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October 20, 2022

VIA ELECTRONIC DELIVERY

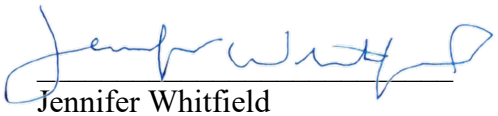
Ms. Sallie Tanner
Executive Secretary
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, Georgia 30334

Re: Direct Testimony of Justin Barnes and Direct Testimony of Mark E. Ellis on Behalf of Georgia Interfaith Power & Light; Docket No. 44280

Dear Ms. Tanner:

Please find enclosed an electronic version of the: **(1) Direct Testimony of Justin Barnes on Behalf of Georgia Interfaith Power & Light**; and **(2) Public Disclosure and (3) Trade Secret versions of the Direct Testimony of Mark E. Ellis on Behalf of Georgia Interfaith Power & Light** to be filed in Docket No. 44280.

Respectfully submitted,



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BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In the Matter of	**)**	
	)	
Georgia Power Company's 2022 Rate Case	**)**	**Docket No. 44280**
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DIRECT TESTIMONY OF JUSTIN BARNES

ON BEHALF

OF GEORGIA INTERFAITH POWER & LIGHT

October 20, 2022

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I. INTRODUCTION

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

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

Q. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A. I am submitting testimony on behalf of Georgia Interfaith Power & Light ("GIPL").

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION ("THE COMMISSION")?

A. Yes. I sponsored testimony in the 2019 Georgia Power Company ("GPC" or "the Company") rate case, Docket No. 42516.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND OCCUPATIONAL BACKGROUND.

A. I obtained a Bachelor of Science in Geography from the University of Oklahoma in Norman in 2003 and a Master of Science in Environmental Policy from Michigan Technological University in 2006. I was employed at the North Carolina Solar Center at N.C. State University for more than five years as a Policy Analyst and Senior Policy Analyst.[1] During that time I worked on the Database of State Incentives for Renewables and Efficiency ("DSIRE") project, and several other projects related to state renewable energy and energy efficiency policy. I joined EQ Research in 2013 as a Senior Analyst and became the Director of Research in 2015. In my current position, I coordinate and

[1] The North Carolina Solar Center is now known as the North Carolina Clean Energy Technology Center.

contribute to EQ Research's various research projects for clients, assist in the oversight of EQ Research's electric industry regulatory and general rate case tracking services, and perform customized research and analysis to fulfill client requests.

Q. PLEASE SUMMARIZE YOUR RELEVANT EXPERIENCE AS IT RELATES TO THIS PROCEEDING.

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

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

[2] The City Council of New Orleans regulates the rates and operations of Entergy New Orleans in a manner equivalent to state utility regulatory commissions.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses several specific aspects of the Company's Application that relate to residential rates. My testimony also includes a discussion of the general nature of cost of service, the existence of interclass and intraclass subsidies, the overall construction of residential rate options, and the Company's assertions regarding the purported "cost shift" associated with the monthly netting option under the Renewable and Non-renewable Resources ("RNR") tariff ("Schedule RNR"). The specific issues that I address in my testimony are as follows:

- The closure of the Residential Service Schedule ("Schedule R") to new premises established after December 31, 2022.
- The closure of the Time of Use – Residential Energy Only ("Schedule TOU-REO") rate to additional customers effective December 31, 2022.
- The continued use of the Time of Use – Residential Demand ("Schedule TOU-RD") as a default rate for new residential premises, which the Commission authorized in its decision in Docket No. 42516.
- The percentage-based design of the Environmental Compliance Cost Recovery Schedule ("Schedule ECCR") as applied to coal combustion residential ("CCR") compliance costs.
- The increase in the residential basic service charge ("BSC") from $0.4603/day to $0.492/day.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into the following sections:

- Section II: I discuss the nature of cost of service, rate design, and "cost shifts" or subsidies in general, as well as in the specific contexts of Schedule ECCR and the Schedule RNR monthly netting option.
- Section III: I address the collective issues associated with the availability of different residential rate options, including the Company's proposals to close Schedule R and Schedule TOU-REO, the reasonableness of using Schedule TOU-RD as the default rate new residential premises, and the overall residential rate options framework in terms of understandability and optionality.
- Section IV: I discuss the reasonableness of the proposed residential BSC and the use of the zero-intercept analysis to identify customer-related costs as it relates to setting BSCs.
- Section V: I provide closing remarks and summarized conclusions.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

A. I have grouped my recommendations according to subject matter categories aligned with the sections of my testimony, as follows:

Cost of Service and Cost Allocation – I recommend that the Commission:

- Modify the manner in which CCR compliance costs are allocated to customer classes and how those costs are recovered in rates because: (a) the current percentage-based adder design of Schedule ECCR fails to reflect that CCR compliance costs are primarily energy-related, and (b) results in those costs being borne disproportionately by the residential customer class. The revised Schedule ECCR should use an energy-based allocation factor and a uniform volumetric charge design.

- Pending any further information presented as part of the Company's supplemental testimony on this issue and subsequent responses by Staff and intervenors, disregard the Company's assertions regarding the alleged "cost shift" created by the Schedule RNR monthly netting option because the basic revenue erosion frame under which the Company presents the issue is flawed. The identification of the character, direction, and magnitude of a cost shift requires a far more extensive analysis of cost of service than the Company presents in its simplistic revenue erosion calculation. The only cost shift between Schedule RNR and non-RNR customers present in the Company's proposed rates is an object of the Company's own creation.

Residential Rate Options – I recommend that the Commission:

- Reject the Company's proposals to close Schedule R to new premises established after December 31, 2022 and to close Schedule TOU-REO to new customers because doing so would: (a) steer customers onto Schedule TOU-RD, which has been significantly more expensive for customers than other available rates during its tenure as the default rate for new premises, and (b) create inequities within the residential class between new and existing customers.
- Eliminate the use of Schedule TOU-RD as the default rate for new premises because: (a) it has been significantly more expensive to customers than other available rates, and (b) demand rate designs in general are inferior to volumetric time of use ("TOU") rates for providing economically efficient and consistent, actionable price signals to residential customers.
- Re-designate Schedule R as the default rate for new residential premises because it is demonstrably less expensive on average compared to Schedule TOU-RD. In the

alternative, should the Commission desire to retain a time-varying rate as the default rate for new residential premises, I recommend that it designate Schedule TOU-REO for this purpose.

- Pursue available options for presenting customers with clearer and more understandable information on available rate options, including but not limited to: (a) directing the rebranding the TOU-RD rate which is presently referred to as the "Smart Usage" rate by the Company, and Schedule Time of Use – Plug-In Electric Vehicle ("Schedule TOU-PEV"), which is not limited to customers with plug-in electric vehicles ("EVs"), and (b) directing GPC to develop a rates calculator tool to assist customers in selecting the rate best suited to their circumstances.

Residential BSC – I recommend that the Commission deny the Company's proposed increase and instead retain the current BSC because: (a) the current BSC already recovers costs in excess of the Company's truly customer-related costs, and (b) the Company's cost of service analysis shows a decrease rather than an increase in customer-related costs. Both of these facts, considered separately or in concert, render an increase in the BSC unjustified.

II. COST OF SERVICE, COST ALLOCATION, AND SUBSIDIES

A. Background Discussion

Q. PLEASE DESCRIBE THE PRINCIPLE OF "COST CAUSATION" IN RATEMAKING.

A. Cost causation refers to the ratemaking principle that costs should be allocated to customers who caused those costs to be incurred. Rates that allocate the cost of providing service to a customer are generally considered fair and equitable rates.

Q. IN GENERAL, HOW DOES GEORGIA POWER CLASSIFY COSTS FOR THE PURPOSES OF ALLOCATING COSTS TO CUSTOMERS?

A. Georgia Power classifies costs as belonging to one of three categories: demand-related, energy-related, or customer-related costs. Demand-related costs are those incurred to serve peak demand. Energy-related costs are those incurred to generate electricity. Customer-related costs are those costs associated with enabling customers to receive electricity service.

Q. PLEASE PROVIDE SOME EXAMPLES OF THESE COST CLASSIFICATIONS.

A. Customer-related costs are typically unrelated to a specific customer's energy consumption. Providing a customer with a meter or preparing and sending bills are costs incurred as part of a customer being able to receive electricity service. The amount, or level, of customer-related costs is unrelated to the amount of electricity an individual customer purchases. Overall, these types of costs increase for the utility based on the number of customers as opposed to the energy usage characteristics of customers.

Demand-related costs are incurred to supply customers with their maximum, or peak, power needs. These costs are driven by the amount of energy a customer uses during

one or more time increments, unlike energy-related costs which are driven by the amount of energy a customer uses over an extended span of time.

Energy-related costs are those costs the Company incurs from providing electricity to customers. These types of costs to the Company increase based on the volume of electricity the customers consume. For example, fuel is consumed to generate electricity, and the more electricity customers purchase, the more fuel is consumed, the higher the overall fuel costs. Other examples include regular equipment maintenance such as lubricating moving parts that is performed based on a set number of operating hours, or management of coal combustion residuals where combustion of some quantity of fuel results in the creation of some quantity of solid waste material. Any costs that increase in proportion to the quantity of electricity generated should be classified as energy-related costs.

Q. IS IT POSSIBLE TO PERFECTLY ALLOCATE COSTS TO THE CUSTOMERS THAT CAUSED THEM?

A. No, for a variety of reasons. To begin with, it is impractical to directly allocate costs to individual customers, so customers are grouped into different classes such as residential, commercial, industrial, etc. That grouping alone results in imperfect cost allocation among individual customers within each class, since not all customers within a customer class are identical. A circumstance in which some customers pay costs caused by other customers is often called a "cost shift" since the burden of costs that result from some customers' activity is effectively shifted onto other customers.

For instance, customers located in rural areas have fewer customers per mile of power line than customers in more densely populated urban areas, but both rural and urban

customers of the same customer class pay the costs for all power lines allocated to that customer class. The result in this example is that customers located in densely populated areas effectively subsidize customers located in areas with less population density. Similarly, multi-family customers tend to take service from larger capacity shared infrastructure that benefits from economies of scale, making their service on a per-customer basis less costly than service for more dispersed single-family homes. Multi-family customers may also differ considerably from single-family home customers in terms of their overall usage and demand, and the patterns of their usage and demand, due to differences in electric end uses and residence characteristics (e.g., prevalence of electric heating and water heating, smaller residences, etc.).

There are often cases where experts disagree on how costs should be classified, or the allocation methodology used to allocate costs, which can influence one's perspective on the existence and magnitude of any cost shift present in a utility's rates. For instance, the Company's practice of classifying a portion of costs of the shared distribution system as customer-related using its zero-intercept analysis and allocating those costs based on the number of customers within a rate class is not accepted in many jurisdictions.[3] Similarly, the measures of demand used to allocate production demand costs are often a source of disagreement in rates proceedings because the selection of a methodology invariably produces "winners" and "losers" and it is challenging to develop bright line tests that indicate which methodology is the most appropriate. In other words, the impacts of

[3] Because this methodology allocates a larger amount of costs to highly populated classes like the residential class, it results in the residential class producing a lower return (i.e., below "parity") and appearance that the residential class is being subsidized by other rate classes. Eliminating this element of the Company's cost of service study would result in the residential class showing a higher return and classes composed of larger non-residential customers showing lower returns.

classification and allocation decisions play a significant role in determining the amounts of costs that a group of customers is deemed to be responsible for causing, making the question of whether a cost shift is present a matter of perspective.

Q. PLEASE ELABORATE ON THE NATURE OF COST SHIFT IN RATEMAKING.

A. To some extent cost shifts are an unavoidable consequence of the ratemaking process. Details and nuances of cost causation are inevitably blurred as a result of the aggregation, classification, grouping, and allocation that occurs with both costs and customers. The technical and interdependent nature of components in the electric system also complicates achieving a perfect allocation of costs in accordance with the principle of cost causation.

However, there are multiple types of cost shifts that we can generally describe. The previous example of a cost shift or subsidization of rural customers by urban customers could be considered an intraclass cost shift, or a cost shift that occurs between members of the same customer class. Cost shifts can also occur between different customer classes as an interclass cost shift, when, for example, residential customers are paying for costs caused by industrial customers or vice-versa.

Other types of subsidization or cost shifts exist as well. There are intertemporal (a.k.a. generational) cost shifts in which costs caused during one time period are paid by customers in a different time period, either earlier or later. Another type of cost shift is an interparty shift, where costs or risks that might otherwise be the burden of the utility or its investors are shifted onto customers.

Q. DO GEORGIA POWER CUSTOMERS EXPERIENCE COST SHIFTS?

A. Cost shifts of various types exist throughout the Georgia Power system. Some, such as the previously described intraclass cost shift between urban and rural customers, could be

considered structural since they result from the design of the basic ratemaking process. Other cost shifts, however, are the result of more deliberate choices.

Consider, for example, some of the cost shifts associated with the Vogtle nuclear expansion project. Current customers are charged for Nuclear Construction Cost Recovery but may or may not receive future benefits from the construction for which they are paying. This is an example of an intertemporal cost shift where costs are charged to customers in one time period but benefits are received by customers in a different time period. Ratepayers in some future time will receive the benefits of electricity from this nuclear facility, but some of the ratepayers today who have been allocated these costs will never receive the benefits of electricity from this facility.

The cost recovery for the Vogtle expansion project could also be considered an interparty cost shift. Customer financing via construction work-in-progress ("CWIP") reduces the risk to other investors (e.g., equity and debt holders) and mitigates potential risks to the Company if the facility does not operate as expected in the future. A full pass-through of fuel costs presents a similar type of risk-shifting, as doing so places the entirety of fuel price risk on customers rather than sharing that risk between customers and a utility's shareholders.

Q. ARE YOU OBJECTING TO THE COST RECOVERY MECHANISMS USED FOR VOGTLE COSTS OR FUEL COSTS?

A. No, not in this testimony. I am simply pointing out that cost shifts: (a) exist in many forms, (b) can be caused by the necessity of using approximations to define cost responsibility, as well as intentional decisions, and (c) are inextricably linked to the perspective from which one views the accuracy of the mechanisms used to define cost responsibility.

B. Schedule RNR Monthly Netting and Schedule ECCR

Q. ARE THERE OTHER EXAMPLES OF POTENTIAL COST SHIFTS IN GEORGIA POWER'S RATE PROPOSAL THAT WARRANT THE COMMISSION'S ATTENTION IN THIS PROCEEDING?

A. Yes. The Company alleges that the Schedule RNR monthly netting option creates a cost shift wherein monthly netting participants are being subsidized by non-participants. The Company has also proposed an adjustment to its proposed revenue requirement to recover a projected $1.4 million of revenue erosion which they have attributed to monthly netting compared to compensation for exports to the grid at avoided cost. This purported cost shift is the basis of the Company's position that the Schedule RNR monthly netting option should not be expanded to allow additional customers to enroll.

The Company also proposes to continue the current design of Schedule ECCR, which uses a percentage-based bill adder to charge customers for environmental compliance costs, the bulk of which relate to costs incurred for remediation of CCR storage sites.

Q. HAS THE COMPANY ADEQUATELY DEMONSTRATED THAT THE SCHEDULE RNR MONTHLY NETTING OPTION CAUSES A COST SHIFT TO NON-PARTICIPANTS?

A. Understanding that the Company has been directed to file supplemental testimony on this issue, it did not do so in in its initial direct testimony for two reasons.

First, revenue erosion should not be conflated with interclass or intraclass cost shifting. Absent the Company's proposed revenue adjustment, any revenue erosion would be borne by the Company's shareholders. Non-participant customers would be indifferent

because their own rates would not be affected. In other words, the purported $1.4 million cost shift to non-RNR ratepayers only exists because the Company created it by making this revenue adjustment.

Second, there are two facets to any question of cost shifting: (a) the costs to serve a group of customers, and (b) what they pay for service. The Company's revenue erosion projection addresses only one side of this equation. A complete picture is only possible with a more extensive evaluation of the long-term costs that monthly netting participants impose on the system, including the costs that they avoid for all customers or cause to be avoided for by customers within their rate class.

Q. IS THERE A REASON FOR THE COMMISSION TO GIVE CONSIDERATION TO SHAREHOLDER INTERESTS IN REGARD TO THE PROJECTED REVENUE EROSION?

A. No. The purported revenue erosion is one very small piece of potential variations in utility revenue, and the earnings band and sharing mechanism already adequately addresses the interests of shareholders by allowing the Company to petition for incremental cost recovery if its earned return on equity ("ROE") falls below 9.5%. The Company does not propose any changes to this mechanism in the current proceeding. This mechanism offers a global solution to the potential for under- or over-earning with recognition that variations in earnings are inevitable.

Carving out potential lost revenues from individual sources is counter to the purpose of the earnings band framework, which does not entitle the Company to any particular amount of revenue within the band. Stated another way, why should the Company be permitted to recover additional revenue for the benefit of shareholders if it is

already earning an adequate return for those shareholders as defined by the lower boundary of the earnings band?

Q. PLEASE EXPLAIN WHY YOU ARE RAISING SCHEDULE ECCR DESIGN AS A MATTER FOR COMMISSION CONSIDERATION AS IT RELATES TO THE ISSUE OF COST SHIFTING.

A. The design of Schedule ECCR is a matter for close Commission attention because: (a) the amount of costs associated with CCR remediation is large (and will continue to grow), and (b) the present design is inconsistent with cost causation. Total proposed ECCR revenue is $937,513,791, or 10.6% of proposed overall total revenue. Schedule ECCR is not subjected to a specific cost allocation protocol for the purpose of the distributing that revenue requirement between customer classes. Rather, the allocation is effectively based on class revenues because Schedule ECCR uses a standard percentage adder to customer bills. As a consequence, Schedule ECCR effectively "enhances" every component of base rates, such as fixed customer charges, demand charges, and the different varieties of energy charges (e.g., on-peak, off-peak, individual tiers within Schedule R). This suggests that the costs being recovered via Schedule ECCR are a mix of customer-related, demand-related, and energy-related costs. However, this is not the case in practice. Rather, the bulk of costs being recovered under Rider ECCR are for CCR remediation, which is energy-related in character.

Q. WHY SHOULD CCR REMEDIATION COSTS BE CONSIDERED ENERGY-RELATED RATHER THAN DEMAND- OR CUSTOMER-RELATED?

A. CCRs are produced when coal is burned as fuel. Every megawatt-hour ("MWh") of electricity generated from the combustion of coal generates a predictable quantity of CCRs.

Therefore, costs associated with CCRs are an energy-related cost and should be allocated on an energy basis. The creation of CCRs has no plausible connection to the number of customers on the system, nor does it have any relation to monthly demand peaks, maximum class demands, or levels of on-peak or off-peak energy use. The determinant of total CCR volume is total energy generated, therefore an energy allocator is appropriate.

Q. IS THERE ANY MERIT TO THE ARGUMENT THAT CCR IMPOUNDMENTS ARE FIXTURES TO COAL-FIRED GENERATION UNITS, AND THEREFORE SHOULD BE SUBJECT TO THE SAME ALLOCATION METHODOLOGY AS THE PLANT ITSELF?

A. No. The impoundment could be considered a fixture, but the CCRs themselves are not somehow tied to the plant. The very fact that in many cases CCRs must be relocated for disposal, and the costs of that relocation are directly related to the volume that must be moved, lends further support to their energy-related character. This is distinctly different from capital investments in pollution control equipment that are made in order to continue to allow a plant to operate to meet system demand and energy needs.

Q. SHOULD THE FACT THAT SOME CCR REMEDIATION COSTS ARE ASSOCIATED WITH RETIRED PLANTS AFFECT THE COST ALLOCATION REGIME?

A. No. Some amount of intergenerational cost shift will be present no matter how costs are recovered from present customers. Newer customers will always shoulder a portion of the burden of paying for the legacy costs of past users. There is no cost allocation regime that is inherently fairer for addressing this intergenerational issue. However, an energy-based allocation is fairer overall because: (a) a portion of the customer base did play a role in

causing those legacy costs due to their past energy use (i.e., there has not been 100% customer turnover), and (b) not all of the Company's coal-fired generation units are retired so CCRs that require disposal are still being produced.

Q. HOW DOES THE CURRENT ALLOCATION OF CCR COSTS COMPARE TO AN ENERGY-BASED ALLOCATION?

A. The Company's proposed rates allocate the residential rate group 50.6% of ECCR costs, of which the bulk are CCR remediation costs, resulting in a total allocation of roughly $474.1 million to residential customers. By contrast the residential customer class accounts for only 34.3% of total system energy requirements. If an energy allocator was used in place of the present regime, residential customers would be allocated roughly $321.4 million, or approximately $152.7 million less than the Company's proposal. The current framework that causes residential customers to bear a disproportionate share of CCR remediation costs is a clear cost shift in which residential customers are subsidizing customer classes who cause greater costs by consuming of greater amounts of energy.

Q. HAVE REGULATORS IN OTHER STATES REACHED THE SAME CONCLUSION THAT CCR REMEDIATION COSTS ARE ENERGY-RELATED AND SHOULD THEREFORE BE ALLOCATED USING AN ENERGY FACTOR?

A. Regulators in both Virginia and North Carolina determined that allocating costs associated with CCR remediation on an energy basis was consistent with the principle of cost causation. In Virginia, in a proceeding on the establishment of Dominion Energy Virginia's Rider CCR, the Hearing Examiner found "a direct connection between the volume of CCR materials to be remediated … and the volume of fuel that was burned at the four Power

Stations over many years."[4] Based on the established energy basis allocation of fuel-related costs and the consistency of applying "a uniform energy rate to recover all CCR remediation costs" with past fuel cost recovery "allocating … CCR costs on an energy basis is consistent with cost causation."[5] Elaborating on this finding, the Hearing Examiner observed: (a) that although an energy-related allocation may result in higher costs to high-load customers those high-load customers also experienced a greater share of energy-related benefits from the combustion of coal, and (b) that allocating CCR costs on an energy basis was therefore "reasonable and equitable."[6] The final order from the full Virginia State Corporation Commission agreed with and adopted this finding.[7]

In North Carolina, the North Carolina Utilities Commission ("NCUC") likewise concluded it was appropriate to "allocate all coal ash expenditures by the energy allocation factor, rather than the demand-related production plant allocation factor."[8] Duke Energy Carolinas ("DEC") had initially proposed to allocate coal ash costs on a demand basis, a position opposed by several parties. After consideration, the NCUC ultimately agreed "with Public Staff witness Maness that the amount of coal ash correlates with the amount of energy produced from coal, and that the entire DEC system benefited from that energy."

[4] Va. Corp. Comm'n, Case No. PUR-2021-00045, Report of Mary Beth Adams, Hearing Examiner at 27 (Sept. 3, 2021) https://scc.virginia.gov/docketsearch/DOCS/5jsv01!.PDF.
[5] *Id.*
[6] *Id.*
[7] Va. Corp. Comm'n, Case No. PUR-2021-00045, Final Order at 5-6 (Oct. 26, 2021) https://scc.virginia.gov/docketsearch/DOCS/5vh901!.PDF.
[8] N.C. Util. Comm'n, Docket No. E-7, SUB 1146 Docket No. E-7, SUB 819 DOCKET No. E-7, SUB 1152 Docket No. E-7, SUB 1110, Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction at 325 (June 22, 2018) https://starw1.ncuc.gov/ncuc/ViewFile.aspx?NET2022&Id=80a5a760-f3e8-4c9a-a7a6-282d791f3f23.

Accordingly, the NCUC ordered that coal ash costs be allocated system-wide on the energy-related factor.[9]

Q. HOW DO YOU RECOMMEND THAT THE COMMISSION ADDRESS THE COST SHIFT CAUSED BY THE DESIGN OF SCHEDULE ECCR?

A. The Commission should direct GPC to modify Schedule ECCR to use an energy-based allocation factor to determine class revenue requirements, and to modify the rate design from a percentage-of-bill based design to a uniform volumetric charge.

III. RESIDENTIAL RATE OPTIONS

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S PROPOSALS FOR REVISING THE RATE OPTIONS AVAILABLE TO RESIDENTIAL CUSTOMERS.

A. The Company proposes to close two fully volumetric residential rates (Schedule R and Schedule TOU-REO) to certain residential customers after December 31, 2022. Schedule R uses a non-time-differentiated inclining block rate design during the summer (June – September) and a declining block structure during the non-summer months. Schedule TOU-REO uses a two pricing period design with an on-peak period during the summer months and a flat rate for summer off-peak and non-summer use. Schedule R would remain available to residential premises that established service prior to January 1, 2023.[10] However, unlike Schedule R, Schedule TOU-REO would only remain available for

[9] *See id.* at 324-325.
[10] 2022 Rate Case Hr'g Tr. Vol 1 at 911. (Sept. 28, 2022). (Transcripts from the GPC Direct Testimony Hearings on September 28-30, 2022 are marked as Volume 1.)

customers already on that rate prior to January 1, 2023.[11] With these changes, newly established residences would be left with a choice between the following rate schedules:

- Schedule TOU-RD (coined "Smart Usage"), which contains a monthly maximum demand charge applied during all months and a volumetric two-period TOU design with an on-peak period during the summer months and a flat rate for summer off-peak and non-summer use. Schedule TOU-RD was made the default residential rate for new premises starting January 1, 2021;
- Schedule TOU-PEV, (coined "Plug-In Electric Vehicle"), which is a fully volumetric whole-home TOU rate with three-period design during the summer months (on-peak off-peak, super off-peak) and a two-period design (off-peak and super off-peak) during the non-summer months. Despite its name, Schedule TOU-PEV is available to customers without electric vehicles; and
- The Pre-Pay and Flat Bill rates.

Q. HOW DOES THE COMPANY JUSTIFY ITS PROPOSAL FOR THESE CHANGES TO ITS RESIDENTIAL RATE OPTIONS?

A. Company Witness Legg describes two primary objectives. First, he describes the closure of Schedule R to new premises established after December 31, 2022 as "the logical next step in the Company's ongoing efforts to encourage residential customers to move toward more modern rate structures" and "toward more modern rate designs that send price signals that more appropriately reflect the cost of service."[12] Witness Legg further seems to be asserting that similar proposals from other utilities are common, stating "utilities across the

[11] *Id.* at 917.
[12] *Id*. at 910.

country are proactively moving away from more antiquated volumetric rate designs (such as the R tariff) and toward more modern rate designs that send price signals that more appropriately reflect the cost of service."[13]

With respect to Schedule TOU-REO, Witness Legg states that the proposal to close Schedule TOU-REO to new customers is motivated by a desire to "streamline the Company's tariff portfolio and avoid customer confusion."[14] He further notes that GPC has two additional time-varying rate schedules that would remain available to customers (Schedule TOU-RD and Schedule TOU-PEV), and relates his view that Schedule TOU-RD rate provides "customers the most accurate price signals while providing three opportunities to save (shifting usage out of on-peak times, staggering appliance use to reduce demand, and simply using less energy)."[15]

Q. WHAT IS YOUR REACTION TO THE COMPANY'S PROPOSALS AND ITS STATED JUSTIFICATIONS?

A. I urge the Commission to deny the Company's specific proposals with respect to Schedule R, Schedule TOU-REO and TOU-RD. I fundamentally disagree with Company Witness Legg's testimony that Schedule TOU-RD provides "the most accurate price signals" and that it provides most customers with reasonable opportunities to save money on their electric bills. As I discuss in in Section III(A) of my testimony, demand rates have considerable structural flaws that result in a misalignment with cost causation and economically inefficient price signals, in particular when they are applied to residential customers. Consequently, the Company's apparent desire to steer customers towards

[13] *Id.*
[14] *Id.* at 917.
[15] *Id.*

Schedule TOU-RD, which started with the Company's efforts in 2019 to designate Schedule TOU-RD as the default rate for new premises starting in 2021, rests on a weak foundation. This weak foundation is evidenced by the fact that, contrary to Witness Legg's assertions, there is no trend in utilities moving away from volumetric rate designs in schedules available to residential customers.

Furthermore, I object to the Company's proposals and stated justifications for the following reasons:

- The closure of Schedule R to new premises starting in January 2023 would create an undeniable inequity within the residential customer class based on the arbitrary distinction of living in a newly constructed home.
- During its tenure as the default rate for new residential premises, Schedule TOU-RD has proven to be significantly more expensive to participating customers than other available rate options, rendering further efforts to steer customers towards this rate not in the best interests of GPC's residential customers.

On the matter of the need to streamline the Company's residential rate offerings in order to avoid customer confusion, I agree that there is the potential for customers to become confused about their options, and be unable to determine the rate that best suits their needs. However, I disagree that the number of options is necessarily the core problem, or that the Company's customers' interests would be best served by reducing rate optionality in the manner the Company proposes. Rather, part of the problem lies in the confusing manner that the Company presents those options to customers, such as Schedule TOU-RD being presented with a positive connotation as the "Smart Usage" rate, and misnamed Schedule TOU-PEV being presented as the "Plug-In EV" rate when in fact it is

available to customers without EVs. Another part of the problem is a lack of tools and resources that could assist customers in selecting the rate most suitable for their needs.

Q. AT SEVERAL POINTS YOU HAVE STATED THAT GPC IS ENGAGED IN EFFORTS TO "STEER" CUSTOMERS ONTO SCHEDULE TOU-RD. PLEASE ELABORATE ON THE BASIS FOR THAT ASSERTION.

A. There are several actions that the Company has taken or proposes to take towards this objective, even if the rate itself remains "optional" as follows:

- The use of Schedule TOU-RD as the default rate for newly constructed premises effectively ensures enrollment growth and a steady supply of new prospective participants.
- Schedule TOU-RD is branded as the Smart Usage rate on the Company's website, which has a descriptive, positive connotation for customers seeking to manage their energy bills, and the marketing materials indicate that saving money on the rate requires only "small changes." Both claims are highly questionable.
- The Company now proposes to close the only two-period TOU rate option (Schedule TOU-REO) leaving customers that desire to take TOU service under a two-period TOU rate with one option, Schedule TOU-RD. Furthermore, the only other TOU rate option beyond Schedule TOU-RD that would be available is Schedule TOU-PEV, which is marketed as a rate for customers with Plug-In EVs. A customer without an EV reviewing the Company's website for rate options could easily overlook Schedule TOU-PEV as an option given how it is named and marketed.

- The Company now proposes to close off Schedule R to new residential premises, leaving customers principally with a choice between Schedule TOU-RD and Schedule TOU-PEV, which as noted they could only know that they qualify for by navigating to the tariff itself (which requires clicking through multiple layers on the Company's website that emphasize that TOU-PEV is for EV owners).

A. Flaws of Demand Rates

Q. PLEASE EXPLAIN IN GENERAL WHY DEMAND RATES ARE INCONSISTENT WITH THE PRINCIPLE OF COST CAUSATION.

A. Grid infrastructure costs are caused by aggregate customer contributions to peak demands on different parts and levels of the system. A customer's monthly non-coincident maximum demand[16] only approximates their contribution to those costs for facilities in close proximity to the customer, such as secondary service lines and line transformers. Even line transformers will experience peaks that depart from individual customer peaks if they serve multiple customers because the peak demands of individual customers often do not occur at exactly the same time. The greater the number of customers (and different types of customers) served by a given piece of infrastructure, the greater this diversity benefit becomes.

Non-coincident demand charges fail to account for this diversity and fail to account for the time-differentiated nature of generation, transmission, and distribution capacity costs. The departure from cost causation is particularly pronounced at the generation capacity and transmission level where an enormous amount of load diversity is present, but

[16] Non-coincident demand refers to a customer's demand at any time rather than only during times that coincide with the collective peak demands on the system or a portion of the system.

it also exists at a significant level on the distribution system as individual distribution circuits often serve thousands of customers with different electricity usage patterns.

Q. DO THE COST ALLOCATION METHODOLOGIES USED BY THE COMPANY REFLECT THIS DIVERSITY BENEFIT?

A. Yes. In the Company's cost of service study, production demand costs are allocated based on class demands at the time of the 12 monthly peaks ("12CP"). Certain transmission costs are allocated based on only the monthly peaks during June – September ("Summer 4CP") while the balance of transmission costs are also allocated according to the 12CP methodology.[17]

Distribution cost allocation uses a hybrid system under which a portion of distribution costs are classified as customer-related according to the Company's minimum-intercept study and allocated based on the number of customers, and the remaining balance of costs are classified as demand-related and allocated based on non-coincident maximum class demand. This maximum class demand methodology assigns costs based on the maximum demand of a given customer class during any single hour of the year.[18] Although maximum class demand is sometimes referred to as a "non-coincident peak" allocator because the timing of the maximum demand of a given class may not be coincident with peak conditions on the broader system, this measure of demand still has a coincident character since it measures customer demands coincident with the maximum demand of the class as a whole. This is distinctly different from how a non-coincident demand charge functions because a non-coincident demand charge is based on an individual customer's

[17] 2022 Rate Case Hr'g Tr. Vol. 1 at 893-95 (Sept. 28, 2022).
[18] *Id.* at 896-97.

demand at any time, regardless of whether that demand occurs during times when aggregate class demand or system demand are at their highest.[19]

Q. DOES THE DEMAND CHARGE COMPONENT OF TOU-RD REFLECT THE TIME-DIFFERENTIATED CHARACTER OF DEMAND-RELATED COSTS?

A. No. The TOU-RD demand charge is based on a customer's maximum demand during a 60-minute interval each monthly billing period regardless of when that demand occurs. That demand may be offset from the time periods that are likely to produce a peak on the system or within the residential customer class, and by using a single hourly value, the demand charge fails to reflect the frequency of customer demands on the system during potential peak windows. Likewise, the demand charge does not reflect the summer-peaking character of the Company's system, which drives the Company's generation planning and is a component of the allocation methodology for transmission costs.

Q. DOES THE TOU-RD RATE DESIGN PROVIDE A PRICE SIGNAL THAT PROMOTES EFFICIENT USE OF ELECTRIC SERVICE?

A. No. There are two problems with the design. First, demand charges in general provide an inconsistent price signal to customers. Second, the price signal itself is not actionable for a typical residential customer.

Q. PLEASE EXPLAIN HOW THE TOU-RD PRICE SIGNAL IS INCONSISTENT.

A. The inconsistency in the price signal arises from the fact that the marginal cost of demand from a customer's standpoint is highly diluted by previously registered maximum demands

[19] The rationale for using maximum class demand for distribution cost allocation is that individual segments of the distribution system (e.g., a primary circuit) tend to primarily serve clusters of customers within the same rate class. In reality there can be considerable variations in the timing of peaks for individual substations or circuits in terms of both the time of year and the hour of the day.

within a billing period. During a billing period, any demand below the amount of previous maximum demand has a zero marginal cost. Even if a customer's maximum demand occurs during a peak window, they have no incentive to reduce their demands during future on-peak hours except as necessary to avoid exceeding a maximum demand amount registered earlier in the same billing period. Ultimately, this effect produces economically inefficient outcomes. For instance, during any given summer there are likely to be multiple heat waves with multi-day durations. An economically efficient rate design should incentivize a customer to reduce their demand as much as they can throughout the duration of peak conditions caused by these events. By contrast, demand rates progressively dilute the price signal hour by hour and day by day as a billing period progresses, and fail to account for the frequency and duration of high demands during peak periods.

Q. DOESN'T THE VOLUMETRIC TIME OF USE COMPONENT OF SCHEDULE TOU-RD PROVIDE THIS TYPE OF CONSISTENT PRICE SIGNAL?

A. It does, but the price signal should be stronger. At the Company's proposed rates, the fixed and demand components of Schedule TOU-RD account for roughly 82% of total rate revenue. The on-peak volumetric component accounts for only roughly 8.5% of total rate revenue.[20] For comparison, the on-peak volumetric component of Schedule TOU-REO accounts for approximately 20.2% of rate revenue[21] and the volumetric on-peak component of Schedule TOU-PEV accounts for roughly 20.7% of total rate revenue.[22]

[20] Based on Staff TAI 1-16 Attachment AJ.
[21] Based on Staff TAI 1-16 Attachment AK.
[22] Based on Staff TAI 1-16 Attachment AI.

Q. PLEASE EXPLAIN WHY THE TOU-RD RATE DESIGN DOES NOT PROVIDE AN ACTIONABLE PRICE SIGNAL TO CUSTOMERS.

A. The only way that a customer can reduce their costs under the TOU-RD rate design is to manage their electricity demand during every single hour of a monthly billing period, and ultimately do so consistently month after month. Such close attention to demand management is highly impractical for a typical residential customer, not to mention being unnecessary as a means of reducing system costs.

Q. CAN YOU ELABORATE ON WHY IT IS IMPRACTICAL FOR RESIDENTIAL CUSTOMERS TO EFFECTIVELY MANAGE THEIR DEMAND DURING ALL HOURS?

A. Yes. First, consider the summer months during which there are a total of 2,928 hours, each of which may require the customer's attention even if that hour falls outside of a peak period. The notion that customers should just avoid using major appliances at the same time is much harder to execute than it sounds, in particular because a single instance of relative inattention (or personal need) can produce an outsized bill impact. For instance, during the summer months when an air conditioner is likely to be cycling consistently, it is next to impossible to avoid using an electric dryer during the same time period when the air conditioner is operating. The same is true for other daily necessities, such as cooking with an electric range or oven, not to mention other things like using a dishwasher, coffee maker, toaster, or electric hair dryer. Furthermore, even relatively flexible needs are not infinitely flexible due to family needs and schedules. These challenges are not limited to the summer months. During the winter months any customer with electric heating is likely to experience the same scheduling difficulties, incurring high bills and utility charges

despite the fact the Company does not identify a winter period during which it desires customers to manage their electricity usage.

Q. WHAT TYPES OF RATES PROVIDE A MORE CONSISTENT, ACTIONABLE PRICE SIGNAL THAN THE PRICE SIGNAL SENT BY DEMAND RATES, INCLUDING SCHEDULE TOU-RD?

A. Time-differentiated volumetric rates improve the price signal to make it more consistent by effectively charging customers for their *average* contribution to peak conditions. This provides the customer with the same price signal during all potential peak hours, such that electricity demand during each individual on-peak hour has a meaningful marginal cost. This price signal should incent load shifting away from peak hours, not just those hours where a customer might register a demand above a previous maximum demand. The typical TOU price signal is also more actionable for customers because it presents a simple and predictable risk-reward calculation that can be readily planned around and managed using both technology adoption and behavioral changes.

On a practical level, consider again that the summer months during which there are a total of 2,928 hours. The on-peak period applied for five hours on weekday non-holidays would comprise only 14.5-14.9% of those hours depending on whether the holidays fall on a weekday or a weekend. Clearly, managing energy use during on-peak periods is a more manageable proposition than doing so during all hours. Moreover, managing an on-peak TOU pricing period also allows the customer to focus their efforts on the highest value hours from the standpoint of reducing stress on the system. This allows a customer to employ technologies such as programmable and smart thermostats and other smart appliances or devices (e.g., managed EV chargers) in support of their efforts, and adopt

consistent behavioral patterns for activities that are amenable to flexible timing (e.g., avoid using a dishwasher or an electric dryer).

Q. DO SMART APPLIANCES REALISTICALLY OFFER CUSTOMERS OPPORTUNITIES FOR CUSTOMERS TO MANAGE DEMAND CHARGES?

A. No. Smart appliances are not an effective means to manage demand charges. Smart devices are suited towards management of predictable TOU pricing windows and response to demand reduction dispatch during critical peak periods, but they do not function as a means of reducing demand during all hours of a day as is required to manage a demand charge. For example, a smart thermostat or smart EV charger can be: (a) programmed to concentrate operation during off-peak periods, and (b) respond to a demand reduction dispatch signal during critical peak periods. However, neither of these capabilities are sufficient to manage demand rate cost management because they depend on known, targeted use management periods and targeted dispatch during unpredictable critical peak periods. In fact, their use towards these ends would likely have the effect of concentrating demand during other periods (e.g., overnight low-cost periods) resulting in a higher charge to the customer, despite the fact that they are responding to a signal to reduce their consumption during on-peak periods.

Demand rate management requires integrated, coordinated operation during all hours among these end-uses, as all other electricity end-uses present in a residence. That is not something that smart appliances themselves can manage. Such coordinated management would require an entire "smart home" system where all end-uses are controlled under an overarching objective of limiting demand at all times. Establishing an

integrated smart home is highly impractical for the vast majority of residential customers, whether they reside in new premises or existing homes.

Q. IS THIS VIEW OF RATE DESIGN AND ECONOMIC INEFFICIENCY SHARED BY OTHERS?

A. Yes. The Regulatory Assistance Project ("RAP") recently published a Policy Brief ("RAP Policy Brief"), which I have attached to my testimony as Exhibit JRB-2. In examining the rationale for demand charges, RAP concludes that such charges have little or no place in modern rate design:

> Demand charges as we've known them in the United States should largely become a relic of the past. Current forms of demand charges, based on 15-minute, 30-minute or 60-minute individual customer peaks and often intended to recover the lion's share of capacity costs, are neither cost reflective nor efficient in general. For much of the 20th century, traditional demand charges may have been a second-best alternative that worked reasonably well for high-load-factor industrial customers. Developments of the past several decades have, however, made even this application of demand charges archaic. Such charges do not reflect the cost drivers of the modern electric system, and typical sizing of these charges are larger than justified by proper economic analysis of the electric system. Peak window demand charges, while an improvement over their traditional counterpart, do not solve many of the core deficiencies of demand charges as an efficient pricing mechanism. Time-varying rates, including TOU rates and critical peak pricing, are more efficient than peak window demand charges.[23]

[23] MARK LEBEL & FREDERICK WESTON, REGULATORY ASSISTANCE PROJECT, DEMAND CHARGES: WHAT ARE THEY GOOD FOR? AN EXAMINATION OF COST CAUSATION at 7 (2020), https://www.raponline.org/wp-content/uploads/2020/11/rap-lebel-weston-sandoval-demand-charges-what-are-they-good-for-2020-november.pdf.

Q. WHY DO THE AUTHORS OF THE RAP POLICY BRIEF REACH THIS CONCLUSION?

A. They raise the issues that I have also raised, specifically that what matters for cost causation is not a customer's individual peak, but their contribution to peak demands on the system (or a segment thereof), and that time-differentiated energy rates are more economically efficient than demand rates. They further observe that a significant portion of capacity investment is more properly classified as energy-related rather than exclusively demand-related because, "Put simply, not all capacity costs are incurred to meet peak demand. As a result, capacity costs for generation should either be split into the traditional demand-related and energy-related categories, or else those categories should be updated into a more modern time-based classification framework."[24]

B. Modernization of Electric Rate Design

Q. APART FROM GPC, ARE THERE ANY OTHER INVESTOR-OWNED UTILITIES ("IOUS") IN THE NATION THAT USE A DEFAULT RATE FOR RESIDENTIAL CUSTOMERS THAT INCLUDES A DEMAND CHARGE?

A. No. The Company is an outlier in this respect. To the extent that Company Witness Legg is implying that "antiquated volumetric rate designs" are being replaced with demand rate designs, he is incorrect.

[24] *Id.* at 21.

Q. ARE THERE ANY OTHER IOUS IN THE NATION THAT HAVE CLOSED TRADITIONAL VOLUMETRIC RATE DESIGNS TO NEWLY CONSTRUCTED RESIDENTIAL PREMISES?

A. No. I am not aware of any other utility that has made a proposal of this type in recent years, let alone one that has seen such a proposal adopted. A small number of IOUs have made proposals to establish a demand rate component within the standard residential rate, but none of those proposals have been adopted. There are no other IOUs in the country that either: (a) use rates with demand charge components as default rates for new or existing residential premises, or (b) otherwise apply them in a mandatory fashion in residential rates.[25]

Q. WHAT WOULD BE A MORE ACCURATE CHARACTERIZATION OF TRENDS IN RESIDENTIAL RATE MODERNIZATION?

A. Generally, the trend is towards greater availability of different rate options for the residential class, with an emphasis on making time-varying rates available as an additional option to flat or tiered rates. To be sure, the availability of different rate options has often included new optional demand rates, often with a time-varying element, in addition to volumetric TOU rates. However, there is no trend towards migrating residential customers to demand rates as GPC is seeking to do by using a demand rate as the default rate for new premises and closing other volumetric rate options. Any assertion that such a trend exists is simply inaccurate.

[25] Under cross-examination Company Witness Legg testified that he believed that some other IOUs have established demand rates that are mandatory for residential customers, although he could not name any specifically. 2022 Rate Case Hr'g Tr. Vol. 1 at 1048 ln. 2-19 (Sept. 28, 2022). Company Witness Legg's belief is mistaken.

Where time-varying rates have been adopted as default rates, such as in California, Colorado and Michigan, volumetric TOU rates (not demand rates) have been selected as the default rate. Furthermore, customers in those jurisdictions typically have access to one or more additional volumetric TOU rates beyond the default rate. Most commonly, movement towards TOU pricing for residential customers is to offer at least one relatively "simple" option (e.g., a two-period TOU rate) and at least one more complex option. TOU rates used as default rates tend towards the simple option with other features such as a limited on-peak, off-peak rate spread that help limit customer bill impacts.

Q. ARE THERE ANY EXAMPLES OF REGULATORS RESPONDING TO CONCERNS ABOUT THE IMPACT THAT DEMAND RATES CAN HAVE ON SOME CUSTOMERS AND THEIR ALIGNMENT WITH COST CAUSATION?

A. Yes. In Colorado, regulators recently ordered Black Hills Energy ("BHE") and Xcel Energy Colorado ("Xcel CO") to increase the availability of non-demand rates to small commercial customers. BHE was ordered to expand the eligibility for non-demand rate service to small commercial customers increasing by the maximum customer demand threshold for non-demand rates for small commercial customers from 10 kW to 50 kW.[26] Likewise, in 2021 Xcel CO was directed to increase the maximum customer demand eligibility threshold for its small commercial non-demand rate schedule from 25 kW to 50 kW.[27]

[26] Colo. Pub. Util. Comm'n, Proc. No. 17AL-0477, Decision No. C18-0445 at 25-26 ¶77 (June 15, 2018), https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=887641.
[27] Colo. Pub. Util. Comm'n, Proc. No. 20AL-0432E, Decision No. C21-0536 at 16-17 ¶38 (Sept. 2, 2021), https://www.dora.state.co.us/pls/efi/EFI_Search_UI.Show_Decision?p_dec=28531&p_session_id=.

In the same decision, the Colorado Public Utilities Commission ("COPUC") also required Xcel CO to offer a pilot rate for secondary voltage general service customers ("SG-TOU Pilot") that uses a primarily volumetric TOU-based rate design with a modest demand charge limited to secondary distribution costs. In establishing the SG-TOU Pilot, the COPUC found that there was insufficient evidence to make a broad determination on the virtues of a holistic shift away from demand rates in the proceeding, but noted significant concerns surrounding the cost causation attributes of demand rates, as follows:

> However, we do find the evidence and arguments in the record of this Proceeding demonstrate a clear need for further examination of the merits of developing an alternative approach to rates for the SG customer class that better reflects actual cost causation and the Commission's energy policy priorities. In particular, we recognize that COSSA/SEIA has raised significant and timely issues related to demand rates that warrant a much closer look in the Company's next Phase II rate case. *Those issues include, without limitation, the relationship of non-coincident demand charges to cost causation, and how the Commission should view rates that rely heavily on the demand component for recovery in light of: (a) the broad move to time differentiated rates for other major rate classes in an effort to send more accurate price signals*; and (b) the potential risk that the current design may be at odds with state policy goals related to both solar adoption, as well as electrification of smaller commercial facilities.[28] [Emphasis added.]

Beyond this example, in April 2020 the Delaware Public Service Commission ("DEPSC") ordered Delmarva Power (the state's only IOU) to notify all of their commercial customers of their eligibility for non-demand rates in response to petition from the Delaware Division of the Public Advocate ("DEDPA"). The issue arose due to Delmarva Power's implementation of the customer demand cap in the non-demand small general service rate, which over time resulted in many customers being involuntarily

[28] *Id.* at 9 ¶21.

switched to the medium general service rate, which uses a demand-based rate design. After registering demands below the threshold during the following year, customers that were switched to demand rate were not being switched back to the non-demand rate, or being notified of their eligibility to do so, resulting in many remaining on a rate that was more expensive for them.[29] At the time it was estimated that roughly 5,000 of Delmarva Power's 13,700 medium general service customers (36.5%) qualified for the non-demand small general service rate.[30]

Q. HOW ARE THE EXAMPLES IN COLORADO AND DELAWARE RELEVANT TO RESIDENTIAL DEMAND RATES GIVEN THAT THEY ALL RELATE TO NON-RESIDENTIAL RATES?

