, Smith, Bush and Weathers P. 10 Line 18 through P. 11 Line 5
[18] Docket No. 42310 Testimony of Messrs. Grubb, Smith, Bush and Weathers P. 18, Lines 1-9.



Q. HOW IS GEORGIA POWER GOING TO IMPLEMENT SEASONAL PLANNING?

A. A key step in planning a system with the minimum acceptable reliability is to establish a Target Reserve Margin. Utilities such as Georgia Power establish a year in which additional capacity is needed when the combination of retirement of existing generation capacity, the expiration of purchase power agreement(s), and growth in peak demand cause such a need.

> "Therefore, because the nature of the changing system has resulted in increased winter reliability risks, the Company is adopting seasonal planning to address the winter reliability issues previously identified in the 2016 IRP as well as a newly-identified reliability risk factor. Seasonal planning provides greater visibility into both summer and winter capacity needs rather than limiting reliability decisions to

> a single season. To facilitate this seasonal planning, the Company is adopting a Winter Target Reserve Margin for the winter season in addition to the traditional Target Reserve Margin focused on the summer season ("Summer Target Reserve Margin").[19]"

Q. WHY HAS THIS ISSUE BEEN RAISED IN THE CONTEXT OF THE RATEMAKING PROCESS?

A. The new planning for winter capacity needs appears not to have been integrated into Georgia Power's ACOSS and rate design proposals.

B. Georgia Power should incorporate seasonal planning into ACOSS

Q. DOES MR. VOGT ADDRESS SEASONAL PLANNING IN THE ALLOCATION OF GENERATION COSTS?

A. There is very limited mention of the seasonal planning in Mr. Vogt's testimony, which he feels reinforces the Company's use of its prior methodology to allocate generation based upon a customer group's 12-CP.

> "Since the last filed study, the use of this concept has been strengthened by the fact that the company is now planning for both summer and winter reliability constraints. The summer and winter reliability planning of the company further underscores that no one month or season is adequate at representing the coincident impact of customers on system capacity.[20]"

Q. WHAT DOES STAFF RECOMMEND?

A. Staff recommends Georgia Power perform an evaluation of the use of monthly coincident peaks reflecting more precisely the months where there is the potential for summer and

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[19] Docket No. 42310 Testimony of Messrs. Grubb, Smith, Bush and Weathers P. 15 Line 13 through P. 15 Line 2

[20] Testimony of Mr. Vogt P. 15 Lines 17-22

winter peak demands to occur. This could be done by utilization of an up to 8 CP approach, reflecting a proper balance of assignment of fixed costs to both summertime and wintertime peaks.

Q. DOES THE 12-CP METHODOLOGY CAPTURE THE WINTER LOAD IN DETERMINING THE ALLOCATION OF GENERATION AND SOME OF TRANSMISSION COSTS?

A. Yes, it partially captures this. The 12-CP approach to spreading fixed costs emphasizes every month of the year (including months in which system peak demands are unlikely to occur), and not just the months where winter or summer peak demand are more likely to occur.

C. Tiered Seasonal Pricing to Domestic Customers

Q. YOU NOTED THAT PLANNING FOR WINTER RELIABILITY APPEARS TO HAVE NEITHER BEEN FULLY FACTORED INTO THE COMPANY'S ACOSS MODEL NOR THE COMPANY'S PROPOSALS FOR ITS RATE DESIGN. PLEASE EXPLAIN.

A. The largest group of Georgia Power customers, close to 1.9 million of them, are domestic (residential) Rate R customers. Rate R features an *inclining* block energy rate for summertime usage, which is intended to send a price signal that as consumption increases, so likely do system costs as described in the Company's testimony.[21]

[21] Refer to Legg oral testimony at hearing, transcript p. 801, lines 6-8.

However, after describing in its IRP and Mr. Vogt's testimony how it is now focusing on planning for wintertime peak requirements, the Company has inexplicably retained a moderately *declining* block rate for wintertime consumption. According to the Company, this rate structure has been in place for close to 50 years.[22]

Q. DO ANY OTHER OF THE COMPANY'S RATES FEATURE A DECLINING BLOCK CHARGE FOR WINTERTIME USAGE?

A. Yes. The Small Business Group Time of Use – Energy Only (TOU-EO) rate features a steeply declining block rate structure for the winter season.

Q. WHAT ARE THE PROBLEMS WITH SUCH A RATE STRUCTURE?

A. Just as the *inclining* block rate structure during the summer sends a price signal that as consumption increases, so likely do system costs, a *declining* block rate structure sends the opposite price signal that as consumption increases, system costs, at least system unit costs of service, decline. A price signal embedded within any wintertime rates which incents wintertime usage is clearly in conflict with the Company's winter seasonal planning posture and a likely increasing winter system cost structure as the Company plans for winter reliability.

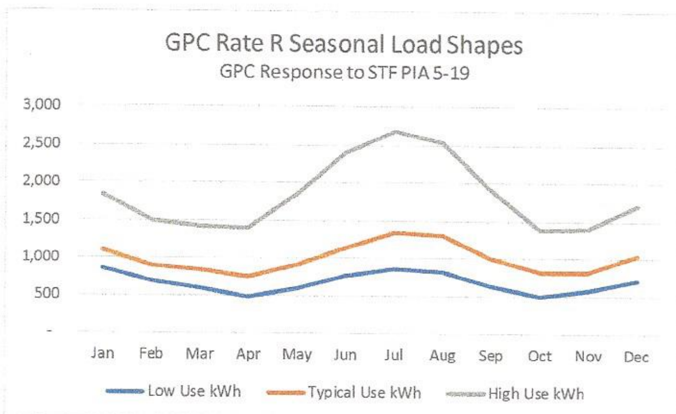
Q. HAS STAFF EXAMINED SEASONAL CONSUMPTION PROFILES FOR GEORGIA POWER DOMESTIC CUSTOMERS? IN OTHER WORDS, IS THIS

A. Yes.

[22] Refer to Company response to STF-PIA 5-20.

Q. BASED ON THIS EXAMINATION, DO THE RATE STRUCTURE CONCERNS STAFF HAS IDENTIFIED REALLY A PROBLEM THAT COULD AFFECT GEORGIA POWER SYSTEM WINTERTIME DEMANDS AND ATTENDANT COSTS?

A. Yes. As the graphic below indicates, for the Company's average low use and typical use customers, wintertime consumption is now either matching or approaching their summertime consumption, respectively.



Q. WHAT DOES STAFF RECOMMEND AS A REMEDY?

A. We recommend that the Commission, in addition to any other rate design changes its finds necessary, order the Company to revise its wintertime declining block rates to a flat energy rate.

Staff recommends that the Commission direct the Company to, by the time it files its next general rate case, examine its block rate structure for Rate R and TOU-RN rates. The Company should determine whether, going forward and in consideration of its wintertime reliability planning and related costs, an *inclining* block rate similar to that in place for summertime usage should be implemented.

In the meantime, Staff recommends the Commission direct the Company to immediately revise its wintertime declining block rate to a single uniform energy rate with its compliance filing in this case, for the reasons just discussed.