A. The use of demand rates in rate designs for non-residential customers has historically been common, in particular for larger customers, but the same is not true for residential rates. This is in part because the prevalence of high load factor customers who benefit from demand rate designs tends to increase with demand. In other words, many non-residential customers subject to demand rates are accepting of them because the rate design costs them less than a volumetric rate would. At the same time, demand rates applied to high load factor customers may have a somewhat better alignment with cost causation because relatively constant demands tend to make an approximation to a customer's contribution

[29] Del. Pub. Serv. Comm'n, Docket No. 20-0217, Order No. 9564 at 5, April 1, 2020, https://delafile.delaware.gov/CaseManagement/ViewFileNetDocument.aspx?Id=5e265e84-c955-4ee9-a58d-319ea565a901&Type=Docket.

[30] Del. Pub. Serv. Comm'n, Docket No. 20-0217, Petition of the DEPSC Staff and the Delaware Division of the Public Advocate at 6, March 10, 2020, https://delafile.delaware.gov/CaseManagement/ViewFileNetDocument.aspx?Id=02f1cc2e-8e3c-44cb-9599-b7424e21753d&Type=Docket.

to peak demands based on a monthly maximum demand measurement somewhat more accurate.

Residential customers in general are highly dissimilar to the types of high load factor customers for whom demand rates are beneficial and for whom cost causation may be fairly well-aligned (even if only incidentally). The Delaware and Colorado examples highlight the fact that, like most residential customers, not all small commercial customers fit this profile, and for those customers demand rates can be punitive and inconsistent with cost causation.

Q. CAN YOU PROVIDE ANY EXAMPLES OF REGULATORS REDUCING THE ROLE THAT DEMAND RATES PLAY IN THE RESIDENTIAL RATE CONTEXT?

A. No, because demand rates are not currently deployed as default or standard residential rates by any IOU in the country. As previously noted, none of the small number of utility proposals in recent years to introduce demand charges into standard or default residential rates have been adopted, so there is no role that demand rates play in residential rate design that could be reduced or eliminated.

Q. ARE THERE ANY OTHER INDICATIONS OF MOVEMENT TOWARDS GREATER AVAILABILITY OF NON-DEMAND RATES TO DIFFERENT TYPES OF CUSTOMERS?

A. Yes. There is a prominent trend is taking place in the context of rates charged for non-residential EV charging. Numerous utilities throughout the country now offer rates that allow volumetric charges to be substituted for demand charges, or establish limits or caps on demand charges for high capacity EV charging stations, in particular public direct

current fast charger ("DCFC") stations. GPC is proposing one such rate in the current proceeding in the form of Schedule Charge It-Electric Vehicle ("CIEV"). Although this trend is associated with a specific challenge faced by high capacity EV charging, at its core it acknowledges the fact that demand charges can be punitive to customers with low load factors.

C. The Schedule TOU-RD Default Rate Experience

Q. PLEASE DESCRIBE HOW SCHEDULE TOU-RD CAME TO BE DEPLOYED AS A DEFAULT RATE FOR NEW RESIDENTIAL PREMISES.

A. In the Company's 2019 rate case, it proposed to make Schedule R unavailable to new residential premises beginning in January 2020. The Settlement Agreement adopted in the 2019 rate case did not adopt this proposal, but did allow the Company to use Schedule TOU-RD as the default rate for new residential premises starting in January 2021. This means that new customers are placed on Schedule TOU-RD unless they opt into another rate option when they begin service. The Settlement also obligated the Company to "report back to the Commission at the time of its next base rate case regarding the adoption of TOU-RD and its use as the default rate for newly constructed residential premises."[31]

Q. HOW IS THE CUSTOMER RATE ELECTION, OR OPT-OUT OPTION, ACTUALLY IMPLEMENTED?

A. The mechanics, such as how a customer specifically is presented with the choice of rates, how they are notified that they have a choice in rates, and how the merits and drawbacks

[31] Ga. Pub. Serv. Comm'n, Docket No. 42516, 2019 Settlement Agreement at 5 ¶21 (Dec. 11, 2019), https://psc.ga.gov/search/facts-document/?documentId=179169. Paragraph 21 of the settlement was incorporated into the Commission's Final Order in the case. *See* Ga. Pub. Serv. Comm'n, Docket No. 42516, Order Adopting Settlement Agreement as Modified (Feb. 6, 2020), https://psc.ga.gov/search/facts-document/?documentId=179856.

of different rate options are explained to customers are not very clear. For instance, the Schedule R and Schedule TOU-RD tariffs and webpages contain no mention that Schedule TOU-RD is the default rate for new residential premises. Likewise, the materials that the Company provides to customers of new residential premises related to the default rate contain no apparent mention of other rate options, considerations that should be made when selecting a rate, or guidance on how to execute a rate election at the time service is being requested, or a rate switch at a later date. The Company appears to provide the same materials to customers that pro-actively select Schedule TOU-RD as it does to those that reside in newly constructed premises. Exhibit JRB-3 contains the Company's response to a Staff data request for this information, which includes a welcome letter and an example of a seasonally sent postcard.[32]

It is possible that further information is provided to customers beginning service at a new premises via customer service agents or through others means, but if so the Company failed to clearly articulate this in written direct testimony, did not include the information in the above noted response or other responses to data requests, and failed to describe its approach to customer engagement with any specificity under cross examination.[33]

[32] Company Response to STF-PIA-2-3 and Attachments A and B.

[33] In response to cross-examination, Witness Legg stated that every time a customer calls into the call center to set up service, representatives discuss rate options available to them. 2022 Rate Case Hr'g Tr. Vol. 1 at 943 ln. 8-10 (Sept. 28, 2022). However, it is unclear if the Company has a conversation with every new customer – or whether this can happen online – and it is unclear how representatives are describing each rate option or whether customers are getting the same description based on consistent delivery of a standardized script.

Q. HAS THE COMPANY FILED ANY REPORT WITH THE COMMISSION ON ITS EXPERIENCE WITH THE ADOPTION OF SCHEDULE TOU-RD AS THE DEFAULT RATE FOR NEWLY CONSTRUCTED RESIDENTIAL PREMISES?

A. To the best of my knowledge there is no such formal report, or any evaluation whatsoever on the experience, lessons learned, improvements made, etc. The Company has responded to various data requests posed by Commission Staff, such as providing statistics on new enrollments and opt-outs, but as far as I can tell it has not conducted any research or analysis on its own initiative. I am not aware of any publicly filed report to the Commission that the Company has conducted in line with the provisions of the 2019 Settlement Agreement.

Witness Legg testified that, at least since before 2019, the Company has not conducted any specific analysis of whether new customers defaulted to TOU-RD have different usage patterns, load, or cost profiles that might differ from customers taking service under other residential rate options.[34] Likewise, Mr. Legg testified that the Company has not studied whether customers that have been on the TOU-RD tariff for at least one year have changed their behavior in response to price signals, or whether customers on the TOU-RD tariff have meaningfully different peak demand than residential customers at large.[35]

[34] 2022 Rate Case Hr'g Tr. Vol. 1 at 1054-55 (Sept. 28, 2022).
[35] *Id*. at 1057.

Q. WHAT HAS BEEN THE EXPERIENCE OF CUSTOMERS ENROLLED ON SCHEDULE TOU-RD UNDER ITS USE AS A DEFAULT RATE FOR NEW RESIDENTIAL PREMISES?

A. Customers on the TOU-RD rate paid more than they otherwise would have for electricity under another available rate. Figure 1 shows a comparison of monthly average bills from June 2021 to May 2022 for customers enrolled on Schedule TOU-RD versus what their bill would have been if they were enrolled on Schedule R. The average TOU-RD bill over this year was $15.98/month higher than it would have been under Schedule R, totaling roughly $192 over the course of this 12-month period.[36]

Figure 1

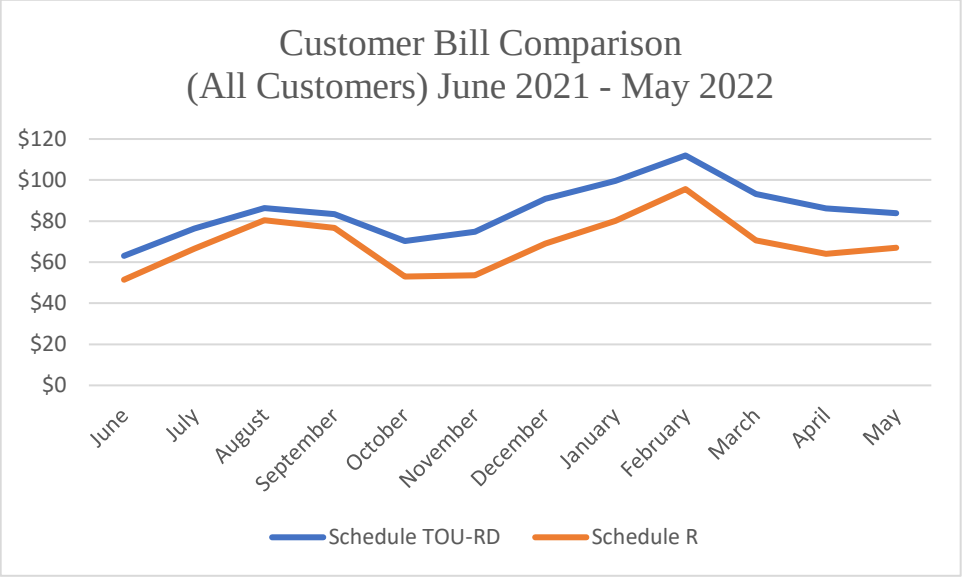


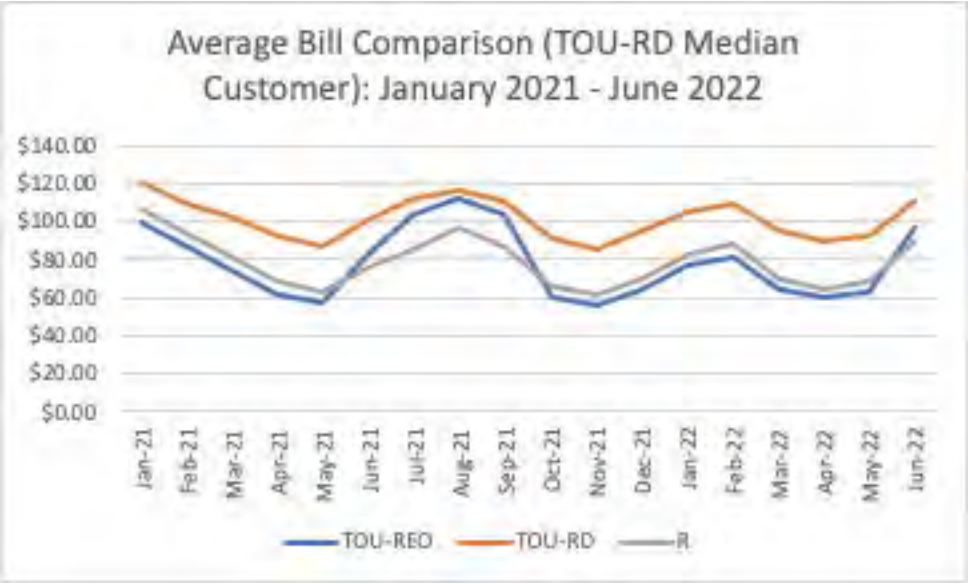
Figure 1 is simply a graphical representation of data provided by the Company in response to a data request. Figures 2 and 3 show comparisons from January 2021 to June 2022 between different rate schedules based on different data sets and my own calculations

[36] Figure 1 created used data provided in response to STF-PIA-2-1 (e.) and (f.), Attachment. It only uses Schedule R as the basis for comparison because the data request was limited to comparing Schedule R and Schedule TOU-RD.

of "shadow" bills under other rate schedules for the Schedule TOU-RD median customer. They also illustrate that Schedule TOU-RD is considerably more expensive for the typical customer than other available residential rate schedules.

Figure 2 shows a monthly shadow bill comparison between Schedules R, TOU-REO, TOU-RD using the demand and energy usage from the median Schedule TOU-RD customer while Figure 3 translates these amounts into average monthly volumetric rates.[37]

Figure 2



[37] Figures 2 and 3 are based on data provided in response to STF-PIA-6-41, Attachment. Schedule TOU-PEV is not shown in Figures 2 and 3 because it uses a different set of pricing windows than Schedules TOU-REO and TOU-RD, making it impossible to calculate a shadow bill based on the available data.

Figure 3

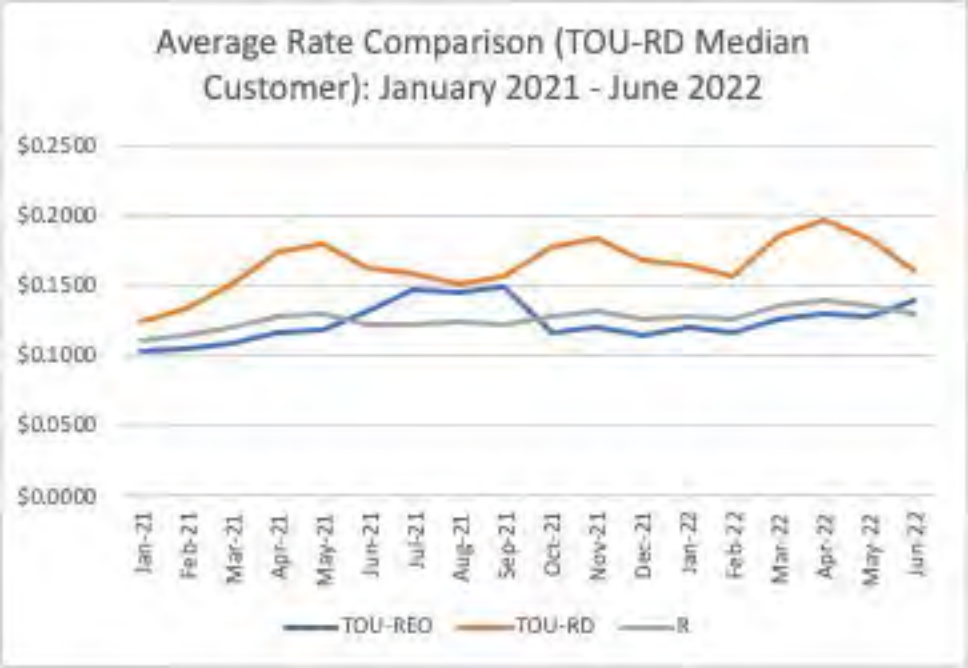
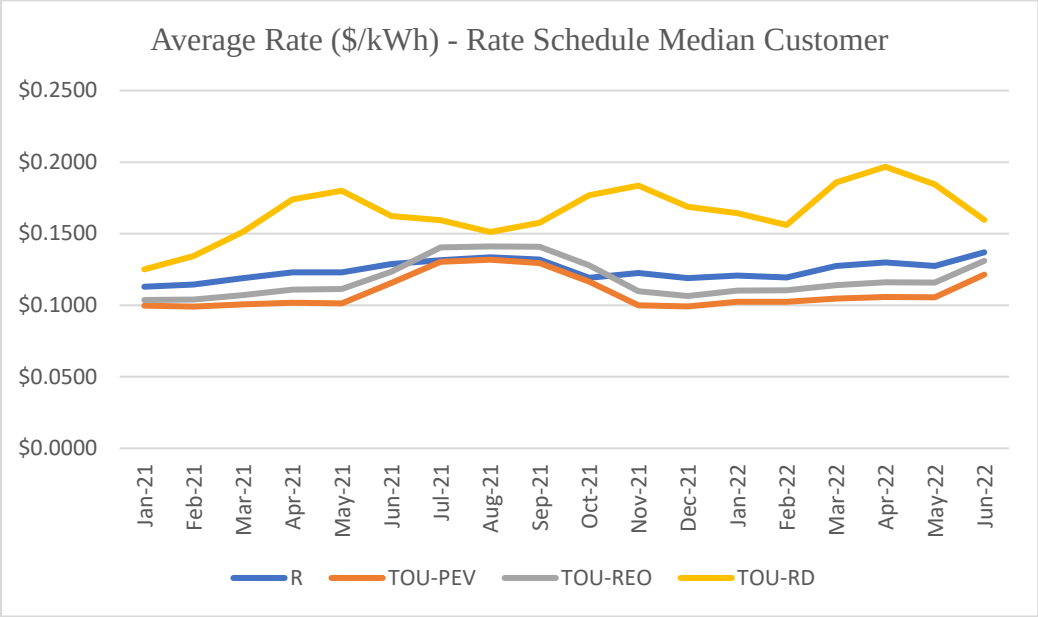


Figure 4 shows the monthly average rate (total bill divided by usage) paid by the class median customer for each of Schedules R, TOU-PEV, TOU-REO, and TOU-RD. Like Figure 3, Figure 4 illustrates that Schedule TOU-RD is an outlier in terms of the average rate it charges customers stated in volumetric terms, in particular during the non-summer months. The difference is significant. On an annual basis the TOU-RD rate is roughly 4.8 cents/kWh higher than the average of the other rates, while during non-summer months the difference increases to roughly 5.6 cents/kWh.[38] The difference between Figure 3 and Figure 4 is that Figure 3 shows the rate the median Schedule TOU-RD customer would have paid under other available rates, while Figure 4 shows the average rate actually paid by the median customer on each of those rate schedules.

[38] Figure 4 is based on data provided in response to STF-PIA-6-41, Attachment.

Figure 4



Q. COULD THESE DIFFERENCES BE ATTRIBUTABLE TO CUSTOMERS THAT MORE ACTIVELY CHOSE SCHEDULE TOU-RD OR WERE ENROLLED ON THE RATE BEFORE JANUARY 2021?

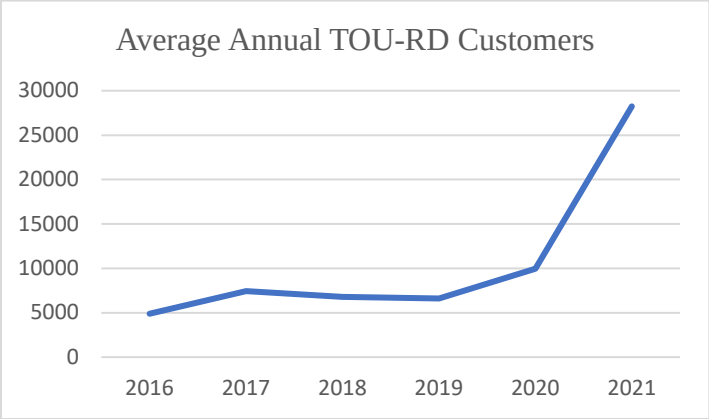
A. No. The vast majority customers on Schedule TOU-RD were enrolled during 2021 or later under the default rate implementation. The Company indicates that as of December 2019 there were 6,564 customers enrolled on Schedule TOU-RD. This increased by 50,853 to 57,417 in May 2022.[39] The Company enrolled a total of 49,809 customers on newly constructed residential premises from January 2021 to May 2022.[40]

[39] Company Response to STF-TAI-1-38 Attachment.
[40] Company Response to STF-PIA-2-1 Attachment, Tab A.

Q. HAVE THE CHARACTERISTICS OF THE TYPICAL TOU-RD CUSTOMER CHANGED SINCE IT WAS ESTABLISHED AS THE DEFAULT RATE FOR NEWLY CONSTRUCTED RESIDENTIAL PREMISES?

A. Yes. As the enrollment count for Schedule TOU-RD has gone up, average usage per customer has declined considerably.[41] Figure 5 shows the recent uptick in enrollment, which is flat from 2017 to 2019, jumps somewhat in 2020, and then increases dramatically in 2021. The 2020 increase in customer enrollment is not explained by the start of the default rate system, but could be attributable to Company efforts to support its goal of moving more customers onto Schedule TOU-RD. In any case, 2020 marks the start of a shift in enrollment and participating customer usage characteristics which then becomes even more pronounced in 2021 with the implementation of the Schedule TOU-RD as a default rate for new customers.

Figure 5



Figures 6 and 7 illustrate that the increase in enrollment in TOU-RD starting in 2020 coincides with: (a) a significant decrease in average annual customer energy use among participants, and (b) a significant increase in the average cost of electricity. Over

[41] Figures 5, 6, and 7 are based on data from the Company's FERC Form 1 filings.

the course of two years, average usage per customer declines by nearly 50% and the cost of electricity goes from being 1.14 cents/kWh cheaper than Schedule R during 2019 to 1.49 cents more expensive in 2021. This indicates that not only were 2021 enrolled customers distinctly different from the historic participant base in terms of average annual electricity use, but also that the customers added in 2020 were a departure from the historic norm.

Figure 6

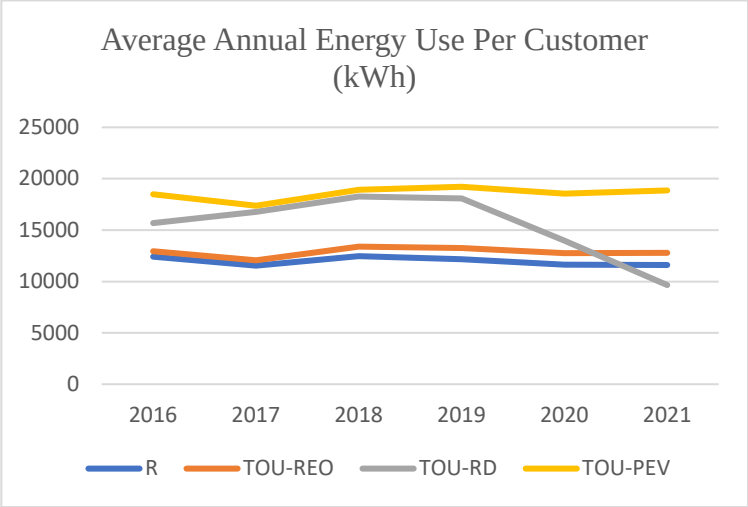
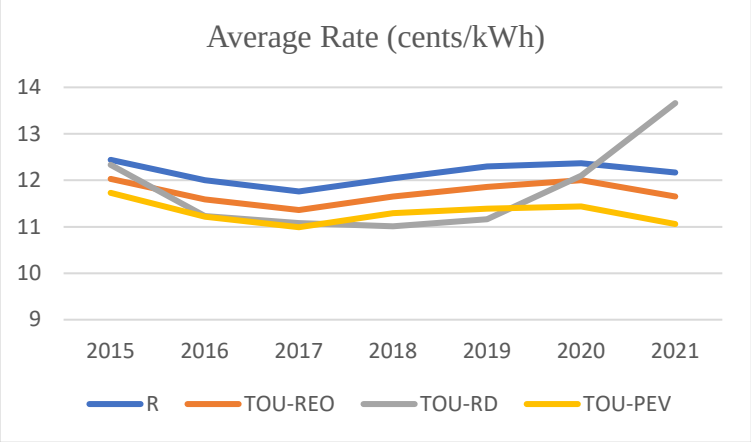


Figure 7



Q. WHY WOULD THE SCHEDULE TOU-RD ENROLLEE USAGE PROFILE HAVE CHANGED SO SIGNIFICANTLY DURING 2020 AND 2021 RELATIVE TO PRIOR YEARS?

A. Customers with relatively higher average usage tend to be customers with high load factors, for whom demand rates are less costly than volumetric rates. High usage customers that benefited from being on the rate were the norm prior to 2020, as one would expect with an optional rate since participants self-select. Such a profound change in the customer composition strongly suggests that at best, customers were unaware that Schedule TOU-RD was not a good fit for their usage patterns, and at worst, they were steered towards service under a rate that is not in their best interest from a cost standpoint.

Q. IF THE TOU-RD IS MORE EXPENSIVE THAN ANOTHER AVAILABLE RATE OPTION, WHY WOULD MOST CUSTOMERS REMAIN ON THE SCHEDULE TOU-RD INSTEAD OF SWITCHING TO ANOTHER OPTION?

A. Assuming that they even know they have the option to change to a different rate, there are two possible reasons. First, Schedule TOU-RD has a one year minimum initial contract term, which presumably prevents a customer from switching until they have received service under Schedule TOU-RD for at least one year. It is not clear specifically how the Company is enforcing this restriction for defaulted customers, but the letter of the tariff is quite clear on this point, stating, "The Customer is required to remain on the TOU-RD

tariff for a period of twelve (12) months from the contract date. … The customer may change tariffs at any time after the initial twelve (12) month term expires."[42]

A second reason could be that they simply do not know any better. Recall that the customers being defaulted are residing in newly constructed premises. Customers may be moving from outside the Company's service territory and be wholly unfamiliar with the Company's rates, or from within the service territory from a dissimilar prior residence (e.g., apartment to single-family home, a different apartment building, or a single-family home with different electric end-uses and/or square footage). Those customers do not have the benefit of being able to compare bills under Schedule TOU-RD to a bill under a different rate because they lack a suitable point of comparison.

Q. ARE THERE ANY OTHER NOTABLE PATTERNS PRESENT IN YOUR EVALUATION OF HOW TOU-RD HAS AFFECTED PARTICIPANTS DURING RECENT YEARS?

A. Yes. The excessive costs are concentrated during the non-summer off-peak months, in particular the "shoulder" spring and fall seasons. This is illustrated in Figures 3 and 4, which show that the difference between the effective volumetric rates that Schedule TOU-RD customers pay compared to what customers would pay with the other rate options is at its highest during the shoulder months. These shoulder months are characterized by lower overall demands on GPC's system, meaning that demand during these periods is not a driver of system costs. The fact that the effective rates for Schedule TOU-RD customers

[42] Witness Legg appeared to say that the Company does not always require customers to stay on the tariff for a full 12 months if they call and complain to a customer service representative. 2022 Rate Case Hr'g Tr. Vol. 1 at 1053 (Sept. 28, 2022). Even so, at best this gives a limited pool of customers an opportunity to leave the tariff early on a case-by-case basis at the discretion of the Company. Some customers might read the tariff and believe the Company would not allow them to switch rates, and so would not bother to make the attempt.

are at their highest during such low cost periods of the year illustrates the misalignment between Schedule TOU-RD and cost causation. Customers on other available residential rates pay higher rates during the highest cost summer months, whereas the reverse is true for Schedule TOU-RD customers.

Q. IS THERE ANY JUSTIFICATION FOR THESE HIGH NON-SUMMER RATES BEING PAID BY SCHEDULE TOU-RD CUSTOMERS, SUCH AS ADDRESSING WINTER PEAKS?

A. No, for several reasons. First, the highest effective rates appear during the shoulder months, not the winter months. Second, the Company has expressly stated that it does not believe there is a need for a winter peak period in its residential TOU rates at present.[43] Third, such a justification would conflict with the design of Schedule R and the Company's two other available TOU rates, which offer lower rates during non-summer months. It is unreasonable for such a material difference in price signal to exist between available residential rates, and Schedule TOU-RD is the outlier in this respect. The problem is not the design of other available residential rates. The problem is the design of Schedule TOU-RD.

Q. IS THERE ANY EVIDENCE THAT INDICATES THAT THE HIGHER RATES AND HIGHER BILLS THAT THE CURRENT ENROLLEES ON SCHEDULE TOU-RD CUSTOMERS NOW FACE ARE JUSTIFIED BASED ON DIFFERENCES IN COST OF SERVICE?

A. No. The Company's assertions that Schedule TOU-RD is the most cost-based residential rate design are based on generalized assertions that are wholly unsupported by any analysis.

[43] Company Response to STF-TAI-1-31.

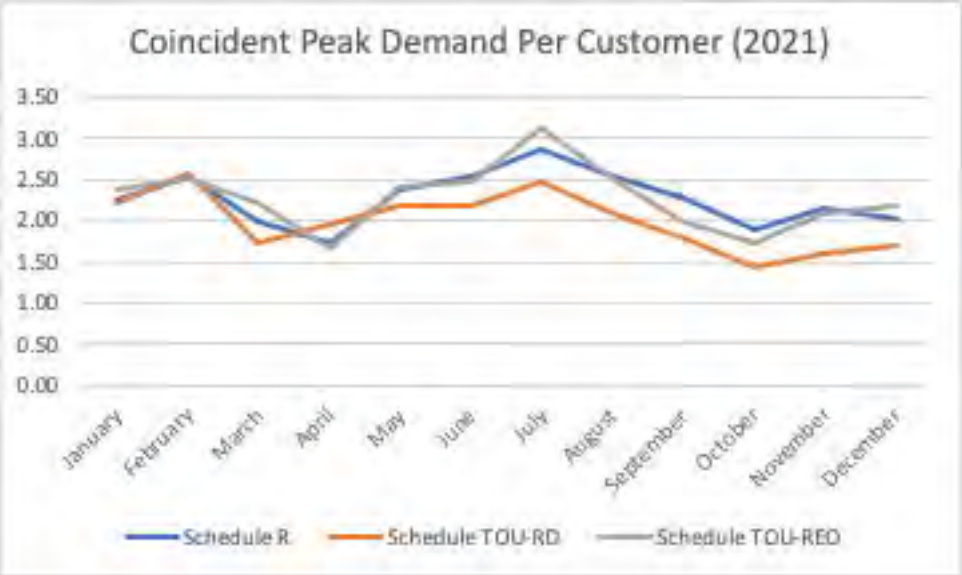
In fact, my own analysis indicates that even though Schedule TOU-RD customers pay overall higher rates and higher bills than they would pay under other available residential rates such as Schedule R and Schedule TOU-REO, on a per-customer basis they contribute lower amounts to the 12CP and Summer 4CP, and, at most, an equivalent amount to maximum class demand.

Q. PLEASE ELABORATE ON HOW THE CURRENT SUITE OF SCHEDULE TOU-RD CUSTOMERS, AS AFFECTED BY THE DEFAULT RATE POLICY FOR NEW PREMISES, ARE LOWER COST CUSTOMERS ON AVERAGE.

A. Figure 8 below shows demand per customer coincident with the monthly system peak for the 2021 historic test year. As illustrated in Figure 8, Schedule TOU-RD customers consistently contribute less on a per-customer basis to peak demands than Schedule R and Schedule TOU-REO customers. This difference grows over time as Schedule TOU-RD becomes more populated with defaulted new construction customers. The data underlying Figure 8 show an average 12CP contribution to peak demand of 1.92 kW/customer for Schedule TOU-RD customers, compared to 2.27 kW/customer for both Schedule R and Schedule TOU-REO customers. A Summer 4CP comparison shows an even larger difference with Schedule TOU-RD customers averaging a 2.11 kW/customer contribution to peak demand, Schedule R customers averaging 2.56 kW/customer, and Schedule TOU-REO customers averaging 2.53 kW/customer.[44]

[44] Monthly peak demand by rate schedule was sourced from the Company's Response to STF-TAI-1-3 Attachment. Monthly customer numbers used to make the per customer calculation were sourced from STF-TAI-2-1 Attachments A, B, C, and G providing the number of customer bills by rate schedule each month.

Figure 8



I also evaluated whether Schedule TOU-RD customers may have contributed more to the maximum residential class demand. I determined that the average contribution to peak demand per Schedule TOU-RD customer was virtually identical (slightly less) to contributions from Schedule R customers, at 3.04 kW/customer, and significantly less than the contributions of Schedule TOU-REO customers (3.61 kW/customer).[45]

Q. WHAT CAN THE COMMISSION CONCLUDE BASED ON THE CUSTOMER EXPERIENCE WITH SCHEDULE TOU-RD AS THE DEFAULT RATE FOR NEW RESIDENTIAL PREMISES?

A. The use of Schedule TOU-RD as a default rate for new residential premises has not been in the best interests of GPC's customers because it has caused a significant number of affected customers to pay more for electric service than they would have paid under other

[45] *Id*. This calculation used customer numbers for July 2021 to align with the timing of the residential class demand during 2021.

available residential rates. The reasons for this are unavoidable flaws with demand rate designs, which are particularly prominent when applied to residential customers.

D. Conclusions and Recommendations on Residential Rate Options

Q. WHAT ACTIONS DO YOU RECOMMEND THAT THE COMMISSION TAKE IN RESPONSE TO THE EXPERIENCES OF CUSTOMERS WHO WERE DEFAULTED TO SCHEDULE TOU-RD?

A. The Commission should eliminate the use of Schedule TOU-RD as the default rate for new residential premises and instead return to the use of Schedule R as the default rate for new residential premises. In the alternative, should the Commission desire to retain a time-varying rate as the default rate, it should designate Schedule TOU-REO as the default rate because it is the simplest TOU rate currently available to residential customers. I am recommending Schedule TOU-REO as a secondary alternative to Schedule R because my analysis shows that summer bill volatility is likely to be higher under Schedule TOU-REO than it is under Schedule R, although annual customer bills would remain similar. By extension, the Commission should deny the Company's requests to close Schedule R to newly constructed residential premises.

Q. SHOULD SCHEDULES R AND TOU-REO REMAIN OPEN TO NEW CUSTOMERS EVEN IF THE COMMISSION DECLINES TO ADOPT EITHER AS THE DEFAULT RATE FOR NEW RESIDENTIAL PREMISES?

A. Yes. Both should remain available to new customers —including those occupying new residential premises —on an opt-in basis even if Schedule TOU-RD remains the default rate for new residential premises. Both of these rates offer relatively simple structures that are more consistent with cost causation than Schedule TOU-RD, as both charge relatively

higher total rates during the summer peak months and lower rates during the non-summer months, whereas Schedule TOU-RD does the opposite.

Q. HOW CAN THE COMMISSION ADDRESS POTENTIAL CUSTOMER CONFUSION REGARDING A SUITE OF AVAILABLE RESIDENTIAL RATE OPTIONS, AS THE COMPANY CONTENDS IS NECESSARY?

A. There are multiple options at the Commission's disposal. The simplest and most obvious is to ensure that the Company's marketing and branding of these rate options accurately reflects their design. That is to say, at a minimum, the misnamed and mis-marketed Schedule TOU-PEV should be rebranded with a more accurate name and description given that it could be a highly viable option for customers who do not have EVs. For instance, it might be rebranded as the "Advanced Time of Use Overnight Discount" rate, which more accurately describes its most notable features of being somewhat more complex than Schedule TOU-REO with the added element of a super off-peak rate during overnight periods. The description could continue to reference its particular suitability for EV customers (e.g., "this rate may be particularly advantageous for EV owners that charge their vehicles at home overnight") without implying that the rate is exclusively for EV customers.

In addition, Schedule TOU-RD should be rebranded as something other than the "Smart Usage" rate because the present branding inappropriately steers customers who desire to manage their energy bills towards it, even though most customers will find doing so highly difficult given the prominent role that the non-coincident demand charge plays in determining their bill. A more accurate nomenclature should reflect the most notable characteristic of the rate: the fact that the largest component of a customer's bill is the

demand component. For instance, it might be referred to as the "Managed Demand" rate with a description indicating that accruing bill savings requires customers to manage their electricity demands during all hours.

The Commission could also direct the Company to develop a rate comparison calculator that would allow customers to download their usage history and through a model provided by the Company, calculate what their historic bills would have been under different available rate options. At present, customers can access granular data on their electricity usage, but it remains up to them to perform the bill modeling necessary to identify the most cost-effective rate for their usage patterns. It is unreasonable to expect the average (or even more sophisticated) residential customer to possess the capabilities to perform this type of modeling themselves. Some customers, in particular lower-income customers, may not have access to the necessary software (e.g., Microsoft Excel), and many others likely lack the skills to develop a rate model.

Q. HOW DO YOU RECOMMEND THAT THE COMMISSION PURSUE YOUR RECOMMENDATIONS FOR PROVIDING RESIDENTIAL CUSTOMERS MORE ACCURATE AND ACTIONABLE INFORMATON THAT ALLOWS THEM TO SELECT THE MOST APPROPRIATE RATE OPTION?

A. Within 90 days of an order in this proceeding, the Commission should direct GPC to file a residential rates marketing, education, and outreach ("ME&O") plan which would, at a minimum, address the appropriate branding of all of the Company's residential rate options and provide a detailed plan and timeline for developing a rate calculator to allow customers to easily identify the best rate for them. The Commission may further wish to identify additional minimum contents and parameters for the ME&O plan, such as comprehensive

materials detailing the information provided to new customers generally and customers occupying a new premises (e.g., fact sheets, welcome letters, and customer service scripts), and a detailed, step-by-step description of how the default rate opt-out process functions for customers taking service at a new premises. The overarching objective should be to ensure that customers are not enrolled on a rate schedule that is disadvantageous to them through ignorance of their options or the inability to make informed decisions due to a lack of appropriate information.

IV. RESIDENTIAL BASIC SERVICE CHARGE

Q. WHAT IS THE COMPANY'S PROPOSAL FOR THE RESIDENTIAL BSC?

A. The Company proposes to increase the nominal residential BSC from $0.4603/day, or roughly $14.00/month, to $0.492/day, or $14.97/month. By "nominal," I am referring to the amount of the BSC as reflected in the various residential rate schedules. The effective BSC rate is higher due to the impacts of percentage-based riders which incrementally increase the rates for all components of a customer's bill. Inclusive of the effects of current and proposed percentage-based riders (i.e., Schedules NCCR, ECCR, DSM, and MFF),[46] the Company proposes an increase in the effective residential BSC from $17.69/month to $18.85/month. Under the proposed rates, the riders account for an additional effective fixed charge of $3.89/month.

[46] The current percentage based riders total 26.38% while the proposed percentage based riders total 27.78%.

Q. HOW DID THE COMPANY DETERMINE THE AMOUNT OF THE PROPOSED INCREASE IN THE RESIDENTIAL BSC?

A. GPC applied the same percentage increase equally across all residential rate components, approximately 6.9%.[47]

Q. WHAT IS THE GENERAL PURPOSE OF THE BSC IN THE COMPANY'S RATES?

A. Fixed monthly charges, or "customer charges," like the BSC, have traditionally been employed to recover costs that vary in proportion to the number of customers served by the utility system. As previously noted, some classic examples of these types of customer-related costs are meters and customer service drops (generally one per customer), and expenses related to monthly meter reading and billing.

Q. IS THE COMPANY'S PROPOSAL TO INCREASE THE RESIDENTIAL BSC JUSTIFIED FROM THE STANDPOINT OF COLLECTING COSTS THAT VARY IN PROPORTION TO THE NUMBER OF CUSTOMERS?

A. No. The Company's cost of service study erroneously classifies a portion of the costs associated with the shared distribution system as customer-related based on its Minimum Distribution System ("MDS") analysis. By "shared distribution system" I am referring to infrastructure logged in FERC Accounts 364-368 pertaining to poles, overhead and underground conductors, underground conduit, and line transformers. This classification also flows down into expense categories associated with the shared distribution system.

Consistent with my 2019 testimony, my position continues to be that all costs associated with the shared distribution system should be classified as demand-related and

[47] 2022 Rate Case Hr'g Tr. Vol. 1 at 907, ln. 7-9 (Sept. 28, 2022).

therefore should not be lumped in with costs which truly vary directly in relation to customers (e.g., meters and service drops) when setting the residential BSC. This position is shared in many other jurisdictions throughout the country.

Q. WHAT WOULD THE RESIDENTIAL CUSTOMER-RELATED UNIT COSTS BE IF THE MDS ASSUMPTION IS REMOVED FROM THE COMPANY'S COST OF SERVICE STUDY.

A. For the residential class as a whole, I estimate that the amount is $13.77/month per customer. This is $1.20/month less than the proposed tariffed residential BSC ($14.97/month) and $5.08/month less than the effective fixed charge would be under GPC's collective proposal. In order to create an effective BSC equivalent to the $13.77/month amount, the nominal BSC would need to be reduced to $10.78/month at the Company's proposed percentage rider amounts. If Schedule ECCR is modified to use a volumetric rate structure, as I recommend, the nominal BSC amount necessary to yield an effective BSC of $13.77/month is $12.88/month.

Q. PLEASE EXPLAIN HOW YOU MADE THIS CALCULATION.

A. I arrived at this figure first by eliminating the MDS component from the Company's historic test year 12CP version of the Company's cost of service study, and then modifying the amount of customer-related rate revenue to the point where the customer-related revenue requirement produced a return equivalent to the overall residential class return. I then divided the required revenue amount by the number of customer bills during a year to

produce a monthly revenue need per customer. This approach is equivalent to how Company Witness Vogt developed a customer-related unit cost in the 2019 rate case.[48]

In addition to eliminating the MDS element, I made several adjustments to exclude certain expenses that should not be considered customer-related for the purpose of setting the residential BSC. These exclusions in aggregate reduced the monthly residential customer-related cost by $0.42/month. The specific exclusions I made are as follows:

- Pre-Pay program expenses, which are attributable to the pre-pay program itself rather than the broader residential customer class.
- Selling and Demonstration expenses, which relate to the promotion of utility services.
- Expenses associated with the Company's membership in the Electric Power Research Institute ("EPRI").

Q. IS THE PROPOSED INCREASE IN THE RESIDENTIAL BSC JUSTIFIED EVEN IF THE EFFECTS OF THE MDS ARE INCLUDED WHEN SETTING CUSTOMER-RELATED COSTS?

A. No, for two reasons. First, the Company's estimated residential customer-related costs have actually decreased relative to the amounts the Company specified in its 2019 rate case. In the 2019 rate case Company Witness Vogt sponsored testimony indicating that its residential customer-related costs were $24.36/month.[49] I have calculated that the residential customer-related costs based on the cost of service study filed in the current proceeding, without excluding the MDS assumption or making any other adjustments, are $22.34/month, a decrease of $2.02/month.

[48] Ga. Pub. Serv. Comm'n, Docket No. 42516, Document Filing No. 177523, Direct Testimony of Lawrence J. Vogt, Ex. LJV-9, https://psc.ga.gov/search/facts-document/?documentId=177523.
[49] *Id*.

Second, embedded cost studies are more useful for determining the amount of revenue to be collected in total and from different groups of customers, not how to collect it in the form of rate design. Using customer-related unit costs produced by an embedded cost study in a deterministic fashion to set a residential BSC ignores the wealth of other ratemaking considerations and objectives. I also discussed the application of these other considerations and objectives at length in my 2019 testimony.

Q. WHY DID THE CUSTOMER-RELATED UNIT COSTS DECLINE IN THE PRESENT CASE RELATIVE TO THE 2019 RATE CASE?

A. The primary factor that changed is a decrease in the customer-related component the Company calculates for shared distribution system infrastructure using its MDS analysis. The customer-related component of shared distribution plan decreased from 46.9% in the 2019 MDS analysis to 32.6% in the current version.[50] The customer-related percentages decreased significantly for three Federal Energy Regulatory Commission ("FERC") accounts in the present study relative to the 2019 study, as follows:[51]

- Account 364 (poles): 47.8% (2019) to 32.2% (2022)
- Account 365 (overhead conductors): 56.5% (2019) to 43.4% (2022)
- Account 368 (line transformers): 90.2% (2019) to 49.7% (2022)

[50] Company Response to STF-PIA-8-9(c).
[51] Sourced from Company Response to STF-TIA-1-2, Attachment, Summary Tab for 2022 values, and Company response to STF-PIA-8-9, Attachment, Summary Tab for 2019 values.

Q. WHAT SPECIFICALLY CHANGED IN THE HOW THE COMPANY CONDUCTED THE MDS EVALUATION IN THE PRESENT CASE RELATIVE TO THE 2019 RATE CASE?

A. The most significant change the Company made is to how it develops current costs for line transformers based on past booked costs. In the current case the vintage adjustment to booked costs for line transformers used GPC-specific estimates rather than South Atlantic region Handy Whitman Indices of component cost inflation over time.[52] This change addresses a significant problem that I identified in the 2019 MDS study that produced customer-related percentages for pad-mounted transformers in excess of 100% (e.g., 219% for single-phase pad-mounted transformers), which is a clear impossibility.[53] This change is the primary reason that the estimated customer-related percentage for line transformers decreased so dramatically, from roughly 90% to 50%.

The Company also made a change in how it determines the customer-related component for certain accessory equipment. In the 2019 MDS study it classified this "Other Unitized Equipment" relating to overhead conductors (FERC Acct. 365) as 100% customer-related, whereas in the current MDS analysis the allocation was revised to base it off the customer- and demand-related split for primary overhead conductors.[54] This change also partially addresses a critique from my 2019 MDS analysis.

[52] Company Response to STF-PIA-8-9(b).
[53] *See* Company Response to STF-PIA-8-9, Attachment, Acct 368 Tab, cell U57.
[54] Company Response to STF-PIA-8-9(b).

Q. ARE YOU ENDORSING THE COMPANY'S MDS ANALYSIS FOR DETERMINING CUSTOMER-RELATED COSTS IN THIS CASE GIVEN THE CORRECTIONS THAT THE COMPANY HAS MADE TO ITS EVALUATION RELATIVE TO THE 2019 STUDY?

A. No. The Company's present MDS study is more reasonable than its 2019 evaluation because some errors have been addressed, but it does not change the fact that the MDS concept itself rests on shaky methodological ground. Moreover, the changes in the 2022 results relative to the 2019 study underscore the subjective nature of the entire exercise.

Q. WHAT IS YOU RECOMMENDATION TO THE COMMISSION REGARDING THE LEVEL OF THE RESIDENTIAL BSC.

A. I recommend that the Commission deny the Company's proposed increase and instead leave the residential BSC unchanged from its present amount, contingent on the Commission also adopting my recommendation to modify Schedule ECCR from using a percentage-based structure to a volumetric structure. With this change, the difference between the effective BSC at the current $14.00/month rate and the effective BSC that reflects a cost-based rate that does not reflect the use of the MDS would be small. In fact, the Commission would be justified to reduce the residential BSC by $1.12/month ($0.039/day) to achieve this outcome, but retaining the current charge produces a similar result and could be viewed as maintaining greater consistency in rates.

Q. WOULD RETAINING THE CURRENT RESIDENTIAL BSC STILL BE APPROPRIATE IF THE COMMISSION ACCEPTS THE USE OF MDS AS AN ELEMENT OF CALCULATING CUSTOMER-RELATED COSTS?

A. Yes, because even with the inclusion of the MDS, the decrease in customer-related costs since the 2019 rate case allows the Commission to retain the current charge while at the same time providing an incremental, gradual movement towards the Company's supposed "cost-based" residential BSC.

V. CONCLUSION

Q. DO YOU HAVE ANY CLOSING REMARKS TO MAKE TO THE COMMISSION ON THE MATTERS THAT YOU HAVE ADDRESSED IN YOUR TESTIMONY?

A. Yes. I ask that the Commission take note of several key conclusions that I have reached in my evaluation of the Company's application and implement my associated recommendations.

1. The design of Schedule ECCR, including the cost allocation regime and the rate design, is inconsistent with cost causation and results in significant cost shifting to the residential class. Accordingly, it should be modified to allocate costs based on an energy factor and charge customers for those costs using a uniform volumetric charge.
2. The only cost shift associated with the Schedule RNR monthly netting option that the Company has identified thus far is of the Company's own creation via a proposed $1.4 million revenue adjustment that benefits its shareholders. This proposed revenue adjustment is inappropriate because the existing earnings band and revenue sharing mechanism already adequately addresses shareholder interests.