V. RATE DESIGN & LOW USE CUSTOMERS

Q. YOU PREVIOUSLY SUGGESTED CHANGES TO THE GEORGIA POWER SEASONAL BLOCK RATE STRUCTURE FOR DOMESTIC CUSTOMERS. ELSEWHERE IN YOUR TESTIMONY, YOU DESCRIBE THE BILL IMPACTS OF THE COMPANY'S PROPOSED BASIC SERVICE CHARGE INCREASE ON LOW USAGE CUSTOMERS. HAVE YOU MADE ANY OTHER FINDINGS WITH RESPECT TO BLOCK RATES AND USAGE PROFILES, ESPECIALLY FOR LOW USE CUSTOMERS?

A. Yes. We have examined the cumulative consumption curves of Rate R customers to determine whether the Company's proposed continuation of block rate consumption breakpoints was appropriate.

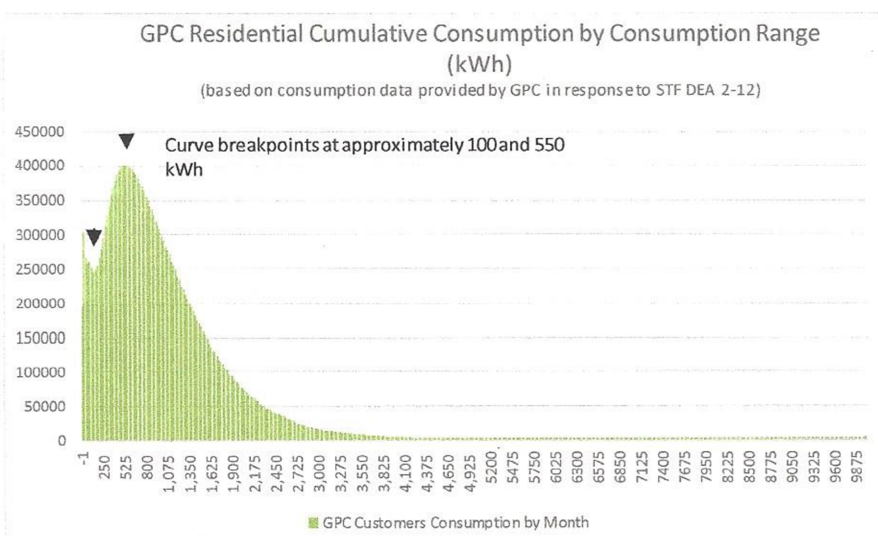
A cumulative consumption profile is used to determine appropriate breakpoints in block energy rates. Inflection points in the curve highlight where cumulative consumption patterns between lower and higher use customers diverge, and therefore the appropriate block rate design breakpoints.

Recall that the Company's proposed Rate R block structure, in addition to featuring inclining summer and declining winter block rates, is tiered based on consumption level. Specifically, Rate R provides three separate energy rates depending on consumption level. The first block of usage has been set for monthly consumption from 0-650 kWh, the second from 650-1000 kWh and the third block rate applies to consumption > 1000 kWh.

This block structure has been in place for close to fifty years (Transcipt Day 2, Legg, p. 799).[23]

Q. WHAT DOES STAFF'S ANALYSIS REVEAL?

A. From the analysis, the annualized cumulative consumption profile for residential Rate R customers is shown below:



[23] IBID

From this analysis, we conclude that the Company's first block cutoff at 650 kWh is in the ballpark of a natural breakpoint in cumulative consumption, but about 100 kWh higher than what the profile implies the cutoff should be.

There is also a substantial segment of low use Georgia Power Rate R customers using 100 – 150 kWh or less monthly.

Q. WHAT DOES THIS IMPLY?

A. We have several observations from this analysis.

First, the Company's first block rate from 0-650 kWh applies to customers with distinctly different usage patterns between very low use and what the Company deems as average low use customer consumption. It may be appropriate to develop an ultra low use block rate for Rate R residential customers, applying to usage of say 100 – 150 kWh or less per month.

Second, the Company's first block rate may be set a bit too high at a 650 kWh breakpoint; there is a natural group of customers consuming at between 100 – 150 kWh to about 550 kWh.

Finally, there doesn't appear to be any particular reason for a block rate applying to usage above 1000 kWh per month since there is no natural grouping of such higher use customers, other than for rate continuity purposes.

Q. BASED ON THIS ANALYSIS , WHAT DOES STAFF RECOMMEND?

A. While the Company focuses in this application on the introduction of modern rate designs,[24] it has not addressed indicated rate design changes to its current, most widely-subscribed residential Rate R, most notably regarding its declining winter block rate.

We recommend that the Commission order the Company to reexamine and restructure its Rate R block breakpoints with its next general rate case application.

VI. MODERNIZATION OF RATES

A. Foundations for Modern Georgia Power Rate Design

Q. COMPANY WITNESS DR. FARUQUI FOCUSES HIS TESTIMONY LARGELY ON MODERNIZING RATES, WHY IT MAKES SENSE IN TODAY'S ELECTRIC UTILITY SERVICE ENVIRONMENT, AND PROVIDES A BLUEPRINT FOR GEORGIA POWER RATE DESIGN GOING FORWARD. HAS HE CORRECTLY CHARACTERIZED WHERE THE INDUSTRY IS HEADED IN TERMS OF RATEMAKING ADVANCES?

A. Yes. Dr. Faruqui has correctly captured the trend of modernizing rates, however Staff disagrees that Dr. Faruqui has provided the appropriate blueprint for how to accomplish that. Some of his proposed rate designs, particularly 3-part rates for residential customers which include a demand charge based on peak demand during a month, are not only controversial in some jurisdictions, they also may fail to send appropriate price signals,

[24] See especially the prefiled direct testimony of Company witness, Dr. Faruqui.

violating the Bonbright ratemaking principle of *economic efficiency* upon which he relies as support for his recommended reforms.

In addition, the Company's limited success at marketing time of use rates to residential customers in particular suggests that the Company should proceed slowly and cautiously as it implements more modern rates, otherwise the Bonbright principles of *gradualism, bill stability and customer satisfaction* may be violated as well as it rolls out its modern rate design reforms.

B. Three-Part Rates

Q. PLEASE EXPLAIN THREE PART RATES.

A. On pp. 7-9 of his testimony, Dr. Faruqui asserts that Bonbright says:

> "…the most cost-reflective rate[25] is a three-part rate that combines:
>
> 1. A fixed monthly charge to recover the full costs of billing, metering and customer service and sometimes it also includes a minimum distribution system element.
>
> 2. A demand charge for recovering distribution capacity costs that is often recovered on a non-coincident peak basis. Sometimes the demand charge will also include the cost of transmission capacity and the cost of generation capacity; but the practice varies by utility.
>
> 3. A time-varying energy charge for recovering energy costs that may include the cost of transmission capacity and the cost of generation capacity. This could take one of many forms, such as a simple time-of-use rate, a critical-peak pricing rate, a variable-peak pricing rate, or a real-time pricing rate."
> (footnote added).

[25] And, presumably the most *economically efficient* rate that also promotes consumer *equity*. Refer to Faruqui prefiled direct testimony, p. 8, lines 11-12.

Dr. Faruqui goes on to note that "the precise structure of the rate varies by utility. Sometimes the demand charge is based on non-coincident demand, and sometimes on coincident demand."

Q. DOES STAFF DISAGREE WITH THESE STATEMENTS?

A. As discussed earlier, we do not agree that the fixed monthly customer service charge should include an MDS element. Staff would also take exception to a demand charge that is based on a customer's non-coincident peak demand.

Q. WHY DOES STAFF OBJECT TO A DEMAND CHARGE THAT IS BASED ON A CUSTOMER'S NON-COINCIDENT PEAK (NCP) DEMAND?

A. We reject the notion that such a demand charge sends the proper price signal, and is therefore *economically efficient* and promotes consumer *equity*.

A demand charge based on a customer's NCP sends a poor price signal, because it is incurred regardless of when a customer's NCP occurs. If the NCP occurs outside of the Georgia Power system peak hours, when there is excess capacity, it is not leading to higher generation and transmission, and possibly even distribution costs. If that is the case, it is not equitable. That customer is contributing the same towards meeting system peak demand costs as a customer whose NCP occurs coincident with the Georgia Power system peaks, yet the non-system coincident peak customer is not causing any increased Georgia Power system peak cost.

It is not economically efficient in such a case, because a customer with a non-system coincident, NCP demand is likely improving overall system load factor by utilizing excess system capacity without causing increased system costs. A greater overall system load factor is economically efficient. But in such a case where a customer with the non-system coincident, NCP demand is being charged for and discouraged from using electricity in those non-system coincident peak hours, that objective is frustrated.

Another critical flaw with a demand charge based on maximum monthly demand is that absent any tools for monitoring consumption profiles, which will be discussed next, customers are unlikely to know when they are reaching their peak demand. In that case, they are in no reasonable position to be able to control it, which leads to bill instability and overall consumer dissatisfaction.

Q. ALTERNATIVELY, WHAT PEAK DEMAND BILLING DETERMINANT WOULD SEND A BETTER PRICE SIGNAL, REFLECT COST CAUSATION AND PROMOTE ECONOMIC EFFICIENCY?

A. A demand charge that is based on Georgia Power system coincident peak demand or a short pre-defined window of time when such system coincident peak demand is likely to occur, otherwise known, respectively, as a coincident peak demand charge or as a time-of-use demand charge.

If a customer could be alerted to when the Georgia Power system coincident peak is being reached, said customer would be in position to alter their demand and/or shift their peak demand to non-system coincident peaks, which would promote economic efficiency and customer satisfaction. The problem is there doesn't appear to be any rigorous Georgia Power communications systems in place to alert customers when a system coincident peak is being reached.

For all of the foregoing reasons, we recommend that, should the Commission ever approve any widespread residential demand charges, they be based on peak demands that are known to be coincident with Georgia Power system peaks as in a coincident peak demand charge, or likely to be as in a time of use demand charge.

C. Domestic Rate Class TOU Rates

Q. DOES THE COMPANY CURRENTLY HAVE ANY RESIDENTIAL TARIFFS WITH A DEMAND CHARGE?

A. Yes. In the Company's 2013 Base Rate Case (Docket No. 36989-U), the Commission approved the time of use – residential demand (TOU-RD). The demand charge billing determinant is, unfortunately, based on maximum demands whenever they occur, not a coincident peak or time-of-use based demand determinant.

Q. WHAT RECOMMENDATIONS DOES STAFF HAVE REGARDING THE TOU-RD RATE DESIGN?

A. We recommend that the Commission order the Company to revise the TOU-RD tariff so that the demand billing determinant is based on short predefined window of no more than 3-4 hours during which the Georgia Power system is virtually certain to peak.

D. Elimination of R-Rate to New Premises as of January 1, 2020

Q. DESCRIBE THE COMPANY'S PROPOSAL TO NO LONGER OFFER THE RESIDENTIAL RATE TO CUSTOMERS ESTABLISHING SERVICE IN "NEW" PREMISES AS OF JANUARY 2020.

A. On page 12 of the testimony of Company witness Legg, he asserts that the Company proposes to modify the R tariff to make it unavailable to new residential premises beginning in January 2020. He expounds further to say that utilities across the country are rapidly moving away from traditional volumetric rate designs to more modern rate designs that send price signals that more appropriately reflect costs.

Q. SHOULD THE COMPANY ALLOW NEW PREMISES BUILT AFTER JANUARY 2020 TO SIGN UP FOR THE RESIDENTIAL STANDARD RATE (R-23)?

A. Yes. Staff supports marketing and education to grow customer adoption of modern rates in the Georgia Power service territory to encourage customers to choose rates that can both benefit customers and the economic usage of the Georgia Power system. Staff, however, does not support the monopoly utility provider in the service territory eliminating a choice for customers. The default tariff option of the Time of Use-Residential Demand (TOU-RD) rate will be confusing to new customers who may not have enough education or access to data to minimize their bills. In addition, the Company has not provided a clear definition of how it might define new premises under the tariff. With the expansion of energy efficiency options, smart home technologies, and individualized home data analytics, Staff believes that Georgia Power has an opportunity to educate customers and work with new home developers, realtors, and other community stakeholders to encourage adoption of modern rates in new premises, but Staff does not deem it appropriate to prevent any residential customers from choosing the residential standard rate at this time.

Q. IF THE COMMISSION DECIDES TO ADOPT THE COMPANY'S PROPOSAL AND CLOSE THE DOMESTIC CLASS R RATE TO NEW PREMISES, DOES STAFF HAVE RECOMMENDATIONS FOR A MORE GRADUAL IMPACT ON CUSTOMERS?

A. Yes. The Company has proposed that the TOU-RD rate automatically become the default rate for any customers closed out of Rate R due to the Company's proposed elimination of that rate option for customers that occupy "new" premises starting in January 2020.[26] In large part because Georgia Power residential customers are unfamiliar with demand charges, and partly due to the flaws in the existing TOU-RD rate demand billing determinant as explained above, Staff recommends that if the Commission is inclined to foreclose the Rate R option to any new customers, the default rate they would be put under absent any chosen alternative, should be the Time-of-Use – Energy Only (TOU-EO) tariff. New and existing Georgia Power customers stand a better chance of understanding the price signals provided by a time of use energy rate applicable to system peak and other non-peak hours, and adjusting their energy usage accordingly.

[26] Refer to Legg prefiled direct testimony, p. 12, lines 18-28.

We also observe that the proposed change in the tariff to implement a TOU option as the default for customers closed out of the Rate R option is not clear on what defines a "new" premises. Questions that come to mind include the following: Is a new premises a new building on a new footprint/foundation? Can a new premise be interpreted as a remodeled, expanded or rebuilt dwelling on an existing footprint/foundation? Staff recommends that the Company be ordered to more specifically define in its tariff what would constitute a "new" premises if the Company's proposal is adopted.

Furthermore, in keeping with the ratemaking principles of gradualism and customer satisfaction, Staff proposes to either exempt existing (prior to January 2020) Georgia Power customers from this new Rate R foreclosure provision, even if they move to a new premise, or allow any existing Rate R customers in Georgia Power territory that are moving into new premises an ability to opt-in to Rate R. Staff recognizes this would reduce the test pool of new customers forced onto a more modern TOU-based rate, but it would still provide the Company and a small fraction of its domestic customers with experience under a modern TOU-based rate design, and the ability of the latter to adapt their energy use in alignment with the price signals embedded in the newer more modern rates. Staff is in favor of increased customer adoption of modern rates, but the most gradual approach that promotes customer satisfaction is through customer marketing and education, rather than limiting customer choice.

E. Company Marketing and the Acceptance of Modern Rate Designs

Q. DR. FARUQUI STATES IN HIS TESTIMONY THAT IN OTHER JURISDICTIONS WHERE MODERN RATE DESIGNS HAVE BEEN IMPLEMENTED, CUSTOMERS HAVE "HAPPILY ACCEPTED"[27] THEM. FURTHERMORE, HE ARGUES THAT CUSTOMERS HAVE FOUND SUCH DESIGNS "RELATIVE EASY TO UNDERSTAND."[28] WHAT HAS BEEN GEORGIA POWER'S EXPERIENCE?