3. The use of Schedule TOU-RD as a default rate for new residential premises has not been in best interest of the Company's customers because Schedule TOU-RD has proven to be poorly suited as a cost-reflective rate for residential customers and has been significantly more expensive on average for the current suite of Schedule TOU-RD customers than other rate options. The Commission should act based on this new information by eliminating the use of Schedule TOU-RD as the default rate for new residential premises and redesignating Schedule R as the default rate, or in the alternative Schedule TOU-REO if it wishes to retain a time-varying price signal as part of the residential default rate.
4. In line with conclusion (3) above, and in the interest of allowing the diverse class of residential customers greater opportunities to control their energy costs through selecting the best rate for their individual circumstances, the Commission should deny the Company's proposals to close Schedule R to new residential premises and close Schedule TOU-REO to new enrollments.
5. The manner in which the Company presents rate options to residential customers is confusing and fails to promote effective customer understanding and rate selection. Most specifically, the branding of Schedule TOU-RD as the "Smart Usage" rate and Schedule TOU-PEV as a rate for customers that own EVs, even though non-EV customers may enroll in Schedule TOU-PEV, are problematic. In order the remedy this problem, I recommend that the Commission direct the Company to file, within 90 days of an order in this proceeding, a residential rates ME&O plan that at a minimum addresses the appropriate branding of all of the Company's residential rate options and

contains a detailed plan and timeline for developing a rates calculator that allows customers to easily identify the rate that best suits their circumstances.

6. The current residential BSC is already sufficient to recover truly customer-related costs, and the Company's cost of service analysis shows a decrease rather than an increase in customer-related costs. Both of these facts, considered separately or in concert, render an increase in the residential BSC unjustified.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Exhibit JRB-1

Georgia Power 2022 Rate Case – 44280

Georgia Interfaith Power & Light

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EDUCATION

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Master of Science, Environmental Policy, August 2006
Graduate-level work in Energy Policy.

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Bachelor of Science, Geography, December 2003
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RELEVANT EXPERIENCE

Director of Research, July 2015 – present
Senior Analyst & Research Manager, March 2013 – July 2015
EQ Research, LLC and Keyes, Fox & Wiedman, LLP Cary, North Carolina

- Oversee state legislative, regulatory policy, and general rate case tracking service that covers policies such as net metering, interconnection standards, rate design, renewables portfolio standards, state energy planning, state and utility incentives, tax incentives, and permitting. Responsible for service design, formulating improvements based on client needs, and ultimate delivery of reports to clients. Expanded service to cover energy storage.
- Oversee and perform policy research and analysis to fulfill client requests, and for internal and published reports, focused primarily on drivers of distributed energy resource (DER) markets and policies.
- Provide expert witness testimony on topics including cost of service, rate design, distributed energy resource (DER) value, and DER policy including incentive program design, rate design issues, and competitive impacts of utility ownership of DERs.
- Managed the development of a solar power purchase agreement (PPA) toolkit for local governments, a comprehensive legal and policy resource for local governments interested in purchasing solar energy, and the planning and delivery of associated outreach efforts.

Senior Policy Analyst, January 2012 – May 2013;
Policy Analyst, September 2007 – December 2011
North Carolina Solar Center, N.C. State University Raleigh, North Carolina

- Responsible for researching and maintaining information for the Database of State Incentives for Renewables and Efficiency (DSIRE), the most comprehensive public source of renewables and energy efficiency incentives and policy data in the United States.
- Managed state-level regulatory tracking for private wind and solar companies.
- Coordinated the organization's participation in the SunShot Solar Outreach Partnership, a U.S. Department of Energy project to provide outreach and technical assistance for local governments to develop and transform local solar markets.
- Developed and presented educational workshops, reports, administered grant contracts and associated deliverables, provided support for the SunShot Initiative, and worked with diverse group of project partners on this effort.
- Responsible for maintaining the renewable portfolio standard dataset for the National Renewable Energy Laboratory for use in its electricity modeling and forecasting analysis.
- Authored the *DSIRE RPS Data Updates*, a monthly newsletter providing up-to-date data and historic compliance information on state RPS policies.

- Responded to information requests and provided technical assistance to the general public, government officials, media, and the energy industry on a wide range of subjects, including federal tax incentives, state property taxes, net metering, state renewable portfolios standard policies, and renewable energy credits.
- Extensive experience researching, understanding, and disseminating information on complex issues associated with utility regulation, policy best practices, and emerging issues.

SELECTED ARTICLES and PUBLICATIONS

- EQ Research and Synapse Energy Economics for Delaware Riverkeeper Network. *Envisioning Pennsylvania's Energy Future*. 2016.
- Barnes, J., R. Haynes. *The Great Guessing Game: How Much Net Metering Capacity is Left?*. September 2015. Published by EQ Research, LLC.
- Barnes, J., Kapla, K. *Solar Power Purchase Agreements (PPAs): A Toolkit for Local Governments*. July 2015. For the Interstate Renewable Energy Council, Inc. under the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *2013 RPS Legislation: Gauging the Impacts*. December 2013. Article in Solar Today.
- Barnes, J., C. Laurent, J. Uppal, C. Barnes, A. Heinemann. *Property Taxes and Solar PV: Policy, Practices, and Issues*. July 2013. For the U.S. DOE SunShot Solar Outreach Partnership.
- Kooles, K, J. Barnes. *Austin, Texas: What is the Value of Solar; Solar in Small Communities: Gaston County, North Carolina*; and *Solar in Small Communities: Columbia, Missouri*. 2013. Case Studies for the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *The Report of My Death Was An Exaggeration: Renewables Portfolio Standards Live On*. 2013. For Keyes, Fox & Wiedman.
- Barnes, J. *Why Tradable SRECs are Ruining Distributed Solar*. 2012. Guest Post in Greentech Media Solar.
- Barnes, J., multiple co-authors. *State Solar Incentives and Policy Trends*. Annually for five years, 2008-2012. For the Interstate Renewable Energy Council, Inc.
- Barnes, J. *Solar for Everyone?* 2012. Article in Solar Power World On-line.
- Barnes, J., L. Varnado. *Why Bother? Capturing the Value of Net Metering in Competitive Choice Markets*. 2011. American Solar Energy Society Conference Proceedings.
- Barnes, J. *SREC Markets: The Murky Side of Solar*. 2011. Article in State and Local Energy Report.
- Barnes, J., L. Varnado. *The Intersection of Net Metering and Retail Choice: an overview of policy, practice, and issues*. 2010. For the Interstate Renewable Energy Council, Inc.

TESTIMONY & OTHER REGULATORY ASSISTANCE

Wisconsin Public Service Commission. Docket No. 5-UR-110. September 2022. On behalf of RENEW Wisconsin. Wisconsin Electric Power Company general rate case application. Provided an exhibit showing residential fixed charges among all major IOUs in the nation and testimony explaining the methodology used to develop the exhibit.

Wisconsin Public Service Commission. Docket No. 6690-UR-127. September 2022. On behalf of RENEW Wisconsin. Wisconsin Public Service Corporation general rate case application. Provided an exhibit showing residential fixed charges among all major IOUs in the nation and testimony explaining the methodology used to develop the exhibit.

Wisconsin Public Service Commission. 3270-UR-124. September 2022. On behalf of RENEW Wisconsin. Madison Gas and Electric general rate case application. Provided an exhibit showing residential fixed charges among all major IOUs in the nation and testimony explaining the methodology used to develop the exhibit. (*Note: Exhibit was introduced at the hearing and testimony on the methodology provided orally at the hearing; written testimony was not filed).*

Michigan Public Service Commission. Case No. U-20836. May 2022. On behalf of the Michigan Energy Innovation Business Council and The Institute for Energy Innovation. DTE Electric Company general rate case application. Addressed the utility's proposal for changes to its DG Tariff, including excluding generation capacity value from the export rate and requiring DG customers to take service under a newly proposed residential demand rate. Also evaluated the cost causation and other rate attributes of the proposed residential demand rate.

Virginia State Corporation Commission. Docket No. PUR-2021-00171. January 2022. On behalf of Appalachian Voices. Old Dominion Power Company general rate case application. Evaluation of the cost basis for the residential customer charge, AMI deployment and the timeline for deployment of TOU rates, class allocation of distribution and production demand costs, and the Company's proposal for a DSM/EE pilot program and cost recovery rider.

Michigan Public Service Commission. Case No. U-20963. June 2021. On behalf of the Michigan Energy Innovation Business Council and the Institute for Energy Innovation. Consumers Energy Company general rate case. Provided an evaluation of the utility's proposed home battery program and offered recommendations for modifications to the program to improve its cost-effectiveness and delivery of benefits to participants and non-participants through changes to battery operational plans, elimination of restrictions on consumer use of the batteries, battery sizing modifications to fit actual customer needs, and use of solar-paired storage to provide greater resiliency.

Colorado Public Utilities Commission. Proceeding No. 20AL-0432E. March 2021. On behalf of the Colorado Solar and Storage Association and the Solar Energy Industries Association. Public Service Company of Colorado (Xcel Energy Colorado) general rate case. Provided analysis and recommendations on several non-residential rate design issues, including the utility's practice of switching small commercial customers to demand rates, relaxing the demand threshold at which commercial customers are subject to demand rates, the utility's proposal for modifying time-varying pricing windows, and the establishment of a pilot time-of-use rate for Secondary General (SG) commercial customers intended to remedy the misalignment between the SG non-coincident demand rate design and cost causation and set a foundation for a default time-varying rate option for SG class customers.

Kentucky Public Service Commission. Docket Nos. 2020-00349 and 2020-00350. March 2021 (Phase 1) and July/August 2021 (Phase 2). On behalf of the Kentucky Solar Energy Industries Association. Kentucky Utilities and Louisville Gas and Electric general rate case applications. Provided an analysis of the utilities' current tariffs governing purchases from qualifying facilities and recommended changes to align them with state regulations, recent precedent, and accepted methodologies of energy and capacity pricing.

South Carolina Public Service Commission. Docket Nos. 2020-264-E and 2020-265-E. February 2021. On behalf of the Solar Energy Industries Association and the North Carolina Sustainable Energy Association. Docket for establishing a Solar Choice tariff for customers of Duke Energy Carolinas and Duke Energy Progress. Provided testimony in support of a stipulated settlement discussing the critical role that a proposed smart thermostat rebate and enabling technologies more generally play in the successfully meeting the legislative objectives for Solar Choice tariffs.

South Carolina Public Service Commission. Docket No. 2020-229-E. January 2021. On behalf of the Solar Energy Industries Association and the North Carolina Sustainable Energy Association. Docket for establishing a Solar Choice tariff for customers of Dominion Energy South Carolina. Provided an analysis of the proposed Solar Choice tariff from the standpoint of NEM successor best practices, alignment with the enabling statute, and cost of service basis. Offered an alternative Solar Choice tariff proposal based on

this analysis. Surrebuttal testimony provided an evaluation of solar customer cost of service correcting erroneous assumptions used by the Office of Regulatory Staff in its direct testimony.

Virginia State Corporation Commission. Docket No. PUR-2020-00134. January 2021. On behalf of the Behind the Meter Solar Alliance. Docket for Dominion Virginia's 2020 RPS Plan. Offered testimony supporting the designation of small-scale resource carve-out eligibility being limited to behind the meter resources, based on the underlying Virginia statute and other public policy reasons.

South Carolina Public Service Commission. Docket No. 2019-182-E. October 2020. On behalf of the Solar Energy Industries Association and the North Carolina Sustainable Energy Association. Docket for establishing a cost-benefit analysis methodology and protocols for net metering and DERs. Provided discussion of historic regulatory use of DG cost-benefit and cost of service studies, how results should be viewed, and a discussion of the role of economic benefits and resiliency in DER cost-benefit analyses.

Kentucky Public Service Commission. Docket No. 2020-00174. October 2020. On behalf of the Kentucky Solar Industries Association. Kentucky Power general rate case. Provided an evaluation and critique of the cost of service support for, and design of, Kentucky Power's proposed net metering successor tariff and offered recommendations for developing cost-based DER rate designs. Also recommended changes to the utility's QF tariff and calculation of capacity costs.

New Jersey Board of Public Utilities. Docket No. EO18101111. September 2020. On behalf of Sunrun, Inc. Public Service Gas and Electric energy storage deployment plan proposal. Offered alternative proposal for a program utilizing non-utility owned energy storage assets under an aggregator model with elements for benefits sharing and ratepayer risk reduction.

Virginia State Corporation Commission. Docket No. PUR-2020-00015. July 2020. On behalf of Appalachian Voices. Appalachian Power Company general rate case. Analysis of the cost basis for the residential customer charge, the Company's winter declining block rate proposal, and a proposed Coal Asset Retirement Rider (Rider CAR) providing for advance collection of anticipated accelerated depreciation of coal generation assets. Provided an alternative residential customer charge recommendation and an alternative rates proposal for addressing winter bill volatility for electric heating customers.

North Carolina Utilities Commission. Docket No. E-2 Sub 1219. April 2020. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Progress general rate case. Provided analysis of available rate options for electric vehicle charging and recommended the adoption of residential and non-residential EV-specific rate options and appropriate design characteristics for those rate options.

North Carolina Utilities Commission. Docket No. E-7 Sub 1214. January 2020. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Carolinas general rate case. Provided analysis of available rate options for electric vehicle charging and recommended the adoption of residential and non-residential EV-specific rate options and appropriate design characteristics for those rate options.

Virginia State Corporation Commission. Docket No. PUR-2019-00060. November 2019. On behalf of Appalachian Voices. Old Dominion Power Company general rate case application. Analysis of the cost basis for the residential customer charge, proposal to change the residential customer charge from a monthly charge to a daily charge, and design of proposed customer green power program and utility owned commercial behind the meter solar proposal. Proposed modified optional rate structure for mid- to large-size non-residential customers with on-site solar and/or low load factors.

Georgia Public Service Commission. Docket No. 42516. October 2019. On behalf of Georgia Interfaith Power and Light, Southface Energy Institute, and Vote Solar. Georgia Power Company general

rate case application. Analysis of the cost basis for the residential customer charge, the validity of the utility's minimum-intercept study, and a proposal to change the residential customer charge from a monthly charge to a daily charge.

Hawaii Public Utilities Commission. Docket No. 2018-0368. July 2019. On behalf of the Hawaii PV Coalition. Hawaii Electric Light Company (HELCO) general rate case application. Provided analysis of HELCO's proposed changes to its decoupling rider to make the decoupling charge non-bypassable and the alignment of the proposed modifications with state policy goals and the policy rationale for decoupling.

Virginia State Corporation Commission. Docket No. PUR-2019-00067. July 2019.* On behalf of the Southern Environmental Law Center. Appalachian Power Company residential electric vehicle (EV) rate proposal. Provided review and analysis of the proposal and developed comments discussing principles of time-of-use (TOU) rate design and proposing modifications to the Company's proposal to support greater equity among rural ratepayers and greater rate enrollment. ***This work involved comment preparation rather than testimony.**

New York Public Service Commission. Case No. 19-E-0065. May 2019. On behalf of The Alliance for Solar Choice. Consolidated Edison (ConEd) general rate case application. Provided review and analysis of the competitive impacts and alignment with state policy of ConEd's energy storage, distributed energy resource management system, and earnings adjustment mechanism (EAM) proposals. Proposed model for improving the utilization of customer-sited storage in existing demand response programs and an alternative EAM supportive of utilization of third party-owned battery storage.

South Carolina Public Service Commission. Docket No. 2018-318-E. March 2019. On behalf of Vote Solar. Duke Energy Progress general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, AMI-enabled rate design plans, excess deferred income tax rider rate design, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

South Carolina Public Service Commission. Docket No. 2018-319-E. February 2019. On behalf of Vote Solar. Duke Energy Carolinas general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, AMI-enabled rate design plans, excess deferred income tax rider rate design, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

New Orleans City Council. Docket No. UD-18-07. February 2019. On behalf of the Alliance for Affordable Energy. Entergy New Orleans general rate case application. Analysis of the cost basis for the residential customer charge, rate design for AMI, DSM and Grid Modernization Riders, and DSM program performance incentive proposal. Developed recommendations for the residential customer charge, rider rate design, and a revised DSM performance incentive mechanism.

New Hampshire Public Utilities Commission. Docket No. DE 17-189. May 2018. On behalf of Sunrun Inc. Review of Liberty Utilities application for approval of customer-sited battery storage program, analysis of time-of-use rate design, program cost-benefit analysis, cost-effectiveness of utility-owned vs. non-utility owned storage assets. Developed a proposal for an alternative program utilizing non-utility owned assets under an aggregator model with elements for benefits sharing and ratepayer risk reduction.

North Carolina Utilities Commission. Docket No. E-7 Sub 1146. January 2018. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Carolinas general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system

study, allocation of coal ash remediation costs, and grid modernization rider proposal, including the reasonableness of the program, class distribution of costs and benefits, and cost allocation.

Ohio Public Utilities Commission. Docket No. 17-1263-EL-SSO. November 2017*. On behalf of the Ohio Environmental Council. ***Testimony prepared but not filed due to settlement in related case.** Duke Energy Ohio proposal to reduce compensation to net metering customers. Provided analysis of capacity value of solar net metering resources in the PJM market and distribution of that value to customers. Also analyzed the cost basis of the utility proposal for recovery of net metering credit costs, focused on PJM settlement protocols and how the value of DG customer exports is distributed among ratepayers, load-serving entities, and distribution utilities based on load settlement practices.

North Carolina Utilities Commission, Docket No. E-2 Sub 1142. October 2017. On behalf of the North Carolina Sustainable Energy Association. Duke Energy Progress general rate case application. Analysis of the cost basis for the residential customer charge and validity of the utility's minimum system study, allocation of coal ash remediation costs, and advanced metering infrastructure deployment plans and cost-benefit analysis.

Public Utility Commission of Texas, Control No. 46831. June 2017. On behalf of the Energy Freedom Coalition of America. El Paso Electric general rate case application, including separate DG customer class. Analysis of separate DG rate class and rate design proposal, cost basis, DG load research study, and analysis of DG costs and benefits, and alignment of demand ratchets with cost causation principles and state policy goals, focused on impacts on customer-sited storage.

Utah Public Service Commission, Docket No. 14-035-114. June 2017. On behalf of Utah Clean Energy. Rocky Mountain Power application for separate distributed generation (DG) rate class. Provided analysis of grandfathering of existing DG customers and best practices for review of DG customer rates and DG value. Developed proposal for addressing revisions to DG customer rates in the future.

Colorado Public Utilities Commission, Proceeding No. 16A-0055E. May 2016. On behalf of the Energy Freedom Coalition of America. Public Service Company of Colorado application for solar energy purchase program. Analysis of program design from the perspective of customer demand and needs, and potential competitive impacts. Proposed alternative program design.

Public Utility Commission of Texas, Control No. 44941. December 2015. On behalf of Sunrun, Inc. El Paso Electric general rate case application, including separate DG customer class. Analysis of separate rate class and rate design proposal, cost basis, DG load research study, and analysis of DG costs and benefits.

Oklahoma Corporation Commission, Cause No. PUD 201500274. November 2015. On behalf of the Alliance for Solar Choice. Analysis of Oklahoma Gas & Electric proposal to place distributed generation customers on separate rates, rate impacts, cost basis of proposal, and alignment with rate design principles.

South Carolina Public Service Commission, Docket No. 2015-54-E. May 2015. On behalf of The Alliance for Solar Choice. South Carolina Electric & Gas application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2015-53-E. April 2015. On behalf of The Alliance for Solar Choice. Duke Energy Carolinas application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2015-55-E. April 2015. On behalf of The Alliance for Solar Choice. Duke Energy Progress application for distributed energy programs. Alignment of proposed programs with distributed energy best practices throughout the U.S., including incentive rate design and community solar program design.

South Carolina Public Service Commission, Docket No. 2014-246-E. December 2014. On behalf of The Alliance for Solar Choice. Generic investigation of distributed energy policy. Distributed energy best practices, including net metering and rate design for distributed energy customers.

AWARDS, HONORS & AFFILIATIONS

- Solar Power World Magazine, Editorial Advisory Board Member (October 2011 – March 2013)
- Michigan Tech Finalist for the Midwest Association of Graduate Schools Distinguished Masters Thesis Awards (2007)
- Sustainable Futures Institute Graduate Scholar Michigan Tech University (2005-2006)

Exhibit JRB-2

Georgia Power 2022 Rate Case – 44280

Georgia Interfaith Power & Light

RAP®

REGULATORY ASSISTANCE PROJECT

NOVEMBER 2020

Demand Charges: What Are They Good For?

An Examination of Cost Causation

Mark LeBel and Frederick Weston, with contributions from Ronny Sandoval



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The analysis in this paper rests on the shoulders of earlier RAP publications, in particular:

Lazar, J., & Gonzalez, W. (2015). *Smart rate design for a smart future.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/

Linvill, C., Lazar, J., Dupuy, M., Shipley, J., & Brutkoski, D. (2017). *Smart non-residential rate design.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/smart-non-residential-rate-design/

Weston, F. (2000). *Charging for distribution utility services: Issues in rate design.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/charging-for-distribution-utility-services-issues-in-rate-design/

That said, responsibility for the information and views set out herein lies entirely with the authors.

Executive Summary

Demand charges, rates that are applied to an individual customer's maximum short-term usage (typically 15, 30 or 60 minutes) in a billing period, have existed since nearly the beginning of the electric industry. While utilities often favor demand charges, economists have continually questioned whether they are an efficient form of pricing. With the widespread adoption of advanced metering, this is an opportune time to reconsider demand charges, even for industrial customers, and replace them with more efficient time-varying energy (kilowatt-hour) rates.

Traditional monthly demand charges have always provided a perverse incentive that does not reflect cost causation for shared system costs. Individual customer noncoincident peaks (NCPs) do not reflect the coincident peaks that drive *shared* generation and delivery capacity costs. The price signal that demand charges send — to lower individual customer NCP and to level a customer's load over time — is substantially different than a price signal to reduce usage at the time of coincident peaks. As a result, demand charges penalize customers for usage at times that do not impose particularly high costs and encourage them to waste effort and money shifting loads off their own maximum hour (and sometimes onto high-load system hours).

The historic exception to this rule is a customer that has a nearly 100% coincidence factor with the relevant peaks. The prototypical example of this in the mid-20th century was an industrial customer with very high load factors. Demand charges could be reasonable in the past only as applied to this specific category of customers. But, in today's electric system, even this justification for demand charges falls away. High penetrations of nondispatchable but variable renewable generation means that a 100% load factor is unlikely to be, from a system perspective, the most desirable load shape. Rather, flexible load — load that can respond to swift changes in the availability of supply, perhaps in the middle of the day for solar and late at night with wind — becomes cheaper to serve than unvarying loads in systems marked by high penetrations of variable supply.

Historically, demand charges have frequently been sized to recover most or all shared system capacity costs. Again, this may have been reasonable enough in the mid-20th century for certain customers, but it does not reflect the economics and engineering of a modern electric system. The choices that system planners make are trade-offs between different types of costs. Much "capacity" investment today aims to reduce energy costs and is not incurred to meet peak reliability needs. This means that a significant portion of investment in generation, transmission and distribution plant (and the associated operation and maintenance expense) cannot be reasonably described as demand-related or driven by peak reliability needs. Any pricing structures that reflect the marginal costs of peak system capacity should be sized properly to reflect these distinctions. That includes

demand charges, if appropriate, as well as time-varying energy pricing.

It is fair to ask whether a properly sized "peak window" demand charge solves these issues. Although such a charge is superior to traditional demand charges for the pricing of shared capacity costs, peak window demand charges nonetheless retain many of the shortcomings of their traditional counterparts. Customers who have high usage at many times throughout the peak period should be charged more for capacity than customers who have a single high usage interval in that same window. Time-varying energy pricing provides superior incentives to optimize usage at all relevant times. Simple time-of-use rates are fairer and more efficient than peak window demand charges and can be made even more so by overlaying them with pricing that is responsive to critical peak conditions.

A few analysts and economists have identified several narrower applications where pricing structures akin to demand charges could be appropriate and reasonably efficient: (1) site infrastructure for individual customers, (2) risks related to customer variability at peak times and (3) timer peaks. While more research into these applications might be merited, demand-based pricing would only be a second-best approximation of a more efficient but potentially more administratively complex time- and location-based pricing system.

1. Introduction

Demand charges have existed almost since the beginning of the electric industry in the 1880s. They were originally called Hopkinson rates after John Hopkinson, a British engineer who described the concept in 1892. Hopkinson believed that costs of "plant and conductors"[1] — namely capacity costs — for an electric utility should be charged to customers based on the "greatest rate of supply the consumer will ever take."[2] Shortly thereafter, a meter was developed that could capture the highest kW power draw from the customer, defined over a period of an hour or half-hour, during an entire billing period (now typically a month). These rates became prevalent for industrial customers in the early 1900s.[3]

It did not take long, however, before economists called into question their putative cost-causation rationale. In 1941, future Nobel Prize winner in economics W. Arthur Lewis argued that the cost-causation case for demand charges was often based on "a simple confusion. … The maximum rate at which the individual consumer takes is irrelevant; what matters is how much he is taking at the time of the station's peak."[4] In 1970, prior to becoming chairman of the New York Public Service Commission, Cornell University professor Alfred E. Kahn wrote that demand charges are "basically illogical."[5] More recently, University of California professor and California Independent System Operator board member Severin Borenstein opined that "it is unclear why demand charges still exist."[6]

Electric utilities and some consultants still make broad arguments for demand charges that are, at their core, the same as those made more than a century ago. In 2016, the Edison Electric Institute (EEI) asserted that "demand charges provide accurate price signals" and "better collect capacity costs [than other kinds of prices]."[7] EEI made this

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[1] Hopkinson, J. (1901). *Original papers: Vol. 1, Technical papers*, p. 257. Cambridge University Press.

[2] Hopkinson, 1901, p. 261.

[3] There was a debate within the electric utility industry about rate design in the 1890s. A time-of-use meter was invented nearly simultaneously with the demand meter, and some industry participants argued that time-of-use rates would be superior. See Hausman, W. J., & Neufeld, J. L. (1984). Time-of-day pricing in the U.S. electric power industry at the turn of the century. *The RAND Journal of Economics, 15*(1). This time-of-use meter disappeared from discussion relatively quickly, however, as an industry consensus formed around demand charges. Neufeld argues that demand charges were a part of utility strategy to discourage industrial customers from relying on distributed generation, known as "isolated plants" at the time. Neufeld, J. (1987, September). Price discrimination and the adoption of the electricity demand charge. *Journal of Economic History, 47*(3), 693-709. In addition, Samuel Insull, president of Chicago Edison (later Commonwealth Edison) and a major player in the industry, happened to own a part of the patent for the demand charge meter. See Yakubovich, V., Granovetter, M., & McGuire, P. (2005). Electric charges: The social construction of rate systems. *Theory and Society, 34,* 597-612.

[4] Lewis, W. A. (1941). The two-part tariff. *Economica, 8*(41), 252.

[5] Kahn, A. E. (1970). *The economics of regulation: Principles and institutions: Vol. 1, Economic principles*, p. 96. John Wiley & Sons.

[6] Borenstein, S. (2016). The economics of fixed price recovery. *The Electricity Journal, 29*(7), 10.

[7] Edison Electric Institute. (2016, February). *Primer on rate design for residential distributed generation,* p. 6. https://www.eei.org/issuesandpolicy/generation/NetMetering/Documents/2016%20Feb%20NARUC%20Primer%20on%20Rate%20Design.pdf

argument simultaneously for two different types of demand charges: (1) the traditional monthly noncoincident peak (NCP)[8] demand charge, based on an individual customer's NCP across an entire billing period, and (2) a peak window demand charge,[9] based on an individual customer NCP within a defined multihour interval, similar to the on-peak period for a time-of-use (TOU) rate.[10] In addition, there has been a push by EEI and many utilities to expand the application of demand charges beyond just the industrial and large commercial customer classes to small business and even residential customer classes.

Demand charges as we've known them in the United States should largely become a relic of the past. Current forms of demand charges, based on 15-minute, 30-minute or 60-minute individual customer peaks and often intended to recover the lion's share of capacity costs, are neither cost reflective nor efficient in general.[11] For much of the 20th century, traditional demand charges may have been a second-best alternative that worked reasonably well for high-load-factor industrial customers. Developments of the past several decades have, however, made even this application of demand charges archaic. Such charges do not reflect the cost drivers of the modern electric system, and typical sizing of these charges are larger than justified by proper economic analysis of the electric system. Peak window demand charges, while an improvement over their traditional counterpart, do not solve many of the core deficiencies of demand charges as an efficient pricing mechanism. Time-varying rates, including TOU rates and critical peak pricing, are more efficient than peak window demand charges.

If there is a role for demand charges in today's electric system, it is much narrower than the one it performs for industrial customers in many jurisdictions. Modern versions of

[8] A customer's noncoincident peak is its highest demand, in kilowatts, measured at the meter during the period in question. This customer demand can be measured based on different intervals, typically 15, 30 or 60 minutes. "Noncoincident" means that this demand does not necessarily occur at the time of a system peak.

[9] There is no standardized terminology for this type of demand charge where determination of the maximum demand for the billing period considers only a limited number of peak hours, similar to the peak period for a time-of-use rate. We find the "peak window demand charge" description more apt than the other alternatives.

[10] Less commonly, daily-as-used demand charges are part of the discussion, which we raise later in this paper. As the name implies, it is a demand charge for a customer's individual NCP in a given 24-hour period, sometimes limited to a peak window within that day and sometimes excluding weekends and holidays. This means that the ratchet feature of a daily-as-used demand charge is reset every day and not every billing period, as with other demand charges. In this paper, we do not focus on contract (ex ante) demand charges, although they share many features with these other alternatives.

[11] There are other issues at play in the debate around demand charges, particularly whether residential and small business customers can understand and manage these types of rates and the related potential for inequitable bill impacts. See Chernick, P., Colgan, J., Gilliam, R., Jester, D., & LeBel, M. (2016). *Charge without a cause? Assessing electric utility demand charges on small consumers.* (Electricity rate design review paper No. 1). https://votesolar.org/files/6414/6888/3283/Charge-Without-CauseFinal_71816.pdf; and Lazar J. (2015). Use great caution in design of residential demand charges. *Natural Gas & Electricity*. https://www.raponline.org/wp-content/uploads/2016/05/lazar-demandcharges-ngejournal-2015-dec.pdf. The question of understandability of demand charges by residential and small business customers is a longstanding one. D. J. Bolton notes that a 1948 report by a government commission in Great Britain rejected demand charges for residential customers on two bases: (1) understanding of the rate and (2) the potential reaction to an overload encouraging higher usage levels going forward. Bolton, D. J. (1951). *Electrical engineering economics: Vol. 2, Costs and tariffs in electricity supply*, p. 255. (2nd ed. rev.). Chapman & Hall. We do not delve into these issues at length in this paper.

these charges need to be more rigorously fashioned to achieve economic efficiency and advance the public good than they have been historically. We examine three more nuanced cases where demand charges have been identified as a potentially efficient pricing mechanism: (1) site infrastructure for individual customers, (2) risks related to customer variability at peak times and (3) timer peaks. In these situations, pricing structures with some similarities to demand charges may be appropriate. In each of these cases, demand-based pricing would only be a second-best approximation of a more efficient time- and location-based pricing system.

Unless we reexamine fundamental ratemaking practices critically in light of the modern electric system and new technologies, we will miss major opportunities to optimize system costs, ensure reliability and improve societal outcomes. While utilities and some consultants have been pushing for new applications for demand charges, regulators and utilities should be moving in the opposite direction by replacing demand charges for industrial customers with more accurate pricing mechanisms.

2. Historic Cost-Causation Argument for Demand Charges

A frequently used but inaccurate cost-causation argument for demand charges begins with the observation that several of the most important cost categories can be denoted in kilowatts (kW) or megawatts (MW).

- Generation capacity is denominated in kW or MW, reflecting the maximum instantaneous power output of a given unit.
- Transformers are rated in kilovolt-ampere (kVA) or megavolt-ampere (MVA), a unit of apparent power[12] closely related to kW or MW.
- Conductors are rated in amps for the level of current that they can handle. For a given voltage, this leads to a maximum kW or MW power flow for that conductor (power equals current times voltage).[13]

From these engineering descriptions, which are accurate but potentially misleading, some analysts conclude that, because generation and delivery capacity can be measured in units of power (kW or MW), their costs are demand-related. Making the leap to retail rate design then becomes easy: Capacity costs are rated in kW, so prices should be reflected

[12] Apparent power is the combination of active and reactive power in an alternating current circuit that needs to be supplied to serve load. This includes the power components that are needed to energize the circuit but don't transfer useful power to the load.

[13] For three-phase power, power is current times voltage times the square root of 3.

in kW.[14] This is the essence of the argument made by EEI, but it rests on several fallacies.

Some earlier writers, including W. Arthur Lewis, D. J. Bolton and James Bonbright, are open to demand charges to a certain extent but are quite candid about their limitations and significant downsides. Important factors in this more nuanced determination include:

- The diversity and coincidence factors[15] of any group of customers who might face a demand charge.
- The relative metering costs for flat kilowatt-hour (kWh) rates, demand rates and time-varying rates.
- The ability (or lack thereof) for customers to economically shift certain types of load.
- The broad similarity of capacity and fuel costs for many generation alternatives (typically thermal steam units) prior to 1960.

Lewis acknowledged the metering problem in his 1941 article, "The Two-Part Tariff." He stated that "the two-part tariff [a demand charge and an energy charge] is superior to having a single undifferentiated price which discourages off-peak consumption, *but inferior to charging different prices at different times*, though it may sometimes be more convenient than the latter if the measurement and timing of consumption are costly."[16] In the early and mid-20th century, only simple kWh metering was economic for small customers (that is, the system benefit from the response to time-differentiated pricing did not exceed the cost of the metering necessary to support it), while more sophisticated metering could be justified for industrial customers.

In 1951 Bolton noted, with some approval, that demand charges were much more common for industrial customers than residential.[17] He observed that residential customers' peaks are more random, that is to say more diverse (spread out in time) and less likely to be correlated with system peaks: "A metered demand system for such a [residential] consumer would mean making a high charge for payment at times when it was most unlikely to matter."[18] He opined that the load of many large industrial customers is not

[14] It is worth noting that these "kW" demand measurements are actually measured in units of kilowatt-hours per hour and simplified to be presented as measures of kW demand.

[15] Diversity of demand for a utility reflects the temporal differences in usage among customers. Peak coincident demand at any level of the system is less than the sum of customers' individual peaks because of these temporal differences. The calculated "diversity factor" provides a quantitative measure of these differences; conversely, a "coincidence factor" measures the extent to which these individual peaks do line up. These concepts are defined and discussed further in Section 3.1.

[16] Lewis, 1941, pp. 255-256 (emphasis added). Even in 1941, Lewis thought that it was no longer the case that demand metering would be cheaper than time-based metering, with one alternative being simple timers and another being "ripple control," where a utility sends a high frequency signal to flip an equipment switch.

[17] Bolton, 1951, p. 255. Bolton's proposed ideal "scientific tariff" features a TOU rate and no demand charges, where the on-peak price recovers demand-related costs. See Bolton, 1951, pp. 249-250.

[18] Bolton, 1951, p. 255.

particularly susceptible to shaping, because it is "motive power" (i.e., motors to run large equipment), and the electricity costs represent a small fraction of overall costs for these firms.[19] This type of industrial customer has strong incentives, given a set amount of productive capacity, to have the highest operating factor possible and thus a high load factor.[20] This industrial load pattern implies a significant likelihood that an individual customer's peak in a given month or year is closely linked to the customer's demand at the time of system peak.

Bonbright, writing originally in 1961, stated that traditional demand charges provide some benefits from "a tendency of existing customers to spread their loads over a longer period in order to minimize their demand charges, instead of bunching them during short period likely to coincide with the heavy loads of other customers."[21] Bonbright then went on to observe that electric rate design in those days "[was] far from ideal, and practical rate makers will do well to consider seriously its alleged infirmities viewed from the standpoint of its critics among the academic economists." He noted in particular that there was little sense in "the imposition of demand charges which penalize consumers for high individual demands even though these demands come at hours or seasons that fall well off the peak loads imposed on the system as a whole or even on any major part thereof."[22]

Up until 1960, most generation options, with the exception of hydroelectric power, had very similar cost characteristics. Steam generation was the predominant capacity type, and there were few differences in cost among coal, oil and natural gas units. Even fuel prices were broadly similar. In such a system, there is a better case that all capacity is similarly situated to serve peak reliability needs and thus can be considered demand-related. As discussed later, this issue goes to the sizing of any demand charges if they can be shown to be a reasonable solution (in limited circumstances at best).

This combination of factors — (1) an industrial customer base with a relatively small number of customers, most of whom had high load factors, high peak-coincidence factors and high levels of consumption and (2) a large number of residential customers with lower coincidence factors and relatively low consumption per customer — provided a rough rationale for the rate designs that prevailed throughout most of the United States in the 20th century and are now lingering into the 21st. In pricing, this typically manifested itself in significant demand charges for large industrial classes to recover nearly all capacity costs and in fully volumetric energy rates for residential and small business customers.

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[19] Bolton, 1951, p. 238.

[20] Load factor is the ratio of an end user's actual energy usage in a period to its maximum potential usage in that period. It is calculated as follows: kWh/(peak demand x total hours), within the specified period.

[21] Bonbright, J. (1961). *Principles of public utility rates*, p. 311. Columbia University Press. https://www.raponline.org/knowledge-center/principles-of-public-utility-rates/

[22] Bonbright, 1961, p. 316.

In this historical context, this could be relatively fair and efficient for a narrow slice of customers that meet the relevant description. To the extent that other customers that could share capacity (e.g., churches and schools; offices and movie theaters) were faced with demand charges, these customers were treated unfairly and often paid significantly more costs than they caused.

3. Why Demand Charges Are Inefficient

Some of these arguments for demand charges held sway in the past, even though the better case for time-varying energy charges was well understood. Today, the features of the modern electric system undermine even the more nuanced historic case for demand charges altogether. This is true for large industrial customers as well as for residential and small business customers.

The original advocates of demand charges often focused on what they thought was a fair and efficient division of historic accounting costs. Modern economists, even those who still advocate for demand charges, recognize that this older perspective is in error and argue (correctly) that rate structures should be designed to efficiently optimize *future* costs.[23] This perspective leads one to the conclusion that rates should be reflective of forward-looking marginal costs. In utility regulation, this concept is translated into different operative regulatory language in different jurisdictions, calling variously for rates that discourage wasteful usage, reflect actual costs or ensure the causer pays those costs. But in each case, the underlying microeconomic principle is the same: Rate design should ensure that the actions customers take to minimize their own bills are consistent with the actions they would take to minimize system costs. The nitty-gritty of designing rates in this framework is how to fairly and efficiently reflect marginal costs in prices. The best way to conceptualize this is to examine how the customer responds to a given rate design — both its form and its magnitude. An efficient rate design will lead to customer behavior that optimizes system costs.

The marginal consumption incentives for customers in any system of time-varying rates are fairly straightforward: (1) discourage usage in periods of relatively high rates and (2) encourage usage in periods of relatively low rates. Prices that achieve these outcomes are charged in a way that is both (1) consistent (all kWh at a given time or system condition are treated the same) and (2) symmetric: If an increase in consumption causes a bill to rise by $10, then the same sized decrease causes a bill to decline by $10.

The incentives presented by a typical demand charge structure are somewhat more

[23] See, for example, Boiteux, M. (1960). Peak-load pricing. *The Journal of Business, 33*(2), 157-179. (H. W. Izzzard, Trans.); Kahn, 1970; and Crew, M. A., & Kleindorfer, P. R. (1979). *Public utility economics.* St. Martin's Press.

complex.[24] If a customer is perfectly flexible (indifferent as to when they take electricity from the grid) and has perfect foresight, a demand charge would clearly incentivize a 100% load factor within the relevant time frame (e.g., each month). Of course, such customers do not exist in the real world,[25] although there are some customers that come close to having 100% load factors because of the nature of their operations: 24-hour supermarkets, data centers and certain types of factories.

Because customers do not have perfect foresight and infinite flexibility, it is only possible to talk about the incentives created by a demand charge at a certain level of generality. The most obvious features of a demand charge are that it directly (1) discourages higher individual customer NCP demand and (2) encourages levelization of load within the relevant time period. The related key feature of all types of demand charges is that they act as a ratchet, even if the ratchet is not applied across multiple billing periods.[26] Once a certain level of demand has been reached, customers then face a *lower* marginal cost for the remainder of the period to which the demand charge applies, as long as they have a power draw between zero and their previous individual demand peaks.

When the demand charge impacts a particular consumption decision, it can be quite punitive — imagine paying $5 to $10 to make toast for a family, which is exactly what can happen with a poorly designed residential demand charge.[27] This shows up as a high marginal cost for a subset of hours and consumption decisions. But otherwise, if a particular consumption decision does not pose a substantial risk of setting the demand charge, then consumption becomes cheaper — defined solely by the other charges without any demand charge implications. This means that optimal customer decision-making under a demand charge is quite complex and depends on the level of foresight and the value of consumption across all of the relevant time periods. Of course, most customer decision-making will not necessarily be optimal but rather based on rules of thumb, particularly for residential and smaller commercial customers.

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[24] Sandford Berg and Andreas Savvides did some theoretical work that incorporated the granular incentives of a demand charge into a traditional economic model of consumption. See Berg, S. V., & Savvides, A. (1983, October). The theory of maximum kW demand charges for electricity. *Energy Economics (5)*4, 258-66. However, this was a two-period model with numerous simplifying assumptions. Such a simplified theoretical model does illuminate certain features of a demand charge, but the authors note numerous areas for further work. To our knowledge, this line of theoretical research has not been pursued.

[25] This is true in particular because customer "utility" from electricity is not solely about the amount of consumption. Customers also enjoy significant convenience benefits for certain usage timing, again assuming that on-site storage and energy management are not cheap and convenient enough to smooth these features out.

[26] Some rates that do not meet this criterion are occasionally described as demand charges, such as annual system coincident peak capacity charges. These types of charges may, however, be better thought of as a type of time-varying rate or perhaps in a third category of their own.

[27] A toaster is approximately 1 kW demand; see Home Energy Saver & Score: Engineering Documentation. (n.d.). *Default energy consumption of MELs*. http://hes-documentation.lbl.gov/calculation-methodology/calculation-of-energy-consumption/major-appliances/miscellaneous-equipment-energy-consumption/default-energy-consumption-of-mels. If a customer uses it for 15 minutes straight at the time of the customer's individual peak, the monthly demand billing determinant increases by 1 kW with a corresponding bill increase.

As the analysis in the subsections that follow shows, demand charges — whether of the traditional monthly variety or the peak window variety — are inefficient and inequitable for the pricing of shared system costs, as is the continued reliance on them. There are three interrelated reasons for this:

1. Traditional monthly demand charges provide an inaccurate price signal that is unrelated to high-cost periods for nearly all customers and which leads to inefficient customer efforts and investments in response to its incentives. The changes in the electric system due to dramatic increase in wind and solar generation mean that, from a system perspective, very high industrial load factors are not necessarily optimal.
2. Even in cases where a traditional demand charge could be justified, the sizing of demand charges to recover nearly all generation and delivery capacity costs reflects an outdated perspective of the engineering and economics of the electric system. Modern cost allocation and rate design must reflect the trade-offs between different types of expenses and investments. Much capacity investment is designed to reduce energy costs and line losses and should be charged on that basis.
3. Although a reasonably sized peak window demand charge is superior to a traditional monthly demand charge, time-of-use and other kinds of time-varying rates remain more efficient and equitable. These time-varying rate options are enabled by the dramatic decrease in the cost of sophisticated metering over the past two decades.

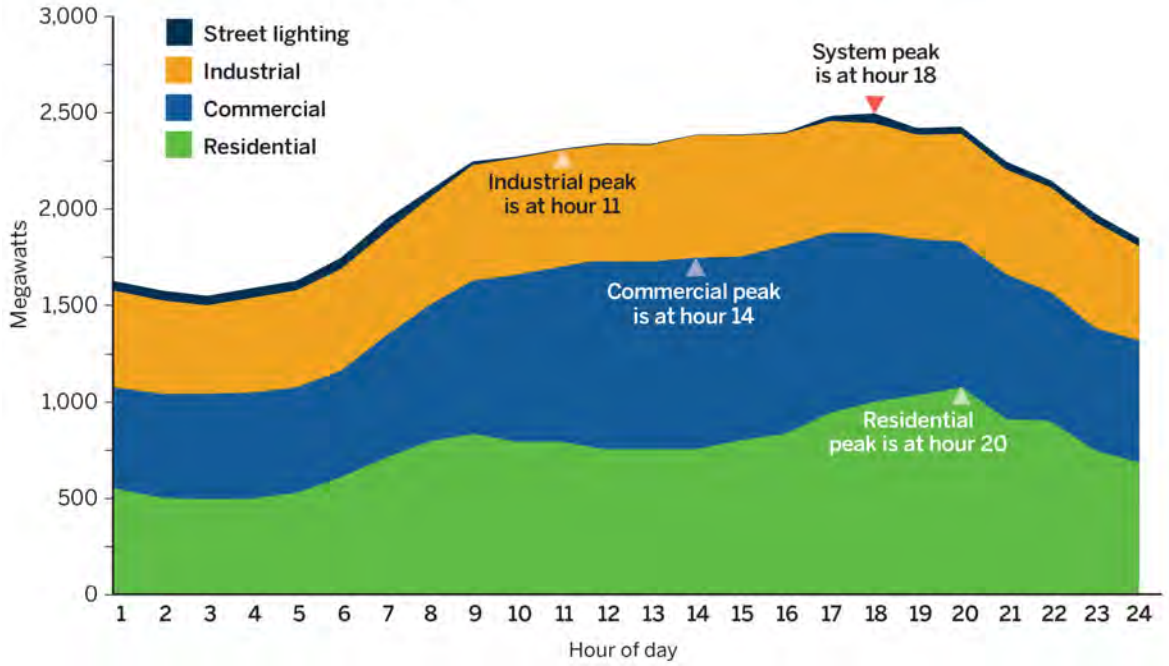
3.1 Individual Peaks Are Not the Same as System Peaks

Virtually all of the electric system consists of capacity that is shared among customers. With the exception of facilities that serve one or a very few customers, each component of the system is sized to meet an expected peak coincident demand of the customers it serves. The costs incurred to meet peak coincident demand, both short-run variable costs and capacity investment, are a significant portion of overall system costs. As a matter of economic efficiency, it is crucial that prices reflect the marginal costs of meeting the coincident system peak. Peak coincident demand is not simply the sum of the customers' individual peak demands but is rather something less, often significantly so. This phenomenon is known as *diversity* of demand and reflects the temporal differences of usage across the relevant customer base.

Customer loads are diversified at every level of the utility system. At the system level, the peak is determined by that combination of customer class loads that produces the highest instantaneous demand. That system peak might, or might not, coincide with the peak demand of any one customer class, and that system is likely interconnected to other systems with slightly different loads, through a shared transmission network. Figure 1 shows illustrative customer class loads on a system peak day. Each of the customer classes has a highest load hour at a different time: hour 11 for industrial, hour 14 for commercial

and hour 20 for residential. The load for the lighting class is roughly the same across many different hours when the sun is down. The overall peak is at hour 18, which is different than any of the class peaks.

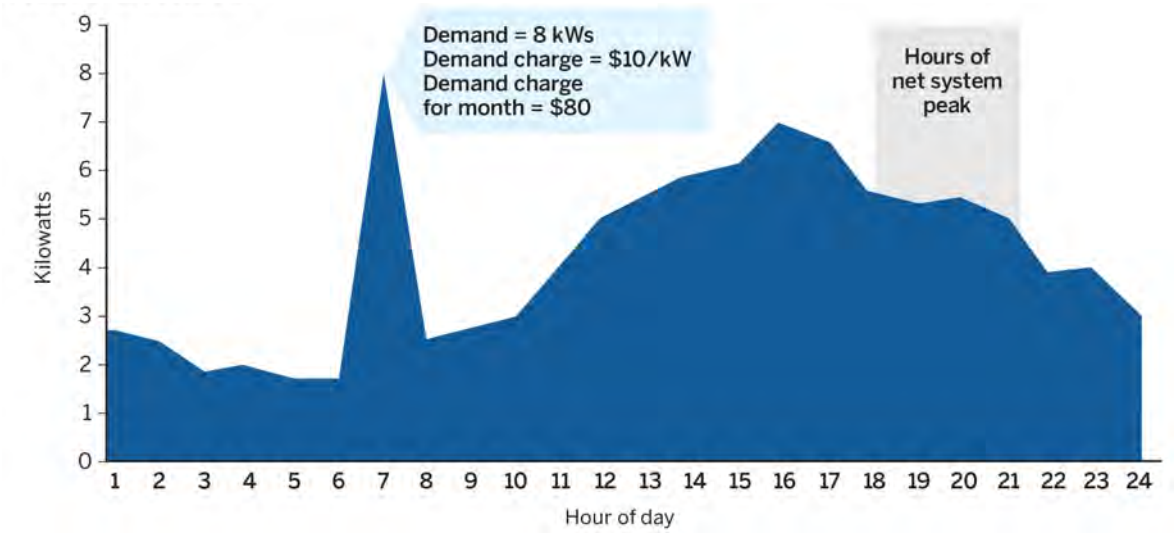
Figure 1. Diversity at the customer class level



Diversity can be quantified as the ratio of the sum of the subgroup peaks to the relevant coincident peak — the diversity factor. In this illustrative example, the diversity factor of the customer classes is 1.1. Diversity factors cannot go below 1 because in the extreme case where all subgroups peak at the same time, the sum of the subgroups equals the overall coincident peak. As long as customers peak at different times, diversity factors are higher as you consider smaller subgroups. Load diversity across individual customers is even greater than across customer classes.