A. In response to Staff data request,[29] Georgia Power indicated that only 1% of its 2.24 million domestic class customers have enrolled/opted into any kind of time of use rate option. Despite Dr. Faruqui's assertions, it is clear that for the Company's customers, few have understood, accepted, or opted into such modern rate designs.

Q. DOES DR. FARUQUI MAKE ANY RECOMMENDATIONS ON EASING CUSTOMERS' TRANSITION TO MODERN RATES?

A. Yes. In his testimony he offers several suggestions, including rolling out the new rates gradually, offering them initially on an opt-in basis prior to making them mandatory or default rates, implementing them for customers establishing new service, and developing customer education and marketing campaigns on new rate options.[30]

Q. DO YOU AGREE WITH HIS RECOMMENDATIONS?

A. Yes, again in consideration of key ratemaking principles of gradualism, customer acceptance and satisfaction, bill stability and eventually, economic efficiency. The

[27] Refer to Faruqui prefiled direct testimony, p. 13, line 25.
[28] IBID, p. 10, lines 4-5.
[29] STF-PIA 5-12.
[30] Refer to Faruqui prefiled direct testimony, p. 12, lines 3-15.

Company has been aggressive in marketing its Flat Bill program (which does not send price signals but has been a choice for certain customers and is more appealing than other options to survey participants) and its Pre-Pay program (which likewise is a choice for certain customers who have had difficulty with bill payments and have incurred or are seeking to avoid additional deposits as would be required under the R-rate, and is appealing to survey participants). Staff believes this marketing has been consistent, measured, and led to ongoing growth in adoption of these rate options. Staff believes that the Company can also expand customer interest in modern rates through traditional and modern marketing and increasing customer education and information, including the expansion of data access as discussed later in this testimony.

F. Supporting Infrastructure required with Mandatory TOU Rates

Q. AS NOTED IN THE TESTIMONY OF COMPANY WITNESSES DR. FARUQUI AND MR. LEGG, IT IS CLEAR GEORGIA POWER BELIEVES THE TIME HAS COME TO BEGIN TO IMPLEMENT MODERN RATE DESIGN REFORMS. HAS THE COMPANY ESTABLISHED THE REQUISITE COMMUNICATIONS AND TOOLS NECESSARY TO EXPLAIN AND MARKET THESE OPTIONS TO ITS CUSTOMERS?

A. No. The Company and its customers seem remarkably unprepared at this point. For instance, less than 1% of residential customers have signed up for the TOU rate and Dr. Faruqui under cross examination agreed that the number is very small (Transcript (Tr.)

719). This undersubscription indicates a failure by the Company thus far in its marketing of these options.

In addition, the Company has noted that it does not make hourly data available to customers who could use that information to compare rate options, nor does it have any "shadow billing" infrastructure or online bill calculator tools which customers could use to evaluate how they would fare under modern rate design proposals touted by the Company (Tr. 744-745).

In short, we find that the Company's residential customers in particular are left ill-equipped to understand how the Company's proposed modern rates would affect them and their bills.

VII. ADDITIONAL RATE DESIGN CONCERNS

Q. THE COMPANY HAS MADE NUMEROUS OTHER PROPOSALS WITH REGARD TO RATES. PLEASE DISCUSS SOME OF THESE AND YOUR FINDINGS AND RECOMMENDATIONS.

A. Below we address a number of related issues and the policy foundation for any recommendations.

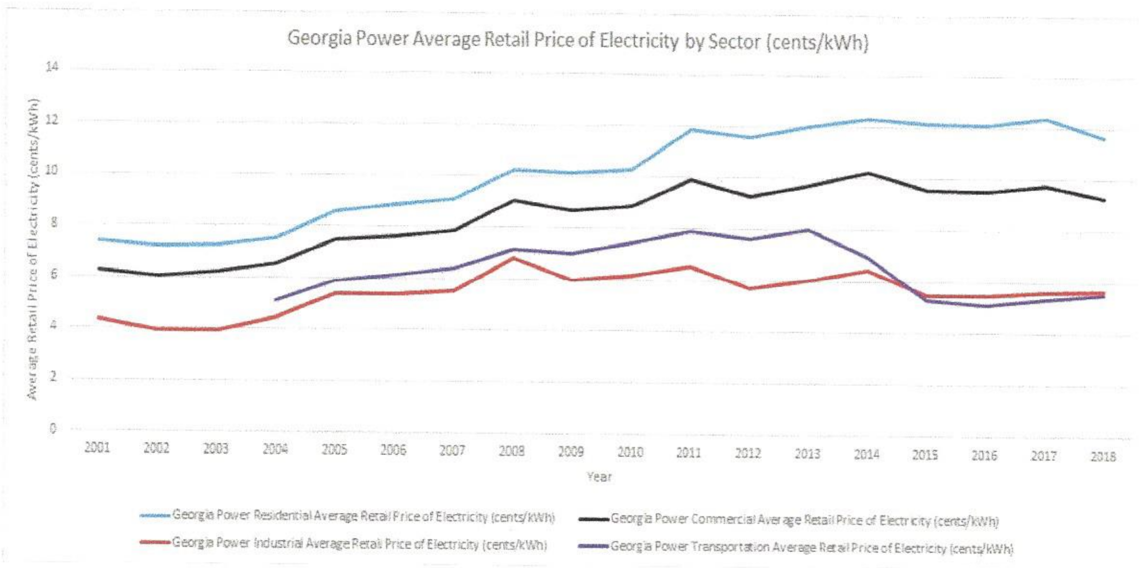
A. Parity among the Rate classes

Q. THE COMPANY'S ALLOCATED COST OF SERVICE STUDIES FILED IN SUPPORT OF ITS RATE CASES HAVE GENERALLY FOUND THAT RESIDENTIAL CUSTOMERS HAVE BEEN UNDER-CONTRIBUTING TOWARDS THEIR ALLOCATED COST OF SERVICE, WHILE OTHER CUSTOMERS HAVE BEEN OVER-CONTRIBUTING. IN GENERAL, IS ACHIEVING PARITY AMONG THE RATE CLASSES IN TERMS OF THEIR ALLOCABLE CONTRIBUTION TO COST OF SERVICE AND SYSTEM-WIDE RATE OF RETURN AN IMPORTANT OBJECTIVE IN DESIGNING RATES?

A. Yes, for the very reasons of satisfying the *economic efficiency* and consumer *equity* ratemaking principles espoused by the Company and referred to in our testimony.

Q. HAS THE GEORGIA PUBLIC SERVICE COMMISSION ORDERED, AND THE COMPANY ACHIEVED, MOVEMENTS TOWARDS RATE PARITY OVER TIME?

A. Yes, as demonstrated by graphic generated by Staff (based on EIA data),



it can be seen that since 2001, residential average rates have been escalating at a faster pace than they have for other commercial and industrial classes. This indicates that the overall class contribution to Georgia Power cost of service and revenue requirements for the residential customers has been growing, and that of industrial customers has been declining. The Commission appears to have been successful in approving rates that move towards parity, all the while balancing against a host of other ratemaking objectives.

B. Low Income Customers

Q. **PLEASE DESCRIBE ACTIONS TAKEN BY THE COMPANY TO ADDRESS THE CONCERNS OF LOW-INCOME CUSTOMERS.**

A. As described in the testimony of Mr. Legg[31], the Company is eliminating Authorized Payment Location (APL) fees used by many Pre-Pay customers, as well as credit and debit card transaction fees. The Company believes, and we agree, that this should

[31] Legg prefiled testimony, pp. 18-19.

"...reduce the impact of fees to many lower income customers as they are the predominant users of this payment channel."[32]

Staff believes this is particularly appropriate given that in 2017 [33], the Company closed its customer service offices where customers could pay their bills free of such charges. This will be particularly helpful for unbanked or underbanked customers for whom cash payments at an APL may be the only payment option considering the Company's cost-saving decision to close its customer service offices since the previous rate case. Staff recognizes that the all other customers will absorb these transaction costs, expects the Company to seek to minimize these expenses in any case and finds this measure appropriate. Staff does recognize that this will not reduce the burden of rate increases on all low-income customers, since not all low-income customers pay their bill in a manner that involves fees.

Q. DOES STAFF HAVE ANY OTHER RECOMMENDATIONS REGARDING THE COMPANY'S POLICIES FOR LOW-INCOME CUSTOMERS?

A. Yes. During the direct hearing, Company Witness Legg was asked about the Company's Senior Low-Income Discount program.[34] He noted that the up to $24/month discount qualification is based on the Federal Poverty Limit guideline.

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[32] IBID, p. 19, lines 6-7.
[33] http://www.walb.com/story/35818808/ga-power-all-businesses-offices-to-close-payment-locations-still-open
[34] Transcript Day 3, Legg, pp. 904-906.

Upon further questioning, he testified that this discount is applied at the *household* level, not on the number of qualifying low-income individuals living at that household, say a married couple each with $15,000 in annual income.

Q. DOES STAFF HAVE ANY RECOMMENDATIONS REGARDING THE APPLICATION OF THIS DISCOUNT?

A. Yes. We recommend that this discount should be available to households with two senior citizens with combined incomes that fall below 200 percent of the federal poverty guidelines for a two-person household. We further recommend that the program, and the assistance it provides, be reconfigured to provide the same level of discount to each qualifying household member so that the assistance flexes with the number of qualifying members of the household even if at a commensurately lower level in order to keep the dollars associated with the discount the same.

Q. SHOULD THE COMPANY CONSIDER EXPANSION OF ITS ASSISTANCE PROGRAMS TO OTHER INCOME QUALIFIED CUSTOMERS?

A. Yes. Staff recommends consideration of an expansion of income qualified discount opportunities. As noted in cross examination to the Company's direct testimony, there was not a significant discussion of low income customers and high energy burdens in how the Company proposed its rate design, except with regards to the decision to eliminate payment fees as a potential benefit to many of these customers among others.[35] Staff believes that the Company should be required to address the needs of high energy burden customers, including customers who are not yet senior citizens. Staff

[35] Transcript Day 2, Legg, pp. 814-817.

intends to work with the Company to facilitate an Income Qualified Customer Working Group following the model of the Demand Side Management Working Group to encourage data collection, research, and analysis to seek to leverage the Company's assistance programs to income qualified customers, including discounts, and to inform the Company's next rate case or an interim proceeding to adopt pilot discount options.

C. Tariff Inequities and Consolidation

Q. DOES STAFF HAVE ANY OTHER RECOMMENDATIONS REGARDING THE COMPANY'S RATE DESIGN PROPOSAL FOR SIMILARLY-SITUATED COMMERCIAL CUSTOMERS?

A. Yes. During cross-examination Mr. Legg[36] was asked about the history and application of time of use rate for schools and multiple businesses. In that line of questioning, it was revealed that the TOU-MB rate was available only to franchise-run and owned restaurants, but not individually-owned franchise label or non-franchise restaurants.

Q. WHAT ARE YOUR CONCERNS?

A. That line of questioning revealed a likely consumer *equity* imbalance in the Company's application of its tariff requirements and benefits.

The TOU-MB rate features a beneficial off-peak and super off-peak rate design. The concern is that it is an example of how similarly-situated customers who may individually own a franchised restaurant, or their own brand restaurant, with hours of

[36] Transcript Day 2, Legg, pp. 906-913 and pp. 925-928

service and a common consumption profile to TOU-MB customers, do not receive the benefit of the rate merely because of a tariff definition.

For Staff, this highlights the need to examine all of the Georgia Power commercial and industrial tariffs for similar inequities. We recommend that the Commission order the Company to do so. Further, the Company should consolidate customers on less-beneficial tariffs into the rate classes with more beneficial tariffs under which they would otherwise qualify but for such a meaningless distinction as in the above example.

Q. **DOES STAFF SUPPORT THE COMPANY'S PROPOSED CHANGE TO CLOSE THE OUTDOOR LIGHTING GOVERNMENTAL ("OLG") AND OUTDOOR LIGHTING NON-GOVERNMENTAL ("OLNG") TARIFFS EFFECTIVE JANUARY 2020?**

A. Yes. Staff agrees that the customer and technology driven transition towards Light Emitting Diodes (LEDs) for outdoor lighting supports this change. This is a good example of the market justifying the closure of an increasingly outdated tariff option.

Q. **DOES STAFF SUPPORT THE COMPANY'S PROPOSED LANGUAGE CHANGES AS OUTLINED IN ITS FLAT-5 TARIFF?**

A. No. Staff does not support the proposed Flat-5 tariff. Our concern is with certain deletions and insertions proposed by the Company. The Company removed the 12-month history requirement in the deleted language of the applicability requirements for customers to "…have been in their current residence over the previous 12 months, have had their electricity priced on the "Residential Service" or "FlatBill" tariff over the previous 12 months, …" and proposes to make FlatBill applicable to residential customers "***located at premises*** having no less than 12 months of metered usage history…"(***emphasis added***). **These changes would allow new Georgia Power customers, when establishing their account, to choose the FlatBill tariff and be charged a monthly bill based on that premises, another household's, previous 12-month usage.**

Q. WHAT DOES THE CURRENT FLATBILL PRICING STRUCTURE REQUIRE?

A. The current FlatBill pricing structure was approved by the Commission in 2002. It requires: a one-year contract with billing based on a customer's 12-month historical usage on the Residential R rate *at that residence*, includes a Risk Adder for excessive usage, offers no true-up and provides for renewal with a new offering based on the previous 12-month usage and a comparison to the Residential rate.

Q. DESCRIBE THE GENESIS OF THE PROPOSED CHANGES TO THE CURRENT FLATBILL TARIFF.

A. Around Fall 2017, the Company approached the Commission Staff with a proposal to conduct pilots which might be requested to be made permanent in the 2019 Base Rate Case. Staff met with the Company to discuss proposed Pay By Day and FlatBill First Year pilots. After several discussions and proposed changes agreed to by the Staff and the Company, the pilots were launched.

Q. HOW MANY CUSTOMERS WERE OFFERED AND TOOK THE FLATBILL FIRST YEAR OFFERING?

A. For the FlatBill First Year (6-month pilot), 529 customers signed up with a 53% take rate. For the FlatBill First Year (12-month pilot), 454 customers signed up with a 53% take rate.

Q. **ARE YOU AWARE OF ANY OTHER UTILITY THAT HAS A SIMILAR RATE OFFERING?**

A. No, we are not. When Staff met with the Company to discuss the FlatBill FirstYear pilot, which is now being proposed to be made permanent, Staff asked whether any other utility or even Georgia Power's own customers has asked for this. Their response was they were not aware of any other utility with a similar offering but they had received some requests from some customers for this type of offering.