Traditional monthly demand charges impose a rate on each customer that is independent of the system peak, as illustrated in Figure 2 on the next page. These demand charges provide little, if any, incentive to minimize a customer's contribution to system peak, unless a strong correlation exists between the customer's peak and the system's, a circumstance known as a high coincidence factor. In this illustrative example, a residential customer has an electric water heater that runs for nearly a full hour in the morning and a substantial cooling load in the afternoon.

Figure 2. Illustrative monthly noncoincident peak demand charge for an individual residential customer



Demand charges encourage customers to flatten their own load curves relative to their individual maximum usage but do not necessarily encourage them to consume energy in ways that optimize system costs. If we assume that Figure 2 shows customer usage before a traditional monthly demand charge is imposed, we could expect significant changes in usage after application of this charge. It would be reasonable to expect this customer to attempt to reduce the 8 kW demand reached at 7 a.m. In the case of an electric water heater, the individuals living in the house could change their behavior or adjust the settings on the water heater. If the customer could reduce that morning peak, then there would be some incentive to reduce the afternoon peak caused predominantly by cooling load. In this case, the customer would benefit by moving some portion of that load away from hour 16 to other hours, including possibly during the system peak from hours 18 to 21. Furthermore, this customer could increase overall kWh consumption since the marginal cost would be lower at times (often including the system peak) when there is little risk of triggering a higher demand charge.

More generally, a flat individual customer load shape may not, in fact, be what is best for the system and is in fact worse than a low load factor with predominantly off-peak usage. The clearest illustration of this is street lighting load, which, for most systems, falls entirely outside the system peak hours and has a roughly 50% load factor. If we designed and sized a demand charge for street lighting on the same basis as a typical demand charge for industrial customers, it would force this low-cost off-peak load to pay as much for system capacity as an industrial customer using the same amount of power during the peak periods. This is virtually never done, however, and street lighting is treated as a separate rate class without any demand charges.

D. J. Bolton summarized the basic problem facing utilities and regulators in the middle of the 20th century:

> The aim should always be the improvement of the *system* load factor, and the only justification for an elaborate tariff is that it shall contribute directly to this end. ... If these costs are passed on to the consumer as they stand, in the form of a two-part [maximum demand] tariff, the fixed charge will be levied on the consumer's individual [maximum demand] instead of his effective demand on the system. The consequence will be that low-load-factor consumers will be overcharged (since they are given insufficient credit for their greater diversity) whilst the high-load-factor consumers are under-charged.
>
> The weakness of such a tariff when applied to the small individual consumer is that it treats load factor as a variable and diversity factor as a constant. ... But, in practice, diversity factors vary from consumer to consumer almost as much as load factors, and moreover, in the opposite direction.[28]

In other words, diverse customers can efficiently *share* capacity, and rate design should recognize this fact. As Bolton mentioned, it is often the case that small users have *lower* load factors but more diversity and thus less impact on peak. This is still true today because many small residential users have lower levels of heating and cooling usage (smaller residences) and often have similar appliances (microwaves, toasters, dishwashers and dryers) that are used more sporadically than larger residential customers. This means that the load factor for each individual appliance is lower, but the power characteristics are similar for each usage of an appliance.

As described in Section 2, demand charges may present a rough price signal to control peak system demand for customers with a high system-peak coincidence factor. In that case, controlling a customer's individual peak does systematically reduce the overall coincident peak. One case where this could be true historically is large industrial customer classes, where individual customer usage is driven by large equipment that is constantly used throughout every working day of the year. Even for this type of customer, however, there remains the question of whether load can be shifted from peak hours to off-peak hours. A critical peak energy price would produce a superior price signal, to actively reduce usage at critical peak hours, rather than maintain steady usage at those hours if such a shift is possible. Indeed, industrial customers in Texas, faced with significant, narrowly focused transmission charges based on four coincident peak hours, use specialized consultants to help them identify, in advance, the hours to which those

[28] Bolton, 1951, p. 107-108 (emphasis in original). Bolton was writing at a time when, in operations, customer demand was taken largely as a given and much of the resource mix was dispatchable thermal generation. In those circumstances, improvement of system load factor would, all else again being equal including overall kWh consumption, lead to a reduction in total system costs.

charges will be applied and reduce usage sharply in those hours.[29]

For a diverse customer class, however, the share of customers who face this demand charge price signal at system peak times is random and inconsistent. In almost any hour, whether near system peak or the lowest-load hours of the year, some customers will face the demand charge price signal. Also, a substantial number and, at times, a majority of customers (e.g., those customers who have already hit their peaks in the billing period) face a lower marginal cost at system peak times. While this is very blunt and inaccurate, it could be a sharper price signal than a traditional flat kWh rate in some circumstances, although a customer's likelihood of facing those circumstances would vary randomly. In contrast, a well-designed TOU rate provides the broadly correct incentive for all marginal consumption choices by all customers, sending a consistent price signal for on-peak and off-peak periods; a critical peak pricing rate can be even more precise, focusing on specific hours when the electric system is under stress.[30]

The undesirable effects of demand charges are made worse by ratchets across billing periods — the mechanism by which a maximum demand in one period becomes the basis for minimum billed demand in subsequent periods. For example, billing demand may be the greater of this month's noncoincident maximum load and 80% of maximum in the previous 12 months. Once a maximum demand is hit, the customer has little incentive to reduce demand in the following periods. Unless individual customer peak is closely linked to system peak, there remains little incentive to minimize usage at a time of system peak.

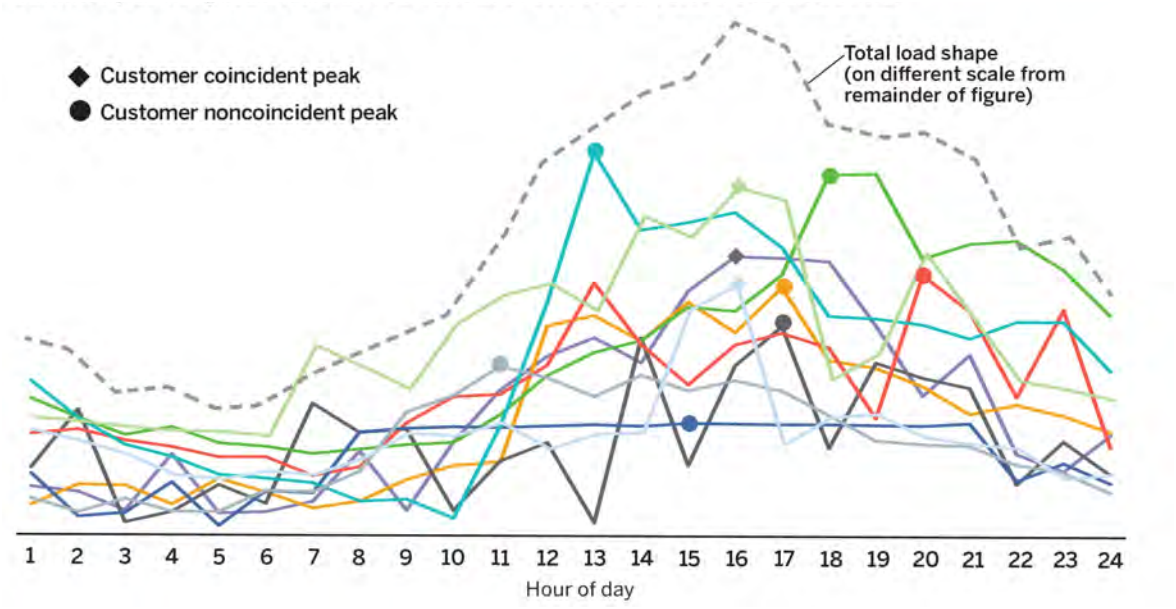
It is only when one gets close to the end user that the components of the system — the final line transformers, secondary distribution lines and service lines — are sized to meet a very localized demand that can be directly attributed to a small number of customers. Even at this level, there can be significant diversity among customers sharing a single transformer.

[29] Zarnikau, J., & Thal, D. (2013, September). The response of large industrial energy consumers to four coincident peak (4CP) transmission charges in the Texas (ERCOT) market. *Utilities Policy, 26*, 1-6.

[30] To be more precise, we should say a "relevant component of the system" since different components of the system may hit peaks at different times. It's not unusual to see a systemwide peak occur at a particular hour on a particular day, but for individual elements of the subtransmission and distribution systems to hit peaks at other times. Expressing these peaks in prices and capturing each user's causal relationship to them is a challenge of time-varying rate design and, to the extent that this reflects different peaks in different areas of the system, may require locational distinctions as well. Precision is valuable, but complexity may produce inferior customer response.

Figure 3 shows actual data from a confidential load research sample on a summer peak day for 10 residential customers who share a line transformer. The total load shape is on a different scale than the individual customer loads.

Figure 3. Summer peak day load from 10 residential customers on one line transformer

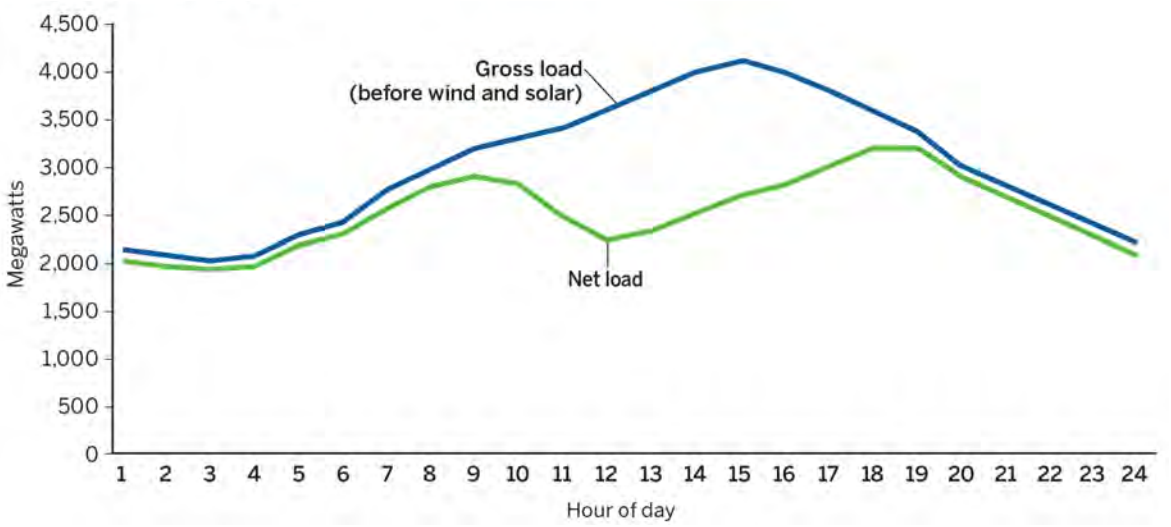


Source: Confidential load research sample

This demonstrates how diversity determines the need for the sizing of system elements. Only three of the 10 customers peak at the same time as the 4 p.m. coincident peak for the group, and the coincident peak is only 86% of the sum of the individual peaks on this day, which translates into a diversity factor of 1.16. This is just the variation on a particular high-load day. Although not shown in this figure, this coincident peak is only 64% of the sum of the annual NCPs for the individual customers, which translates into a diversity factor of 1.56.

At least two features of the modern electric system are changing the traditional argument that high-load-factor industrial customers should be subject to demand charges. First, the timing of traditional peaks and valleys, and by extension their effect on both short-run variable costs and longer-term capacity needs, is changing due to the increased prevalence of variable renewable resources. In regions where solar generation has increased rapidly, the “duck” curve is now a familiar phenomenon, as shown in Figure 4. Second, relatively low-cost on-site energy storage means that *all customers* have the potential for economically shiftable load and can respond to time-based price signals.

Figure 4. Illustrative net load curve



In such a situation, the benefits of shifting energy intensive industrial load from early evening to midday could be quite large. But this could mean *an increase* in the customer load factor, which is substantially discouraged by demand charges.

3.2 A Significant Portion of Capacity Investment Is Not Demand-Related

Traditional cost allocation terminology makes a distinction among demand-related, energy-related and customer-related costs. This terminology may obscure more than it illuminates. In particular, the term "demand-related" is often used to imply that demand charges are a proper pricing method for recovering costs so designated. Moreover, "demand-related" has typically referred to system peak demand and not individual customer peaks.[31] Other terminology, such as "peak-related," is more descriptive of the concept and avoids confusion with the use of "demand" in other contexts (such as "demand for energy").

[31] See Bolton, 1951, p. 132 (describing demand-related costs as "a cost proportional to system demand") and pp. 143-144 (describing how to spread costs across a wide number of potential system peak hours). In rate design, these same costs might be recovered through demand charges for certain customer classes. When determining the rate in dollars per kW, the total costs are then divided over the larger denominator of individual NCP demand, without accounting for load diversity within the class. This reduces the dollars per kW as charged to each customer from the dollars per kW used to assign costs to each class. This reduction is labeled differently in different jurisdictions, such as an "effective demand factor." However, this reduction is passed through to all customers and does not correct for differences in the timing of individual customer peaks. Customers who have demand highest at peak times receive a discount, and those who have demand highest at other times are overcharged.

Advocates for demand charges sometimes assert that most or all capacity costs are demand-related, which maximizes the size of the demand charge (if one is at all justified).[32] This leads to the large magnitude of the demand charges for industrial customer classes in many states. However, significant portions of capacity costs are not demand-related but are in fact incurred to meet energy needs. Investments in generation, transmission and distribution in the modern electric system may serve either of the two primary objectives of system planners, but the degree to which demand plays a role in each objective is different. These two goals are: (1) ensuring reliability (in both operational and investment time frames) and (2) meeting year-round system load at least cost. In many respects, reliability concerns arise predominantly at peak system hours.[33] Meeting system load at least cost, by its very nature, must consider usage patterns across every hour of the year. To meet these two objectives, system planning, investment and operation must jointly consider not only the engineering and physics of the electric system but also the economics of the relevant choices. We see this tension in the evolving landscape of capacity resources.

With respect to generation, most capacity costs may have been demand-related prior to the invention of the modern combustion turbine in the 1960s. In an electric system dominated by largely homogenous steam generation capacity, a MW of capacity built for peak demand could be used equivalently year-round.[34] In such a situation, generation capacity costs could be allocated and charged predominantly at peak times.

The existence of multiple different types of generation capacity, storage and demand response changes this analysis significantly.[35] Aggregate supply (generation, storage and demand response) must be sufficient for systemwide coincident peaks, as well as contingencies across many other hours of the year, such as when outages (unforced and even planned, such as nuclear refueling) combine with other circumstances (e.g., unusual weather) to push demand up against the limit of available resources.

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[32] See Faruqui, A., & Davis, W. (2016, July). Curating the future of residential rate design. *Electricity Daily*, 23. http://files.brattle.com/files/7137_curating_the_future_of_rate_design_for_residential_customers.pdf. The authors state that "a large share of a utility's costs are actually driven by investment in infrastructure, such as generation capacity and transmission and distribution (T&D) networks. These costs are not directly related to the amount of energy that is consumed; they are, instead, driven by various measures of maximum electricity demand." See also the description of an idealized rate design that "recover[s] capacity costs through demand charges" in Faruqui, A. (2019, June 1). 2040: A pricing odyssey. *Public Utilities Fortnightly*, p. 56.

[33] Reliability can be thought of as having two dimensions, in terms of both system security and resource adequacy. The former refers to operational time frames, being assured that the system has sufficient resources to meet demand in real time. The latter refers to investment time frames, being assured that the system will continue to deploy needed capacity to reliably serve load over the longer term. Both kinds of reliability are relevant to this discussion.

[34] Even this historic scenario is a substantial oversimplification due to significant level of hydro generation in many areas.

[35] Bonbright recognized this briefly in a footnote; see Bonbright, 1961, 354, fn 15. By 1970, this was a better understood and less theoretical concept so that Kahn spent multiple pages discussing it; see Kahn, 1970, pp. 97-98. M. A. Crew and P. R. Kleindorfer formalized mathematical models of optimal pricing with multiple different types of generation capacity; see Crew & Kleindorfer, 1979.

The optimal mix of resource types depends on the broader load patterns. Different generation technologies have different capabilities and different cost characteristics and should not be blindly lumped together as "capacity" for cost allocation and rate design purposes. The kind of capacity that one would build to meet short-term coincident peak needs, as well as reserves on short notice throughout the year, is much different than the kind of capacity that one would build to generate year-round. Indeed, for very infrequent needs, demand response (paying customers to curtail usage for a short period) is proving much cheaper than building *any* kind of generation resource that is seldom used. In order to be economic, capacity that serves only short-term needs must have low upfront investment costs, such as combustion turbines or demand response, but can have higher short-term variable costs when it is used. The combustion turbine is cheap to build but relatively inefficient and expensive to run. In contrast, a larger investment can only be justified by lower expected short-run variable generation costs and a higher expected capacity factor. As a result, this high-upfront-cost capacity lowers the total cost of both meeting peak demand and serving energy needs over the planning horizon.

So there is a trade-off between capacity costs and energy costs. Put simply, not all capacity costs are incurred to meet peak demand. As a result, capacity costs for generation should either be split into the traditional demand-related and energy-related categories, or else those categories should be updated into a more modern time-based classification framework.[36] Under any reasonable version of the demand-related classification, it is important to recognize that the capacity costs placed here are to serve relatively short-period peak reliability needs.

Even the appropriate short-period peak reliability capacity costs should be charged on a broader basis than the absolute peak hour of the year for several reasons. One is that, while planners and operators generally have a good idea of when a system peak is likely to occur, they by no means know for sure. Consequently, there is a reliability value to capacity in many hours that should be reflected in prices.[37] A second is that the actual peak can be influenced by pricing structures. For example, if a system peak could be reliably predicted for the 5 p.m. hour on a given day, charging a higher price at that single hour could just push that same peak to 4 p.m. without a meaningful reduction. This is the "whack-a-mole" problem. Taking both of these issues into account, some writers have referred to the relevant set of peak hours as the "potential peak" period.[38] This is a major consideration in the determination of on-peak hours for a TOU rate or a peak

[36] See Lazar, J., Chernick, P., Marcus, W., & LeBel, M. (Ed.) (2020). *Electric cost allocation for a new era: A manual.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/electric-cost-allocation-new-era/

[37] The operating reserves demand curve mechanism in the ERCOT wholesale market is one means of establishing that value across the entire year. In many areas, the loss of load probability is relatively high for only 50-100 hours per year, which is the typical design criteria for critical peak pricing and demand response programs.

[38] Bolton, 1951, p. 143.

window demand charge. A related challenge is that different elements of the system (e.g., generation, transmission and distribution) may peak at different times, which should be accounted for to the extent possible.

Generation capacity also has some reliability value in off-peak hours. Generation reliability issues may come primarily at peak times but certainly not exclusively. This can be because of generator outages (both planned and unplanned), unusual weather, transmission outages, other operating constraints or a combination of the above. D. J. Bolton commented in 1951 that there had been several times that load needed to be shed in off-peak seasons because of generator maintenance, which was "a definite indication of demand-related expenses on account of generating plant" even in off-peak seasons.[39] A loss-of-energy-expectation study calculates the year-round generation reliability risks and is one of the best ways to allocate demand-related generation capacity costs (but not energy-related generation capacity costs) over the entire year.[40] A probability-of-dispatch method, alternatively, assigns the total costs of generation resources to the hours in which each resource provides service.

Many of these same considerations apply to the transmission and distribution system, and an analyst should look to the underlying purposes and benefits of system investments to allocate and charge them properly. Several different kinds of transmission capacity are intended to deliver energy and are not designed primarily to meet reliability needs. The transmission segment that connects a generating unit to the broader transmission network can be properly thought of as a generation-related cost and charged on the same basis as the underlying generator. In many situations, long transmission lines are needed to connect low-cost generation resources, such as remote hydroelectric facilities or mine-mouth coal plants, to the network. These long lines are built to facilitate access to cheap energy and should be classified on that basis. Last, transmission lines built to facilitate exchanges between load zones are not necessarily most highly used at peak times but are used to optimize dispatch and trade energy across many hours of the year.

Other parts of the transmission and distribution network do need to be sized to meet peak demand and other reliability contingencies. But there are several different engineering options for transmission and distribution networks that have implications with respect to line losses, another clear energy-related benefit.[41] There are generally two types of losses incurred across the transmission and distribution system: no-load losses and load losses. No-load losses are incurred primarily to energize transformers (both station transformers

[39] Bolton, 1951, p. 143.

[40] Lazar et al., 2020, p. 132.

[41] See generally Lazar, J., & Baldwin, X. (2011). *Valuing the contribution of energy efficiency to avoided marginal line losses and reserve requirements.* Regulatory Assistance Project. https://www.raponline.org/knowledge-center/valuing-the-contribution-of-energy-efficiency-to-avoided-marginal-line-losses-and-reserve-requirements/

and line transformers). Smaller transformers consume less energy in this respect, but overloaded transformers incur high load-related losses, so optimal transformer sizing saves energy.

The system planning considerations for load losses, also known as resistive losses, are more complex. These losses occur as electrical current flows through each element of the system. These losses manifest themselves in the form of heat and reduce the amount of useful power that can supply customer loads. This relationship is represented by the formula:

Load losses (in kW) = $I^2 \times R$

Where I = current (in amps) and R = resistance (in ohms)

Load losses can be decreased by reducing the resistance or reducing the current. Installing conductors with thicker metal wires is a simple way to reduce resistance, but these larger conductors are more expensive. Investments that reduce the current can, however, be much more effective because losses go up with the square of current. Any investment that reduces the current by 50% will reduce load losses by 75%, and any investment that reduces the current by 90% will reduce load losses by 99%. Since the current required to supply load is highest during peak demand periods, system losses are greatest during peak demand periods. There are several different types of capacity investments that reduce current substantially:

- Higher voltage lines: There is a direct relationship between the voltage of a line, the current passing through the line and the power delivered.
    - Current (in amps) = power (in kW)/voltage (in volts)
    - As a result, increasing the voltage by a factor of 10 reduces the current by 90%, which in turn reduces load losses by 99%.
- Siting substations closer to loads: By siting substations closer to loads, one can reduce the losses incurred by having conductors at lower voltages supply loads across long distances — the latter condition resulting in higher currents and relatively higher losses.
- Converting single-phase distribution lines to three-phase power: Three-phase power requires one additional conductor and additional space for the arrangement of the lines. For three phase lines, current = power/(voltage x √3). At the same voltage, current drops by 42.3% and load losses are reduced by two-thirds.
- Distribution level control of voltage and reactive power: Capacitor banks, smart PV inverters, voltage regulators and other more distributed assets across the system can compensate for voltage and reactive power needs at a local level that would

otherwise need to be met through the supply of upstream resources delivered through the grid — the latter condition resulting in higher currents and greater incurred losses.

- Optimizing the location and size of line transformers: Siting transformers closer to customers allows for shorter secondary lines that have low voltage and thus higher losses per foot. For some areas, this may require additional transformers, which comes at a cost. Smaller transformers also have lower no-load losses. Unfortunately, smaller transformers have lower rated capacities and thus higher load losses for a given level of current. Conversely, larger transformers have higher no-load losses but lower load losses. These complex economics should be analyzed to account for trade-offs between capital costs and energy losses. Modern advanced metering infrastructure (AMI) systems provide the ability to prepare heat maps on each transformer, enabling optimal sizing to minimize costs and losses.[42]

All of these factors should be accounted for in both cost allocation and rate design. Energy-related benefits from transmission and distribution capital investments are quite extensive. In a relevant sense, nearly all transmission lines are built with a substantial purpose of minimizing line losses for the delivery of large volumes of energy. Choice of the voltage level for a transmission line, either for a new line or upgrading an old line, involves higher capital costs for higher voltages with the counteracting benefit of lower losses. These costs are energy-related costs, not capacity-related costs. Furthermore, many of these energy benefits from investments to minimize line losses are not static over the course of the year. They increase dramatically at times of system peak because current delivered over the system is much higher, and marginal system losses at the time of peak can be 15-20% in many utility systems.[43] In addition, these benefits can be compounding because they are not limited to fuel costs or wholesale purchases. A more efficient transmission and distribution system can lower generation capacity requirements as well, including reserves.

All of these economic and engineering phenomena should be properly reflected in any analyses of cost causation. More specifically, these distinctions must be passed into rate design or else it gives rise to opportunities for customers to take inappropriate advantage by gaming the rates, with bill savings that far exceed any long-term reduction in system costs. The experience of the British Central Electricity Generating Board, a wholesale provider, provides a stark example of this in the late 1960s. The central board charged the regional boards for generation capacity costs based solely on a narrow peak window. In response, the regional area boards built their own combustion turbines at significantly lower cost to generate during these peak hours. This forced the central board to change its

[42] See Lazar, J. (2018, October 18). *Smart grid and community benefits — with no rate increase? How Burbank made it happen.* Regulatory Assistance Project. https://www.raponline.org/blog/smart-grid-and-community-benefits-with-no-rate-increase-how-burbank-made-it-happen/

[43] Lazar & Baldwin, 2011, p. 4.

wholesale rates, charging for only marginal capacity costs in a short peak and charging for the bulk of capacity costs in a broader period.[44] The key insight in this scenario is that demand-related costs charged to peak times should only reflect the marginal costs of relatively cheap generation, storage or demand response capacity costs incurred for short-period peak reliability purposes.

Modern examples of this pricing problem can be found in the current practices of several independent system operators and generation and transmission suppliers. For example, ERCOT currently charges on the basis of the highest hour in each of the four summer months for recovery of embedded transmission system costs to distribution service providers. This type of pricing mechanism is inappropriate for transmission costs and furthermore distorts the operation of the wholesale energy markets by over-incentivizing a wide range of customer actions.[45] Similarly, many electric cooperatives, charged by their generation and transmission suppliers on the basis of NCP demand imposed on the wholesale supplier, have installed water heater control systems to mitigate this demand at much lower cost than the avoided demand charges. Since the generation and transmission demand charges include the cost of baseload units and transmission, they greatly overstate the value of localized NCP load reductions. While these are wholesale examples, the same economic proposition also extends to retail rates.

3.3 Time-Varying Energy Rates Are More Efficient Than Peak Window Demand Charges

Once one acknowledges the time-dependent nature of cost in the generation and delivery of electricity to end users on a shared system, one must necessarily acknowledge the superiority (as matters of economic efficiency and fairness) of prices that reveal to those end users that temporal variability in cost to those that do not. The question, then, is simple: What should those prices look like? In some sense, a peak window demand charge does recognize this time dependency. However, a comparison of the incentives presented by time-varying demand charges and time-varying kWh charges reveals why time-varying kWh charges are the better approach.

There are several types of time-varying energy rates to be considered today.[46] Key design choices for these rates include the number of time periods, whether the price for each time period is set long in advance or can itself vary based on system conditions and market

[44] Kahn, 1970, pp. 97-98.

[45] See Hogan, W., & Pope, S. (2017, May). *Priorities for the evolution of an energy-only electricity market design in ERCOT*, pp. 69-79. Harvard University and FTI Consulting. https://hepg.hks.harvard.edu/publications/priorities-evolution-energy-only-electricity-market-design-ercot-0. We do not endorse the proposed solution of Hogan and Pope but agree with the transmission pricing problem that they describe.

[46] From this definition we exclude seasonal rates and kWh prices that vary from billing period to billing period. These kinds of rates can also reflect the cost-causation basis of rates but provide little or no incentive to manage usage within a billing period.

outcomes, and the actual prices for each time period.[47] The simplest is known as a time-of-use or time-of-day rate, which utilizes a small number of preset time periods and prices within each billing period. The most sophisticated time-varying rates are typically described as real-time prices, which are updated at short, regular intervals (e.g., hourly) based on prices in wholesale energy markets.

There are also options that combined preset time periods with pricing that varies based on system conditions in a predictable manner. With critical peak pricing, or the related peak-time rebate alternative, higher prices for times when the grid is stressed are set well in advance, but the days (and perhaps the hours) where these higher prices apply are actively chosen in response to system conditions. Variable peak pricing, as currently offered by Oklahoma Gas & Electric,[48] adds another layer of price differentiation by allowing more preset options for the on-peak price period. The on-peak price depends on market conditions: low, standard, high and critical. This choice between four different alternative on-peak prices allows for a higher level of precision in marginal incentives. All of these variations share a common goal — to improve the load shape for a utility by decreasing peak period load and shifting some of that to off-peak periods.

In this context, it is most natural to compare peak window demand charges with simple TOU rates because many of the key parameters can be kept constant. For both of these options, the peak time periods and the prices charged are set well in advance and can be set to recover the same categories of costs. Holding those two variables constant, peak window demand charges are inferior to time-varying kWh charges in that same peak window, as a general method for charging peak capacity costs, for two related reasons:

1. The inefficiency of the ratchet that all demand charges impose, which incorrectly underprices usage in the rest of the peak window within the billing period.
2. Unfair intraclass cost allocation, with those customers with demand diversity subsidizing those with more continuous usage.

Peak window demand charges can certainly elicit customer response and incentivize them

[47] The options that are available in practice depend on metering technology, which has evolved substantially over time. In the early part of the 20th century, TOU rates could be implemented with meters that operated on timers, where one track would record on-peak usage every day and another track would record off-peak usage every day. No distinction based on weekends or holidays was possible. By 1941, more sophisticated versions were available with remote controls that could switch the meters between tracks on command. Since that time, many more innovations have occurred to enable different types of time-varying rates. Three-period TOU rates became common for large industrial customers in France beginning in the 1950s. With advanced metering infrastructure and a sophisticated data collection and billing system, the possibilities are nearly endless. Even without AMI, simple TOU meters have long been available that track on-peak and off-peak usage based on programmed timers, which can exclude weekends and holidays from on-peak periods.

[48] Oklahoma Gas & Electric. (2018, June 18). *Standard pricing schedule: R-VPP variable peak pricing.* https://www.oge.com/wps/wcm/connect/c41a1720-bb78-4316-b829-a348a29fd1b5/3.50+-+R-VPP+Stamped+Approved.pdf?MOD=AJPERES&CACHEID=ROOTWORKSPACE-c41a1720-bb78-4316-b829-a348a29fd1b5-mhatJaA

to shift load from inside to outside that window.[49] Nevertheless, peak window demand charges share many of the faults of traditional monthly demand charges, just on a different scale. Once again, the key distinction is between the consistent and symmetric marginal incentive of a time-varying kWh rate and the arbitrary effects driven by the demand charge's ratchet.

A close examination of customer behavior reveals why energy-based prices are preferable to demand charges even within a peak window. In any system with significant customer diversity, a large number of customers will not have their individual peaks at the time of the system's peak. Still, it could be that a substantial number of customers peak at the time of the system peak. The proportion of one to the other matters if demand charges are to have a significant linkage to the system peak. Customers who are at risk of setting the individual peak for the demand charge face a high marginal price for consumption, but those who are not face a lower marginal price. This proportion will vary from service territory to service territory and over time as technology evolves.

Customer behavior under a peak window demand charge would likely even vary based on completely arbitrary factors. That could be whether certain customers are at the beginning of their billing period or whether a significant event that led a customer to incur a largely unavoidable peak (e.g., hosting a party during a peak window) happened before that very high-load time. This randomness can be entirely avoided. The fair and efficient solution is to continue to treat all consumption as marginal, a condition that is achieved by time-varying kWh rates.

In the absence of technology that automates response to changes in prices, the ratchet problem for peak window demand charges may be diminished by the inability of customers to respond accurately to its incentive structure. It is unlikely that people going about their daily lives can do more than respond to the broad incentives provided by either an on-peak kWh price in a simple TOU rate or a peak-window demand charge. In both cases, the easiest answer may very well be just "consume less during the peak window period."[50] This could mitigate the harm posed by the ratchet, but it also begs the question about the underlying rationale if there is no customer response.

A modest subset of residential customers may be able to respond to the next rule of thumb presented by a peak window demand charge: to operate as few end uses as possible simultaneously. Fully responding to the incentives posed by a demand charge requires

[49] See, for example, Stokke, A., Doorman, G., & Ericson, T. (2009). *An analysis of a demand charge electricity grid tariff in the residential sector.* (Discussion Paper No. 574). Statistics Norway, Research Department. https://ideas.repec.org/p/ssb/dispap/574.html

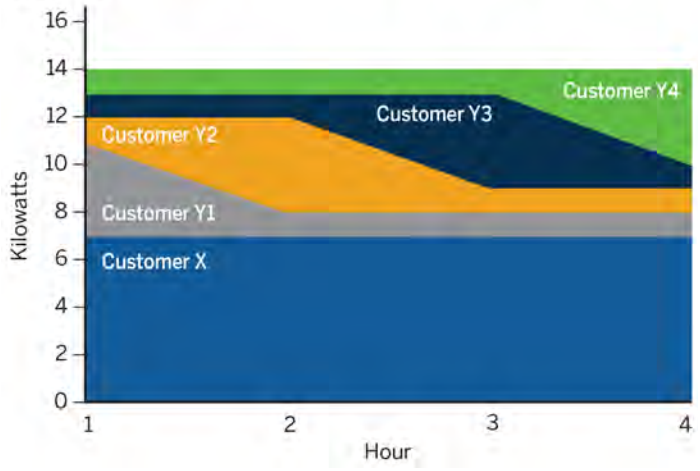
[50] For example, the Mid-Carolina Electric Cooperative has a three-hour peak window demand charge for residential customers. On the relevant page of its website, the peak window demand charge is labeled as an "on-peak charge." None of the advice given to manage this rate is specific to the actual working of a demand charge and could equally apply to a three-hour on-peak kWh rate. Mid-Carolina Electric Cooperative. (n.d.). *Rate structure.* http://www.mcecoop.com/content/rate-structure

customers to track their demand and know whether they are currently at risk of setting a high demand for the billing period — too much to ask of many residential and small business customers.

However, energy management technology, enabled by software and "supercharged" by on-site storage, will be able to adjust usage in a far more responsive manner than ordinary people could manage alone. Such energy management is likely feasible today for larger customers and could very well be widely feasible for smaller customers in the next few years. At least one company, Energy Sentry (http://energysentry.com/index.php), has developed a residential "demand controller" that automatically sheds less critical loads (water heaters, clothes dryers) when priority loads (microwaves, coffee makers, hair dryers) are activated. Such technology would allow customers to respond more effectively — *from their perspective* — to the incentives provided by a demand charge. But that is not to say that the overall efficiency of the electric system will be improved, since customer responses to demand charges do not typically optimize use of the system.

Peak window demand charges also create intraclass cost allocation problems, which are linked closely to the above efficiency concerns. Peak window demand charges still overcharge the low-load-factor customer and undercharge the high-load-factor customer. This is illustrated in the case of several smaller customers whose aggregate consumption adds up to the load of a single larger customer. Such a hypothetical is shown in Figure 5 for a four-hour peak period.

Figure 5. Customer load comparison illustrating ability to share capacity



Customers Y1, Y2, Y3 and Y4 have, in the aggregate, the same load profile as Customer X. Each of the Y customers has a peak of 4 kW for a total billing determinant of 16 kW under a peak window demand charge. However, Customer X has a peak of 7 kW, which translates into a billing determinant of 7 kW under a peak window demand charge. This means that Customer X is charged less than half the amount that the Y customers are for the *exact same aggregate load pattern*. The four diverse customers can efficiently share capacity and should not be penalized by a price structure that fails to account for their diversity. Time-varying energy-based charges solve this problem.

Peak window demand charges, though an improvement on monthly NCP demand charges,

still come up short in the effort to send accurate information to consumers about peaks and other high-cost events. The occurrence of a peak cannot be known in advance, and, indeed, its timing depends in part on price structure. Shifting hours within a peak period does not necessarily lower the overall peak. Figure 6 is a comparison of two customers with equal kWh consumption in the peak period, one with a flat consumption throughout that period and another that varies.

Figure 6. Comparison of two customers



Compared with Customer X with a flat load pattern, Customer Z with the varying load pattern likely increases the chance of a system peak in hour 2, but by the same token likely decreases the chance of a system peak in hour 3. But the reverse can be said for Customer X compared with Customer Z: Customer X raises the likelihood of a system peak in hour 3 and decreases the likelihood of a system peak in hour 2. Advocates of demand charges consistently fail to explain why these types of discrepancies are justified by cost considerations.

Even well-designed TOU rates do not necessarily reflect critical peak times very well. For example, a four-hour weekday on-peak window for only the highest demand months will include around 200-400 hours annually. These will necessarily contain some days with higher peaks than others and only a limited number of hours that define utility capacity needs for reliability purposes at peak. Simple TOU rates do not distinguish in this regard between the moderate peaks (e.g., ordinary days in the summer) and the very highest peaks (e.g., extremely hot days in the summer). In short, the implication is that simple TOU rates do not provide a sharp enough incentive on actual peak days.[51] In any case, we are no longer bound to simple TOU pricing. Dynamic rates, including critical peak pricing, peak-time rebates, variable peak pricing and real-time pricing, all better address peaking issues because they provide higher marginal prices at the times of maximum system stress. By concentrating customer attention on the hours that actually drive costs, the more dynamic rates produce better results for the electric system and society.

By its very nature, a demand charge cannot present symmetric and consistent marginal incentives in the same way as a time-varying kWh charge. Compared to traditional demand charges, properly sized peak window demand charges have a better cost causation

[51] This is referred to as the needle-peaking problem in Crew & Kleindorfer, 1979, p. 186.

basis because they can be linked to the time periods that drive higher system costs. Daily as-used demand charges[52] applied to peak windows could be a further improvement on peak window demand charges, and, better yet, these peak window daily-as-used demand charges could fluctuate according to system conditions. However, this is only an improvement because it converges on the better solution, a system of time-varying kWh rates. Given the rate design possibilities that AMI offers, what reason is there to retain demand charges at all?

4. What Might Be Left for Demand Charges?

The foregoing demonstrates that the typical argument for demand charges, as used for generation, transmission and shared distribution capacity, is substantially flawed. Even so, we want to investigate if there are any circumstances, however limited, for which demand charges are an efficient rate design.

Some theorists have identified a different and, in our minds, much narrower set of rationales for demand charges. The case for time-varying rates relies substantially on the diversity of load and the lack of a direct relationship between individual customer peaks and the system peaks that drive costs. A diverse set of customers may, in the aggregate, create a predictable load profile much of the time. But what if this diversity goes away in an unpredictable manner? Or, for that matter, in a predictable one? Is there something about the causation of costs in special and *limited* circumstances that warrants charging for peak incurrences of short-term (e.g., 15-minute) demand for individual customers? To answer this question, we consider three cases that, on their faces, might present a marginal-cost justification for demand charges. The first is one that we have carved out from the beginning: capacity costs that are not shared, such as dedicated transformers and service drops, which we term "dedicated site infrastructure."[53] This illustrates some important issues relevant to any broader theoretical case for demand charges. The second is the cost associated with uncertainty in customer behavior. The third is timer peaks, a phenomenon where customers shift usage in response to hours with lower prices.

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[52] RAP authors, writing with partners from Synapse Energy Economics, previously recommended daily-as-used demand charges for standby service to large combined heat and power customers, as an alternative to monthly standby demand charges. The purpose was to recognize that different combined heat and power customers would have scheduled and forced outages on different days and could share the same capacity to provide their standby service. This was certainly an improvement on monthly demand charges for such customers, but, in light of the progress made in metering and time-varying energy-based rate structures, there's every reason to think today that such time-varying energy rates are equally appropriate to customers with on-site generation. Johnston, L., Takahashi, K., Weston, F., and Murray, C. (2005, December 1). *Rate structures for customers with onsite generation: Practice and innovation*. National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy06osti/39142.pdf

[53] RAP has previously recommended a small transformer or site infrastructure demand charge for secondary voltage customers, particularly those customers with dedicated site infrastructure. See Lazar, J., & Gonzalez, W. (2015, July). *Smart rate design for a smart future*, pp. 53-54. Regulatory Assistance Project. https://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/

4.1 Dedicated Site Infrastructure

Dedicated transformers and service drops for individual customers are, by definition, not shared infrastructure. The relative importance of this category of cost will vary by customer class. Larger commercial and industrial customer classes, as long as they are taking secondary voltage service, will often have dedicated transformers for each customer or a dedicated transformer bank for customers taking three-phase power. Dedicated transformers will be rare for residential customers in urban and suburban areas, but single-family homes will almost always have a dedicated service drop. The largest industrial customers may have their own primary line (effectively serving as a dedicated service drop) or a dedicated substation (effectively serving as a dedicated transformer). In rural areas, each customer will typically have a dedicated transformer, at which point transformers are customer-specific site infrastructure.

For these customer-specific site infrastructure costs, there is no diversity of demand between the customer meter and point of connection with the shared system. As a result, individual customer NCPs are certainly relevant to the sizing of these components. One might conclude from this that a demand charge can provide a reasonable pricing incentive here. The time period for such a demand charge should have nothing to do with a shared peak since there is no sharing of the infrastructure. Nor should it be limited to peak windows since the peak for an individual customer could occur at any time. The cost of these components may be no more than about $1/kW/month, a fraction of typical demand charges.[54]

There are also other ways of efficiently pricing this category of costs. A similar set of customer incentives may be presented by a connected load charge for a set amount of local capacity. Such a connected load charge can help with efficient sizing, but only if it's accompanied by a fee for overages or the automatic tripping of circuits when demand would cause an overage. Even then, a connected load charge provides no incentive for customers to manage their usage efficiently; that is, there are no cost savings to be gained by keeping their demand below the level of the predetermined connected load. A charge that establishes the relationship of the customer's individual peak demand to the sizing of these components might, however, give the customer some incentive to minimize peaks.

It is worth examining this issue at the level of engineering and planning. What type of customer behavior would minimize the risk of transformer overload and degradation? Or what type of customer behavior would allow utilities to size dedicated transformers more efficiently?

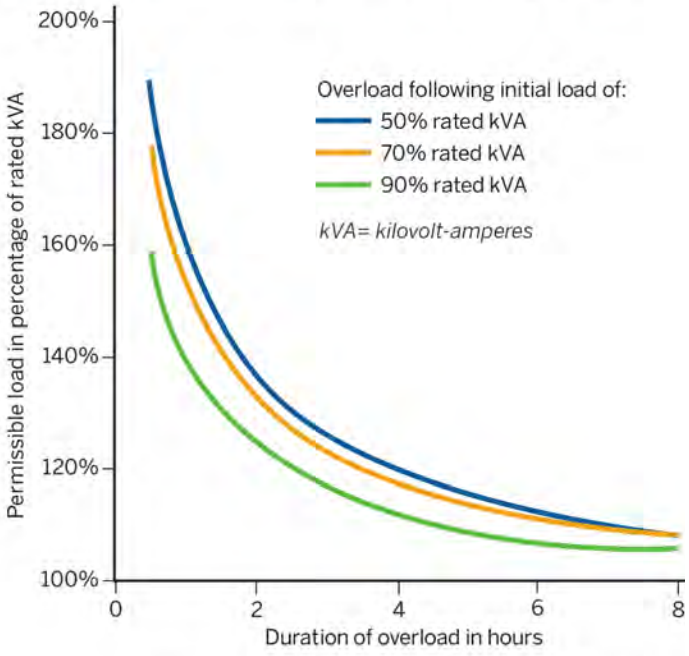
Capacity ratings for the different elements of the electric system are set with many

[54] Seattle City Light, for example, has a large general service rate with specific charges for transformer investment; these are $0.27/kW/month. Seattle City Light. (n.d.). *City Light rates.* https://www.seattle.gov/light/rates/summary.asp

engineering limits in mind. Many of the most important considerations revolve around the heating — and overheating — of components, particularly transformers and conductors. This has a number of different implications. For example, effective delivery capacity can be higher in the winter than the summer or higher in the cool nighttime than during the sunny daytime. The capacity ratings for individual system elements are for sustained loads in typical conditions, but loadings can exceed those ratings on a regular basis without necessarily incurring significant damage. As Tom Short colorfully puts it, a conductor rated 480 amps "will not burst into flames at 481 [amps]."[55]

Figure 7[56] demonstrates the maximum overload that a transformer can take without shortening its operating life, by examining two primary variables: (1) the initial load prior to any overload and (2) the duration of an overload. If a transformer has had light loads (50% of its rating), it can sustain a short-term overload of nearly 190% or a four-hour overload of just over 120%.

Figure 7. Permissible transformer overloads for varying periods



Source: Bureau of Reclamation. (1991). *Permissible Loading of Oil-Immersed Transformers and Regulators*

The important question then is what kind of rate design incentivizes optimal customer behavior with respect to this equipment. Panagiotis Andrianesis and Michael C. Caramanis have developed an algorithm for dynamic nodal locational marginal costs for distribution systems that offers an intriguing approach to pricing for these customer-specific facilities. For line transformers, the pricing formula is a real-time price per unit of energy that follows the transformer thermal response dynamics, which is essentially the temperature of the cooling oil in each transformer.[57] Similarly, a critical peak energy charge could apply for the few hours per year when a transformer is

[55] Short, T. A. (2004). *Electric power distribution handbook*, Section 3.5, p. 140. CRC Press.

[56] Bureau of Reclamation. (1991). *Permissible loading of oil-immersed transformers and regulators.* https://www.usbr.gov/power/data/fist/fist1_5/vol1-5.pdf

[57] Andrianesis, P., & Caramanis, M. (2019). *Distribution network marginal costs: Part 1, A novel AC OPF including transformer degradation.* arXiv. https://arxiv.org/abs/1906.01570

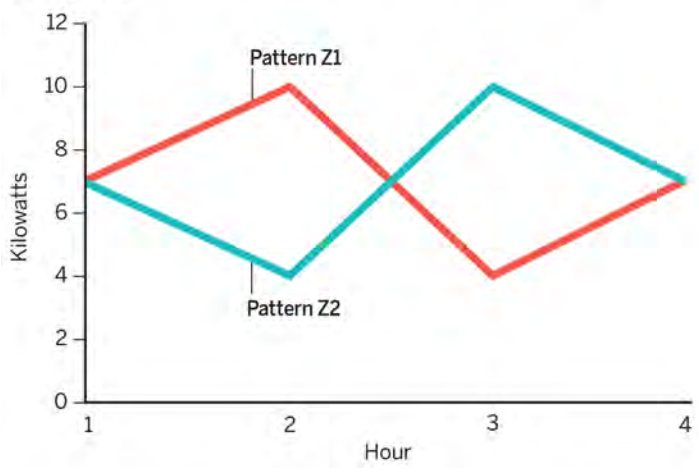
stressed but would require real-time monitoring and pricing to be applied on a transformer-by-transformer basis.

This type of short-run marginal cost pricing does not resemble a demand charge and has the virtue of linking closely in time the incurrence of high marginal costs to the prices charged. These approaches are quite sophisticated and could be costly to administer. To achieve a rate that is more feasible now, a simpler structure would be necessary. A daily-as-used demand charge or a traditional monthly demand charge, based on 15-minute or 30-minute peaks, could certainly discourage the extremely high short-term peaks that would damage a transformer. Those options might not do enough, however, to discourage a sustained, multihour overload.