Q. **DID STAFF HAVE CONCERNS THAT CUSTOMERS CHOOSING THE FLAT BILL PILOT COULD BE OVERBILLED OR UNDERBILLED AS COMPARED TO THE RESIDENTIAL R RATE UNDER THIS BILLING STRUCTURE?**

A. Yes, Staff had and continues to have these concerns. As discussed above, for customers selecting FlatBill for the first year's contract, the current FlatBill tariff requires a customer's *12-month historical usage on the Residential R tariff living at that residence.* FlatBill renewals are based on adjustments (either higher or lower) to the previous 12-month Flat Bill usage. Regarding overbilling, in addition to the Risk Adder already included in the calculation of the FlatBill, a customer could end up with a higher bill as compared to the Residential service rate simply due to the fact that the usage is not based on that resident's actual historical 12-month usage, as it is with the current Flat Bill tariff. Factors such as customer behavior and household size definitely determine the amount of electricity consumed. Likewise, the opposite could occur, where a customer ends up with a lower bill as compared to the R rate.

Q. **DID STAFF REQUEST INCLUSION OF CUSTOMER PROTECTIONS TO ADDRESS ITS CONCERNS IN THE PILOT?**

A. Yes, a provision was agreed to by Staff and the Company.

Q. **DOES THE FLAT-5 TARIFF LANGUAGE INCLUDE SUCH PROVISION?**

A. No it does not. Although the Company surveys show a high level of customer satisfaction with the pilot, we believe these changes will lead to possible overcharging and customer dissatisfaction, and complaints to this Commission.

Q. **WOULD THIS FLAT-5 TARIFF SEND APPROPRIATE PRICE SIGNALS TO CUSTOMERS AND ENCOURAGE THEM TO CONSERVE ENERGY?**

A. No, as mentioned above neither the current Flat Bill nor the proposed Flat Bill First Year Pilot send price signals to customers to conserve energy as customers have the ability to consume as much as they want during one 12-month period then switch to another rate option instead of re-enrolling and paying a higher flat bill to account for this high level of usage.

Q. **ALTERNATIVELY, WOULD STAFF SUPPORT A BUDGET BILLING OPTION FOR NEW CUSTOMERS?**

A. Yes. When meeting with the Company to discuss this offering for new customers, Staff insisted the Company conduct a BudgetBill First Year pilot. Currently, as with the

FlatBill requirements, customers are required to have 12-month usage history *at that residence.* However, unlike FlatBill, customers billed are trued up based on actual usage which eliminates the need for a Risk Adder. As compared with the FlatBill First Year Pilots, there was a 64% take rate with 828 signed up customers in 4 days.

Q. **WHAT DO YOU RECOMMEND TO PROVIDE NEW CUSTOMERS FLAT OR NEARLY FLAT BILLING OPTIONS?**

A. Although the Company has stated that it is evaluating offering the BudgetBilling First Year, based on the Company's survey results, the Staff recommends it begin offering, as of the effective date of the new rates approved in this proceeding, the Budget Billing option to new customers with the Company since there will be no harm to these customers as the customer's bill will be adjusted in a timely manner according to their actual usage.

Q. **DOES STAFF HAVE ANY ADDITIONAL CONCERNS REGARDING PROPOSED TARIFFS?**

A. Yes. As discussed above, there was a Pay By Day Pilot conducted. The Pay By Day Pilot combines PrePay with FlatBill so customers will pay a set price per day for electric service. It is a one-year contract with penalties as with FlatBill for unenrolling prior to the one-year period end and requires a customer's 12-month historical usage at that premises. There were 1024 participants with a 4.6% take rate (based on a mail campaign). According to the Company's survey, it had a high level of customer satisfaction. However, we have concerns with the level of education provided to customers when signing up for the Pay by Day tariff. The Commission's Consumer Affairs department has received a number of complaints from customers who may not have clearly understood the costs associated with unenrolling from the Pay by Day pilot. We would expect that the Company would educate its customers on such details prior to enrolling customers in such programs.

Q. DOES STAFF SUPPORT THE CHANGES THAT THE COMPANY HAS PROPOSED TO CUSTOMER FEES?

A. As noted earlier, Staff fully supports the elimination of APL, credit card and any other transaction fees for residential customers. Staff does not oppose the Company's proposal to increase the reconnect at pole fee or the underground residential distribution service fee to reflect the Company's actual costs of these specific services.

Q. HAS GEORGIA POWER PROPOSED ANY REVISIONS TO ITS DSM AND SOLAR RELATED TARIFFS?

A. Yes. The Company proposed revisions to both of its DSM tariffs, DSM-R and DSM-C. In its filing, the Company also requested approval of revisions to the RNR and Simple Solar tariffs.

Q. PLEASE DESCRIBE THE COMPANY'S REVISIONS TO THE DSM RESIDENTIAL AND COMMERCIAL TARIFFS.

A. The Company updated the Residential and Commercial DSM tariffs to recover the DSM expenses and Additional Sum that were proposed in the 2019 DSM Certification case as well as the under and over recoveries resulting from the true-up of the respective tariffs in prior years. The Company later filed an errata and updated portions of the DSM revenue requirements to reflect the Commission's decision in the 2019 DSM Certification case.

Q. FOR WHAT TIME PERIOD WILL THE PROPOSED DSM TARIFFS REMAIN IN PLACE?

A. The proposed DSM tariffs will remain in place through the end of 2020. Under the Company's proposed alternative rate plan, the Company will update each DSM tariff by November 1, to be effective January 1 of the following year.[37]

Q. DOES STAFF HAVE ANY CONCERNS REGARDING THE PERCENTAGES CONTAINED IN THE PROPOSED DSM-R AND DSM-C TARIFFS?

A. Yes. Due to the timing of the rate case filing, the Company's proposed DSM-R and DSM-C tariffs were based on its proposed DSM Budgets and Additional Sum[38]. The DSM budgets and Additional Sum that were ultimately approved by the Commission were different than the Company's request. As stated earlier, the Company filed errata which contained adjustments to the DSM revenue requirements and was also provided in response to STF-PIA 10-4.

Q. WHAT ADJUSTMENTS DOES STAFF RECOMMEND TO THE CALCULATION OF THE DSM-R AND DSM-C TARIFFS?

A. Staff is recommending two additional adjustments to the calculations of the DSM-R and DSM tariffs as shown in Staff Exhibits_ RS-RT. One adjustment is to lower the carrying

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[37] Refer to Legg prefiled direct testimony, page 11, lines 1-2.

[38] IBID, page 10, lines 22-25.

charges on the under recovered balance which is based on Staff's recommended return on equity (ROE) and the other adjustment is to the Income Expansion factor which was also adjusted to reflect lower the uncollectible expense.

Q. WHAT IS STAFF'S RECOMMENDATION REGARDING THE PROPOSED DSM-R AND DSM-C TARIFFS?

A. Staff recommends approval of the revised DSM-R and DSM-C tariffs as shown on Staff Exhibit BBDF-5.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED REVISION TO THE SIMPLE SOLAR TARIFF.

A. As first mentioned in the 2019 IRP, the Company plans to expand its Simple Solar program by adding an additional discounted pricing tier for Simple Solar Large Volume participants. As customer interest in the Simple Solar program continues to grow, Georgia Power has identified the need for greater flexibility for large customers.