4.2 Risks of Customer Variance at Peak Times

Load diversity isn't static and can fluctuate in ways that are both predictable and unpredictable. Predictable changes often occur around the weather, one of the few variables that simultaneously affects all customers in a given area. Regarding unpredictable changes, consider a simple hypothetical illustrated in Figure 8.

Figure 8. Two hypothetical load patterns randomly chosen by customers



If there are 10 "random-load" customers who flip a fair coin to determine whether their load profile corresponds to either Z1 (heads) or Z2 (tails) in Figure 8, the average load in each hour across a large number of trials will be 70 kWh.[58] However, system planning must not only deal with the expected average load but rather the chances of higher load. Unfortunately, in any given trial of this scenario, the probability of five heads and five tails — leading to a demand of 70 kW in every hour — is only 24.6%. There is a small but nonzero chance that every customer gets either heads or

[58] In this illustrative example, we consider each customer to have a flat load within each hour. This means that kW and kWh are largely interchangeable as units. Similar examples could, however, be constructed with demand varying in smaller increments (e.g., 30, 15 or 5 minutes), and similar results could be obtained.

tails, leading to a 0.2% probability of a peak load of 100 kW. The full spectrum of potential results for this hypothetical scenario with 10 random-load customers is shown in Table 1.

Table 1. Peak load and probabilities for 10 random-load customers

Coin flip result	High load: Number of customers	Low load: Number of customers	Peak load (kWs)	Probability
10 heads or 10 tails	10	0	100	0.2%
9 heads or 9 tails	9	1	94	2.0%
8 heads or 8 tails	8	2	88	8.8%
7 heads or 7 tails	7	3	82	23.4%
6 heads or 6 tails	6	4	76	41.0%
5 heads and 5 tails	5	5	70	24.6%

The cumulative odds of a peak of 88 kWh or higher is 10.9%, and a peak of 82 kWh or higher is 34.4%. In this hypothetical scenario, it is clearly beneficial to have customers flatten their load curves to 7 kW every hour within this time period. Table 2 shows the range of possible results and associated probabilities for six random-load customers corresponding to either pattern Z1 or Z2 and four flat-load customers with a demand of 7 kW in each hour.

Table 2. Peak load and probabilities for six random-load and four flat-load customers

Coin flip result	High load: Number of customers	Low load: Number of customers	Flat load: Number of customers	Peak load (kWs)	Probability
6 heads or 6 tails	6	0	4	88	3.1%
5 heads or 5 tails	5	1	4	82	18.8%
4 heads or 4 tails	4	2	4	76	46.9%
3 heads and 3 tails	3	3	4	70	31.3%

The risk of a peak of 88 kW or higher drops from 10.9% to 3.1%, and the risk of a peak of 82 kW or higher drops from 34.4% to 21.9%. If the customer choices are uncorrelated, this type of risk goes down as the number of customers increases.[59] However, if the customer choices are correlated, between hour 2 and hour 3 in this hypothetical, the risk does not necessarily decrease with a higher number of customers.

[59] The ratio of the variance to the expected total decreases in proportion to the square root of the number of customers.

This simple example is the essence of the argument made by Michael Veall.[60] He demonstrates that, for a given level of average customer demand during a peak, higher variance customers lead to a risk of higher peaks, particularly if they are correlated. This, in turn, results in a need for higher capacity planning margins. Veall constructs a detailed economic model of optimal peak period pricing. He states that the traditional monthly demand charge does not reasonably address this issue, but rather a peak window demand charge can serve as marginal price on a customer's variance. He notes additional caveats: "If there are many small users with uncorrelated demands, the effects of an individual user's variation on total system variation will be small. But if users are large or their demands are correlated, variance charges are important."[61] Finally, Veall's result demonstrates that, if a peak window demand charge is to be imposed, it should be paired with an on-peak kWh rate.[62] The logic around risk and Veall's theoretical model present an argument for a peak window demand charge that is substantially different from those that utilities put forward. And again, we see a more defensible justification for peak window demand charges for larger-volume customers. But the key question of correlations and *levels of risk* has been neglected in the discussion around demand charges and is only a theoretical possibility in Veall's model. Furthermore, Veall's model does not consider the possibility of more granularly dynamic time-varying kWh rates.

Marcel Boiteux, the influential French economist and executive for Électricité de France (EdF), does discuss risk and uncertainty in a 1952 paper, written jointly with his colleague Paul Stasi.[63] When it comes time for tariff design, Boiteux and Stasi describe two different zones of the shared electric system: (1) the "collective network" and (2) the "semi-individual network, whose capacity depends particularly on the uncertainties of consumption of each customer."[64] With respect to the collective network, they find that the "uncertainties of individual consumption" are small enough to be ignored.[65] And, finally, their analysis of the "semi-individual network" is dominated by risk and the irregularities of individual customer's loads. This leads them to a justification for a complex system of subscription-based contract demand charges, with higher prices for contracted demand in

[60] Veall, M. (1983). Industrial electricity demand and the Hopkinson rate: An application of the extreme value distribution. *The Bell Journal of Economics, 14*(2), 427-440.

[61] Veall, 1983, p. 429.

[62] Veall, 1983, p. 431. Veall notes that this on-peak kWh price could, in principle, even be negative, which would be a curious result.

[63] Boiteux, M., & Stasi, P. (1964). The determination of cost of expansion of an interconnected system of production and distribution of electricity. In J. Nelson (Ed. & Trans.). *Marginal cost pricing in practice.* Prentice Hall. (Original work published in 1952).

[64] Boiteux & Stasi, 1964, p. 117.

[65] Boiteux & Stasi, 1964, p. 117

peak periods and lower prices in other periods. However, Boiteux and Stasi offer little but generalities as to the demarcation of the semi-individual network:

> The extent of the zone within which the uncertainties of individual demands have a very marked influence on the collective cost is greater in proportion to the irregularity of the demands considered, and to the correlations among these demands. This extent depends also on the density of consumption, for the number of customers supplied from a given node plays an important role in the "reduction of uncertainties."[66]

Based on these considerations, Boiteux and Stasi largely describe the generation and transmission system (150-220 kV) as the "collective network" and the distribution system (15-60 kV) as the "semi-individual" network.[67] They are discussing these issues in the context of the then-new Tarif Vert for high voltage industrial customers, and the discussion could be read in a manner that is limited to those customers. This could mean that the dividing line for the semi-individual network could vary by the size of customer. Whether residential customer fluctuations are correlated in a significant and pertinent way is another empirical question Boiteux and Stasi do not address. It is unclear whether the irregularities of individual residential customers would ever be significant enough to matter at a level higher than a shared transformer.

4.3 Timer Peaks

Michael A. Crew and Paul R. Kleindorfer (1979) raise another area where a demand charge could theoretically be efficient, which they describe as the secondary preferences of customers, given the structure of time-varying rates, and the shifting of demand to notionally off-peak times. This is colloquially known as a timer peak. This occurs if customers increase their usage substantially during hours with low rates or more specifically right at the time when low-priced hours begin.[68] In the worst-case scenario, TOU rates can theoretically just shift the system peak without reducing it if enough usage is shifted to hours with low prices. The same is true of coincident peak window demand charges. This outcome can be avoided by managing the number of periods in the rate, the hours covered by each period and the relative prices. One utility has designed a TOU rate in which each customer chooses a three-hour peak period of 4-7 p.m., 5-8 p.m. or 6-9 p.m. All of these customers have 6-7 p.m. in their peak period; two-thirds of them have 5-6 p.m. and 7-8 p.m. in their peak period; and one-third have either 4-5 p.m. or 8-9 p.m. in their

[66] Boiteux & Stasi, 1964, p. 123

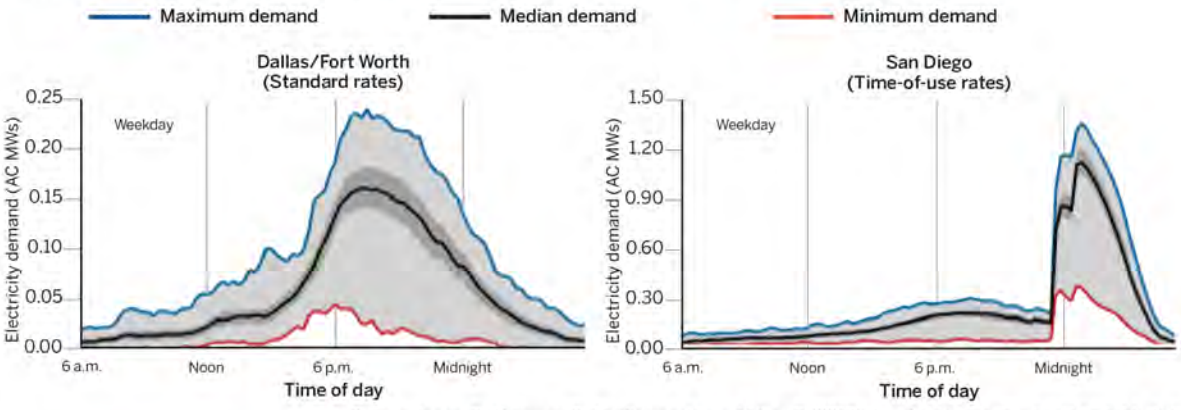
[67] Boiteux & Stasi, 1964, p. 110.

[68] Bonbright mentions this as a possible objection to time-of-use rates. See Bonbright, 1961, p. 362, fn 23: "In Chapter 10 of his book already cited in footnote 10, Davidson suggests this type of rate [time of day and time of season] as preferable to the familiar Hopkinson-type rate. But among the objections to it is the danger that its sharp breaks will create surges in the loads imposed on a power station or on a distribution line."

peak period. This provides the utilities with the most powerful pricing signal during the most likely peak hour but substantial peak reduction in the adjacent hours.[69] Another simple solution is to apply different hours to different classes or subclasses. For example, single-family residences may have their tariff shifted one hour earlier than apartments, or secondary general service one hour later than primary general service.

If the more general system peaks are not impacted significantly enough by this phenomenon to warrant changing the structure of the rate, more granular and local issues can theoretically arise. Figure 9 shows a set of results from a San Diego Gas and Electric rate for electric vehicles, where the "super off-peak" rate begins at midnight.[70]

Figure 9. Real-world illustration of timer peak with EV charging on TOU rate



Source: Jones, B., Vermeer, G., Voellmann, K., & Allen, P. (2017). *Accelerating the Electric Vehicle Market*

This is a rational customer response to a TOU rate, at least for specific end uses. If an electric vehicle is parked at home in the evening and will not be used again until morning, then the customer has a significant amount of flexibility to choose when charging will begin. The very beginning of the lowest price period is an obvious time to start charging. While this may not present an issue at the generation and transmission level, assuming midnight remains an off-peak period, bunching of EV charging could lead to issues at the more local level.

Again, thinking about a line transformer helps focus the analysis. If five single-family homes are served by one shared transformer and all five of those homes have EVs that start charging at midnight, then impacts at the line transformer level are a possibility. Furthermore, what if those houses have other timed usage that starts at the beginning of the lowest price period? Sending a secondary price signal that discourages households

[69] Salt River Project. (n.d.). *SRP EZ-3 price plan.* https://www.srpnet.com/prices/home/ez3.aspx

[70] Jones, B., Vermeer, G., Voellmann, K., & Allen, P. (2017). *Accelerating the electric vehicle market*, p. 16. M.J. Bradley & Associates. https://www.mjbradley.com/sites/default/files/MJBA_Accelerating_the_Electric_Vehicle_Market_FINAL.pdf

from turning on all of their major end uses at midnight could be effective. A daily-as-used demand charge can send such a signal if it were applied across 24-hour periods. A more traditional monthly demand charge, however, will send that signal in a much more attenuated way. A connected load charge based on a contract demand for the cost of connection, with fees for overages, similar to the Électricité de France Tempo rate for residential customers,[71] would send a similar price signal as well.

There are other ways to deal with this phenomenon besides price signals with demand-charge features. The beginning of the off-peak period with the lowest price could be staggered for different customers, for example, beginning at 10 p.m. for one-third of customers, midnight for another third and 2 a.m. for the last third. For customers with long-duration controlled loads, like water heaters or electric vehicles, this would be easy for the customer to manage and beneficial to the utility. To maximize the benefits of such an approach, one would need to have a relatively even split among those three options for the customers on each shared transformer. Load management programs and smart devices could deal with this type of issue as well. For some loads, particularly water heating and EV charging, we anticipate advanced devices that will enable the utility to manage loads to minimize costs and enable customers to benefit from even lower off-peak rates for enabled devices.

One could even question how much of a problem this poses to the longevity of the shared transformers in question. The ambient temperature has almost always cooled off by midnight, and several hours of low or moderate loads could allow the transformer to cool from significant levels of usage during the day or early evening. In certain circumstances, it could be more convenient and cost-effective to upgrade any potentially affected transformers, particularly where multiple water heaters or EV chargers are served from a single transformer.

5. Conclusion

Demand charges, of either the traditional monthly NCP or peak window variety, are not efficient, as a general matter, for shared system capacity costs because:

- For the vast majority of customers, any peak reduction signal in a traditional monthly demand charge is weak and inaccurate.
- Traditional calculations for demand charges have included far too many costs as demand-related. Ideally, utility commissions will adopt a new time-based classification

[71] Electricite de France. (n.d.). *Tarif Bleu: Regulated sale tariff for electricity*. https://particulier.edf.fr/en/home/energy-and-services/electricity/tarif-bleu.html

and allocation framework for generation, transmission and shared distribution costs.[72] Failing that, the numerous energy benefits from capacity investments should be properly accounted for — that is, reflected in energy, not demand, charges.

- Simple TOU rates are superior to peak window demand charges in their own right, but AMI enables time-varying energy charges, such as critical peak pricing, peak-time rebates and variable peak pricing, that much more accurately target times of system stress and reward end users for shifting their loads to off-peak times.

Although we have shown the significant downsides to using current forms of demand charges, in very limited circumstances there might be cost- and efficiency-related justifications for certain types of demand charges. But such charges would be significantly lower than those prevailing for industrial customers in the United States today. Dedicated site infrastructure is a small portion of utility system costs, and typical demand charges would not necessarily provide an optimal signal to control these costs. The primary concerns around timer peaks are almost certainly limited to local infrastructure.

As for the general risk of customer variance and correlation, little work has been done to investigate the statistical bases of this more sophisticated case for demand charges. We think that it is unlikely that such an analysis would find that a substantial demand charge would be fairer or more efficient than time-varying energy charges. Lastly, there is a better case for demand charge-like structures for large customers, who are more likely to have significant dedicated site infrastructure. One might also argue that high variance at peak times among these customers has a more significant chance of influencing the overall system peak. Any such demand charges may not look like Hopkinson rates and would likely be only a second-best solution to a sophisticated system of time-varying energy charges.

The economic and regulatory principles that underlie these judgments are not new. The inescapable essentials of microeconomic theory are at work here. Boiteux, Bonbright and Kahn follow these principles and theories, as do the other scholars and practitioners we cite. In 1964, Paul Garfield and Wallace Lovejoy[73] also stepped into the fray. They converted principles of economic efficiency and fairness into straightforward criteria for assessing the merits of cost allocation methods and rate designs for generation and delivery capacity costs:

- All utility customers should contribute to capacity costs.
- The longer the period of time that customers preempt others' use of capacity, the more they should pay for the use of that capacity.

[72] Lazar et al., 2020.

[73] Criteria adapted from Garfield, P., & Lovejoy, W. (1964). *Public utility economics,* pp. 163-165. Prentice Hall.

- Any service that makes exclusive use of a portion of capacity should be assigned all of the costs for that portion of capacity.
- The allocation of capacity costs should change gradually with changes in the pattern of usage.
- More capacity costs should be allocated to on-peak usage than off-peak.
- Interruptible service (or other forms of utility restrictions and control) should be allocated less in capacity costs as the degree of restriction increases.

Only time-varying energy charges can meet all of these objectives simultaneously. Demand charges for shared costs are demonstrably less efficient and less equitable than they.



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Exhibit JRB-3

Georgia Power 2022 Rate Case – 44280

Georgia Interfaith Power & Light

GEORGIA POWER COMPANY
Docket No. 44280
Georgia Power Company's 2022 Rate Case
Staff Data Request No. STF-PIA-2

STF-PIA-2-3

Question:

Please provide informational materials provided to customers of new residential premises related to the default rate (TOU-RD).

Response:

New customers to the Smart Usage rate (TOU-RD) receive a welcome letter that confirms their enrollment and provides helpful information to educate them on how to take advantage of the rate's design. This information is provided to all customers who enroll in the rate – regardless of whether they reside at a newly established premises or at an existing premises. This information is provided via email if an email address is available; otherwise, it is provided by direct mail.

Additionally, customers enrolled in Smart Usage receive multiple seasonal postcards that highlight the on and off-peak pricing differences. The message includes specific reminders to shift usage to capitalize on the TOU design as well as emphasizing the importance of managing demand.

The materials provided also encourage customers to visit the Georgia Power website for more information on the Smart Usage rate and for tips on managing their energy usage.

Examples of the welcome letter and postcard communications are provided in STF-PIA-2-3 Attachment A and STF-PIA-2-3 Attachment B, respectively.

DropDateLS

Endorsement Line*****SP-Sort Position T-Tray Number P-Bundle Number
Full Name
Business
Address Line 1 Address Line 2
City, State ZIP Code

Smart Usage

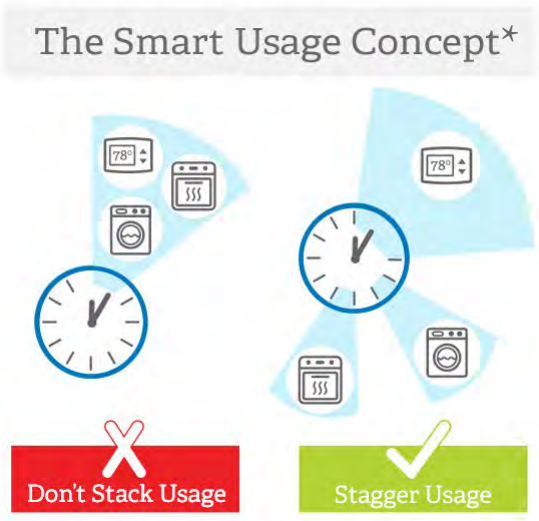
Your account #AccountNumber is now enrolled in Smart Usage.

With Smart Usage, the power to save is in YOUR hands.

Customers on Smart Usage can save on their energy bill by making small changes to how and when they use energy. In fact, this rate plan provides 3 ways to save:

1. How you use energy matters.

Certain appliances – like clothes dryers, ovens, and dish washers – are some of the biggest energy users in your home. By just using these appliances at different times of the day, you can reduce your demand on Georgia Power's system and lower your monthly energy bill.*



2. When you use energy matters.

During summer months, our customers use the most energy and it costs the most to produce. By shifting some usage outside of the peak period that occurs from 2 – 7 p.m. on summer weekdays, customers can enjoy lower cost energy –which can lead to savings on their bill.

3. Less is always more.

As with all rate options, the less energy you use the more you can save. Find ways to reduce usage – such as converting to LED light bulbs or installing a programmable thermostat – to stay comfortable and spend less.

Visit **georgiapower.com/smartusage** for even more information, FAQs, and a short video about your rate plan. Thank you for being a valued Georgia Power customer and we hope you enjoy your experience on Smart Usage.

Smart Usage Rate Plan

Terms and Conditions

By choosing to participate in the residential Smart Usage rate plan, you agree to pay the monthly Smart Usage charges for electric service to the service address associated with the account number used in online enrollment for at least twelve months, beginning with the first bill rendered on the Smart Usage rate.

Your Smart Usage rate does not include fuel, taxes, and other charges, nor does it include Georgia Power security lights, or other Georgia Power products and services should you have any.

These Smart Usage terms apply only for electric service to the designated account(s) and address. If you transfer service to another address, you will need to reapply for the Smart Usage rate.

Georgia Power offers the Smart Usage rate plan pursuant to the current residential rate filing, which is on file with the Georgia Public Service Commission.

For further terms, conditions, and information, please visit the Smart Usage section of GeorgiaPower.com.

Smart Usage

Small changes can bring savings during the summer

Georgia Power



Electricity prices are higher from 2 p.m. – 7 p.m. on weekdays, June 1 – September 30

Thank you for participating in **Georgia Power's Smart Usage** program. We wanted to remind you that you may enjoy savings on your electric bill by shifting some of your summer electric usage to the "off peak" evening and weekend hours when our energy prices are much lower. Specifically, consider reducing your usage between the hours of **2 p.m. and 7 p.m. Monday through Friday (June – September).**



Also, remember that it is always important to use your major appliances – like clothes dryers, oven, and dishwasher – at different times to reduce your demand on Georgia Power's system and lower your monthly energy bill.

By taking these steps, the power to save is in your hands! Visit our website at **www.georgiapower.com** for helpful tips in reducing and shifting usage.

Thanks again for being a part of the **Smart Usage program**.

Georgia Power

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BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In the Matter of	**)**	
	)	
Georgia Power Company's 2022 Rate Case	**)**	**Docket No. 44280**
	)	
	)	
	)	

DIRECT TESTIMONY OF MARK E. ELLIS

ON BEHALF

OF GEORGIA INTERFAITH POWER & LIGHT

October 20, 2022

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[*Remainder of page intentionally left blank.*]

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND PROFESSIONAL AFFILIATION.

A. My name is Mark E. Ellis. I am an economic and financial consultant. My business address is 8595 Nottingham Place, La Jolla, CA 92037.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Georgia Interfaith Power and Light (GIPL).

Q. DO YOU CERTIFY UNDER PENALTY OF PERJURY THAT, TO THE BEST OF YOUR KNOWLEDGE, THE TESTIMONY YOU WILL GIVE IN THIS PROCEEDING IS TRUE AND CORRECT?

A. Yes.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND PROFESSIONAL WORK EXPERIENCE.

A. I graduated from Harvard University with a Bachelor of Science in Mechanical and Materials Sciences and Engineering and from the Massachusetts Institute of Technology with a Master of Science in Technology and Policy.

I have over 25 years of professional experience in the energy industry. Before starting my consulting practice in 2020, I led the strategy function at Sempra Energy for fifteen years. My responsibilities included developing and implementing the enterprise-wide cost of capital estimation process. This critical corporate finance function entailed thorough and ongoing research of the academic and practitioner literature on the historical cost of capital and the various cost of capital estimation methodologies and models; creating a process to estimate, quarterly, the forward-looking, risk-adjusted cost of capital for Sempra's portfolio of companies spanning a variety of geographies and lines of business; and calibrating the results against historical data and reputable, objective third-party estimates.

Previously, I held various positions in strategy, project development, and engineering with McKinsey, ExxonMobil, Southern California Edison, and Sanyo Electric. Last year, I provided expert testimony on behalf of The Utility Reform Network (TURN) before the California Public Utilities Commission in PG&E's application (A.21-20-04-23) for a $7.5-billion wildfire cost securitization. Earlier in 2022, I provided expert testimony on behalf of The Protect Our Communities Foundation (PCF) before the California Public Utilities Commission in the three

California utilities' application (A.21-08-013 et seq.) to suspend the Cost of Capital Mechanism (CCM). I am currently working on or have completed other utility regulatory cases in New Hampshire, Hawaii, Georgia, and Wisconsin. Attachment MEE-1 contains more detail on my background.

A. Summary of Conclusions

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

A. I have been asked by GIPL to assess Georgia Power Company's (GPC) test year 2023 cost of capital application to analyze and calculate the return on equity (ROE) and equity ratio that are (1) adequate to ensure that GPC, from 2023 to 2025, earns a return on its investments "commensurate with returns on investments in other enterprises having corresponding risk," and (2) "sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[1]

Q. GENERALLY, WHAT CONCLUSIONS DO YOU REACH FROM YOUR ANALYSIS AND CALCULATIONS?

A. The Commission can substantially reduce the authorized ROE requested by Georgia Power, and thereby customer costs (by a billion dollars per year), while still enabling Georgia Power to attract debt and equity investment capital, fairly compensate investors for risk, and maintain Georgia Power's current credit rating.

Q. WHAT ARE YOUR RECOMMENDED AUTHORIZED ROE AND EQUITY RATIO?

A. I recommend an authorized return on equity (ROE) equal to Georgia Power's cost of equity (COE) and paired with an equity ratio that, together with my recommended ROE, minimizes customer costs while maintaining Georgia Power's financial integrity, fairly compensating debt and equity investors for risk, and *improving* Georgia Power's credit rating. My recommended authorized ROE is 5.54% at an equity ratio of 61.7%.

[1] *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 603 (1944) (attached as MEE-2).

B. Summary of Findings

1. Georgia Power's cost of capital testimony employs flawed models and assumptions that systematically produce upwardly biased ROE estimates.

Q. THERE IS A SIGNIFICANT DIFFERENCE BETWEEN YOUR RECOMMENDATIONS AND GEORGIA POWER'S RECOMMENDED ROE AND EQUITY RATIO. HOW DO YOU EXPLAIN THAT?

A. The divergence arises from differences in both the models and input assumptions used to determine our respective ROE and equity recommendations.

Georgia Power's cost of capital expert, Mr. James Coyne, uses four models in developing his recommended return on equity (ROE). Two of those models, the Risk Premium Analysis (RPA) and Expected Earnings Analysis (EEA), both suffer from a severe, invalidating conceptual flaw: they are based on utilities' authorized or forecast *return on equity*, not their actual *cost of equity* (COE), or the "the return *to the equity owner* … commensurate with returns on investments in other enterprises having corresponding risks."[2] Thus, these two models are not commonly used in finance outside of utility regulatory proceedings because they do not actually estimate the *cost* of equity. These models are akin to developing a nutrition recommendation based on what people *actually* eat, not on what they *should* eat to maintain a healthy weight.

The other two models used by Mr. Coyne – the discounted cash flow model (DCF) and capital asset pricing model (CAPM) – are widely used throughout finance to estimate the cost of capital. But Mr. Coyne's implementations of each suffer from numerous flaws which bias his results upward.

In implementing the DCF, Mr. Coyne uses unnecessarily long trailing price histories to calculate the dividend yield, which bias his figures upward, and he assumes demonstrably unrealistic, economically impossible long-term dividend growth rates.

In implementing the CAPM, he uses an interest rate forecast long and widely known to be systematically upwardly biased. He cherry-picks a beta calculation methodology that does not reflect current investor risk perceptions and applies the "Blume" adjustment that is not valid

[2] *Id*. (emphasis added).

for utilities, both of which upwardly bias his results. He fails to examine other, more robust beta estimation methodologies, investigate whether the pandemic-related changes in market conditions and investor perceptions of utility risk were temporary or have been sustained, or compare his results to the long-term history of utility betas.

Mr. Coyne's chosen methodology does not reflect the wide range of ways beta could be estimated, each of which could produce dramatically different results. As Nobel laureate Fischer Black, one of the pioneers of empirical testing of beta and the CAPM, famously admonished, "Watch out for data mining!"[3] – running an analysis several different ways but reporting only the outcomes that support one's conclusions.

To estimate the CAPM market risk premium, Mr. Coyne uses the same flawed implementation of the DCF used for his proxy group, again producing an economically impossible result.

Finally, Mr. Coyne fails to adjust his ROE estimates for differences in equity ratio among the proxy group members, and between the proxy group average and Georgia Power.

Mr. Coyne's capital structure recommendation is similarly deficient. While the testimony of Georgia Power's credit expert, Mr. David M. Fetter, refers to key metrics used in assessing credit quality, Mr. Coyne does not provide any analysis or calculations demonstrating how ROE affects those metrics, and how the impact of ROE on those metrics influences his proposed equity ratio. Regulators in other states have authorized ROEs that are substantially lower than those requested by Georgia Power, with comparable or lower equity ratios, without adversely impacting their utilities' credit ratings, suggesting the Commission can substantially reduce the ROE requested by Georgia Power, and thereby customer costs, while maintaining its credit rating.

[3] Fischer Black, *Beta and Return*, 20(1) J. Portfolio Management 8 (1993) (Available at hhtps://jpm.pm-research.com/content/20/1/8.)

2. More rigorous, fact-based analysis of Georgia Power's COE and credit metrics yields a recommended ROE roughly 50% lower and an equity ratio slightly higher than Georgia Power's proposal.

Q. PLEASE SUMMARIZE THE MAIN FINDINGS OF YOUR ROE ANALYSES FOR GEORGIA POWER.

A. Like Mr. Coyne, I use the DCF and CAPM, two models that are widely used throughout finance, to estimate the cost of capital. Unlike Mr. Coyne, I am careful to use realistic and rigorously supported assumptions about long-term dividend growth rates, current interest rates, and risk profiles and premia.

As I explain in Section III.A below, the equity ratio required to maintain any given level of credit quality depends on the ROE. Consequently, the ROE and equity ratio must be determined jointly. Instead of Mr. Coyne's crude equity ratio peer group comparison, which does not consider the most important metrics of credit quality, I model the inter-relationships between key credit metrics, ROE, and equity ratio to arrive at the optimal equity ratio that minimizes customer costs while meeting the return and credit quality requirements of both equity and debt investors.

Figure 1 summarizes the key findings of my review of Mr. Coyne's analysis, the modifications required to correct its deficiencies, the resulting COE estimates, and my ROE and equity ratio recommendations. More rigorous, fact-based, and accurate analyses result in a substantially lower recommendation for Georgia Power's ROE: 5.54%, roughly one half of Mr. Coyne's recommended 11.00%, and a slightly higher equity ratio, 61.7% vs. Mr. Coyne's 56%.

Based on my analysis of Georgia Power's general rate case filings, its proposed combined rate of return on both debt and equity, grossed up for taxes, accounts for more than 25% of its revenue requirement.[4] My recommended ROE and equity ratio would reduce Georgia Power customer costs by approximately 11%, over $1 billion, per year.

[4] M. Ellis analysis of data in 2022 Rate Case, Georgia Power Document Filing No. 190559, Ex. APA-SPA-ADH-MBR-1, Schedule 1 (June 24, 2022).

Figure 1. Comparison of Coyne and Ellis ROE methodologies and results[5]
Percent

Model	Coyne	Ellis	Comment
DCF	**8.99**	**5.97**	
Dividend yield	3.29	3.36	Coyne: excessively long trailing price histories (up to 180 trading days) introduces upward bias Ellis: one-month trailing price history (~21 trading days)
Constant growth rate	5.61	NA	Coyne: extrapolates DPS using analysts' 3-to-5-year EPS growth forecasts • Economically impossible • Estimates are upwardly biased • Low correlation between EPS and DPS forecasts • Inconsistency between EPS and DCF forecast starting periods • Results are inconsistent with analysts' own return forecasts
Initial growth rate	NA	5.49	Analysts' EPS growth rates for three years to mitigate upward bias
Terminal growth rate	NA	1.57	Based on long-term historical utility DPS growth rate equal to inflation
CAPM	**13.55**	**5.41**	
Risk-free rate (30-year Treasury) • Current • Forecast	 2.72 3.40	 NA 3.56	Coyne: current (30-trading day average) and forecast from source known to provide systematically upwardly biased estimates for decades Ellis: current (one-month trailing average) rate
Beta	0.85-0.88	0.48	Coyne: 5-year weekly; inflated due to early-2020 market turmoil and not reflective of current market conditions Ellis: 5-year monthly; balances long-term historical trend and current market conditions
Market risk premium • Historical • Forward	11.78-12.46 NA 11.78-12.46	3.86 4.86 2.87	Coyne: forward-looking using flawed CG DCF Ellis: average of forward-looking using MS DCF and long-term historical average; MS DCF long-term growth rate equal to pre-capita GDP
Risk Premium Analysis	**10.12**	**NA**	Conceptually invalid: equates COE to ROE
Expected Earnings Analysis	**11.03**	**NA**	Conceptually invalid: equates COE to ROE
Mean – Levered – Unlevered	**10.92** NA	**5.69** 4.78	 59% proxy group average *market* equity ratio
Flotation cost adjustment	**0.08**	**NA**	Conceptually invalid: assumes M/B ratio = 1.0
Equity ratio	**56**	**61.7**	
Relevered COE/ recommended ROE	**11.00**	**5.54**	

[5] 2022 Rate Case Hr'g Tr. Vol. 1 at 659-660 (Sept. 28, 2022); Ex. JMC-4. (Transcripts from the GPC Direct Testimony Hearings on September 28-30, 2022 are marked as Volume 1.)

C. Organization of testimony

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, I review a few key conceptual issues related to the cost of capital and capital structure. Next, I provide a detailed assessment of Mr. Coyne's cost of equity estimation methodology and implementation. For the DCF and CAPM, the two of Mr. Coyne's four cost of equity models that are valid, I explain various modifications to his methodology and assumptions to correct for the deficiencies in Mr. Coyne's analyses and then provide the resulting COE estimates. I then apply the capital structure concepts reviewed in the first part of my testimony to determine the optimal equity ratio that minimizes customer costs while satisfying the demands of equity and debt investors. Finally, I estimate the potential savings to customers from adopting my recommended ROE and equity ratio instead of Mr. Coyne's proposal.

II. CONFUSION BETWEEN THE *RATE OF RETURN ON* CAPITAL AND *COST OF* CAPITAL HAS LED TO EXCESSIVE AUTHORIZED RETURNS.

A. *Rate of return on* capital and *cost of* capital are not the same: rate of return on capital is a financial performance metric, whereas cost of capital is the measure of economic cost described in the *Hope* case.

Q. WHAT IS THE OBJECTIVE IN SETTING A UTILITY'S AUTHORIZED RATE OF RETURN?

A. The authorized rate of return is the amount of money, expressed as a percentage of capital invested, that a utility is allowed to recover in customer rates to compensate debt and equity investors for assuming the risks of investing in the utility

The Supreme Court provides the guiding ratemaking principles in its 1944 *Hope Natural Gas* case, in which it directs ratemakers to arrive at "just and reasonable rates" by a "balancing of the investor and the consumer interests."[6] Consumer interests are straightforward: they want to minimize costs and rates. Investors include holders of both the utility's debt and equity. A utility's debt investors expect to receive their contractual interest payments. Debtholders therefore have a "legitimate concern with the financial integrity of the company whose rates are being regulated,"[7] i.e., the utility's credit quality and anticipated ability to fulfill its

[6] 320 U.S. 591, 603.
[7] *Id.*

obligations to debtholders. Equity investors expect a fair return, defined in *Hope* as "commensurate with returns on investments in other enterprises having corresponding risks."[8]

Q. HOW DOES THE RATE OF RETURN ON CAPITAL DIFFER FROM THE COST OF CAPITAL?

A. The rate of return on capital, often shortened to "rate of return," is an accounting metric of financial performance, calculated by dividing the value *returned* to investors – e.g., interest, net income – by the amount of capital invested. The cost of capital is the return investors *expect* on their investment. It is referred to as a "cost" because it reflects what investors demand in return for assuming the risk of the investment and, therefore, what companies must pay for that investment. The *rate of return* on each form of capital, whether calculated retrospectively or estimated prospectively, may or may not equal its respective *cost of capital*.

Q. HOW DOES THE *AUTHORIZED* RATE OF RETURN ON CAPITAL DIFFER FROM THE RATE OF RETURN AND THE COST OF CAPITAL?

A. The *authorized* rate of return refers to a specific use of this accounting metric to determine a utility's revenue requirement and customer rates. According to long-established ratemaking principles, which will be explained in more detail below, the authorized rate of return should be set equal to the cost of capital. Figure 2 summarizes the differences between these three sets of metrics for debt, equity, and the combined return.

[*Remainder of page intentionally left blank.*]

[8] *Id.*

Figure 2. Comparison of terminology: cost of capital, (rate of) return on capital, and authorized rate of return

	Cost	(Rate of) return	Authorized rate of return
Capital	*Cost of capital*	*(Rate of) return on capital*	*Authorized rate of return*
	Economic concept: payment investors require to assume risk of investment	Accounting concept: measured performance, historical or prospective	Regulatory concept: profitability benchmark determined by regulators to set utility revenue requirement and customer rates, balancing customer and investor interests
Equity	*Cost of equity (COE)*	*(Rate of) return on equity*	*Authorized return on equity (ROE)*
	Forward-looking return, based on *market* value of equity, investors expect in compensation for risk assumed; not directly observable	Profitability metric equal to net income divided by *book* value of equity	Per *Hope*, should equal cost of equity to ensure investors are adequately compensated at minimal customer cost
Debt	*Cost of debt*	*(Rate of) return on debt*	*Authorized cost of debt*
	Forward-looking market-based interest rate on debt with commensurate credit risk, adjusted for *expected* default and liquidity risk	Contractual interest (coupon) rate, adjusted for *actual* default or transaction losses	Contractual interest rate; weighted average of current (for existing debt) and expected (for anticipated new debt)

Q. WHAT PRINCIPLES DO YOU USE TO DETERMINE YOUR RECOMMENDED AUTHORIZED RATE OF RETURN?

A. As the National Association of Regulatory Utility Commissioners (NARUC) has explained, "Fundamental financial concepts demonstrate that the fair rate of return to use in ratemaking for a utility is its *cost of capital* in order to achieve the proper balance between customers and investors."[9] Mr. Coyne has also acknowledged, in ROE testimony in other jurisdictions, "that the allowed rate of return should equal the cost of capital."[10] The objective in setting a utility's authorized rate of return should, therefore, be to set the rate of return on each source of capital – debt and equity – as close as possible to the actual cost of each source of capital.

Q. DOES THE APPROACH TO CALCULATING COST OF EQUITY DIFFER FROM THE APPROACH TO CALCULATING COST OF DEBT?

A. Yes. The cost of outstanding debt can be directly determined from its contractual interest rates. Similarly, the cost of debt expected to be issued can be accurately determined from known interest rate indexes for debt of comparable credit quality, such as Moody's utility bond

[9] John D. Quackenbush, *Cost of Capital and Capital Markets: A Primer for Utility Regulators*, Nat'l Ass'n of Regul. Util. Comm's at 10 (2019) (emphasis added) https://bit.ly/3Th1lC8.

[10] Cal. Pub. Util. Comm'n, Docket No. A 22-04-008 et seq., Reporters' Transcript: Virtual Proceeding at 65 (September 12, 2022).

indexes, which, in turn, are based on interest rates directly observed in the market. In contrast, the cost of equity, both existing and to-be-issued, cannot be directly observed and must be estimated using various models.

Q. WHY IS THE DISTINCTION BETWEEN THE COST OF CAPITAL AND RATE OF RETURN IMPORTANT?

A. The cost of capital and rate of return (on capital) are entirely different concepts. The rate of return is a financial performance metric. The cost of capital is an economic concept. Nonetheless, they are frequently referred to interchangeably in utility regulatory proceedings, perhaps in part because finance professionals commonly refer to the cost of capital as the *expected* return (on capital).[11]

The muddling of the difference between the cost of capital and the rate of return is not just of semantic concern, particularly for the cost of equity, which must be estimated using various models rather than directly observed (like the cost of debt).

This confusion between the *cost of* capital and the *return on* capital has infiltrated some of the models commonly used in utility cost of capital proceedings to estimate the cost of equity. These models' apparent influence on regulatory decisions, though, does not make them correct or mean they provide a suitable basis for estimating the cost of equity.

Models that rely exclusively on historical or forecast utility rates of return on equity, without reference to utilities' actual cost of equity, should be rejected outright. Mr. Coyne uses two such models, one relying exclusively on historical authorized ROEs, the other on forecast ROEs. These models incorporate no information about the actual cost of equity and are therefore inherently flawed and produce invalid results. Consistent with the fairness principle described by NARUC, and Mr. Coyne's own statements, only models that estimate the *cost* of equity should be used to determine the authorized ROE.

[11] *See, e.g.*, TIM KOLLER, MARC GOEDHART ET AL., VALUATION, 5TH ED. MCKINSEY & CO. 35 (2010): "The cost of capital is the price charged by investors for bearing the risk that the company's future cash flows may differ from what they anticipate when they make the investment. The cost of capital to a company equals the minimum return that investors expect to earn from investing in the company. That is why the terms *expected return to investors* and *cost of capital* are essentially the same. The cost of capital is also called the discount rate, because you discount future cash flows at this rate when calculating the present value of an investment, to reflect what you will have to pay investors" (emphasis in original).

B. Multiple, diverse sources of evidence demonstrate that utilities' authorized ROEs far exceed their cost of equity.

Q. DO AUTHORIZED ROES REFLECT THE ACTUAL COST OF EQUITY?

A. No. Substantial, robust evidence suggests that authorized ROEs for nearly all U.S. utilities exceed their cost of equity. Georgia Power's ROE follows this national pattern. Below, I provide three diverse analyses that compellingly demonstrate, individually and collectively, the substantial gap between authorized ROEs and utilities' actual cost of equity: expected equity return forecasts produced by investment professionals, utility market-to-book ratios, and the increasing spread between authorized ROEs and interest rates.

1. Investment firms' expected return forecasts for the U.S. equity market as a whole – which is riskier, on average, than utilities – are consistently lower than utilities' authorized ROEs.

Q. ARE THERE OTHER PUBLIC SOURCES FOR COST OF EQUITY ESTIMATES OUTSIDE UTILITY REGULATORY PROCEEDINGS?

A. Utility cost of capital proceedings are not the only purpose for which expected returns on equity are estimated. Investment firms, such as JP Morgan, BlackRock, and T. Rowe Price, regularly publish capital market assumption reports (CMAs) – expected return forecasts for various asset classes. Figure 3 summarizes a survey of U.S. equity market return forecasts published by over thirty firms in 2021.

The CMA forecasts shown in Figure 3 are grouped by assumed investment horizon: less than ten years, ten years (the most common), and more than ten years.[12] The average across the longer-term 10-year and more-than-ten-year horizons, 5.7%, is approximately 40% less than the average ROE authorized for regulated utilities throughout the United States in 2021, 9.5%.[13] Not a single one of the forty-two expected return forecasts that I reviewed[14] is as high as the average ROE yielded by any of Mr. Coyne's models.

[12] Thirty-four CMA reports were reviewed, of which two were excluded due to insufficient data on investment horizon or return type (geometric or arithmetic).

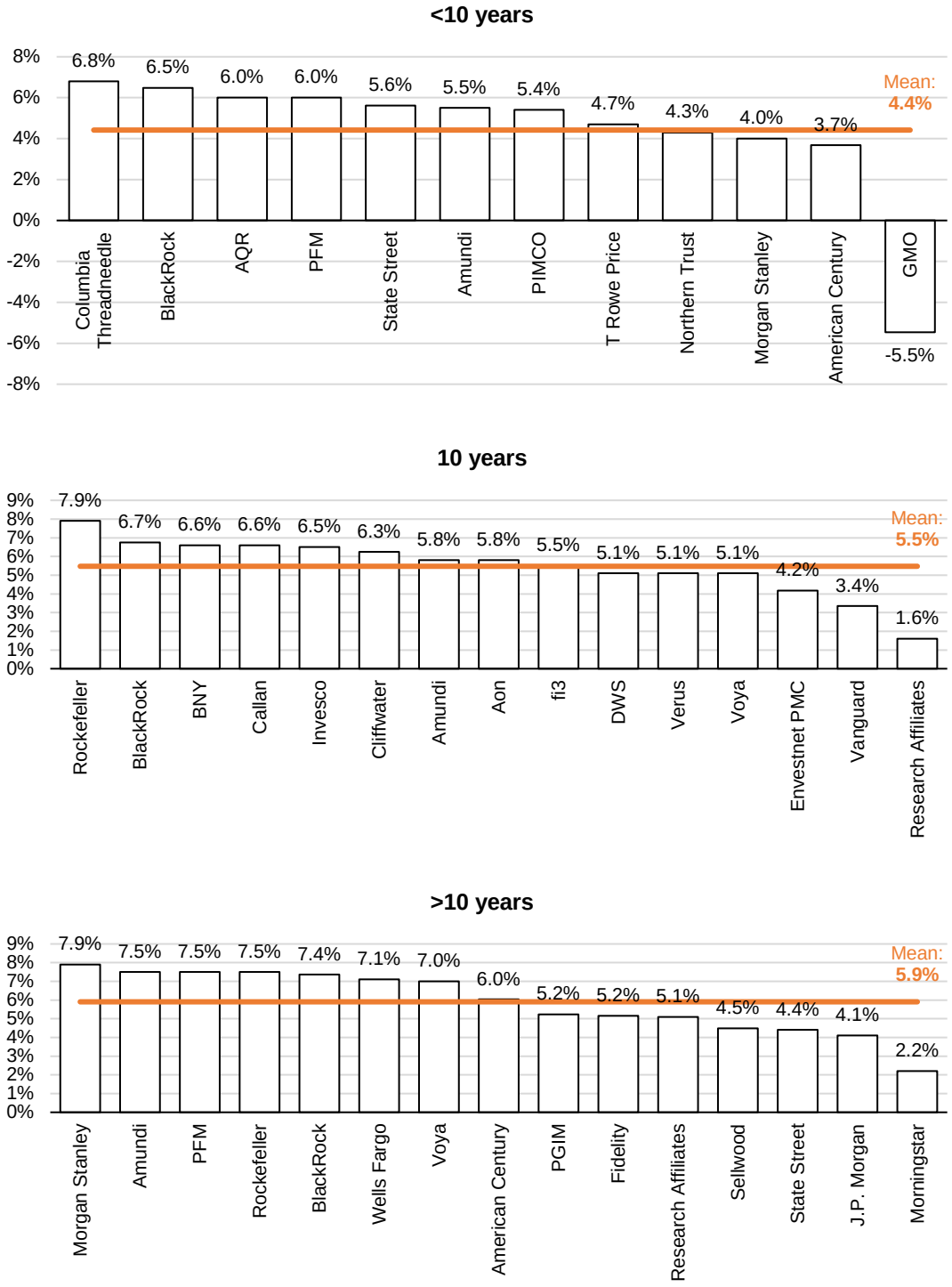
[13] M. Ellis analysis of S&P Global Market Intelligence data, https://www.spglobal.com/marketintelligence/en/ (last accessed October 6, 2022). [Hereinafter referred to as "M. Ellis analysis of S&P GMI data."]

[14] Some CMAs included forecasts for multiple time horizons, so the number of forecasts exceeds the number of reports.

CMA equity market return forecasts are a relevant and useful benchmark for utility ROEs because U.S. utilities, including Georgia Power, are lower-risk – both historically and prospectively – than the market, and therefore investors have *lower* return expectations for utilities than for the market. The fact that authorized utility ROEs are so much higher than the expected returns on the overall market, which is higher risk, is a compelling indicator that authorized ROEs far exceed utility investors' expected returns, i.e., utilities' actual cost of equity.

[*Remainder of page intentionally left blank.*]

Figure 3. U.S. equity market expected returns[15]
Nominal, geometric



[15] M. Ellis analysis of investment firm CMA reports.

2. Market-to-book ratios reveal that utilities' cost of equity is substantially lower than authorized ROEs.

Q. WHAT IS A MARKET-TO-BOOK RATIO?

A. "Market" value refers to the price one must pay to purchase a share of a company's stock at any given time. "Book" value refers to the net equity invested in a company. In general, market value reflects the discounted value of a company's future cash flows, while book value reflects the historical investment in the company. The market-to-book ratio (M/B) is a commonly used financial metric that indicates the amount of shareholder value added in excess of shareholders' return expectations.

Q. HOW DOES A MARKET-TO-BOOK RATIO RELATE TO RETURNS?

A. It is a well understood financial principle that a market-to-book ratio greater than 1.0 indicates the company is expected to earn a return on its investment in excess of the actual cost of capital. A positive net present value (NPV), i.e., the value of a company minus its investments, is the signature indicator of a rate of return that exceeds the cost of capital. NPV is equal to investment multiplied by (M/B – 1.0), so M/B exceeding 1.0 indicates that NPV is positive.

Q. WHAT DO UTILITY STOCK MARKET-TO-BOOK RATIOS REVEAL ABOUT ROES RELATIVE TO UTILITIES' COST OF EQUITY?

A. It has long been recognized that utilities' market-to-book (M/B) ratios provide insight into the relationship between authorized return and the true cost of capital. Legendary regulatory economist Alfred Kahn[16] called attention to this phenomenon over fifty years ago in his 1970 classic, *The Economics of Regulation: Principles and Institutions*:

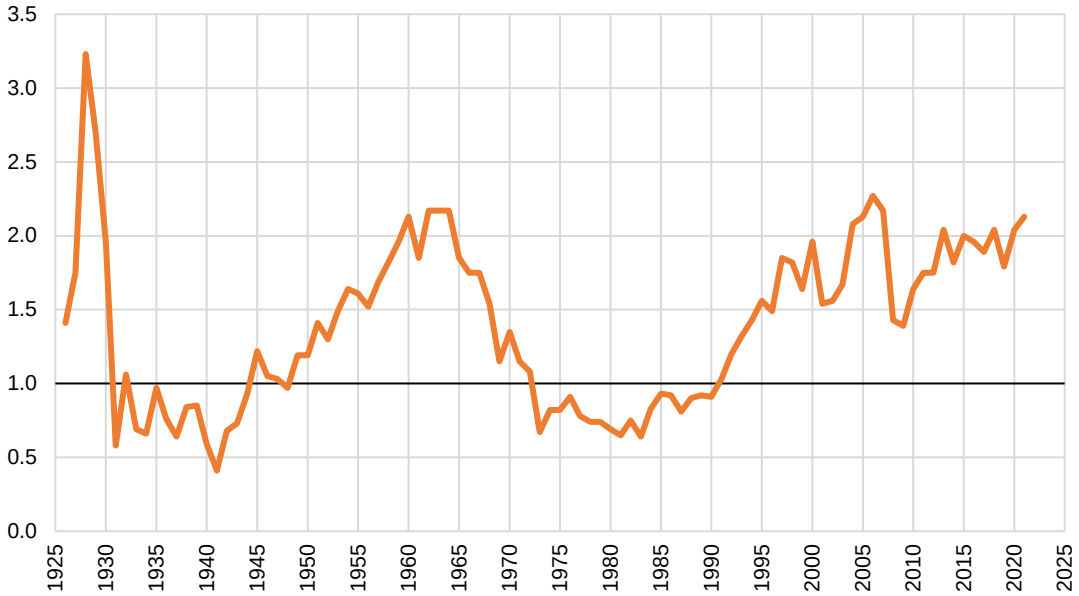
> [T]he sharp appreciation in the prices of public utility stocks, to one and half and then two times their book value during this period, reflected … a growing recognition that the companies in question were in fact being permitted to earn considerably more than their cost of capital. … The source of the discrepancy between market and book value has been that commissions have been allowing *r*'s [returns on equity] in excess of *k* [market cost of equity]; if instead they had set *r* equal to *k*, or proceeded at

[16] *See, e.g.*, Susan Lang, *Economist Alfred Kahn, 'father of airline deregulation' and former presidential adviser, dies at 93*, Cornell Chronicle (December 27, 2010) https://news.cornell.edu/stories/2010/12/alfred-kahn-father-airline-deregulation-dies-93.

> some point to do so … the discrepancy between market and book value … would have disappeared, or would never have arisen.[17]

Kahn was referring to the period of the late 1940s to 1965, but the observation that utilities trade above book value is equally valid today. As seen in Figure 4, the utility sector average M/B ratio has exceeded 1.0 for nearly thirty years and, except for a short period after the global financial crisis, has exceeded 1.5 since 1995.

Figure 4. Utility sector average market-to-book ratio[18]
Year-end



The average of Mr. Coyne's proxy group members' M/B ratios, listed in Figure 4, is even higher, at 2.1.[19] As Kahn observed, the utility sector trading at 1.5 to 2.0 times book value for decades clearly demonstrates that utilities have once again been "permitted to earn considerably more than their cost of capital."

[17] ALFRED KAHN, THE ECONOMICS OF REGULATION: PRINCIPLES AND INSTITUTIONS, MASS. INST. TECH. 48, fn. 60, 50 (1970).
[18] M. Ellis analysis of French Data Library (FDL) data https://mba.tuck.dartmouth.edu/pages/faculty/ken.french/data_library.html (last accessed October 2, 2022).
[19] M. Ellis analysis of S&P GMI data (last accessed October 2, 2022); M/B ratio is the monthly average for September 2022.

Figure 5. GPC proxy group market-to-book ratio and Value Line return on book equity[20]
September 2022

			Value Line return on book equity (%)		
Utility	**Ticker**	**M/B**	2022	2023	'25-'27
ALLETE	ALE	1.22	8.0	8.0	9.0
Alliant	LNT	2.46	11.0	11.0	11.0
Ameren	AEE	2.37	10.0	10.0	10.5
AEP	AEP	2.12	10.5	10.5	11.0
Duke	DUK	1.69	9.0	9.0	9.5
Edison Int'l	EIX	1.82	11.0	11.0	12.0
Entergy	ETR	1.98	10.5	10.5	11.0
Evergy	EVRG	1.65	8.5	9.0	10.0
Hawaiian Electric	HE	1.87	9.5	9.0	9.5
IDACORP	IDA	2.02	9.0	9.0	9.5
NextEra	NEE	4.61	12.5	11.5	13.5
OGE	OGE	1.90	12.0	12.0	13.0
Portland General	POR	1.63	9.5	9.5	10.0
Xcel	XEL	2.50	9.5	9.5	10.0
Mean		**2.13**	**10.0**	**10.0**	**10.7**

Another commonly referenced textbook on utility regulation, Kolbe, Read, and Hall's *The Cost of Capital: Estimating the Rate of Return for Public Utilities*, recommends using a M/B ratio of 1.0 as a "guide for regulators" in setting the cost of capital:[21]

> The market-to-book ratio expresses the market value of the firm's outstanding common stock to the book value of its equity. If the two are equal the expected return on the book will equal the expected return on the market value of the company, which in turn will equal the cost of capital for a company of that degree of risk.

Kahn and Kolbe, et al., drew their conclusions from the basic financial concept of net present value (NPV) discussed above. Because utilities trade at a premium to book value (i.e., invested capital), they have positive NPVs – prima facie evidence that they are earning more than their cost of capital.

[20] M. Ellis analysis of S&P GMI data (last accessed October 2, 2022); Company Response to STF-BAI-1-1 Attachment Coyne F.

[21] A. LAWRENCE KOLBE, JAMES A. READ, JR., GEORGE R. HALL, THE COST OF CAPITAL: ESTIMATING THE RATE OF RETURN FOR PUB. UTIL., CHARLES RIVER ASSOCIATES, INC. at 25 (1984).

Q. IN PRACTICAL, DOLLARS-AND-CENTS TERMS, WHAT DOES IT MEAN FOR A UTILITY TO HAVE A MARKET VALUE THAT IS HIGHER THAN ITS BOOK VALUE?

A. In practical terms, this means that, for every dollar of equity a utility invests, shareholders receive back not just their investment plus a reasonable return, which would be the case when M/B = 1.0, but additional value equivalent to their equity investment multiplied by (M/B – 1.0). At current M/B ratios near 2.0, authorized ROEs effectively double the value of utilities' equity investments, *on top of* returning their cost of equity. Such high returns are not necessary to attract capital and needlessly increase customer costs.

Q. ARE YOU ABLE TO CALCULATE GEORGIA POWER'S MARKET-TO-BOOK RATIO?

A. Georgia Power is not publicly traded, so its market value is not directly observable. Nonetheless, The Southern Company's market-to-book ratio, averaging 2.82 over the month of September 2022,[22] provides a reasonable estimate.

Q. IS MR. COYNE AWARE OF THE RELATIONSHIP BETWEEN THE MARKET-TO-BOOK RATIO AND RETURNS?

A Yes. Mr. Coyne has acknowledged that a market-to-book ratio greater than 1.0 necessarily implies that investors' expected return, i.e., the cost of equity, is less than their authorized return. In a recent cost of capital proceeding in California, Mr. Coyne testified to the following principles:

- "The terms 'expected return to investors' and 'cost of capital' are essentially the same."[23]
- "The allowed rate of return should equal the cost of capital,"[24] the NARUC fairness principle.
- "A typical [investor] expectation is the utility will earn its allowed return [on book equity]."[25] Mr. Coyne's Expected Earnings Analysis is predicated on this assumption,[26] and the Value Line reports from which the EEA draws

[22] M. Ellis analysis of S&P GMI data (last accessed Oct. 15, 2022).
[23] Cal. Pub. Util. Comm'n, Docket No. A 22-04-008 et seq., Reporters' Transcript: Virtual Proceeding at 62 (September 12, 2022).
[24] *Id*. at 65.
[25] *Id*. at 70.
[26] Ex. JMC-7.

its input assumptions explicitly state that the reports' ROE forecasts are based on allowed returns.[27]

- "[I]nvestors can't buy shares at book value … They [investors] can only buy them [shares of utility stocks] at market value."[28]
- "[M]arket-to-book values [of] electric and gas utilities all hover in around 2.0; although there is variation between companies. It's been a long-term trend towards increasing the market-to-book ratio for utilities."[29]
- It "would be highly unusual" to find "any company in [Mr. Coyne's proxy group] sample that does not have a market value greater than the book value."[30]
- "When market-to-book ratio is greater than 1.0 that means that investors are willing to pay more than book value for the same stream of cash flows."[31]
- "[W]hen an investor pays more for the same stream of cash flows, that necessarily implies a lower return."[32]

The logical conclusions from Mr. Coyne's testimony are that (1) investors' expected returns on *book* equity are based on authorized ROEs (as can be seen in Figure 5, which shows the Value Line ROE data used in Mr. Coyne's EEA; the averages, which range from 10.0% to 10.7%, are in line with the national average ROE authorized for electric utilities in 2020-22, 9.4%[33]); (2) investors pay more than book value when they invest in utilities; (3) investors' expected return on *their* investment, i.e., the cost of equity, must be *less* than the authorized ROE; and (4) according to NARUC's fairness principle, under which the ROE should be set equal to the COE, historical, current, and forecast ROEs, because they systematically exceed the cost of equity, can provide no basis for determining the appropriate authorized ROE.

[*Remainder of page intentionally left blank.*]

[27] *See, e.g.*, Company Response to STF-BAI-1-1 Attachment Coyne F at 5; Value Line, "American Elec. Pwr." at fn. E. (March 11, 2022).
[28] Cal. Pub. Util. Comm'n, Docket No. A 22-04-008 et seq., Reporters' Transcript: Virtual Proceeding at 72 (Sept. 12, 2022).
[29] *Id*. at 73.
[30] *Id*.
[31] *Id*.
[32] *Id*. at 74.
[33] M. Ellis analysis of S&P GMI data.

3. Authorized ROEs and interest rates have diverged without a corresponding increase in utilities' risk profile.

Q. WHY DO REGULATORS APPROVE AUTHORIZED ROES IN EXCESS OF UTILITIES' ACTUAL COST OF EQUITY?

A. A mathematical model called the Pólya urn can provide insight into why regulators have continued to approve authorized ROEs in excess of utilities' actual cost of capital.[34] Historical return on equity decisions can be thought of as balls in an urn. To decide on a new case, the regulator draws a ball from the urn. The ball is then replaced, along with a new ball – representing the current ROE decision – with the same value. This process of sampling-with-replacement-plus-duplication has a self-reinforcing property sometimes called the rich-get-richer or Matthew effect.

Of course, this model is over-simplified because regulators look at other information besides past authorized ROEs. The basic model can be modified to include additional balls in the urn representing new information, such as the estimated current cost of equity. Nonetheless, as long as regulators look at, much less rely on, past ROEs, changes in authorized ROEs will lag changes in the current true cost of equity.

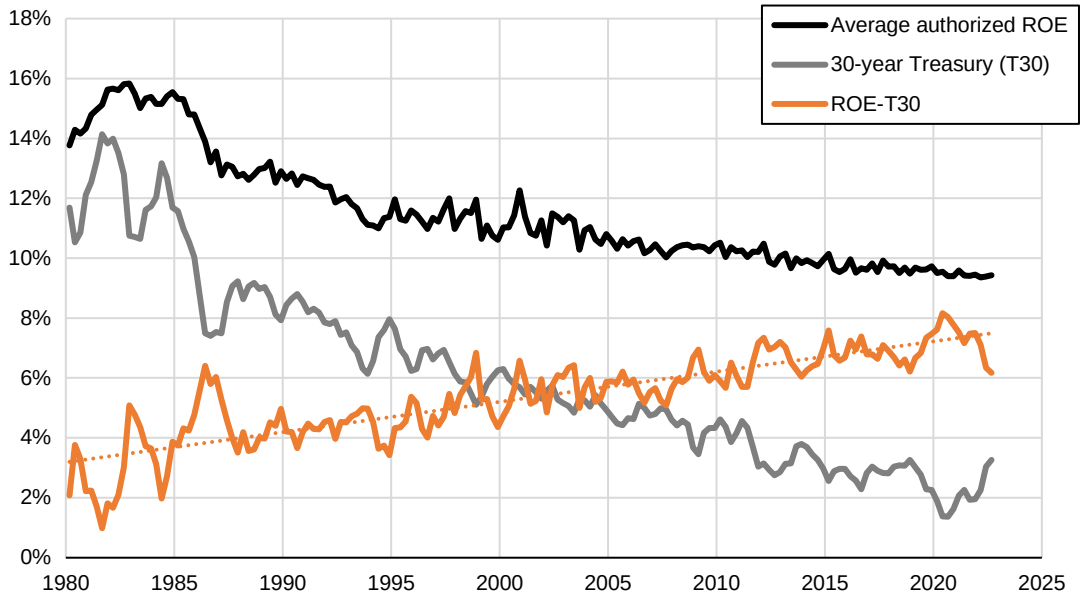
The basic utility regulatory model and risk profile have not changed significantly for decades, so the utility equity risk premium – the spread of the cost of capital over risk-free government interest rates – has remained stable. The Pólya urn model predicts that, in a market in which interest rates and, assuming a relatively stable utility equity risk premium, utilities' cost of equity have been trending downward for decades, authorized ROEs will consistently exceed the actual cost of equity, and the spread will widen over time.

The data confirm the Pólya urn model's prediction of such a widening spread between authorized ROEs and the actual cost of equity. Figure 6 shows the quarterly average authorized ROE for all U.S. utilities, the 30-year Treasury rate, and their difference. While interest rates have declined steadily since the mid-1980s, authorized ROEs have not kept pace. As a result, the ROE-Treasury spread has more than tripled, from approximately 2.3% in the early 1980s to 7.1% in the two years through September 2022. It can be estimated from the Pólya urn model

[34] *See, e.g.,* Learning Machines, *The Polya Urn Model: A simple simulation of "The Rich get Richer"* (Sept. 7, 2021) https://blog.ephorie.de/the-polya-urn-model-a-simple-simulation-of-the-rich-get-richer.

described above that, even under conservative assumptions, regulators, on average, assign no more than a 25% weight to the current cost of equity and at least 75% to recent ROEs. No evidence suggests that utilities' risk profile has systematically increased over this period, so setting ROEs higher and higher relative to utilities' actual cost of equity unnecessarily raises rates and costs to customers.

Figure 6. Quarterly average authorized ROE and 30-year Treasury rate[35]



Others have made similar observations about the growing divergence between authorized ROEs and utilities' actual COEs. In a study published in 2019 exploring potential explanations, Carnegie Mellon researchers David Rode and Paul Fischbeck concluded:[36]

[35] M. Ellis analysis of S&P GMI data (last accessed October 6, 2022); Federal Reserve Bank of St. Louis Economic Data (FRED) data (https://fred.stlouisfed.org/categories/115) (last accessed October 6, 2022).

[36] David C. Rode, Paul S. Fishchbeck, *Regulated equity returns: A puzzle*, 133 Energy Pol'y 1, 16 (2019) https://doi.org/10.1016/j.enpol.2019.110891 (emphasis in original).

> It would appear that regulators are authorizing excessive returns on equity to utility investors and that these excess returns translate into tangible profits for utility firms.
> …
> In the end, we may observe simply that what regulators *should* do, what regulators *say* they're doing, and what regulators *actually* do may be three very different things.

An analogy can be drawn between estimating the cost of equity and developing a nutrition recommendation. Looking at *actual* authorized ROEs to estimate the *required* ROE is akin to developing a calorie intake recommendation based on how much people *actually* eat, not what they need to maintain a healthy weight.

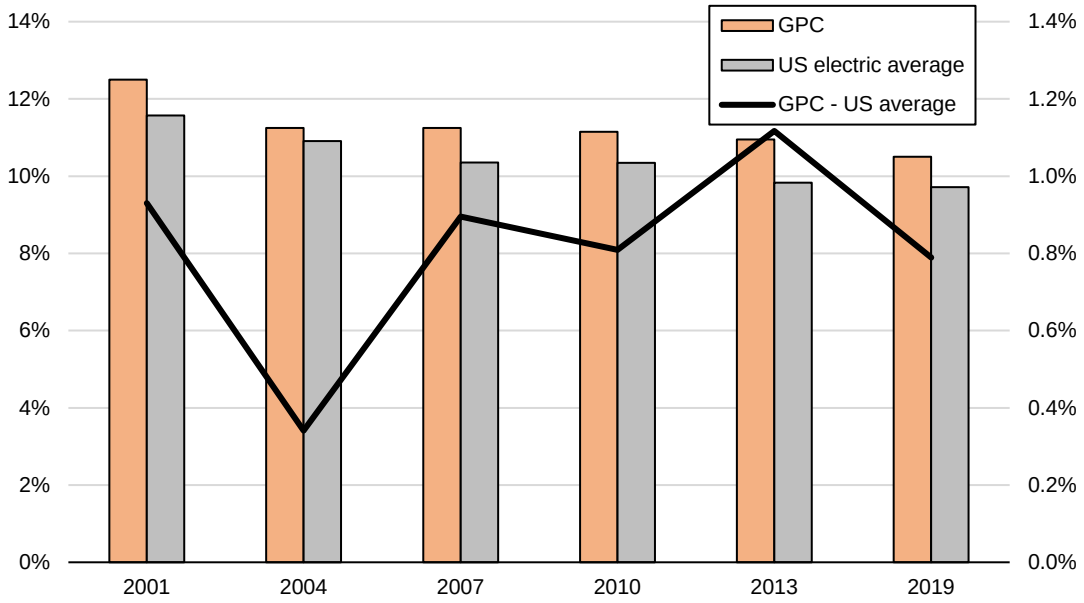
4. <u>These nationwide trends have been even more pronounced for Georgia Power.</u>

Q. DO THESE NATIONAL TRENDS APPLY TO GEORGIA POWER?

A. Yes. Authorized ROEs for Georgia Power have been set substantially higher than the national average authorized ROE for the last two decades, as seen in Figure 7, which shows the difference between GPC's authorized ROEs and the corresponding quarterly national average electric utility authorized ROE in GPC's last five cost of capital authorizations. On average, GPC's authorized ROEs have been 0.8% higher than the national electric utility average.

[*Remainder of page intentionally left blank.*]

Figure 7. GPC and average U.S. electric utility authorized ROE since 2000[37]



III. ROE AND CAPITAL STRUCTURE ARE INTERRELATED AND CANNOT BE DETERMINED SEPARATELY.

A. ROE and capital structure are interrelated through ROE's impact on cash flow.

Q. DOES THE CAPITAL STRUCTURE IMPACT CUSTOMER COSTS?

A. Yes. Capital structure refers to the share of a utility's investment that is funded by debt and equity. Because equity generally has a higher cost than debt, assuming no change in authorized ROE, a higher equity ratio tends to increase customer costs.

Q. DOES THE CAPITAL STRUCTURE IMPACT A UTILITY'S CREDIT QUALITY?

A. Yes. A primary determinant of a company's credit quality – its anticipated ability to repay its debts – is the amount of debt outstanding relative to the total amount of capital, both debt and equity, invested in the company. In general, a higher equity ratio tends to improve a utility's credit quality. Equity ratio is not the only determinant of credit quality, though. As will be explained in more detail below, credit quality is also determined by the amount of cash available to service the debt.

[37] M. Ellis analysis of S&P GMI data (last accessed October 6, 2022).

Q. PLEASE EXPLAIN THE RELATIONSHIP BETWEEN ROE AND CAPITAL STRUCTURE.

A. The testimony of Georgia Power's credit expert, Mr. Steven Fetter, reveals that ROE and capital structure are inextricably linked.

Mr. Fetter describes the importance of the ratio of funds from operations (FFO) to debt in rating agencies' assessments of utility credit quality.[38] FFO and similar cash flow metrics[39] measure the cash available to pay debt interest and principal. What he fails to clarify in his written testimony is that net income is a key component of FFO.[40] Net income, in turn, is the product of rate base, equity ratio, and ROE. Consequently, ROE and equity ratio are key determinants of FFO. During cross-examination, Mr. Fetter acknowledged the relationship between capital structure, ROE, and credit quality:

> Q. [Ms. Whitfield]: On page 14, you talk about key quantitative measures. Specifically, you reference FFO to debt and debt to EBITDA as two core financial ratios that are considered by credit agencies.
>
> A. [Mr. Fetter]: Yes.
>
> Q. Do both of those ratios include inputs that are affected by both capital structure and the return on equity?
>
> A. Well, it certainly factors in the equity/debt split because in one, the debt divides from the bottom and in the other, the debt is divided into by the EBITDA. As far as whether ROE gets factored into this, FFO – ROE ends up resulting in revenues and FFO is a certain measure and EBITDA is an earnings measure. And so ROE would impact those two items.[41]

In the context of the regulatory objective of setting a capital structure that appropriately balances customer and investor interests, as ROE increases, the amount of debt in the capital

[38] 2022 Rate Case Hr'g Tr. Vol. 1 at 799-800 (Sept. 28, 2022).

[39] Mr. Fetter refers to S&P's reliance on FFO; Moody's preferred cash flow metric is cash flow from operations (CFO). *See* GPC data request response STF-NEC-1-1 Attachment AG: Moody's Investors Service, *Georgia Power Company: Update to credit analysis* (October 13, 2021). Mr. Fetter also refers to the debt-to-EBITDA ratio. For utilities, debt-to-EBITDA is less important than FFO/D or CFO/D. For example, the only credit metric cited by Moody's in its "factors that could lead to an upgrade/downgrade" is CFO.

[40] The basic definition of FFO is net income + depreciation and amortization. *See, e.g.*, Corporate Finance Institute, *FFO – Funds from Operations: A measure of cash flow used in real estate* (Dec. 16, 2020) https://corporatefinanceinstitute.com/resources/knowledge/accounting/funds-from-operations-ffo/.

[41] 2022 Rate Case Hr'g Tr. Vol. 1 at 859 (Sept. 28, 2022).

structure can also increase while still maintaining the utility's credit quality; similarly, as the ROE declines, the equity ratio would need to increase to maintain the same creditworthiness.

Curiously, Mr. Coyne's capital structure analysis makes no reference whatsoever to any credit metrics. Instead, he bases his equity ratio recommendation, 56%, solely on a peer comparison.[42]

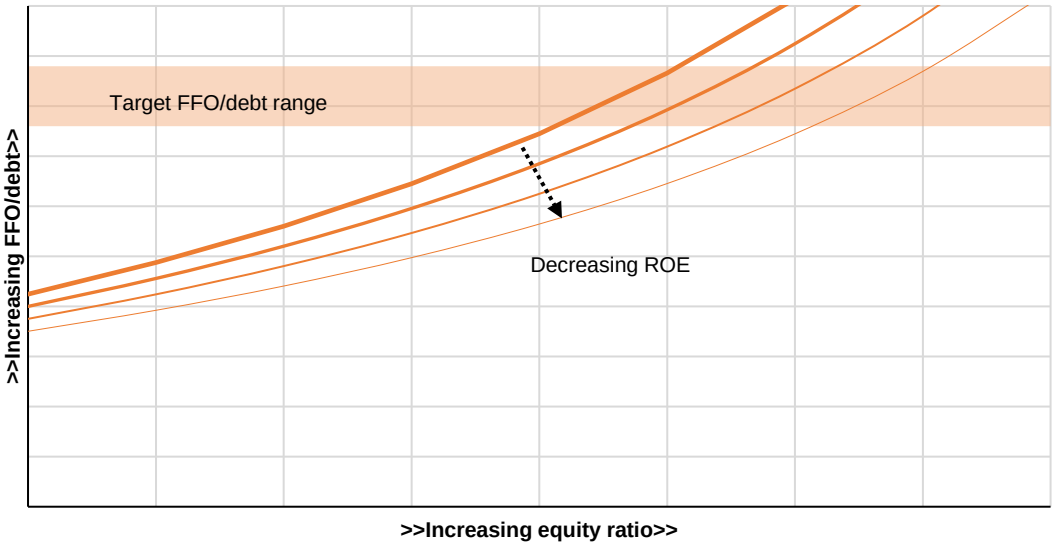
Q. HOW SHOULD A UTILITY'S CAPITAL STRUCTURE BE DETERMINED?

A. The appropriate capital structure can be determined more rigorously by using the analytical methods and metrics employed by credit rating agencies and as described by Mr. Fetter. The level of debt that can be accommodated in the capital structure will vary with ROE, because funds from operation (FFO), a key determinant of a utility's creditworthiness, is based on net income, and net income is based on ROE, for any given credit rating and its corresponding FFO/debt ratio.

Figure 8 illustrates the relationships between equity ratio, ROE, and FFO/debt. The horizontal axis is the equity ratio; the vertical axis is FFO/debt. The light orange horizontal band represents the range of FFO/debt that corresponds to the utility's desired credit rating. The dark orange arcing lines correspond to different levels of authorized ROE, with increasing line thickness representing increasing ROE. Holding the equity ratio constant, FFO/debt declines as the ROE is reduced (moving down from a thicker ROE line to a thinner line). But the decline in FFO/debt when ROE is reduced can be reversed by increasing the equity ratio (moving along the thinner ROE line up and to the right). Any number of combinations of ROE and equity ratio can meet the level of FFO/debt needed to maintain the utility's credit rating. A higher ROE requires less equity to maintain the same FFO/debt and credit rating; a lower ROE can maintain the same FFO/debt and credit rating if it is paired with a higher equity ratio.

[42] 2022 Rate Case Hr'g Tr. Vol. 1 at 672 (Sept. 28, 2022); Ex. JMC-10.

Figure 8. Illustrative relationships between equity ratio, ROE, and FFO/debt



Many observers see utilities' healthy credit ratings and low cost of debt and conclude that the best way to reduce customer costs is to increase the amount of debt in the capital structure. As explained above, current authorized ROEs far exceed utilities' actual cost of equity, so ample scope exists for the Commission to reduce Georgia Power's ROE without adversely affecting its ability to raise equity. At typical utility credit ratings, savings from a lower ROE, after grossing up for taxes, generally more than make up for the incremental cost of any additional equity required in the capital structure. For example, based on analysis of data provided in Moody's October 2021 Georgia Power credit opinion,[43] every 1.0% reduction in ROE reduces total customer costs by approximately 2.0%, *even after* accounting for the approximately 2.0% increase in equity ratio needed to maintain Georgia Power's current cash flow-to-debt ratio.[44]

Total customer costs can be reduced by decreasing the ROE while increasing the equity ratio to maintain the utility's creditworthiness (i.e., its cash flow-to-debt) because the trade-off is not one-for-one. Net income accounts for about 50% of GPC's FFO; other items, such as

[43] M. Ellis analysis of data provided in GPC data request response STF-NEC-1-1 Attachment AG: Moody's Investors Service, *Georgia Power Company: Update to credit analysis* at 10; Ex. 9; Ex. 10 (October 13, 2021).

[44] Moody's preferred cash flow metric is cash flow from operations (CFO), not FFO, and the analysis is based on Moody's CFO/debt data. The basic definition of CFO is net income + depreciation and amortization + changes in working capital, i.e., FFO + changes in working capital. *See* Corporate Finance Institute, *How to Calculate FCFE from CFO?* (Dec. 16, 2020) https://corporatefinanceinstitute.com/resources/knowledge/accounting/how-to-calculate-fcfe-from-cfo/.

depreciation and amortization, account for the rest. Consequently, a relatively large reduction in net income due to a sharp cut in ROE would reduce FFO by roughly half as much in percentage terms. In addition, ROE is grossed-up for taxes, which are not included in FFO, so the savings to customers from a lower ROE is amplified. Rather than "leverage up," i.e., reduce the equity ratio and increase debt, at current ROEs to reduce rates, it is more cost-effective to use any spare credit capacity to reduce the utility's ROE, or even to increase the equity ratio if necessary to maintain a target credit rating, than to increase debt.

Reducing ROE and increasing the equity ratio has the additional benefit of reducing debt-to-capitalization, another key metric used by rating agencies to assess credit quality.[45]

B. Georgia Power's capital structure proposal does not address the interaction between ROE and capital structure.

Q. DOES GEORGIA POWER'S CAPITAL STRUCTURE PROPOSAL TAKE INTO ACCOUNT THE INTERACTION BETWEEN ROE AND CAPITAL STRUCTURE?

A. As Mr. Coyne acknowledged during cross examination, he developed his capital structure recommendation without incorporating the interrelationship between credit quality, ROE, and equity ratio.[46] Neither Mr. Coyne nor Mr. Fetter provides any analysis or calculations demonstrating how FFO/debt interacts with ROE and how that interaction influences GPC's proposed equity ratio. As a result, how much GPC's proposed ROE and/or the equity ratio could be reduced to lower customer costs while still maintaining its desired investment-grade credit rating cannot be assessed from the testimony and data GPC has provided.

GPC's analysis should have included a detailed analysis of the relationships between ROE, equity ratio, and creditworthiness and the impact of different combinations of equity ratio and ROE on customers, lenders, and shareholders so that the Commission could examine the ability of Georgia Power to obtain sufficient capital while minimizing customer costs. The Commission should require Georgia Power to provide a detailed analysis of the relationships between ROE, equity ratio, and creditworthiness so that the Commission possesses the facts it needs to come to fact-based conclusions about Georgia Power's authorized capital structure.

[45] *See, e.g.*, GPC data request response STF-NEC-1-1 Attachment AG: Moody's Investors Service, *Georgia Power Company: Update to credit analysis* at 3 (October 13, 2021).

[46] 2022 Rate Case Hr'g Tr. Vol. 1 at 764-66 (Sept. 28, 2022). Mr. Coyne acknowledges that his capital structure analysis did not involve any analysis of credit metrics like those cited by Mr. Fetter.

C. Georgia Power's ROE and equity ratio can be modified to reduce customer costs without adversely affecting GPC's ability to raise capital.

Q. CAN GEORGIA POWER'S PROPOSED ROE AND/OR EQUITY RATIO BE MODIFIED IN A WAY THAT REDUCES CUSTOMER RATES WHILE MAINTAINING THEIR CREDITWORTHINESS?

A. Evidence from other states suggests both the ROEs and equity ratios proposed by Georgia Power can be reduced while maintaining their creditworthiness. Figure 9 summarizes recent utility rate cases in which the authorized ROE was 9% or less. All of the equity ratios are below the 56% proposed by Georgia Power, yet all of the companies listed in Figure 9 below nonetheless also have comparable or better credit ratings, maintaining their ability to attract capital.

Figure 9. Recent authorized ROEs at or below 9%[47]

Company	State	Service type	Date	ROE (%)	Equity ratio (%)	Issuer credit rating		
						S&P	Moody's	Fitch
Orange & Rockland	NY	E/G	3/19	9.00	48.0	A-	Baa2	BBB+
Otter Tail Power	SD	E	5/19	8.75	52.9	BBB+	A3	BBB
Consolidated Edison NY	NY	E/G	1/20	8.80	48.0	A-	Baa1	BBB+
Central Maine Power	ME	E	2/20	8.25	50.0	A	A2	BBB+
NY State E&G	NY	E/G	11/20	8.80	48.0	A-	Baa1	BBB+
Rochester G&E	NY	E/G	11/20	8.80	48.0	NR	Baa1	BBB+
Corning Natural Gas	NY	G	5/21	8.80	48.0	NR	NR	NR
El Paso Electric	NM	E	6/21	9.00	49.2	NR	Baa2	BBB
Brooklyn Union Gas	NY	G	8/21	8.80	48.0	BBB+	Baa2	BBB
KeySpan Gas East	NY	G	8/21	8.80	48.0	BBB+	Baa1	BBB+
Arizona Public Service	AZ	E	11/21	8.70	54.7	BBB+	A3	BBB+
Central Hudson G&E	NY	E/G	11/21	9.00	50.0	A-	Baa1	BBB+
Commonwealth Edison	IL	E	12/21	7.36	48.7	BBB+	A3	BBB+
Ameren Illinois	IL	E	12/21	7.36	51.0	BBB+	A3	NR
Niagara Mohawk	NY	E/G	1/22	9.00	48.0	BBB+	Baa1	NR
Green Mountain Power	VT	E	8/22	8.57	50.0	A	NR	NR

[47] M. Ellis analysis of S&P GMI; Moody's (https://www moodys.com/); FitchRatings (https://www fitchratings.com/) (last accessed October 6, 2022).

IV. MR. COYNE EMPLOYS FLAWED MODELS AND ASSUMPTIONS THAT SYSTEMATICALLY PRODUCE UPWARDLY BIASED ROE ESTIMATES FOR GEORGIA POWER.

A. Mr. Coyne's methodology relies, in part, on conceptually flawed models.

Q. HOW DOES MR. COYNE ESTIMATE GEORGIA POWER'S ROE?

A. Mr. Coyne employs four different models to estimate Georgia Power's ROE: (1) constant-growth discounted cash flow model (CG DCF); (2) capital asset pricing model (CAPM); (3) risk premium analysis (RPA); and (4) expected earnings analysis (EEA). In the CG DCF, CAPM, and EEA, Mr. Coyne estimates ROEs for a number of proxy group companies and bases his recommended ROEs on the proxy group average.

Q. WHAT IS YOUR OVERALL ASSESSMENT OF MR. COYNE'S APPROACH?

A. Although two of Mr. Coyne's models, the CG DCF and CAPM, are widely used by financial professionals and utility cost of capital experts to estimate the cost of equity, his implementations are deeply flawed. They rely on unrealistic, systematically upwardly biased assumptions that invalidate their results. I describe these deficiencies in more detail in Sections IV.C and IV.E below.

The other two models, RPA and EEA, while frequently used by utility cost of capital experts, are not commonly used elsewhere in finance outside utility regulatory proceedings, and both suffer a severe, invalidating conceptual flaw.

Q. WHAT IS THE INVALIDATING CONCEPTUAL FLAW IN THE RPA AND EEA?

A. Both the RPA and EEA confuse the cost of equity and the return on equity, estimating the cost of equity from historic or forecast returns on equity. The RPA consists of a linear regression model of historical quarterly-average authorized ROEs against historical quarterly-average 30-year Treasury yield. Mr. Coyne's EEA estimates the cost of equity using ROE forecasts provided by investment research firm Value Line. The primary drivers of Value Line's ROE forecasts for the proxy group companies, in turn, are the companies' most recent authorized ROEs.[48]

Both the RPA and EEA are essentially models of past ROE decisions, not the actual cost of equity. By design, therefore, they repeat the historic overearnings arising from the excess

[48] *See, e.g.,* GPC data request response STF-BAI-1-1 Attachment Coyne F at 5: Value Line, "American Elec. Pwr." (March 11, 2022), fn. E.

ROEs authorized in the past. As explained in Section II.A above, the cost of equity and the return on equity are two entirely different concepts; there is no basis to assume that they will or should be equal. In fact, as explained in Section II.B above, authorized ROEs have diverged dramatically from utilities' actual cost of equity, as reflected in the disparity between authorized ROEs and substantially lower forecast returns for the U.S. equity market as a whole, despite the latter's higher risk; utility market-to-book ratios exceeding 1.0 for decades; and the growing divergence between average authorized ROEs and interest rates. Basing a utility's authorized ROE on historically authorized ROEs without any reference to the *actual cost of equity*, as both the RPA and EEA do, merely perpetuates these errors.

A simple calculation illustrates the EEA's conceptual flaw in equating ROE and COE. ROE is the ratio of earnings to the book value of equity. But investors cannot buy shares at book value; they must pay market value. The market value of the stocks Mr. Coyne chose to include in his peer group tend to trade at a significant premium over book value, currently an average of 2.1x. Mathematically, if investors pay more than book value for the same stream of earnings, their expected return, i.e., the cost of equity, *must* be less than the ROE calculated using the book value.[49] For companies earning just their cost of equity, the *expected* return, i.e., the cost of equity, can be estimated by dividing earnings per share (EPS) by equity book value per share (BVPS).[50] EPS can be expressed as the product of ROE and book value per share, so COE can similarly be expressed as ROE divided by the market-to-book ratio.[51] COEs so calculated are dramatically lower than Mr. Coyne's EEA estimates. For example, Value Line's forecast '25-'27 ROE for Alliant Energy Corporation is 11.0%,[52] and as of September 30, 2022, Alliant's market-to-book ratio was 2.17,[53] so investors' expected return would be

[49] A simple example illustrates why this must be true. Suppose one pays $1 for an investment that guarantees a payment of $0.10 – a return of $0.010/$1.00 = 10% – every year into perpetuity. If instead the initial cost was $2 instead of $1 for the same perpetual stream of $0.10 per year, the return would be $0.10/$2.00 = 5%. If the initial investment for the *identical* cash flow stream is higher, the return is lower.

[50] Aswath Damodaran, *Implied Equity Risk Premium: Principles & Mechanics* at 5 https://pages.stern.nyu.edu/~adamodar/pdfiles/eqnotes/webcasts/ERP/ImpliedERP.pdf (last accessed July 22, 2022).

[51] COE = EPS / stock price = ROE x book value per share / stock price = ROE / M/B.

[52] GPC data request response STF-BAI-1-1 Attachment Coyne F at 2: Value Line, "Alliant Energy" (March 11, 2022).

[53] M. Ellis analysis of S&P GMI (last accessed October 2, 2022).

only approximately 11.0/2.17 = 5.07%.[54] As Kahn explained, and Mr. Coyne has acknowledged (see Section II.B.2 above), M/B ratios greater than 1.0 imply COE is less than ROE. It is simply mathematically impossible for COE to equal ROE when M/B is not equal to 1.0, yet Mr. Coyne's RPA and EEA are nonetheless premised on this mathematical impossibility.

FERC has also recognized the flaws in the RPA and EEA. In Opinion No. 569 (November 2019), FERC rejected the use of both the RPA and EEA to estimate the cost of equity. With regard to the EEA, FERC explained "that relying on the Expected Earnings model would not satisfy the requirements of *Hope*":

> In particular, we find that the record does not support departing from our traditional use of market-based approaches to determine base ROE. Under the market-based approach, the Commission sets a utility's ROE to equal the estimated return that investors would require in order to purchase stock in the utility at its current market price. In *Hope*, the Supreme Court explained that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks." In order to determine this, we must analyze the returns that are earned on "investments in other enterprises having corresponding risks," but investors cannot invest in an enterprise at book value and must instead pay the prevailing market price for an enterprise's equity. As a result, the expected return on a utility's book value does not reflect "returns on investments in other enterprises" because book value does not reflect the value of any investment that is available to an investor in the market, outside of the unlikely situation in which market value and book value are exactly equal. Accordingly, *we find that relying on the Expected Earnings model would not satisfy the requirements of* Hope.[55]

FERC initially rejected the RPA for similar reasons:

[54] The EEA suffers other flaws, such as the growth adjustment to book value which does not account for new share issuance, but their effect is minor relative to the central conceptual flaw of confusing ROE and COE.

[55] Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc., Docket No. EL14-12-003, Opinion No. 569, 169 FERC at 103 ¶ 61,129 (emphasis added) (2019).

> [T]he Risk Premium model is likely to provide a less accurate current cost of equity estimate than the DCF model or CAPM because it relies on previous ROE determinations, whose resulting ROE may not necessarily be directly determined by a market-based method, whereas the DCF and CAPM methods apply a market-based method to primary data. For example, previous ROE determinations may not involve an explicit determination as to whether an ROE is just and reasonable, but instead focused on whether to allow an ROE incentive adder or were approving a preexisting RTO-wide ROE for a new RTO member. Similarly, many previous ROE determinations used in the Risk Premium model were the product of rate case settlements. Such settlements often involve compromises on a variety of issues present in a rate case, of which the appropriate ROE is only one. Consequently, such settlements could include ROEs that are not representative of the market cost of equity because the ROEs were negotiated above or below that market cost of equity in order to form an overall settlement package, together with negotiated outcomes on other issues, that were acceptable to the parties.[56]

Although FERC subsequently reinstated the RPA in Opinion No. 569-A (May 2020), the D.C. Circuit Court of Appeals found that FERC's reinstatement of the RPA was arbitrary and capricious and has vacated Opinion 569-A.[57]

In the same California cost of capital proceeding referenced in Section II.B.2 above, Mr. Coyne acknowledged that his Risk Premium Analysis and Expected Earnings Analysis are not based on utilities' cost of equity:

[*Remainder of page intentionally left blank.*]

[56] Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc., Docket No. EL14-12-003, Opinion No. 569, 169 FERC at 166 ¶ 61,129 (2019).

[57] Van Ness Feldman, LLP, *D.C. Circuit Court of Appeals Decision Puts FERCs Revised Method for ROE Determinations in Question* (August 10, 2022) https://www.vnf.com/dc-circuit-court-of-appeals-decision-puts-fercs-revised-method-for-roe-determinations-in-question.

Q. Isn't it true that two of your models, the risk premium analysis, RPA, and the expected earnings analysis, EEA, are not based on the utilities' actual cost of equity?

A. Yeah.

Q. The RPA is based on historical authorized ROEs; correct?

A. It's based on an historic relationship between allowed return by regulatory commissions and Treasury yields.

Q. The EEA is based on forecast ROEs; correct?

A. Yes. That's based on a forecast of ROEs.[58]

Despite his acknowledgement that ROE systematically exceeds COE, Mr. Coyne's RPA and EEA nonetheless estimate COE based on historical and forecast ROEs – in direct contradiction to the NARUC fairness principle that he has endorsed. For these reasons, the results of Mr. Coyne's EEA and RPA models should be rejected outright.

B. Mr. Coyne fails to account for differences in equity ratios among the proxy group members.

Q. HOW DOES THE EQUITY RATIO AFFECT THE COST OF EQUITY?

A. All else equal, a lower equity ratio tends to raise the cost of equity. This can be understood intuitively. The cash generated by a business is pledged to holders of its debt and equity, with debtholders having first priority. As the equity ratio declines, a smaller share of the cash goes to equity owners. To the extent there is uncertainty in the cash generated, it is amplified by a lower equity ratio, increasing the riskiness of those cash flows. This increased risk is reflected in a higher cost of equity.

The companies in Mr. Coyne's proxy group have different equity ratios, and their average, 53%,[59] is different from the 56% he proposes for Georgia Power, so their costs of equity cannot be used to estimate Georgia Power's under his proposed equity ratio. In addition, Mr. Coyne compares the equity ratios on a book basis; this is incorrect. When determining the cost of capital, the market value of equity should be used.[60]

[58] Cal. Pub. Util. Comm'n, Docket No. A 22-04-008 et seq., Reporters' Transcript: Virtual Proceeding at 65-66 (September 12, 2022) [edited for clarity].

[59] Ex. JMC-10.

[60] *See, e.g.,* TIM KOLLER, MARC GOEDHART ET AL., VALUATION, 5TH ED. MCKINSEY & CO. 204 (2010): "Where possible, you should estimate *market* values of the elements of the current capital structure" (emphasis added).

I will revisit adjusting the COE model results for differences in equity ratios among the proxy group members, and between the proxy group average and Georgia Power, in Section V.A below.

C. Mr. Coyne's DCF model uses upwardly biased dividend yield calculations and unrealistically extrapolates analyst earnings growth forecasts into perpetuity, producing economically impossible results.

Q. WHAT IS YOUR ASSESSMENT OF MR. COYNE'S DCF MODEL?

A. Mr. Coyne uses the constant-growth version of the DCF model (CG DCF) in his analysis, with a growth rate equal to equity analysts' consensus 3-to-5-year EPS growth rate estimates. The key shortcoming in his implementation of the CG DCF is the assumption that dividends can grow at analysts' estimated EPS growth rates into perpetuity. This economically impossible assumption upwardly biases his results dramatically.

Q. PLEASE DESCRIBE THE CONSTANT-GROWTH DCF MODEL.

A. The constant-growth DCF is based on the well-known and widely used mathematical formula for the value of a growing perpetuity stream of cash flows. It assumes a single, constant rate of cash flow growth. In the constant-growth DCF model used by Mr. Coyne and many other modelers, the cash flows are expected dividends, and the perpetuity value formula can be expressed as:

$$M_0 = D_0 \frac{(1+g)}{(k-g)}$$

where M_0 refers to the current market value (stock price), D_0, the current dividend (typically four times the most recent quarterly payment), g, the forecast perpetuity growth rate, and k, the cost of equity. Rearranging terms, the cost of equity can be expressed as a function of the dividend yield, d ($\frac{M_0}{D_0}$), and growth rate:

$$k = d(1+g) + g$$

In some implementations of the CG DCF, the first-year dividend yield is calculated by multiplying the current yield by $1 + \frac{g}{2}$, instead of $1 + g$, to account for the quarterly, not

annual, payment of dividends. Mr. Coyne uses this approach.[61] Typically, the cost of equity is estimated for each member of the proxy group, with the mean or median reflecting the cost of equity for the target company. Mr. Coyne uses the mean.

The general DCF model, which can allow for varying growth rates over time, is a particularly apt representation of stock returns because its assumptions realistically reflect several key features of share prices and expected returns. First, the DCF model's perpetual cash flow stream assumption mirrors equity's claim on a firm's cash flows into perpetuity. Second, the assumption of steady growth in dividends over time reasonably reflects their much greater stability relative to other potential measures of profitability, like earnings or cash flow. Third, the resulting single discount rate into perpetuity is consistent with the no-arbitrage principle of finance. If investors expected higher (lower) returns in the future, they would impute that into the price today and bid up (down) the price accordingly, such that near-term and long-term returns roughly equilibrate.[62]

But the *constant growth* version of the DCF used by Mr. Coyne is not well-suited for estimating the cost of equity for a utility or any other stock, for two reasons. First, it is not realistic to assume that a utility will maintain its current 3-to-5-year growth rate into perpetuity. At any given time, the 3-to-5-year growth rate will deviate from its long-term trend due to any number of factors, such as weather; economic conditions; new capital projects; regulatory, tax, and other policy changes; and unforeseen events like the Covid-19 pandemic. Second, the results of the CG DCF are particularly sensitive to the perpetuity growth rate assumption. The inaccuracy introduced by assuming a relatively short-term growth rate will be sustained forever invalidates the results of Mr. Coyne's CG DCF. Mr. Coyne's use of analyst estimates, a source

[61] 2022 Rate Case Hr'g Tr. Vol. 1 at 654 (Sept. 28, 2022). It can be demonstrated mathematically that, for dividend yields as of the starting time period of the model (t_0), the common method of using four times the most recent quarterly dividend is already slightly conservative relative to a more accurate quarterly model, and this adjustment is therefore not necessary.

[62] Some equity return projections vary with forecast horizon, generally due to a valuation-reversion assumption in the model, e.g., price-to-earnings ratios returning to their long-term historical average over an initial horizon and remaining at that level afterward. *See, e.g.*, BlackRock Investment Institute, *Capital market assumptions* (2022) https://www.blackrock.com/institutions/en-us/insights/charts/capital-market-assumptions. Whether variation in expected equity returns across different forecast horizons can be estimated with any accuracy is a subject of ongoing debate among academic and investment professionals. Some forecasters assume no mean reversion in their return forecasts. *See, e.g.*, AQR Capital Management, *2014 Capital Market Assumptions for Major Asset Classes* (2014) https://www.aqr.com/Insights/Research/Alternative-Thinking/2014-Capital-Market-Assumptions-for-Major-Asset-Classes).

widely known to be upwardly biased, for his growth rate assumption further invalidates his results.