In this filing, the Company requested to revise the Simple Solar program by adding an additional discounted pricing tier. Specifically, the Company proposes to revise the Simple Solar Tariff Large Volume Purchase Option pricing to change the 0.5¢ per kWh per month tier to the next 1,650,000 kWh of Renewable Energy Credits ("REC") rather than all remaining kWh of RECs. The Company also proposes to add a new pricing tier where all kWh of RECs exceeding 2,000,000 will be priced at the current REC market price offer at the time of the contract execution.

Q. PLEASE DESCRIBE THE COMPANY'S SIMPLE SOLAR PROGRAM.

A. As approved by the Commission on August 2, 2016 in Docket No. 40161 (Georgia Power's 2016 IRP), the Simple Solar program allows customers to participate by purchasing solar RECs for either 100% or 50% of their monthly usage by paying a 1 cent per kWh charge. This program also provides customers Large Volume and Special Event purchase options.

Q. DOES STAFF HAVE ANY CONCERNS REGARDING THE COMPANY'S PROPOSED REVISIONS TO THE SIMPLE SOLAR TARIFF?

A. No. Staff does not have any concerns regarding the Company's proposed revisions to the Simple Solar tariff. As proposed by the Company and stated in the Direct Testimony of Larry Legg, page 15, lines 20-23, the customer will cover their full administrative costs of participating in the program and with the Company's proposed revision, customers wanting to purchase large volumes of RECs will have more options available to meet their renewable energy goals.

Q. DOES STAFF RECOMMEND APPROVAL OF GEORGIA POWER'S PROPOSED SIMPLE SOLAR TARIFF REVISION?

A. Yes. Staff recommends approval of the Company's proposed revision to the Simple Solar (SS-1) tariff.

Q. PLEASE DESCRIBE THE CHANGES THAT THE COMPANY IS PROPOSING TO THE RNR-9 TARIFF.

A. The Company is proposing several changes to the RNR-9 tariff. The changes include;(1) eliminating the $2.82 monthly bi-directional metering charge, (2) adding alternating current ("AC") to the size limits of the generating capacity, requiring that the system generating capacity be based on the nameplate of the inverter(s), and (3) requiring that a customer provide a W-9 if requested by the Company, and requiring that a customer execute an interconnection agreement prior to being allowed to interconnect on its system. The Company also cleaned up the tariff by deleting references to Part 1 Energy Resources which was the prior Green Energy Program that ended after the 2016 IRP.

Q. DOES STAFF SUPPORT THE ELIMINATION OF THE BI-DIRECTIONAL METERING CHARGE?

A. Yes. Staff supports the elimination of the $2.82 monthly bi-directional metering charge. According to the response to STF-PIA 4-3, the cost recovery for reprogramming the meter is now included as part of the Interconnection Testing fee of $5/kW (Staff Exhibit BBDF-6).

The current solar avoided energy cost price is at a level where customers that push back their excess solar energy to the grid needed to export approximately 100 kWh each month to break even after paying this monthly charge. Therefore, many customers have chosen not to participate in the RNR tariff.

Q. WHAT ARE STAFF'S RECOMMENDATIONS REGARDING THE BI-DIRCTIONAL METERING CHARGE?

Staff supports the Company's request to eliminate the $2.82 monthly metering charge but recommends that the bi-directional metering charge remain listed on page 1 of the RNR tariff instead of being deleted as proposed by the Company. Instead of the current $2.82 per month, Staff recommends the words "No Charge" be added to the tariff. Staff is making this recommendation so that customers are aware that bi-directional metering is still an available option.

Q. DOES STAFF AGREE WITH THE COMPANY'S PROPOSED REVISION TO ADD "AC" TO THE SIZE LIMITS FOR THE ELIGIBLE RENEWABLE ENERGY RESOURCE GENERATING CAPACITY?

A. Yes. Staff agrees that the size limits of the renewable and nonrenewable projects should be in AC. Using AC is the Company's current practice although it has not been reflected in the RNR tariff.

Q. DOES STAFF AGREE WITH THE COMPANY'S PROPOSED REVISION THAT THE SYSTEM GENERATING CAPACITY OF ELIGIBLE RENEWABLE ENERGY RESOURCES BE BASED ON THE "NAMEPLATE CAPACITY" OF THE INVERTER(S)?

A. Yes. However, Staff recommends clarifying the Company's proposed revision, by replacing the term "nameplate capacity" - with "maximum continuous output power". For DC to AC generating facilities, the final limiting factor for power that is exported to the grid is the inverter(s). In response to STF-PIA-3, Georgia Power agreed that inverter nameplate capacity "refers to the maximum output power of the inverter(s) as documented on the equipment specifications." To avoid ambiguity, Staff recommends use of the term "maximum continuous output power" in the tariff to eliminate confusion related to selecting an inverter's theoretical maximum output or surge output as the specification that is used by the Company to enforce a system generating size limit.

Q. DOES STAFF HAVE ANY CONCERNS REGARDING THE PROPOSED REQUIREMENT OF THE CUSTOMER TO PROVIDE A W-9 IF REQUESTED BY THE COMPANY?

A. No. Staff does not have any concerns regarding this requirement by the Company.

Q. DOES STAFF AGREE WITH THE COMPANY'S PROPOSED REVISON TO THE RNR TARIFF THAT A CUSTOMER MUST EXECUTE AN INTERCONNECTION AGREEMENT PRIOR TO BEING ALLOWED TO INTERCONNECT?

A. Yes. Currently, customers are required to execute an interconnection agreement, as shown in Staff Exhibit_BBDF-7; however, this requirement had not been included in the RNR tariff.

Q. WHERE WILL A CUSTOMER BE ABLE TO LOCATE THE INTERCONNECTION AGREEMENT?

A. In the proposed RNR tariff, the Company states that the interconnection agreement will be available on the Company's website.

Q. ARE THERE ANY OTHER ISSUES THAT STAFF WOULD LIKE TO ADDRESS REGARDING THE RNR TARIFF?

A. Yes. During the Direct Hearing, Company Witness Larry Legg was asked how the Company currently nets the energy that is exported to the grid from a behind the meter solar system. The Company's current practice is to compensate all kWhs that are exported to the grid at the Company's solar avoided cost. This process was referred to as "instantaneous netting" (Tr. 863).

Q. ARE THERE OTHER "NETTING" APPROACHES CURRENTLY BEING USED TO COMPENSATE CUSTOMERS FOR THEIR SOLAR EXPORTS?

A. Yes. Some utilities utilize a monthly netting approach. Under this approach, a customer's daily solar exports for that month are added together and then subtracted from their purchases from the utility.

Q. DOES STAFF HAVE A POSITION REGARDING HOW THE COMPANY IS NETTING SOLAR EXPORTS?

A. In the past, Staff has had discussions with the Company regarding its netting policies and compliance with The Georgia Cogeneration and Distributed Generation Act of 2001 ("Cogen Act"). Staff is aware that there are other interpretations of how the Cogen Act should be implemented and reflected in the Company's RNR tariff. Staff is waiting to hear the arguments of other parties before taking a legal position. However, whatever the Commission ultimately decides on this issue, the payment that customer's receive for this energy should be clearly reflected on the Company's RNR tariff.

Q. IN ADDITION TO THE PROPOSED REVISONS TO THE RNR TARIFF, DID THE COMPANY ALSO PROPOSE REVISIONS TO ITS RULES AND REGULATIONS FOR CUSTOMER GENERATORS?

A. Yes. The Company is proposing to add Section G. Customer Generation to its Rules and Regulations. The proposed language, among other things, requires all customers who intend to install a customer generation facility to execute an applicable interconnection agreement prior to being allowed to interconnect on the Company's distribution system.

Q. WHAT OTHER REQUIRMENTS DOES PROPOSED SECTION G OF THE RULES AND REGULATIONS REQUIRE OF CUSTOMER GENERATION?

A. Proposed Section G of the Rules and Regulations also requires customers that receive service on the distribution circuit and want to install behind-the-meter generation to adhere to the Company's interconnection process and operations requirements. In addition, customers' systems that are sized 250 kW and above for either stand alone or behind-the-meter must undergo witness testing.

Q. WHERE WOULD A CUSTOMER FIND OUT MORE INFORMATION REGARDING THE COMPANY'S INTERCONNECTION PROCESS AND OPERATIONS REQUIREMENTS?

A. According to the proposed language in Section G, the public can find out more regarding these requirements in the "Behind-the-Meter Distribution Interconnection Summary" on the Company's website.

Q. DOES STAFF RECOMMEND APPROVAL OF THE PROPOSED SECTION G TO THE COMPANY'S RULES AND REGULATIONS?

A. Yes. However, Staff recommends that the Company be required to have a designated link that is easy for customers to find that contains the required interconnection and operations information.

VIII. CUSTOMER USAGE DATA

Q. DOES THE COMPANY CURRENTLY PROVIDE ITS CUSTOMERS ACCESS TO ENERGY USAGE INFORMATION?

A. Yes. Customers on the R-tariff are provided access to their daily usage information through My Power Usage. Residential customers on other residential tariffs, including time of use rates, do not have access to My Power Usage. Commercial customers are provided usage data through Energy Direct and there are subscription levels available ranging in cost from free to $150 per month (Response to STF-PIA-7-1).

Q. DOES THE COMPANY CURRENTLY HAVE THE ABILITY TO PROVIDE HOURLY USAGE INFORMATION TO ITS RESIDENTIAL CUSTOMERS?

A. No. The Company is not currently able to provide hourly usage data to its residential customers. As stated by Company witness, Larry Legg during the direct hearing it is something that the Company is considering and has evaluated in the past (Tr. 819).

Q. WHEN DID STAFF FIRST RAISE THE ISSUE REGARDING THE COMPANY PROVIDING HOURLY DATA TO ITS RESIDENTIAL CUSTOMERS?

A. Staff first raised this issue during the 2013 Georgia Power Rate Case. In the 2013 case, Staff's recommendation was "that the Commission require the Company to further investigate the need for, and costs associated with, providing hourly usage information to all metered customers. Further, Staff recommend[s] that the Company be required to file this information within six months of the Commission Order in this docket." (Direct Testimony of Watkins and Barber, page 59, lines 1-4) As part of the rate case settlement, the Company agreed to further investigate the need for and the costs associated with providing hourly usage data to all metered customers.

Q. WHAT WAS THE RESULT OF THE COMPANY'S INVESTIGATION?

A. In a June 23, 2014 filing, the Company stated that the cost to provide hourly usage data to all metered customers would be approximately $4.2 million for initial investment in additional IT infrastructure (storage capacity) and another $1.2 million per year for ongoing support costs. Staff Exhibit BBDF-8.

Q. WHY IS ACCESS TO HOURLY USAGE INFORMATION IMPORTANT?

A. Staff is of the opinion that providing customers usage information on a daily aggregate basis does not provide enough information to customers so they may better manage their energy usage and their overall energy consumption. Hourly usage data will allow customers to make wiser energy decisions to change behavior and possibly even save on their electric bills. The Company is requesting to "modernize" rate options for their customers. Hourly usage data would allow customers to understand the implications of demand charges, time of use, and other features of modern rate design. Without access to the appropriate usage data, it is extremely difficult for customers to make a determination of which tariff would benefit them the most.

Q. WHAT IS STAFF'S RECOMMENDATION REGARDING THE COMPANY PROVIDING HOURLY USAGE DATA TO ITS CUSTOMERS?

A. Staff recommends that the Commission require the Company to continue its investigation of the costs and benefits of providing hourly usage information to its residential customers and within six months provide an updated cost estimate to provide hourly usage data to all residential customers. After review of the Company's filing, within 60 days, Staff will bring its recommendation on the issue for Commission consideration.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

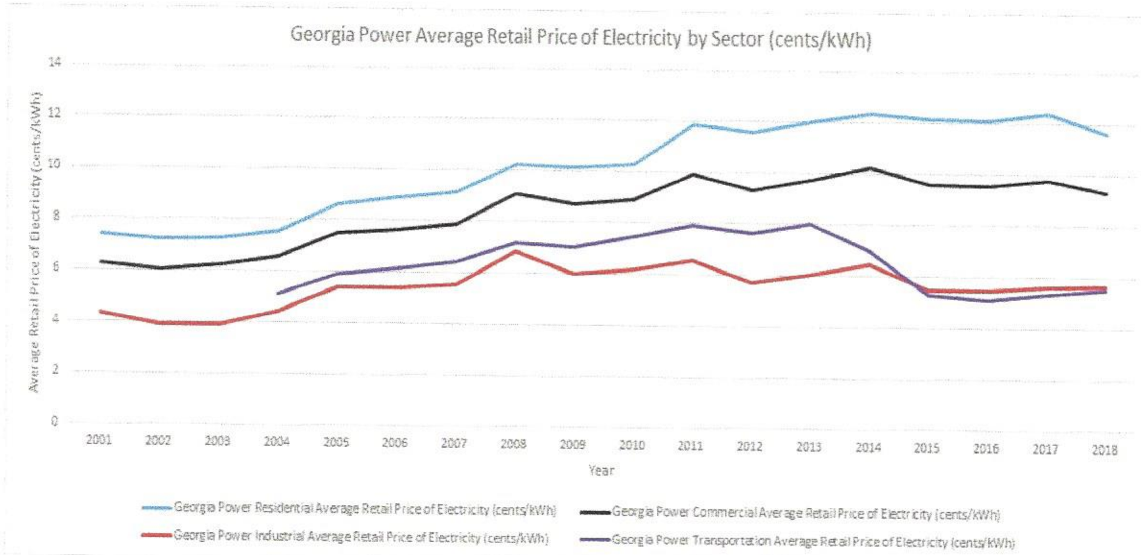
A. Yes.

ALLOCABLE CONTRIBUTION TO COST OF SERVICE AND SYSTEM-WIDE RATE OF RETURN AN IMPORTANT OBJECTIVE IN DESIGNING RATES?

A. Yes, for the very reasons of satisfying the *economic efficiency* and consumer *equity* ratemaking principles espoused by the Company and referred to in our testimony.

Q. **HAS THE GEORGIA PUBLIC SERVICE COMMISSION ORDERED, AND THE COMPANY ACHIEVED, MOVEMENTS TOWARDS RATE PARITY OVER TIME?**

A. Yes, as demonstrated by graphic generated by Staff (based on EIA data),



it can be seen that since 2001, residential average rates have been escalating at a faster pace than they have for other commercial and industrial classes. This indicates that the overall class contribution to Georgia Power cost of service and revenue requirements for the residential customers has been growing, and that of industrial customers has been declining. The Commission appears to have been successful in approving rates that move towards parity, all the while balancing against a host of other ratemaking objectives.