1. Mr. Coyne's dividend yield calculations use unnecessarily long trailing price histories, introducing upward bias to his estimates.

Q. HOW DOES MR. COYNE CALCULATE THE CURRENT DIVIDEND YIELD?

A. To calculate the dividend yield, Mr. Coyne divides four times the most recent quarterly dividend by the trailing average share price over 30, 90, and 180 trading days.[63]

While it is advisable to use a multi-day average of the share price to reduce the effect of any day-to-day price fluctuations that are not reflective of investors' long-term expectations, *all three* of Mr. Coyne's averages are unnecessarily long. Because share prices have a general tendency to trend upward over time, the longer the backward-looking averaging period, the lower the share price will tend to be, introducing upward bias into the dividend yield. Averaging the most recent month of data, approximately 21 trading days, better balances the competing objectives of mitigating the potential short-term volatility cited by Mr. Coyne and reflecting current investor expectations.

2. Mr. Coyne's perpetuity growth rate is based on analysts' 3-to-5-year growth rate forecasts, producing economically impossible results.

Q. HOW DOES MR. COYNE ESTIMATE EACH PEER UTILITY'S PERPETUITY GROWTH RATE?

A. While estimating the current dividend yield is fairly straightforward (although, as just explained, the potential for bias exists even there), estimating the perpetuity growth rate is more subjective. Mr. Coyne uses analysts' consensus 3-to-5-year estimated earnings-per-share (EPS) growth rate provided by Value Line, Thomson First Call (as reported by Yahoo! Finance),[64] and Zacks.[65]

[63] 2022 Rate Case Hr'g Tr. Vol. 1 at 653-54 (Sept. 28, 2022).

[64] The providers of EPS estimates have consolidated and changed their names numerous times over the last two decades. First Call was integrated with I/B/E/S in 2000 and discontinued in 2012 (https://libguides mit.edu/c.php?g=387236&p=2626822). I/B/E/S is now provided by Refinitiv (https://www refinitiv.com/en/financial-data/company-data/ibes-estimates). Refinitiv is the source of Yahoo! Finance's estimates (https://help.yahoo.com/kb/finance-for-web/SLN2310 html).

[65] Mr. Coyne's EPS growth rate forecast sources use the following forecast horizons: Value Line, '19-'21 to '25-'27 (*see, e.g.*, STF-BAI-1-1 Attachment Coyne F); Zack's, 3 to 5 years (https://www.zacks.com/stocks/); Yahoo! Finance, next 5 years (https://finance.yahoo.com/).

The DCF is a model of *dividends*, not earnings, so it would be preferable to use explicit dividend-per-share (DPS) forecasts. While some analysts, such as Value Line, provide DPS forecasts, they are less common, so EPS forecast are typically used instead.

Q. IS IT REASONABLE TO ASSUME ANALYSTS' CONSENSUS GROWTH RATES INTO PERPETUITY IN A DCF MODEL?

A. No. There are several problems with using analysts' estimates for the perpetuity growth rate. A wealth of academic research over decades has found that analyst forecasts tend to be optimistic.[66] Several other observations and analyses demonstrate the unreasonableness of using analysts' 3-to-5-year EPS growth rate estimates for the perpetuity dividend growth rate in the constant-growth DCF model.

Q. WHAT IS YOUR FIRST OBSERVATION OR ANALYSIS THAT DEMONSTRATES THE UNREASONABLENESS OF USING ANALYSTS' 3-TO-5-YEAR EPS GROWTH RATE ESTIMATES FOR THE PERPETUITY DIVIDEND GROWTH RATE IN THE CG DCF?

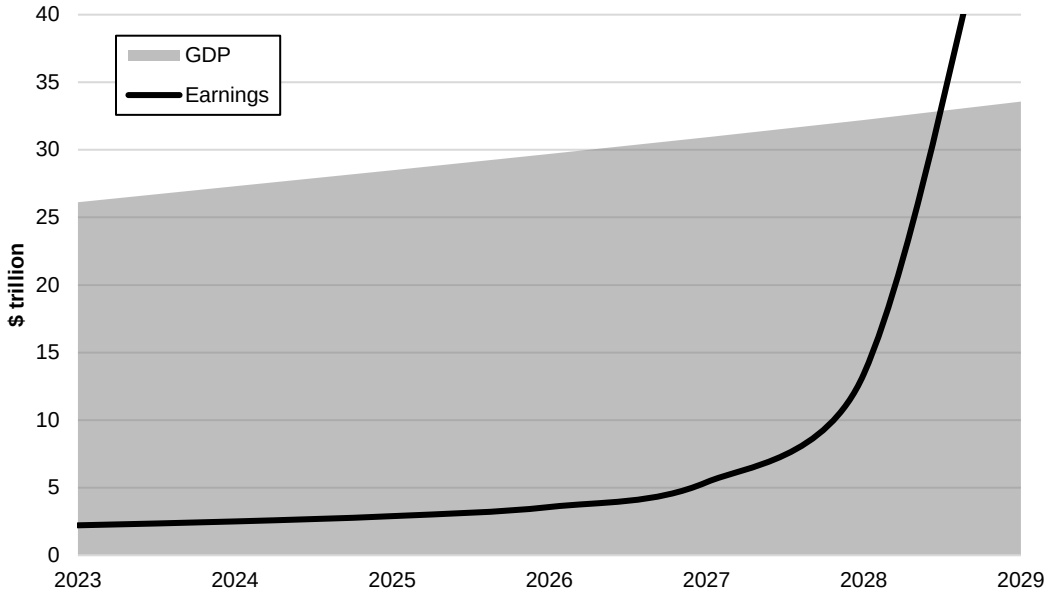
A. It is economically impossible for analyst earnings growth forecasts to be sustained even for one decade, much less into perpetuity. Figure 10 compares the forecast aggregate earnings of the U.S. publicly-traded companies for which analysts provide EPS growth forecasts[67] to forecast U.S. GDP.[68] Currently, these companies' combined earnings are equal to roughly 8% of U.S. GDP. Yet if analysts' growth projections were correct, they would exceed total U.S. GDP in just six years.

[66] *See, e.g.*, Marc Goedhart, Rishi Raj, Abjishek Saxena, *Equity analysts: Still too bullish*, McKinsey Quarterly (Apr. 2010), https://www mckinsey.com/business-functions/strategy-and-corporate-finance/our-insights/equity-analysts-still-too-bullish. For a more recent example, *see also* Stefano Cassella, Benjamin Golez, Huseyin Gulen, Peter Kelly, *Horizon Bias and the Term Structure of Equity Returns* (Nov. 2021), https://ssrn.com/abstract=3328970.

[67] M. Ellis analysis of S&P GMI data for 1,780 U.S. stocks. Excludes companies with growth rates less than -100%.

[68] Sum of the forecasts for each company. Analysts' EPS estimates and growth rates from S&P GMI as of June 30, 2022. GDP forecast is average of Congressional Budget Office, *The 2022 Long-Term Budget Outlook* (July 2022), https://www.cbo.gov/system/files/2022-07/57054-2022-07-LTBO.xlsx.; Energy Info. Admin., *Annual Energy Outlook 2022 Macroeconomic Indicators* (March 2022), Table 20 https://www.eia.gov/outlooks/aeo/excel/aeotab20.xlsx; Soc. Sec. Admin., *The 2022 Annual Report of the Board of Trustees of the Federal Old-Age and Survivors Insurance and Federal Disability Insurance Trust Funds* (June 2022), Supplemental Single-Year Tables, https://www.ssa.gov/OACT/TR/2022/SingleYearTRTables_TR2022.xlsx.

Figure 10. U.S. stock market forecast earnings vs. forecast GDP



The Research Foundation of CFA Institute has made a similar critique of projecting analysts' estimates beyond their forecast horizon:[69]

> Consensus long-term earnings growth estimates routinely exceed sustainable GDP growth. The current consensus growth rate for earnings on the S&P 500, according to the Zacks Investment Research survey, is 10 percent, which, if we assume a consensus inflation expectation of 2-3 percent, corresponds to 7-8 percent real growth. Real earnings growth of 8 percent is six times the real earnings growth of the past century, however, and three times the consensus long-term GDP growth rate. This growth is not possible.

Mr. Coyne himself has acknowledged the potential unreasonableness of assuming analyst growth rates into perpetuity in his CG DCF model, testifying in a recent rate case, "the Multi-Stage DCF can be used when there is concern that short-term growth rates may not be sustainable over the longer-term."[70]

[69] Robert D. Arnott, *Equity Risk Premium Myths: Rethinking the Equity Risk Premium*, 2011(4) CFA Institute 97 (2011) https://bit.ly/3TjGiig.

[70] New Brunswick Energy and Utilities Board Docket No. 491, Liberty Utilities (Gas New Brunswick), *Prepared Direct Testimony: James M. Coyne*, at 39 (March 2021).

Q. WHAT IS YOUR SECOND OBSERVATION OR ANALYSIS THAT DEMONSTRATES THE UNREASONABLENESS OF USING ANALYSTS' 3-TO-5-YEAR EPS GROWTH RATE ESTIMATES FOR THE PERPETUITY DIVIDEND GROWTH RATE IN THE CG DCF?

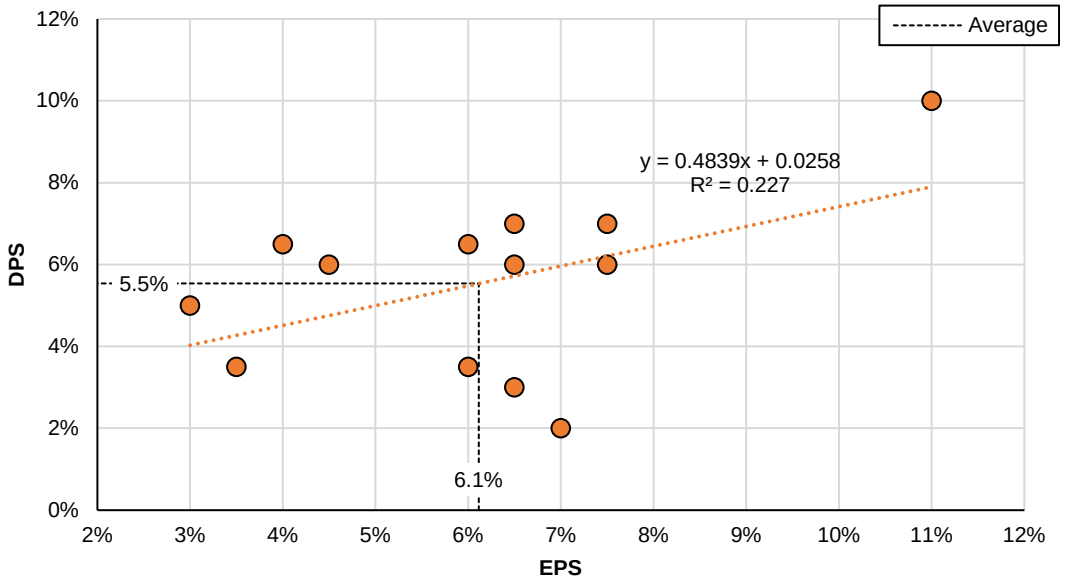
A. Mr. Coyne is correct that "[o]ver the long term … dividend growth can only be sustained by earnings growth,"[71] and EPS and DPS do tend to have similar growth rates over extended, multi-decade periods of time. Nonetheless, EPS growth rates are poor proxies for DPS growth over the 3-to-5-year horizon of analysts' EPS forecasts. This is observed in both forecast and historical data.

Few analysts provide both DPS and EPS projections, but Value Line, one source of Mr. Coyne's growth estimates, does provide both EPS and DPS growth forecasts, and its EPS and DPS projections vary considerably. Figure 11 compares Value Line's forecast EPS and DPS growth rates for the members of Mr. Coyne's proxy group. On average, the DPS growth rate is lower, 5.5% vs 6.1% for EPS; EPS overestimates expected dividend growth, introducing upward bias into Mr. Coyne's DCF results. More importantly, as shown in Figure 11, a cross-plot of Value Line's EPS and DPS growth rate estimates, the correlation between the two sets of numbers is low (R^2 coefficient of 0.23).

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[71] 2022 Rate Case Hr'g Tr. Vol. 1 at 654-55.

Figure 11. Value Line forecast EPS and DPS forecast growth rates[72]

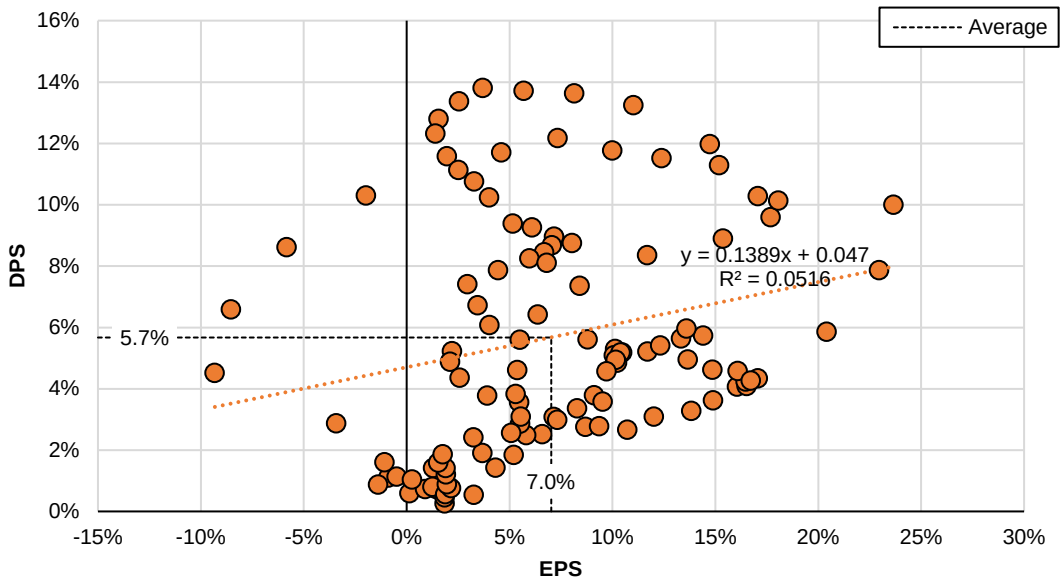


Historically, the variation between EPS and DPS is even greater. Figure 12 compares historical 5-year EPS and DPS growth rates for the S&P 500 from January 1988 through March 2022. Historically, average EPS growth has also been greater than DPS, 7.0% vs. 5.7%, and the correlation between EPS and DPS is even lower than for the forecast growth – R^2 coefficient of just 0.05.

[*Remainder of page intentionally left blank.*]

[72] M. Ellis analysis of data provided in GPC data request response STF-BAI-1-1 Attachment Coyne F: (Value Line reports for each member of Mr. Coyne's proxy group).

Figure 12. Historical S&P 500 EPS and DPS 5-year growth rates[73]



In both the historical and projected data, the average growth rate for EPS is higher than for DPS, seemingly contradicting Mr. Coyne's assertion that "earnings per share [and] dividends per share … grow at the same constant rate."[74] But EPS and DPS do, in fact, grow at roughly the same *compound* rate over the *long term*.[75] Nonetheless, analysts' 3-to-5-year forecast horizons are not long-term, and simply because earnings are more volatile than dividends, the figure reported for EPS growth over analysts' 3-to-5-year forecast period will tend to be higher than DPS, as both the historical growth rates in Figure 12 and the forecast growth rates in Figure 11 demonstrate.

This is due to the mathematical relationship between compound, or *geometric*, and *arithmetic* average growth rates.[76] An illustrative example demonstrates the principle. Suppose both EPS and DPS both grow at a compound average growth rate (CAGR) of 5% over 25 years, but they take different paths to get there. DPS grows at the same 5% every year, or

[73] M. Ellis analysis of data from S&P Dow Jones Indices, *S&P 500 Earning and Estimate Report* (September 30, 2022) https://www.spglobal.com/spdji/en/documents/additional-material/sp-500-eps-est.xlsx.

[74] 2022 Rate Case Hr'g Tr. Vol. 1 at 654.

[75] "Compound" refers to the single, constant growth rate at which an initial value would need to grow to reach a final value. Importantly, the initial value could follow any number of different growth paths to achieve the same compound growth rate. EPS and DPS can have the same compound growth rate over an extended, multi-decade period, but have very different growth rates over the intervening 5-year periods.

[76] *See, e.g.*, Educba, *Difference Between Geometric vs. Arithmetic Mean*, https://www.educba.com/geometric-mean-vs-arithmetic-mean/ (last accessed Oct. 20, 2022).

27.6% over each 5-year period. Annual EPS growth varies between -5% and +15% over each 5-year period, say 15% in the first 5 years, followed by -5%, 0%, 6%, and 10% over the next four 5-year periods. The average of the DPS growth rates over each of the 5-year periods is 5.0%, but the average of the EPS growth rates is 5.2%. The effect is relatively small, but it is another source of upward bias introduced by using EPS growth rates as a proxy for DPS growth.

For the two reasons observed in both forecast and historical data – overestimation on average and low correlation – EPS is a poor proxy for DPS, and it is inappropriate to assume that analysts' relatively short-term EPS growth estimates reasonably reflect investors' DPS growth expectations into perpetuity.

Q. WHAT IS YOUR THIRD OBSERVATION OR ANALYSIS THAT DEMONSTRATES THE UNREASONABLENESS OF USING ANALYSTS' 3-TO-5-YEAR EPS GROWTH RATE ESTIMATES FOR THE PERPETUITY DIVIDEND GROWTH RATE IN THE CG DCF?

A. EPS growth rate horizons are likely not compatible with the CG DCF's forecast horizon. The starting time periods of analysts' estimates are not specified with precision. S&P explains of its estimates:[77]

> Long Term Growth Rate (LTG) is a compound annual growth rate based on current and projected EPS values provided directly by the analysts. … Most analysts define LTG as an estimated average rate of earnings growth for the next 3-5 years. The exact time frame differs from broker to broker. Since the analysts providing LTG may differ from the analysts providing fiscal year estimates and the variation in time periods of 3-5 years, it is not possible to reconcile LTG with fiscal year estimates.

The starting points for Yahoo! Finance's estimates are similarly unknown:[78]

[77] *See* YCharts Financial Glossary, *Long Term Growth Rate*, https://ycharts.com/glossary/terms/eps_est_long_term_growth (last accessed July 22, 2022) (reporting estimates provided by S&P).

[78] *See* Stockopedia Financial Ratio Glossary, *Long Term Growth Forecast*, https://www.stockopedia.com/ratios/long-term-growth-forecast-5107/ (last accessed July 22, 2022) (Referring to Reuters, now Refinitiv, the source of Yahoo! Finance's estimates). *See also,* Yahoo!, *Exchanges and data providers on Yahoo Finance*, https://help.yahoo.com/kb/finance-for-web/SLN2310 html.

> [A]s most analysts do not provide the basis of the calculation of their growth rates, the estimates collected are assumed to include a combination of past and future years with at least one future period included, and are calculated on a compounded annual growth rate (CAGR) basis.

Value Line *does* specify the starting point and forecast horizon of its estimates. Nonetheless, Value Line's growth rate forecast horizons are virtually certain not to be consistent with the dividend yield used in the CG DCF, i.e., the end of the last trading day of the share price averaging period. The starting period for the Value Line growth estimates used by Mr. Coyne, for example, is '19-'21, the midpoint of which, June 2020, is almost three years before the first dividend payment in his DCF model.[79]

EPS can vary significantly from one year to the next, typically much more than the annual variation in DPS. Without knowing the forecast period, it is not possible to determine whether the estimate reflects the growth rate over the three to five years, much less the rate into perpetuity, from the starting point of the CG DCF. Following a year of poor performance, for example, expected growth would be elevated, potentially significantly above what could be sustained long-term.

The incompatibility of the growth estimates can be clearly observed in the data itself. For example, Value Line's growth rate for Edison International is reported as "not meaningful" because the company reported a loss in 2018, the first year of its growth forecast period. Yahoo! Finance's and Zacks's growth rates are both positive, presumably because the starting point of their growth rate forecasts are years in which Edison International reported a profit.[80]

[79] Mr. Coyne calculates average stock prices through April 30, 2022; *see* Ex. JMC-4, fn. 2. The CG DCF assumes annual dividend payments start one year later, or April 30, 2023.
[80] Ex. JMC-4.

Q. WHAT IS YOUR FOURTH OBSERVATION OR ANALYSIS THAT DEMONSTRATES THE UNREASONABLENESS OF USING ANALYSTS' 3-TO-5-YEAR EPS GROWTH RATE ESTIMATES FOR THE PERPETUITY DIVIDEND GROWTH RATE IN THE CG DCF?

A. The expected returns produced by a CG DCF model assuming DPS grows into perpetuity at analysts' 3-to-5-year EPS growth rates are inconsistent with analysts' own expected return forecasts.

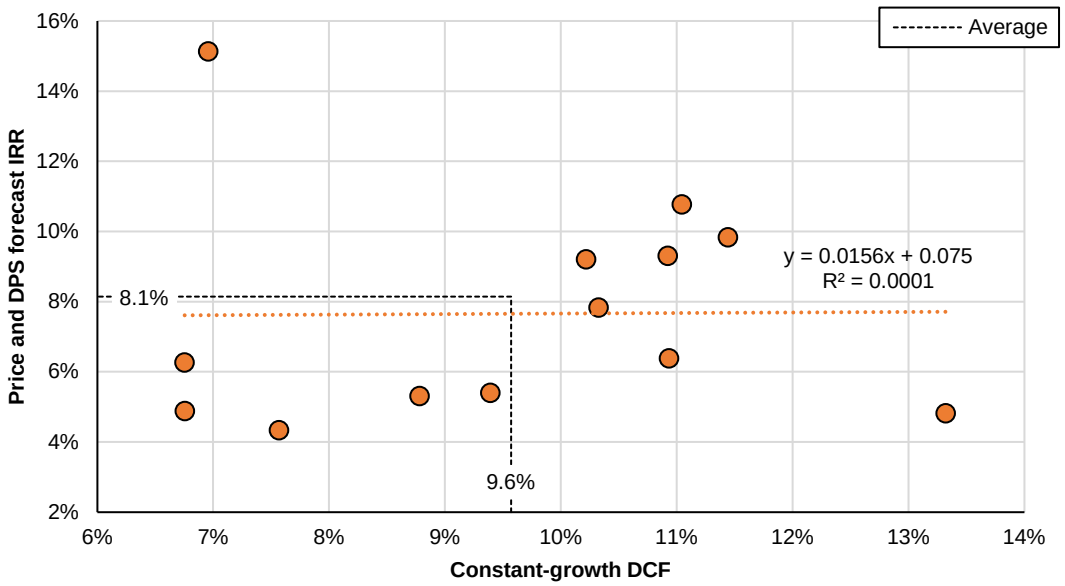
In addition to their EPS and DPS growth rates, Value Line publishes a variety of other forecasts, including for share prices.[81] These forecasts can be used to estimate Value Line's own expected return for each company, which can be compared to the CG DCF results using Value Line's dividend yield and EPS growth rate forecasts in Mr. Coyne's model.[82] Figure 13 compares the results of the two models. The horizontal axis is the COE estimated using Mr. Coyne CG DCF and Value Line's yield and EPS growth rate assumptions; the vertical axis is COE implied by Value Line's own dividend and price forecasts.

On average, the CG DCF COE estimates (9.6%) are significantly higher than the COE implied by Value Line's price and dividend forecast (8.1%). More importantly, there is virtually no correlation between the two sets of model results (R^2 = 0.0). A CG DCF COE based on Value Line's dividend yield and EPS growth bears almost no resemblance to the COE implied in its own dividend and price forecast. The analysts that provide 3-to-5-year EPS growth forecasts clearly do not assume those rates apply to dividends or will be sustained into perpetuity, as Mr. Coyne does. For Mr. Coyne's proxy group, Value Line assumes DPS will grow more slowly, on average, than EPS beyond its forecast horizon.

[81] Value Line reports do not include actual share price forecasts, but EPS and price-earnings multiple (P/E) forecasts. Price can be calculated by multiplying these two figures: P = EPS x P/E. *See* GPC data request response STF-BAI-1-1 Attachment Coyne F (Value Line reports for each member of Mr. Coyne's proxy group).

[82] A simple DCF model can be constructed from Value Line's most recent annual average price (investment), dividend forecast (with missing years interpolated assuming a constant growth rate), and'25-'27 price forecast (exit value). The COE is the internal rate of return (IRR) of this cash flow stream.

Figure 13. COE based on Value Line CG DCF and price and DPS forecast IRR[83]



Q. WHAT IS YOUR FIFTH OBSERVATION OR ANALYSIS THAT DEMONSTRATES THE UNREASONABLENESS OF USING ANALYSTS' 3-TO-5-YEAR EPS GROWTH RATE ESTIMATES FOR THE PERPETUITY DIVIDEND GROWTH RATE IN THE CG DCF?

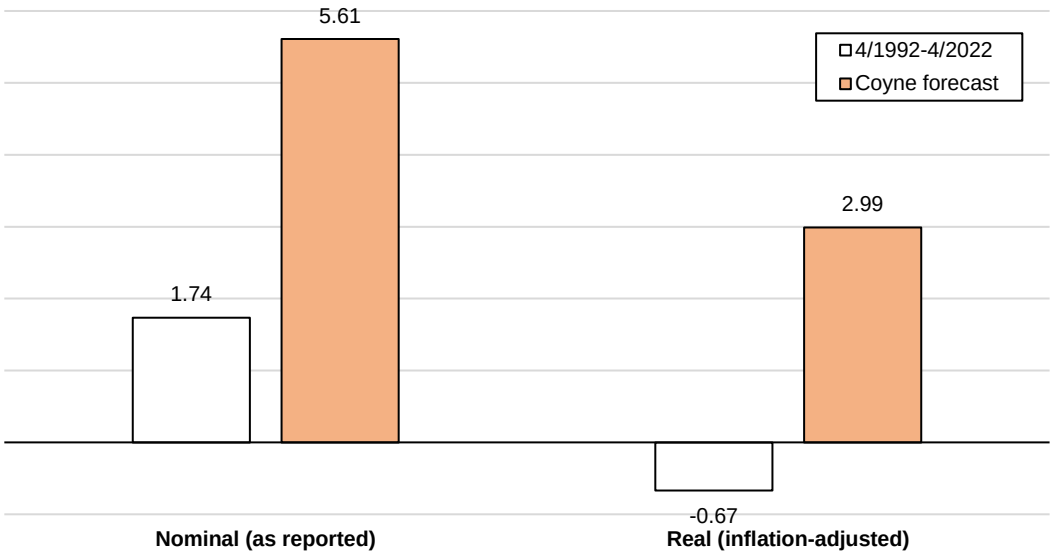
A. Analyst earnings (and, by assumption, dividend) growth forecasts tend to be higher than the companies' long-term historical results, additional evidence that analysts' 3-to-5-year growth forecasts are not sustainable into perpetuity and are therefore unreasonable assumptions in a CG DCF model.

Figure 14 compares the proxy group average growth forecasts to their historical 30-year (1992-2022) DPS compound annual growth rates (CAGR). On average, forecast rates are approximately 4% higher, in both nominal (as reported) and real (inflation-adjusted) terms, than the historical average. The ~4% difference between historical and forecast growth highlights the unreasonableness of assuming analysts' estimates into perpetuity.[84]

[83] M. Ellis analysis of data provided in GPC data request response STF-BAI-1-1 Attachment Coyne F (Value Line reports for each member of Mr. Coyne's proxy group).

[84] Forecast growth rates are adjusted by the monthly average Treasury-TIPS spread for April 2022, 2.54%, to correspond with Mr. Coyne's analysis.

Figure 14. Proxy group average historical and Coyne forecast dividend per share growth[85]
Percent



Q. GIVEN THE NUMEROUS SHORTCOMINGS OF ANALYSTS' FORECASTS, SHOULD THEY BE USED AT ALL IN DCF MODELS?

A. Discounted cash flow models can be a robust approach to estimating expected returns and are widely used throughout finance. The key shortcoming of the constant-growth version of the DCF model – assuming a relatively short-term growth rate into perpetuity – can be easily remedied by assuming that analysts' estimated growth rates apply only for a limited period, after which they converge toward a market- or sector-average terminal growth rate in a multi-stage DCF model (MS DCF), which I describe in more detail in IV.D below. Despite the various deficiencies in analysts' estimates even in the short-term, they are viewed as the best available estimates of near-term investor expectations. That said, relatively little weight should be placed on them in estimating the cost of equity, and the MS DCF model can weight them more appropriately.

[85] M. Ellis analysis of S&P GMI and U.S. Bureau of Labor Statistics (BLS) data (last accessed October 2, 2022); Ex. JMC-4.

3. Mr. Coyne's flawed DCF results should be disregarded.

Q. WHAT IS YOUR CONCLUSION REGARDING MR. COYNE'S DCF RESULTS?

A. Mr. Coyne's DCF model results should be disregarded completely. While, in principle, a constant-growth DCF model could be used to estimate the cost of equity, Mr. Coyne's implementation is deeply flawed. Its dividend yield calculations use excessively long historical price data series, introducing upward bias into the results. More critically, Mr. Coyne's DCF unrealistically assumes analysts' EPS growth estimates are valid for forecasting dividends into perpetuity. Several analyses demonstrate the invalidity of this assumption: the economic impossibility of sustaining EPS growth forecasts even for one decade, much less into perpetuity; the low correlation between analysts' EPS and DPS growth forecasts; the unknown starting period for analyst growth forecasts and therefore likely inconsistency with the DCF model's starting period; the inconsistency between the CG DCF results and analysts' own implied expected return estimates; and the wide disparity between analyst forecasts and utilities' long-term historical DPS growth rates.

D. The Multi-Stage DCF should be used instead of the CG DCF because it allows more realistic cash flow projections, yielding more accurate results.

1. The multi-stage DCF model enhances the CG DCF by allowing different dividend growth rates over time.

Q. WHAT IS THE MULTI-STAGE DCF MODEL?

A. The multi-stage DCF model (MS DCF) enhances the CG DCF by allowing different dividend growth rates over time. As we saw previously, analysts' estimated 3-to-5-year growth rates are too high to be sustained in perpetuity, and may be biased. But analyst estimates should not be ignored completely. Analysts' estimated 3-to-5 year growth rates provide useful information about the relative expected growth across companies. Over the long term though, it is reasonable to assume investors expect growth rates, in real terms, to revert to their long-term historical trends. The MS DCF explicitly models different growth rates over time.

The MS DCF can incorporate any number of stages. For equity valuation, a three-stage model is commonly used, in which the initial stage uses analysts' estimates over their 3-to-5-year forecast horizon, and the terminal stage uses the long-term real historical growth rate plus current long-term inflation expectations. In between lies a transition phase, typically 5 to 15

years, in which the growth rate is the simple average of the initial and terminal rates. The MS DCF model can be expressed as:

$$1 = d\frac{1+g_1}{k-g_1}\left(1-\left(\frac{1+g_1}{1+k}\right)^{t_1}\right) + d\left(\frac{1+g_1}{1+k}\right)^{t_1}\frac{1+g_2}{k-g_2}\left(1-\left(\frac{1+g_2}{1+k}\right)^{t_2}\right) + d\left(\frac{1+g_1}{1+k}\right)^{t_1}\left(\frac{1+g_2}{1+k}\right)^{t_2}\frac{1+g_3}{k-g_3}$$

where d is the current dividend yield; g_1, g_2, and g_3 are the initial, transition, and terminal growth rates, respectively (where $g_2 = \sqrt{(1+g_1)(1+g_3)} - 1$);[86] t_1 and t_2 are the initial and transition stage durations; and k is the cost of equity such that the equation is true. Substantial precedent exists for the MS DCF model, in both its two- and three-stage forms, in both corporate finance and regulatory contexts.[87]

In my implementation of the MS DCF, I assume an initial growth stage of three years – the low end of analysts' EPS growth rate forecast horizon, to mitigate the effect of their upward bias – and a 10-year transition. To account for the quarterly distribution of dividends, I convert the reported rates to quarterly and multiply the number of periods in the initial and transition phases by 4.[88] The dividend yield is the most recent quarterly dividend divided by the average price over December 2021.

2. The MS DCF's initial growth rate can be estimated from analysts' EPS growth forecasts.

Q. HOW DO YOU ESTIMATE THE INITIAL GROWTH RATE FOR THE MS DCF?

A. I use an average of analysts' EPS growth forecasts from S&P Global Market Intelligence (S&P GMI), Yahoo! Finance, and Zacks.

3. The MS DCF's terminal growth rate can be estimated from expected inflation, based on utilities' long-term historical dividend growth.

Q. HOW DO YOU ESTIMATE THE TERMINAL GROWTH RATE FOR THE MS DCF?

A. The terminal growth rate is intended to reflect a sector-wide dividend growth rate toward which all stocks in the peer group are expected to converge over the long term. Figure 15 shows real

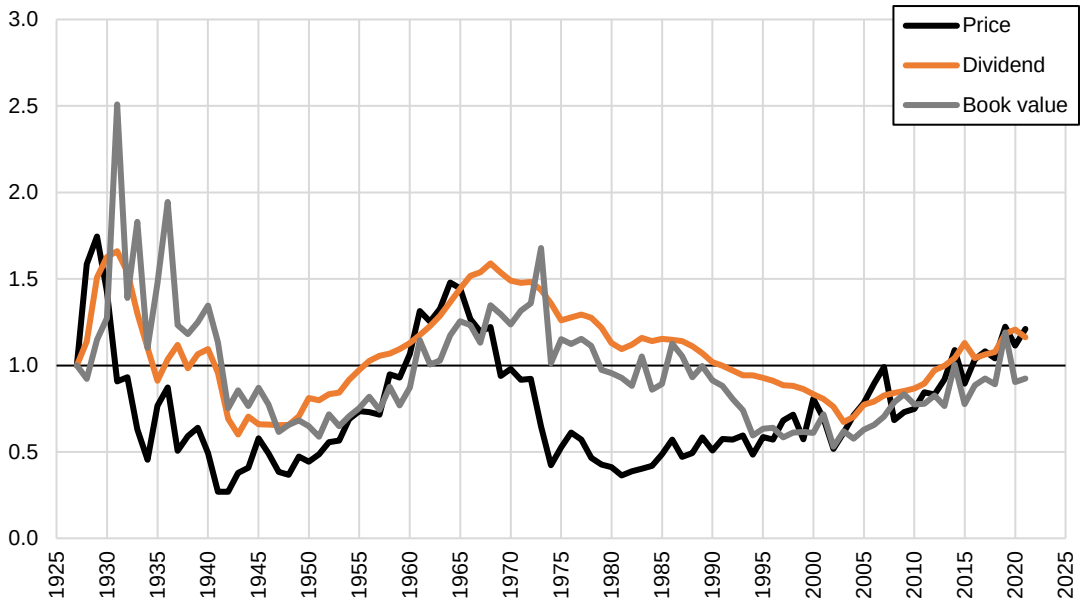
[86] The geometric mean of g_1 and g_3 is used to ensure consistency between annual and quarterly versions of the model.

[87] *See, e.g.*, RICHARD BREALEY, STEWART MYERS, FRANKLIN ALLEN, PRINCIPLES OF CORPORATE FINANCE, MCGRAW HILL/IRWIN 10TH ED. at 83-88 (2010).; Surface Transportation Board, *Use of a multi-stage discounted cash flow model in determining the railroad industry's cost of capital*, 73 Fed. Reg. 47642, 47642-47644 (2008) https://bit.ly/3s9fIMT.

[88] All rates are converted from annual (r_a) to quarterly (r_q) using the formula: $r_q = (1+r_a)^{\frac{1}{4}} - 1$.

utility-sector dividend, price, and book value per share from 1927 through 2020. While there have been periods of growth and decline, the long-term trend for both has been in line with inflation for over 90 years. Based on this long-term history, the terminal growth rate in the MS DCF for the GPC proxy group is assumed to be equal to long-term inflation.

Figure 15. Utility sector real dividend and book value per share, 1927-2021[89]
1927=1.0



For the market as a whole, long-term real DPS growth has tracked GDP per capita, about 1.9% per year.[90] At any given time, some sectors grow faster, some slower. The technology and healthcare industries, for example, have sustained DPS growth rates higher than the market average for decades. Utilities are a mature industry, though, and end-use demand for electricity, gas, and water has grown more slowly than GDP for decades, so it is not unreasonable for utility companies' per-share dividend growth to lag the market as whole. The long-term track record of essentially zero real dividend growth further highlights the unreasonableness of Mr. Coyne's assumption that analyst growth forecasts can be sustained into perpetuity.

[89] M. Ellis analysis of FDL and BLS data (both last accessed October 2, 2022).
[90] *See, e.g.*, ROGER IBBOTSON, JAMES HARRINGTON, STOCKS, BONDS, BILLS, AND INFLATION 2021 SUMMARY EDITION, CFA INSTITUTE RESEARCH FOUNDATION BOOKS at 157-60 (2021) (analysis is for total payout to account for the effect of net stock repurchases).

Q. HOW DO YOU ESTIMATE EXPECTED LONG-TERM INFLATION?

A. For expected long-term inflation, I use Treasury-TIPS spreads. TIPS are Treasury Inflation-Protected Securities, which provide investors a return equivalent to inflation plus the quoted TIPS yield. The difference in yield between Treasurys and TIPS of equal maturity is a current measure of the market's forward-looking inflation expectation over the life of the bonds.

The MS DCF uses inflation for the terminal, not initial or transition, growth rate, so inflation into perpetuity is estimated at the end of the transition phase, not from today. I use the expected inflation, i_{lt}, rate over the period from 20 to 30 years from now, as implied by the difference in the 30-year and 20-year Treasury-TIPS spreads:

$$i_{lt} = \left(\frac{(1+i_{30})^{30}}{(1+i_{20})^{20}}\right)^{\frac{1}{10}} - 1$$

Using average Treasury yields for the month of September 2022, the long-term inflation estimate is 1.45%.[91]

4. <u>The MS DCF produces COE estimates substantially lower than Mr. Coyne's CG DCF.</u>

Q. WHAT ARE YOUR MS DCF COE RESULTS?

A. Figure 16 summarizes the MS DCF results for the GPC proxy group. The average COE for the GPC proxy group is 6.0% – substantially lower than Mr. Coyne's corresponding CG DCF average results of 8%-10%.[92]

[*Remainder of page intentionally left blank.*]

[91] M. Ellis analysis of FRED data (last accessed October 2, 2022).
[92] 2022 Rate Case Hr'g Tr. Vol. 1 at 656 (Sept. 28, 2022).

Figure 16. GPC proxy group multi-stage discounted cash flow COE[93]
As of September 2022

Utility	Price	DPS	Yield %	Initial growth rate (%) S&P GMI	Yahoo!	Zacks	Average	COE %
ALLETE	57.42	2.60	4.53	6.11	8.70	8.15	7.65	8.25
Alliant	60.19	1.71	2.84	6.03	6.30	6.16	6.16	5.50
Ameren	90.72	2.36	2.60	7.25	6.37	7.20	6.94	5.36
AEP	99.21	3.12	3.14	6.25	6.25	6.11	6.20	5.92
Duke	104.95	4.02	3.83	5.64	5.62	6.09	5.78	6.70
Edison Int'l	66.00	2.80	4.24	4.15	4.35	2.97	3.82	6.61
Entergy	113.82	4.04	3.55	6.13	6.19	6.76	6.36	6.50
Evergy	66.72	2.29	3.43	6.37	3.71	5.24	5.11	6.00
Hawaiian Electric	38.13	1.40	3.67	5.28	1.30	2.57	3.05	5.73
IDACORP	107.90	3.00	2.78	4.62	2.70	2.67	3.33	4.78
NextEra	85.43	1.70	1.99	9.88	9.35	9.66	9.63	5.03
OGE	40.35	1.64	4.06	1.50	1.90	3.47	2.29	5.96
Portland General	49.99	1.81	3.62	4.25	3.16	4.63	4.01	5.93
Xcel	72.91	1.95	2.67	6.12	7.04	6.43	6.53	5.37
Mean			**3.36**				**5.49**	**5.97**

Q. DO YOU USE THE MS DCF ELSEWHERE IN YOUR ANALYSIS?

A. Yes. I use it as one of two methods to estimate the market risk premium for the CAPM.

E. Mr. Coyne makes unrealistic, upwardly biased assumptions for all three inputs into his CAPM.

Q. WHAT IS THE CAPITAL ASSET PRICING MODEL?

A. Mr. Coyne's analysis incorporates another well-known COE model, the capital asset pricing model (CAPM). It estimates the cost of equity, k, from the formula:

$$k = r_f + \beta(r_m - r_f)$$

where r_f is the risk-free rate (typically a long-term U.S. Treasury), r_m is the expected return on the market, and β is a measure of risk of the company in question relative to the market. The market risk premium (MRP), the difference between the market return and the risk-free rate, $r_m - r_f$, reflects the additional return investors require as compensation for taking on equity market risk. The CAPM is a simple model of the fundamental financial risk-reward trade-off: investors demand higher returns as risk increases.

[93] S&P GMI; Refinitiv via Yahoo! Finance (https://finance.yahoo.com/); Zacks (https://www.zacks.com/) (last accessed October 2, 2022).

1. The source of Mr. Coyne's risk-free rate assumption has a long and widely known track record of upwardly biased interest rate forecasts.

Q. WHAT RISK-FREE RATE DOES MR. COYNE USE IN HIS CAPM?

A. Mr. Coyne uses the 30-year Treasury (T30). Because the models estimate the expected return on equity, which is a claim on cash flows into perpetuity, the longest-term rate available should be used. The 30-year Treasury is the longest-term risk-free rate, so the T30 is an appropriate term. Mr. Coyne calculates his CAPM COE estimates using both recent historical average and forecast Treasury rates.

Q. DO YOU HAVE ANY CONCERNS WITH MR. COYNE'S RISK-FREE RATE ESTIMATES?

A. Yes, I have two concerns. First, as with the average price calculation for the dividend yield in his DCF model, Mr. Coyne's historical T30 averaging period, 30 days, is too long. Curiously, Mr. Coyne provides no explanation for the use of different averaging periods in the two different models. One month of trading data, typically 20-22 days, is sufficient. Nonetheless, the difference in trailing averaging periods for interest rates generally does not introduce any bias in the results because, unlike stock prices, which tend to exhibit an upward trend over time, daily movements interest rates are random.

Q. WHAT IS YOUR SECOND CONCERN WITH MR. COYNE'S RISK-FREE RATE ESTIMATES?

A. My second concern involves his use of a forecast rate. Using a forecast rate creates inconsistencies with the time horizon of the DCF, which is estimated as of today (or, more precisely, as of the end of the trailing price averaging period). The mathematical formula for the present value of a periodic time series upon which the DCF is based discounts the stream of future cash flows to a "time zero" one period before the first payment. The resulting discount rate is as of that time zero. The first payment in the DCF model is typically assumed to occur one time step from today; therefore, the rate determined by the DCF model is as of today. Using an interest rate expected at some future date in the CAPM produces a COE as of that future date, not today, and that COE is not directly comparable to the DCF's COE.

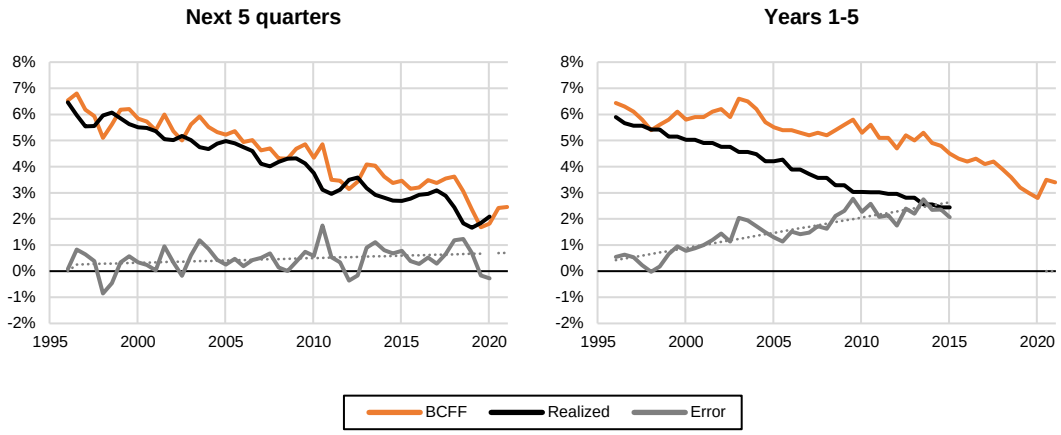
Ignoring the consistency concern, even if we did want to use a forecast rate, in general, commonly available interest rate forecasts are no better predictors of future interest rates than the current market rate. Most importantly, though, I am particularly concerned about Mr.

Coyne's chosen source for his interest rate forecast, Blue Chip Financial Forecasts (BCFF). BCFF's 30-year Treasury forecast has an exceptionally poor track record.

Q. HOW ACCURATE HAVE THE BLUE CHIP FINANCIAL FORECASTS 30-YEAR TREASURY FORECASTS BEEN IN THE PAST/HISTORICALLY?

A. BCFF has a multi-decade track record of producing systematically upwardly-biased forecasts, and the errors have only increased over time. Figure 17 compares the BCFF forecasts used by Mr. Coyne – the average of the next five quarters and years one to five – to their corresponding future average realized rates, going back to BCFF's first long-range forecast in December 1996. The chart shows that BCFF's 30-year Treasury forecasts have consistently overestimated future rates, and the forecast errors have tended to increase over time.

Figure 17. BCFF 30-year Treasury forecast vs. average realized rate[94]



Q. HOW DOES MR. COYNE JUSTIFY HIS USE OF FORECASTS WITH SUCH A POOR TRACK RECORD?

A. Mr. Coyne cites a Massachusetts regulatory decision to argue that "Blue Chip Financial Forecasts is widely relied on by investors and provides a useful proxy for investor expectations for the risk-free rate."[95] BCFF may be relied upon by *some* investors, but no basis exists for Mr. Coyne's claim that BCFF forecasts represent a reasonable proxy for investor expectations.

[94] M. Ellis analysis of BCFF and FRED data. From June 2002 through June 2005, BCFF forecast the long-term average of the 20-year Treasury instead of the 30-year. Those forecasts are used in this analysis and compared to subsequent actual 20-year Treasury rates.

[95] 2022 Rate Case Hr'g Tr. Vol. 1 at 660 (Sept. 28, 2022).

BCFF has no more than a hundred thousand subscribers,[96] less than 0.1% of the hundreds of millions of investors who are exposed to Treasury rates through direct investments or as a benchmark for other investments.[97] Although utility cost of capital experts routinely argue that these forecasts represent the "market's view," 0.1% in no way represents the market. The hundreds of millions of market participants respond to all kinds of information, and the small slice of the market used by Mr. Coyne, via BCFF, does not represent an adequate or reasonably proxy.

Mr. Coyne's argument also implicitly assumes that investors rely *only* on BCFF forecasts, to the exclusion of all other ways that investors might develop their expectations; that they rely on BCFF's forecasts as-is, with no adjustment for their historical inaccuracy; and that investors' only use of the forecasts is for investment decisions. None of Mr. Coyne's assumptions is true. The consistent errors in BCFF forecasts are well-known; the Congressional Budget Office has issued public reports on BCFF's interest rate forecasting errors for nearly twenty years.[98] Many investors undoubtedly take BCFF's forecasts "with a grain of salt" and inform their decisions with other forecasts and information. Finally, BCFF reports include dozens of other forecasts, as well as commentary and analysis. Investors might "rely" on the reports for that other content, not BCFF's interest rate forecasts, per se.

Q. SUPPOSE WE IGNORED THE CONCERN YOU EXPRESSED ABOUT CONSISTENCY WITH THE DCF AND WANTED A FORECAST RISK-FREE INTEREST RATE ASSUMPTION FOR THE CAPM. WHAT SHOULD WE USE?

A. It turns out that current interest rates generally provide an unbiased forecast of future rates. Figure 18 is a cross-plot of the 20-year Treasury rate one year ahead against the current rate. Current interest rates account for approximately 91% of the variation in future interest rates;

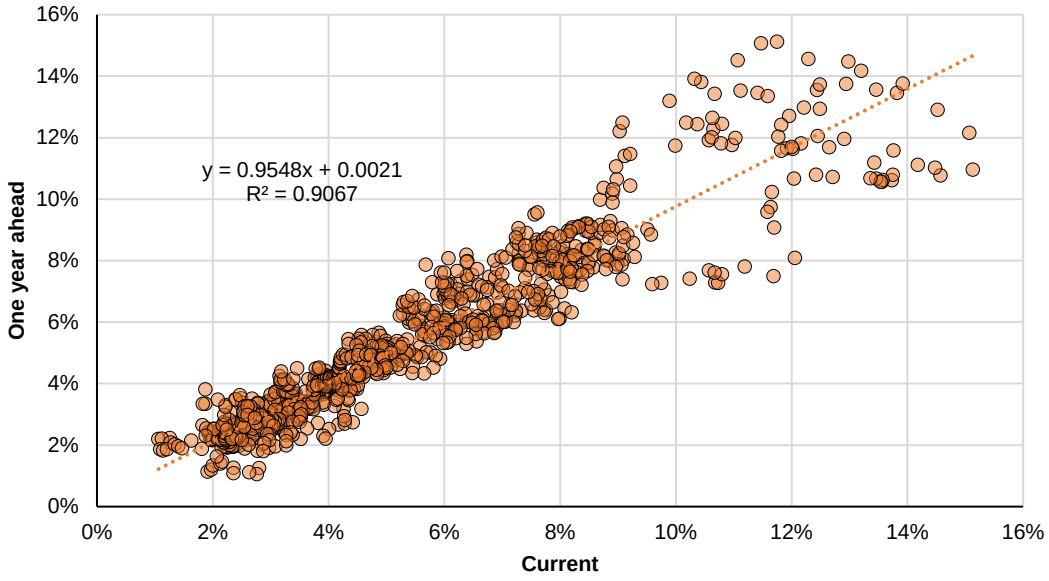
[96] In the 2020 annual report of Wolter Kluwers, BCFF's owner, $905 million of revenue was attributed to the Legal & Regulatory segment, of which BCFF is just 1 of 99 offerings. *See* https://www.wolterskluwer.com/en/legal/our-solutions. BCFF costs approximately $2,500/year. Even assuming BCFF accounts for 10% of segment revenue – roughly ten times the segment average – BCFF has no more than 40,000 subscribers.

[97] More than half of U.S. adults and households are invested in the stock market. *See, e.g.*, Kim Parker and Richard Fry, *More than half of U.S. households have some investment in the stock market*, Pew Research Center (March 25, 2020), https://www.pewresearch.org/fact-tank/2020/03/25/more-than-half-of-u-s-households-have-some-investment-in-the-stock-market/; Lydia Saad and Jeffrey Jones, *What Percentage of Americans Owns Stock*, Gallup (May 12, 2022), https://news.gallup.com/poll/266807/percentage-americans-owns-stock.aspx.

[98] *See, e.g.*, Congressional Budget Office, *CBO's Economic Forecasting Record* at 13, 18 (Nov. 2002), https://www.cbo.gov/sites/default/files/107th-congress-2001-2002/reports/11-07-economicforecast.pdf.

for rates two years in the future, current interest rates explain 83% of the variation in future interest rates, and for rates in three years, current interest rates explain 79%. Regardless of the forecast horizon, the current rate is unbiased – exhibiting no tendency to be systematically too high or too low.[99] Similar predictive validity is obtained for 30-year Treasury and corporate bonds.[100]

Figure 18. Twenty-year Treasury rate, one year in the future vs. current[101]
January 1925-September 2022



More intuitively, markets are forward-looking. If investors expect interest rates to rise, their expectations will be incorporated into current yields. Consider the alternative. Suppose an investor expects the yield on the 30-year Treasury to rise from its current ~3% to 4% over the next six months. There is an inverse relationship between a bond's value and a bond's yield; when the yield rises, the value falls, and vice versa. An investor who expects bond yields to rise would not buy a bond today, because to do so would be to invest expecting a loss; better not to buy the bond at all. But market participants *do* buy at the current 3%, implying that the

[99] The bias in a forecast can be assessed from the decomposition of the mean square error into bias, inefficiency, and random variation components. For the 20-year Treasury, bias accounts for less than 0.2% of forecast error at all three forecast horizons. *See, e.g.*, Jacob Mincer and Zarnowitz, *The Evaluation of Economic Forecasts*, Economic Forecasts and Expectations: Analysis of Forecasting Behavior and Performance at 3-46 (NBER, 1969), http://www nber.org/chapters/c1214.

[100] The 20-year Treasury is used here because much more historical data are available.

[101] M. Ellis analysis of FRED data (last accessed October 2, 2022).

market overall does *not* expect rates to rise in the future. Current yields are the best predictor of future yields, especially for longer-term bonds.

The predictive validity of current rates has been acknowledged among utility cost of capital experts. Reviewing the academic research, Roger Morin, author of the frequently cited practitioner text, *New Regulatory Finance*, concludes, "The literature suggests that on balance, the bond market is very efficient in that it is difficult to consistently forecast interest rates with greater accuracy than a no-change [from the current interest rate] model."[102]

BCFF's consistently poor track record, the high predictive validity of current interest rates, and economic intuition are consistent with an extensive body of research on the superiority of simple prediction models to both more complex models and expert judgment.[103]

Current interest rates are the most accurate and unbiased publicly available estimates for future interest rates that I am aware of. Conveniently, using the current rate also entirely skirts the potential concern about horizon inconsistency with the DCF.

2. Mr. Coyne cherry-picks his beta calculation methodology, ignoring the wide variety of valid potential approaches and best practice for choosing among them.

Q. HOW DOES MR. COYNE ESTIMATE THE BETA IN HIS CAPM MODEL?

A. Mr. Coyne uses beta estimates from two different financial data providers, Value Line and Bloomberg. He uses Value Line's betas as reported. Mr. Coyne overrides Bloomberg's default settings and uses only a subset of the beta estimates Bloomberg provides, such that the calculation methodology and resulting beta estimates he reports for Bloomberg are very similar to Value Line's.

Importantly, Mr. Coyne selects two nearly identical beta calculation methodologies among the multitude of methodologies commonly used by practitioners and academics, specifically the two that currently tend to produce the highest results.

Q. HOW DO BLOOMBERG AND VALUE LINE ESTIMATE THEIR BETAS?

A. Both Bloomberg and Value Line estimate beta from the slope of a linear regression model of a stock's returns against the returns of the market overall. Both calculate "raw" betas from a

[102] ROGER A. MORIN, NEW REGULATORY FINANCE, PUB. UTIL. REPORTS at 172 (2006).
[103] *See, e.g.*, DANIEL KAHNEMAN, OLIVIER SIBONY, CASS SUNSTEIN, NOISE: A FLAW IN HUMAN JUDGMENT, HACHETTE BOOK GROUP at 111-147 (2021).

regression of trailing weekly, price-only returns of the stock in question against the corresponding market returns. Both also report "Blume-adjusted" betas – a weighted-average of approximately 2/3 of the raw beta and 1/3 of the market average of 1.0 – to correct for an empirically observed tendency for betas, on average, to regress toward the market mean over time that I discuss in more detail below.[104] Other details of their respective methodologies differ, which is why their beta estimates are not exactly the same even after Mr. Coyne's modifications to Bloomberg's defaults. Figure 19 summarizes the key elements of Value Line's and Bloomberg's beta estimation methodologies.

Figure 19. Value Line and Bloomberg beta estimation methodologies[105]

Parameter	Value Line	Bloomberg (default)
Return frequency	Weekly	Weekly
Trailing history	5 years	2 years
Index	NYSE Composite	S&P 500
Return calculation		
Price-only/total	Price-only	Price-only
Excess/absolute	Absolute	Absolute
Simple/logarithmic	Logarithmic	Simple
Blume adjustment parameters	0.65 x raw + 0.37	None (unadjusted) 2/3 x raw + 1/3
Rounding	Nearest 0.05	None
Updating frequency	Approximately quarterly	Daily

Q. MR. COYNE WRITES, "[I]T IS IMPORTANT TO EMPHASIZE THAT BETA COEFFICIENTS ARE CALCULATED OVER A FIVE-YEAR PERIOD." IS FIVE YEARS OF WEEKLY RETURNS WITH THE BLUME ADJUSTMENT THE ONLY WAY TO CALCULATE BETA?

A. No. Academic studies commonly use five years of *monthly* returns, without the Blume adjustment. Other financial data providers, including some used by Mr. Coyne elsewhere in his analysis, calculate beta using different trailing histories, return frequencies, and without the Blume adjustment. Yahoo! Finance and Zacks – data sources for some of Mr. Coyne's other

[104] Value Line reports only the Blume-adjusted beta. Bloomberg reports both raw and adjusted beta.

[105] Value Line, "Estimation of Beta by Value Line"; Bloomberg Professional Workstation Guide; "BETA, HRA, BETA, HRA, and CORR Calculation FAQs." Simple price-only returns: $r = \frac{P_{t+1}}{P_t} - 1$; logarithmic price-only returns: $r = \ln \frac{P_{t+1}}{P_t}$.

cost of capital analyses[106] – use five years of monthly returns and are unadjusted, like many academic studies. S&P Global Market Intelligence (S&P GMI), another data source frequently cited by Mr. Coyne,[107] reports 1- and 3-year betas using daily returns, also without the Blume adjustment.[108]

Bloomberg's default trailing history is 2 years. Bloomberg allows users to override several of its calculation parameters, such as the trailing history, market index, and return frequency. Bloomberg also reports both raw and adjusted beta by default. Mr. Coyne apparently overrode Bloomberg's default trailing history parameter and simply ignored its raw beta estimates to arrive at the Bloomberg betas used in his CAPM, which are nearly identical to those provided by Value Line.

Figure 20 lists recent betas from S&P GMI, Yahoo! Finance, and Zacks for Mr. Coyne's GPC proxy group. The average betas are 0.43 and 0.76 for S&P GMI using 1 and 3 years of daily returns, and 0.48 for Yahoo! Finance and Zacks, both using 5 years of monthly returns. All four sources' beta estimates are lower than Mr. Coyne's 0.85-0.88 figures.[109]

Figure 20. S&P GMI, Yahoo! Finance, and Zacks betas[110]
As of September 30, 2022

Utility	Ticker	S&P GMI 1-year daily	S&P GMI 3-year daily	Yahoo! Finance 5-year monthly	Zacks 5-year monthly
ALLETE	ALE	0.44	0.88	0.61	0.61
Alliant	LNT	0.39	0.66	0.46	0.47
Ameren	AEE	0.40	0.72	0.36	0.35
AEP	AEP	0.42	0.61	0.34	0.34
Duke	DUK	0.32	0.71	0.35	0.35
Edison Int'l	EIX	0.53	0.82	0.68	0.67
Entergy	ETR	0.42	0.84	0.57	0.57
Evergy	EVRG	0.44	0.84	0.48	0.48
Hawaiian Electric	HE	0.41	0.66	0.32	0.32
IDACORP	IDA	0.38	0.73	0.56	0.56
NextEra	NEE	0.68	0.84	0.46	0.46
OGE	OGE	0.44	0.77	0.65	0.67
Portland General	POR	0.34	0.81	0.52	0.51
Xcel	XEL	0.37	0.68	0.35	0.34
Mean		**0.43**	**0.76**	**0.48**	**0.48**

[106] Mr. Coyne uses Yahoo! Finance and Zacks EPS growth rates in his DCF model. *See* Ex. JMC-4.
[107] *See, e.g.*, Ex. JMC-9.
[108] M. Ellis analysis of S&P GMI data.
[109] Ex. JMC-5.2.
[110] M. Ellis analysis of S&P GMI data; Yahoo! Finance; Zacks.

Q. WHY DO BLOOMBERG AND OTHER FINANCIAL DATA PROVIDERS USE DIFFERENT BETA CALCULATION METHODOLOGIES, PROVIDE MULTIPLE ESTIMATES, AND ALLOW USERS TO OVERRIDE THEIR DEFAULTS?

A. Beta is intended to be a *forward-looking* measure of relative risk, so it is inherently uncertain. It cannot be measured directly (like an interest rate) and is usually estimated from *historical* data, as the slope of the regression of the returns of a stock against the returns of the market over a recently-ended historical period. Estimates based on historical data generally reasonably reflect future expectations, because most companies' risk profiles change slowly over time. Slowly changing risk profiles prove particularly true for the relatively stable and predictable utility sector.

But if a dramatic change in the market or in individual stocks occurs, as in the pandemic-related market turmoil of early 2020, that change will influence the beta estimate for as long as the period of change is included in the trailing data used in the beta calculation, even if investors' risk perceptions have returned to their level prior to the dramatic change. Analysts should always examine whether the change in market conditions was temporary or is sustained. Mr. Coyle's analysis suffers from his failure to examine whether the pandemic-related change in market conditions was temporary or has been sustained.

Q. HOW CAN WE DETERMINE WHETHER THE CHANGE IN INVESTORS' RISK PERCEPTIONS WAS TEMPORARY OR HAS BEEN SUSTAINED?

A. Determining whether the change in investors' risk perception was temporary or has been sustained is typically done by examining how betas calculated using different amounts of trailing data and returns calculated at different frequencies – for example, daily, weekly, or monthly – have changed over time.

Q. IS THE NEED TO ESTIMATE BETA USING DIFFERENT METHODOLOGIES WELL KNOWN?

A. Yes. Utility cost of capital expert witnesses Michael Vilbert and Bente Villadsen have written about the trade-offs of different methodologies, highlighting the need to consider shorter calculation intervals in the wake of abrupt disruptions such as was experienced first during and then immediately after the pandemic-driven bout of market turmoil in early 2020:

> The choices for the interval for the return data and the length of the beta estimation window involve trade-offs between obtaining more observations through the choice of a longer window and/or more frequent return data, ensuring that no structural change has occurred during the estimation window, and avoiding problems due to insufficient trading activity. … Balancing these considerations, economists typically recommend estimating beta using daily, weekly, or monthly returns over the most recent 2- to 5-year period, with weekly being the more common, *except if there are reasons to think that the industry might be subject to recent changes in systematic risk so that the use of a more recent data window is desirable*.[111]

The need to examine beta using different calculation methodologies is also reflected in data providers' offerings. As explained previously, Bloomberg allows users to easily override its default beta calculation parameters. S&P GMI, in addition to reporting betas calculated using 1 and 3 years of trailing data, provides its users with spreadsheet models that allow them to modify all of its beta calculation parameters.

In using both Value *and* Bloomberg betas, Mr. Coyne implicitly acknowledges that no single beta calculation methodology necessarily reflects current investor expectations. But the differences in the Value Line and (modified) Bloomberg beta methodologies he uses are immaterial. Their different market indexes – NYSE Composite for Value Line, S&P 500 for Bloomberg – are nearly perfectly correlated (0.96 correlation[112]), and their slightly different Blume adjustment weights yield differences in beta of 2% or less across the range of typical raw utility betas (0.4-1.0). Mr. Coyne's chosen methodologies hardly reflect the wide range of ways beta could be calculated, each of which could produce dramatically different results. As Nobel laureate Fischer Black, one of the pioneers of empirical testing of beta and the CAPM, famously admonished, "Watch out for data mining!"[113] – running an analysis several different ways but reporting only the outcomes that support one's conclusions.

[111] BENTE VILLADSEN, MICHAEL J. VILBERT, DAN HARRIS, LAWRENCE KOLBE, RISK AND RETURN FOR REGULATED INDUSTRIES, ACADEMIC PRESS at 73-76 (2017) (emphasis added).

[112] Correlation between five years of weekly, simple, price-only, absolute returns for the S&P 500 and NYSE Composite Indexes, through February 25, 2022. M. Ellis analysis of S&P GMI data.

[113] Fischer Black, *Beta and Return*, 20(1) J. Portfolio Management 8 (1993), https://jpm.pm-research.com/content/20/1/8.

Q. WHICH METHODOLOGICAL DIFFERENCES ACCOUNT FOR THE MOST VARIATION IN BETA ESTIMATES?

A. The largest potential sources of variation in beta estimates arise from their trailing return history duration, return calculation frequency, and Blume adjustment parameters.

Q. HOW DOES THE DURATION OF TRAILING RETURN HISTORY AFFECT BETA ESTIMATES?

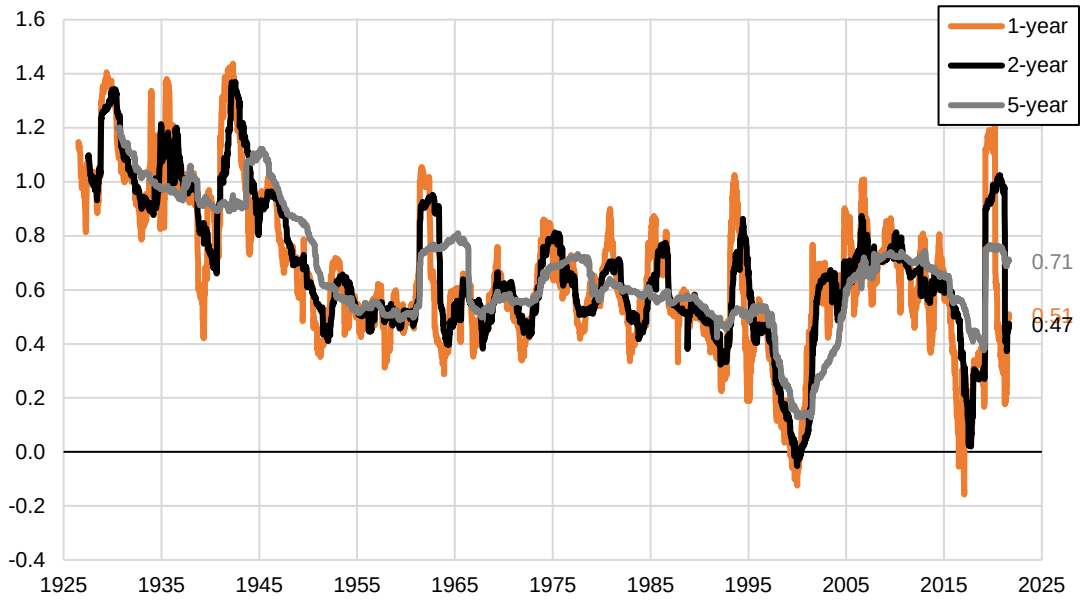
A. Following bouts of high market volatility, such as was experienced in the early days of the pandemic in February and March 2020, betas will be affected as long as the trailing history includes the volatile period, even if market conditions have stabilized. For example, S&P GMI reports unadjusted betas calculated from both 1 and 3 years of daily returns.[114] As of July 27, 2022, the average 1-year beta for the proxy group, which does not include the volatile period, was 0.28; the average 3-year beta, which does include the volatile period, was 0.72.[115] For comparison, on the same day, Yahoo! Finance's and Zacks's group average 5-year unadjusted betas using monthly returns were 0.45.[116]

Figure 21 plots the raw beta for the entire utility sector using 1, 2, and 5 years of weekly returns from June 1926 through May 2022. At any given time, beta can be very sensitive to the trailing history used. As of the end of August 2022, the betas using the 1-, 2-, and 5-year trailing histories were 0.51, 0.47, and 0.71, respectively.

[*Remainder of page intentionally left blank.*]

[114] Personal correspondence with S&P GMI (November 2021).
[115] M. Ellis analysis of S&P GMI data (last accessed October 2, 2022).
[116] M. Ellis analysis of Yahoo! Finance data (last accessed October 2, 2022); Zacks data (last accessed October 2, 2022).

Figure 21. Utility sector raw beta – trailing return history sensitivity[117]
July 1926-August 2022



In general, betas calculated using longer return histories tend to be the more stable over time, as the effect of any short-term period of volatility is reduced by longer surrounding periods of stability. Because utility cost of capital proceedings seek a relatively long-term estimate, it might be tempting to conclude that a longer trailing history is preferred in estimating a utility's beta for purposes of authorizing an ROE. As Vilbert and Villadsen astutely recommend, though, "if there are reasons to think that the industry might be subject to recent changes in systematic risk … the use of a more recent data window is desirable."[118] The current 5-year beta of 0.71, driven by the market turmoil of early 2020, is higher than its historical average since 1955 of approximately 0.55. The 1- and 2-year betas, at 0.51 and 0.47, respectively, are in-line with their long-term historical averages. After the brief period of unusual market volatility in early 2020 not seen since the World War II era, investor perceptions of utility risk quickly settled to their pre-pandemic levels. Because of their shorter trailing histories, the 1- and 2-year betas are more reflective of *current* investor sentiment.

Figure 21 also betrays Mr. Coyne's claim that "the recent movement in betas captures a trend that began five years ago but has been accelerated by the recent market conditions" and

[117] M. Ellis analysis FDL (last accessed July 20, 2022).
[118] BENTE VILLADSEN, MICHAEL J. VILBERT, DAN HARRIS, LAWRENCE KOLBE, RISK AND RETURN FOR REGULATED INDUSTRIES, ACADEMIC PRESS at 73-76 (2017).

that "[t]he substantial increase in Beta coefficients for the proxy group companies represents a significant departure from how investors have typically viewed utilities relative to the broader market and is not just COVID-19 related."[119] Regardless of the duration of the trailing return used, utility sector betas were in a decade-plus-long decline before the pandemic. Once the early-pandemic period of market turmoil fell out of the trailing historical data, as with the 1- and 2-year betas, betas returned to their pre-pandemic levels.

The sharp declines in the 1- and 2-year betas in Figure 21 make it clear that Mr. Coyne's elevated 5-year weekly betas are not valid indicators of current investor expectations but purely artifacts of the inclusion of a transitory and short-term market anomaly.

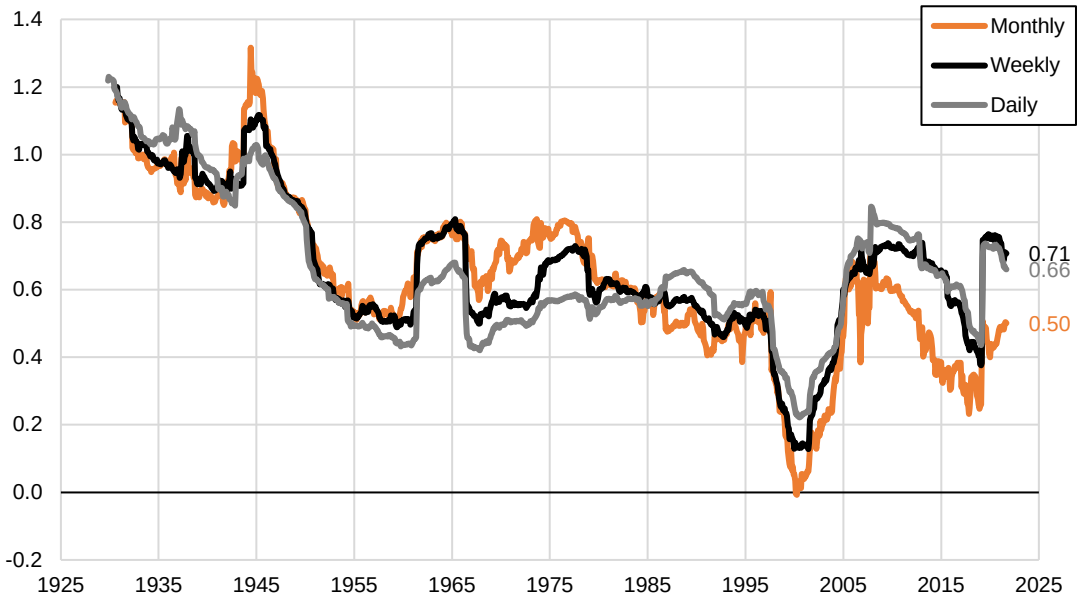
Q. HOW DOES THE FREQUENCY OF RETURN CALCULATION AFFECT BETA ESTIMATES?

A. Figure 22 plots the raw beta for the entire utility sector using 5 years of monthly, weekly, and daily returns from June 1926 through May 2022. As with the trailing history, at any given time, beta can be very sensitive to the return calculation frequency used. As of the end of August 2022, the betas using the monthly, weekly, and daily trailing histories were 0.50, 0.71, and 0.66, respectively. In general, betas tend to be more stable at higher return calculation frequencies. For any given trailing history duration (e.g., 1, 2, or 5 years), shorter return frequencies generate more data for use in the beta calculation: weekly returns generate approximately four times more data than monthly; daily approximately five times more than weekly. As the return frequency increases, any extreme data points are averaged with a larger number of "typical" data points, which tends to mitigate abrupt changes in beta over time.

This finding would tend to recommend using shorter return frequencies, due to their greater stability over time. But the choice of return frequency should reflect the time horizon of the analysis in which the CAPM-derived cost of equity will be used. Utility cost of capital proceedings seek to estimate a cost of equity that applies over a multi-year period. This consideration recommends a longer calculation frequency.

[119] 2022 Rate Case Hr'g Tr. Vol. 1 at 660-61 (Sept. 28, 2022).

Figure 22. Utility sector 5-year raw beta – return calculation frequency sensitivity[120]
July 1926-August 2022



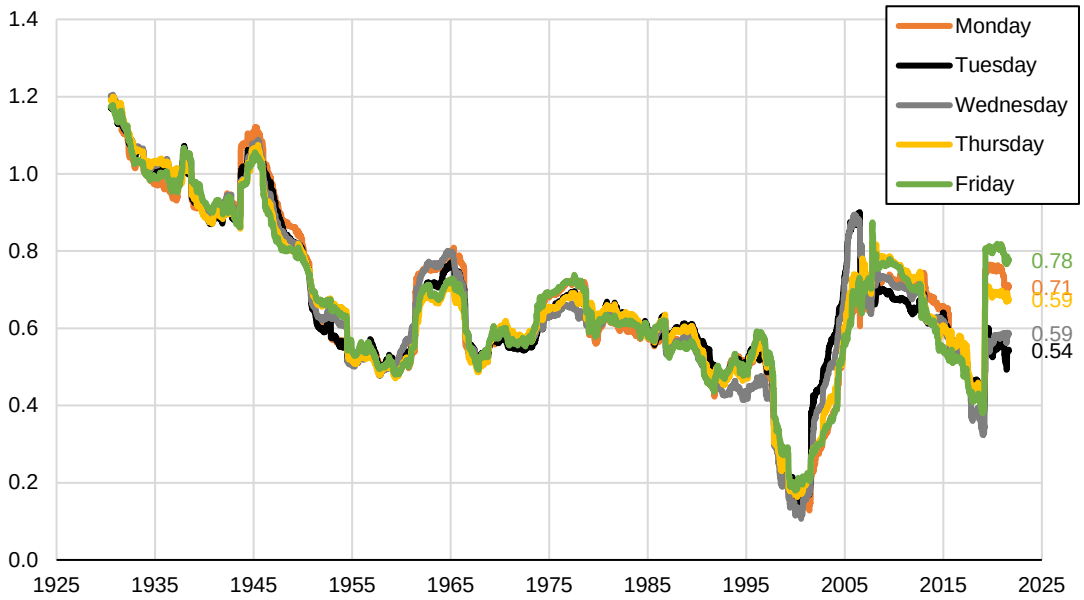
Q. HOW DO OTHER BETA CALCULATION PARAMETERS IMPACT THE VARIATION IN BETA ESTIMATES?

A. Even a beta calculation parameter as seemingly arbitrary as the day of the week on which weekly returns are calculated can materially affect the beta estimate. Figure 23 shows the 5-year trailing beta, i.e., raw Value Line-equivalent, with returns calculated on each weekday. Currently, Friday yields the highest beta, 0.78, but simply changing the calculation day to Tuesday reduces the beta to 0.54, 31% lower. This day-of the-week return calculation effect is only partially mitigated by averaging multiple utilities. The stock prices of individual companies within the sector tend to move together on any given day, so weekly returns calculated on the same day will tend to be similar.

This finding highlights the deficiency in Mr. Coyne's analysis in failing to examine alternative beta calculation methodologies and the potential arbitrariness of his selected methodologies. It also further highlights the need for caution in using the mechanically calculated betas provided by Value Line, Bloomberg, or other financial data providers, particularly betas calculated using weekly returns, without examining how they've changed over time or comparing them to long-term historical averages.

[120] M. Ellis analysis of FDL data (last accessed October 2, 2022).

Figure 23. Utility sector 5-year weekly raw beta – return calculation day sensitivity[121]
July 1926-August 2022



Q. YOU LISTED THE BLUME ADJUSTMENT AS A THIRD SOURCE OF VARIATION IN BETA ESTIMATES. WHAT IS THE ORIGIN OF THE BLUME ADJUSTMENT?

A. The Blume adjustment is based on an analysis conducted by Wharton professor Marshall Blume in the early 1970s. Analyzing beta-sorted portfolios, he found a tendency for betas, on average, to regress toward the market average beta, 1.0, from one time period to the next.[122] Based on this finding, some providers of beta estimates report adjusted betas that are a weighted average of the raw estimate and the market mean. The most common weighting is 2/3 on the raw beta, 1/3 on the market beta (1.0):[123]

$$\beta_{adjusted} = \frac{2}{3}\beta_{raw} + \frac{1}{3}.$$

For stocks with raw betas below 1.0, like most utilities historically, the effect of the adjustment is to increase the beta one-third of the way toward 1.0. For example, a stock with a raw beta of 0.4 would have an adjusted beta of 2/3 x 0.4 + 1/3 = 0.6. For its adjusted beta,

[121] M. Ellis analysis of FDL data (last accessed October 2, 2022).
[122] Marshall E. Blume, *On the Assessment of Risk*, 26:1 J. Finance at 1-10 (1971) https://onlinelibrary.wiley.com/doi/10.1111/j.1540-6261.1971.tb00584.x.
[123] The 2/3 and 1/3 weights are based on the regression coefficients Blume presented in his original paper, which regressed betas in one period against betas in the previous period.

Bloomberg uses the common 2/3 and 1/3 weights. Value Line's weights are similar: 0.67 and 0.35, respectively. Value Line also rounds to the nearest 0.05.[124]

As Vilbert and Villadsen note, "analysts have different views on whether to use raw or adjusted betas,"[125] hence the reporting of unadjusted betas by Bloomberg, S&P GMI, Yahoo! Finance, and Zacks.

Q. IS THE BLUME ADJUSTMENT VALID FOR UTILITIES?

A. No, it is not. The Blume adjustment is based on an observation of the tendency of betas, *on average*, to regress toward 1.0. But not every stock exhibits this tendency. Blume did not investigate whether and how this tendency might vary across stocks with different characteristics.

Rutgers professor Richard Michelfelder investigated the validity of the beta adjustment specifically for utility stocks and found no evidence of the average tendency observed by Blume.[126] This can be clearly seen in Figure 24, which shows the same 7-year monthly beta used by Blume in his original analysis for the entire utility sector going back to 1926. Since the 1950s, the beta for the utility sector as a whole has tended to regress toward 0.50-0.60, not 1.0.[127]

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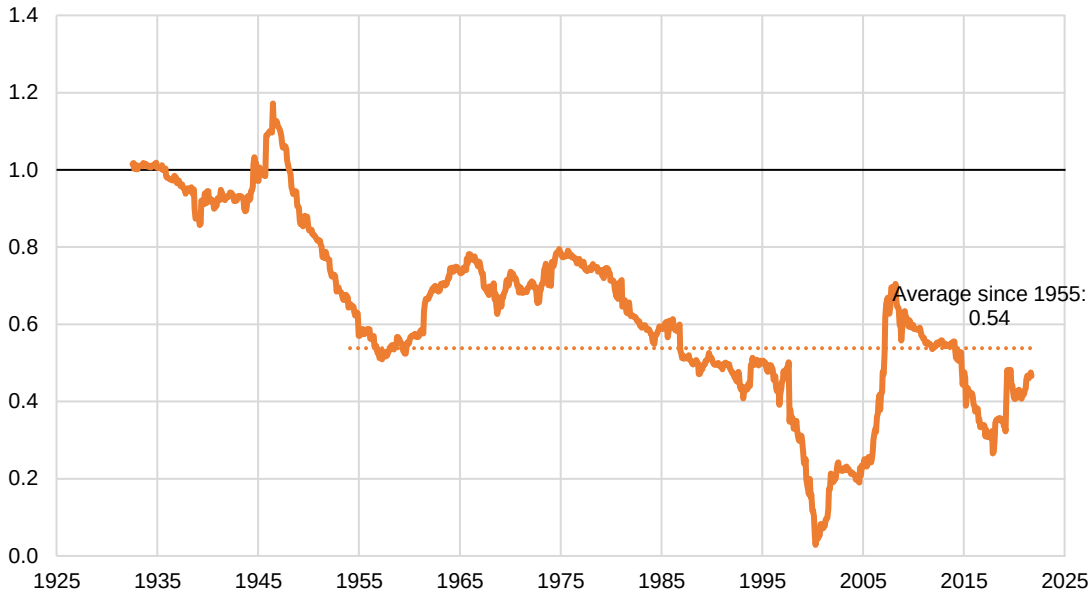
[124] Value Line, "Value Line's Estimation of Beta," personal correspondence (October 6, 2021).

[125] BENTE VILLADSEN, MICHAEL J. VILBERT, DAN HARRIS, LAWRENCE KOLBE, RISK AND RETURN FOR REGULATED INDUSTRIES, ACADEMIC PRESS at 80 (2017).

[126] Richard A. Michelfelder and Panayiotis Theodossiou, *Public Utility Beta Adjustment and Biased Costs of Capital in Public Utility Rate Proceedings*, 26:9 The Electricity Journal at 60-68 (2013).

[127] One might ask whether the utility sector average reflects the tendency of individual utility stocks. Betas are additive, so a tendency for individual utility stocks to regress toward 1.0, on average, would be reflected in the industry beta. Blume used the same logic to extrapolate from the portfolios he analyzed to individual stocks. *See* Eugene F. Fama and Kenneth R. French, *The Capital Asset Pricing Model: Theory and Evidence*, 18:3 J. Economic Perspectives 25, 31 (2004), https://pubs.aeaweb.org/doi/pdfplus/10.1257/0895330042162430.

Figure 24. Utility sector 7-year monthly raw beta[128]
July 1926-August 2022



Blume speculated as to why betas, on average, tend to regress toward 1.0 over time.[129] High-beta firms tend to be newer and smaller; as they mature and grow, they become more risk-averse. In contrast, low-beta firms tend to run out of low-risk investment opportunities and must accept more risk to stay in business. Neither of these causal explanations applies to utility operating companies, like Georgia Power and the publicly traded members of the GPC proxy group. They are large and mature, and their investments tend to have consistently low risk profiles over time. These attributes combine to keep utilities' betas sustainably and significantly below 1.0.

Empirical analysis specifically investigating utility betas, grounded in sound economic reasoning, demonstrates that utility betas do not have a tendency to regress toward the market average and therefore should not be Blume-adjusted.[130]

[128] Market capitalization-weighted average of all NYSE-, AMEX-, or NASDAQ-listed utilities. M. Ellis analysis of FDL data.

[129] Marshall E. Blume, *Betas and Their Regression Tendencies*, 30:3 The Journal of Finance 785-795 (1975), https://onlinelibrary.wiley.com/doi/abs/10.1111/j.1540-6261.1975.tb01850.x.

[130] Blume used mean squared error (MSQ) to assess the accuracy of his adjustment. It can be shown that the standard 2/3 and 1/3 weights increase the MSQ for utility betas by approximately 35%.

Q. WHAT ARE YOUR CONCLUSIONS ABOUT MR. COYNE'S CHOICE OF BETA ESTIMATION METHODOLOGY?

A. The variation in the three most recent beta estimates in Figure 21 suggests we should not unthinkingly use the most recent trailing betas from Value Line, Bloomberg, or any other data provider. It's important to keep in mind that all methodologies are intended to produce *estimates of investors' future expectations*. The elevated current 5-year betas used by Mr. Coyne are artifacts of arbitrary choices of calculation period; there is no reason to believe they reflect investors' current long-term expectations.

The seven-week bout of market volatility in early 2020 was an anomaly, and investor perceptions of utility risk quickly returned to their pre-pandemic levels. The 5-year return history used in Mr. Coyne's beta estimates does not accurately reflect current investor sentiment.

The betas used by Mr. Coyne are inflated because they are (1) Blume-adjusted and (2) incorporate an anomalous period that does not reflect investors' *current, long-term* expectations.

3. Mr. Coyne estimates his market risk premium using a constant-growth DCF model with the same flawed perpetuity growth assumption as his proxy group DCF analysis.

Q. HOW DOES MR. COYNE ESTIMATE THE THIRD ASSUMPTION IN THE CAPM, THE MARKET RISK PREMIUM?

A. Mr. Coyne estimates the market risk premium (MRP) using the same constant-growth discounted cash flow model he uses for the proxy group in his DCF analysis. As detailed in Section IV.C.2 above, Mr. Coyne's fatally flawed implementation of the CG DCF erroneously assumes analysts' 3-to-5-year EPS growth estimates can be sustained into perpetuity, a deficiency of which he is aware. This assumption is invalid for several reasons, perhaps the most compelling of which is that it is simply economically impossible for the market to sustain analysts' forecast growth rates for even a decade, much less forever. Since 1926, U.S. stock market dividend growth has averaged 4.9% (1.9% in real terms)[131] – roughly 40% of the 12.4%-14.2% range assumed by Mr. Coyne.[132] The market has never sustained 12.4% dividend

[131] M. Ellis analysis of FDL data (last accessed October 2, 2022).
[132] Ex. JMC-5.1.

growth for even seven years, much less into perpetuity – certainly raising a legitimate "concern that short term growth rates may not be sustainable over the longer-term." Mr. Coyne nonetheless ignores his own advice and uses the constant growth DCF to estimate his CAPM MRP. Consequently, Mr. Coyne's MRP results beggar belief: at 11.8%-12.5%, they are roughly 2.5 times the long-term historical average of approximately 5%.

4. Mr. Coyne's flawed CAPM results should be disregarded.

Q. WHAT IS YOUR OVERALL ASSESSMENT OF THE CAPM AND MR. COYNE'S IMPLEMENTATION OF IT?

A. The CAPM is conceptually sound and one of the most widely used COE models in corporate finance. But Mr. Coyne's implementation choices – a forecast, not current, risk-free interest rate; a cherry-picked adjusted beta that is not reflective of current market conditions or utilities' long term risk profile; and a flawed MRP model – yields systematically upwardly-biased results. His flawed CAPM results should be disregarded.

F. Implementing the CAPM with more rigorously estimated assumptions produces substantially lower COE estimates.

Q. PLEASE EXPLAIN YOUR IMPLEMENTATION OF THE CAPM.

A. There are three components to the CAPM: the risk-free rate, beta, and the market risk premium. For the risk-free rate I use the current, not forecast, 30-year Treasury rate.

As explained above in Section IV.E.2, beta is the most subjective of the three CAPM parameters, and no single calculation methodology produces the most reasonable estimates in all market conditions. Based on my review of the latest research literature, I use the betas provided by Yahoo! Finance, calculated using five years of monthly returns. Five-year monthly betas are consistent with cost of capital proceedings' objective of estimating a multi-year cost of equity, and their current values strike a reasonable balance between current market sentiment and the long-term historical average for utilities.

I estimate the market risk-premium from the average of the long-term historical trend and a forward-looking estimate calculated using the MS DCF.

1. The risk-free rate, one of the three CAPM inputs, should be estimated from the current, not forecast, interest rate.

Q. HOW DO YOU ESTIMATE THE RISK-FREE RATE?

A. Like Mr. Coyne, I use the 30-year Treasury. I use the most recent full-month average 30-year Treasury rate, for September 2022, of 3.56%. As explained above in Section IV.E.1, current market interest rates provide an unbiased estimate of future rates and are generally superior to publicly available "expert" forecasts.

2. Betas calculated using five years of monthly returns are consistent with the objective of a cost of capital proceeding and strike an appropriate balance between recent market conditions and utilities' long-term historical risk profile.

Q. HOW DO YOU ESTIMATE BETA?

A. As explained in Section IV.E.2 above, no single, widely used approach to estimating beta exists. Beta estimates can vary substantially depending, in particular, on the historical trailing period used, return calculation frequency, and adjustment for long-term trend reversion. I use 5-year monthly betas such as those provided by Yahoo! Finance and Zacks and commonly used in academic studies. Five-year betas using monthly returns are consistent with cost of capital proceedings' objective of estimating a multi-year expected cost of equity. The current average of 0.48 for the GPC proxy group, shown in Figure 20, strikes an appropriate balance between the long-term historical range 0.5-0.6 and current subdued investor perceptions of risk, as reflected in 1-year betas using daily returns of approximately 0.4.

3. The market risk premium estimate should reflect both current market conditions and the long-term historical trend.

Q. WHY CAN'T WE JUST LOOK UP THE MRP LIKE, SAY, WE CAN LOOK UP A STOCK PRICE OR INTEREST RATE?

A. The market risk premium is the difference between investors' expectations of future stock returns and the risk-free (interest) rate. While interest rates are directly observable, expected future market returns are not. The MRP must therefore be estimated. A historical average is a useful check for reasonableness, but the cliché, "past performance is no guarantee of future results," applies. Instead, analysts use a variety of models and input assumptions to estimate the MRP.

Q. HOW DO YOU ESTIMATE THE MARKET RISK PREMIUM?

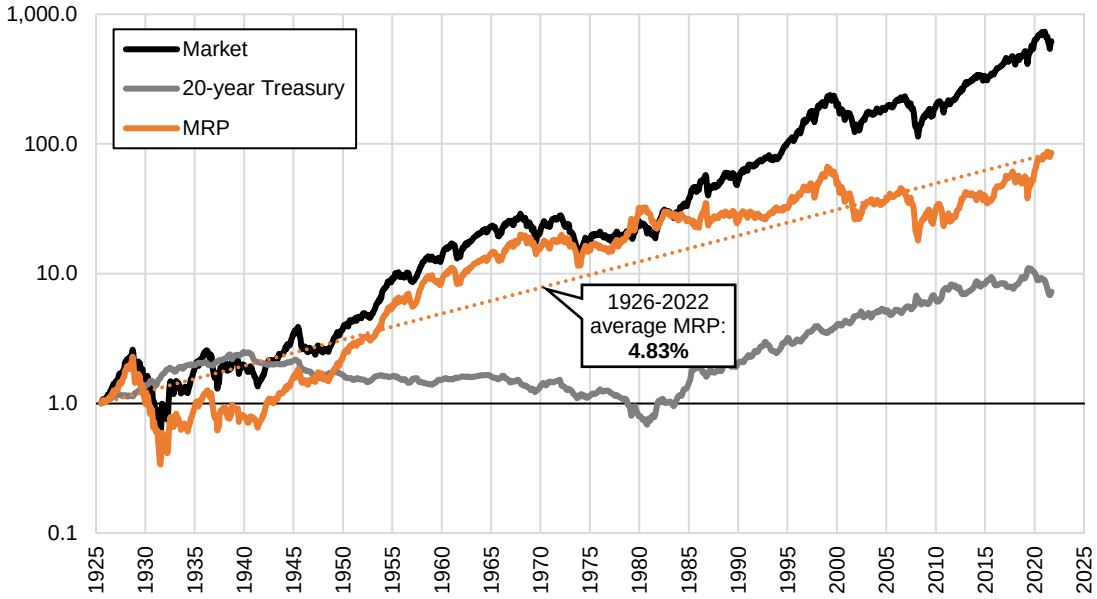
A. I use the average of two methods, one historical, the other forward-looking.

Q. HOW DO YOU ESTIMATE THE HISTORICAL MARKET RISK PREMIUM?

A. I use the long-term historical difference in the average real total returns on the market and long-term Treasury bond.[133]

Figure 25 shows the long-term historical real returns on the market and 20-year Treasury bonds, as well as the implied MRP, from June 1926 through August 2022. Over the last 96+ years, stocks have outperformed 20-year Treasurys by 4.83% per year.

Figure 25. Market, 20-year Treasury, and MRP real total return index[134]
June 1926=1.0 (log scale)



The historical MRP is calculated using 20-year Treasury data because that is the most extensive Treasury bond data set available.[135] Because I use the 30-year Treasury in my CAPM

[133] Total bond return is the monthly interest (the yield divided by 12) plus any capital gain or loss, estimated as the change in value from discounting the remaining interest payments (i.e., the previous time period's interest rate) and outstanding principal at the current time period's interest rate. This method is widely used, for example, by NYU finance professor Aswath Damodaran (*see, e.g.*, http://people.stern nyu.edu/adamodar/pc/datasets/histretSP.xls) and UCLA finance professor Ivo Welch (*see, e.g.*, Ivo Welch, *A Different Way to Estimate the Equity Premium (for CAPM and One-Factor Model Use Only)*, (2008) https://papers.ssrn.com/sol3/papers.cfm?abstract_id=1077876).

[134] M. Ellis analysis of FDL data (last accessed October 2, 2022).

[135] The early historical monthly data available for long-term Treasurys is not specifically for the 20-year. A simple regression model is used to adjust the long-term Treasury data to estimate the 20-year yield.

analysis, though, the premium is reduced by the current difference in the inflation-adjusted 20- and 30-year Treasurys (TIPS), 0.08%, for a 30-year real MRP of 4.75%. Adjusted for the 30-year inflation rate estimated from the Treasury-TIPS spread, 2.24%, the nominal MRP is 4.86%.

Q. HOW DO YOU ESTIMATE THE FORWARD-LOOKING MRP?

A. I apply the same multi-stage DCF model I use for the GPC proxy group to the market as a whole, represented by the S&P 500 Index, and subtract the current 30-year Treasury.

Q. HOW DO YOU ESTIMATE THE CURRENT DIVIDEND YIELD FOR THE S&P 500 INDEX?

A. I use the same methodology I use for the proxy group members: the most recent dividend paid, through September 30, 2022, divided by the average price of the index over the month of September 2022. The current annualized yield is 1.73%.[136]

Q. HOW DO YOU ESTIMATE THE INITIAL GROWTH RATE FOR THE S&P 500 INDEX?

A. I use the weekly estimate provided in S&P's weekly S&P 500 earnings and estimate report. I use this source because it is publicly available, well-known, frequently updated, and produced by the party with the most intimate knowledge of the index. As of September 30, 2022, S&P's estimate for the S&P 500 Index's 3-to-5-year growth rate is 13.6%.[137]

Q. HOW DO YOU ESTIMATE THE TERMINAL GROWTH RATE FOR THE S&P 500 INDEX?

A. Many analysts incorrectly assume long-term dividend growth equal to nominal GDP growth. Historically, per-share payout growth, whether measured as dividends or dividends plus net share buybacks, has tracked GDP per capita.[138] I assume a terminal growth rate based on forecast real long-term per-capita GDP plus the current market forecast for long-term inflation, estimated as described in Section IV.D.3.

[136] M. Ellis analysis of S&P GMI data (last accessed October 2, 2022).

[137] S&P Dow Jones Indices, S&P 500 Earning and Estimate Report (September 30, 2022), https://www.spglobal.com/spdji/en/documents/additional-material/sp-500-eps-est.xlsx (last accessed October 2, 2022).

[138] *See, e.g.*, ROGER IBBOTSON, JAMES HARRINGTON, STOCKS, BONDS, BILLS, AND INFLATION 2021 SUMMARY EDITION, CFA INSTITUTE RESEARCH FOUNDATION BOOKS at 157-60 (2021) (Analysis is for total payout to account for the effect of net stock repurchases).

For long-term per-capita GDP growth, I use the average of the most recent long-term CPI-adjusted forecasts from three government agencies: the Congressional Budget Office (CBO),[139] the Energy Information Administration (EIA),[140] and the Social Security Administration (SSA).[141] I use the compound annual growth rate from 2042 to remove any near-term transitory effects, such as post-Covid economic recovery, and to align with the time period used to estimate long-term inflation (years 21 through 30 from today).

TIPS payouts are tied to CPI, so the Treasury-TIPS spread provides a forecast of *consumer* price inflation. In contrast, real GDP forecasts are deflated by the GDP deflator, which reflects the prices of all domestic expenditures, including by businesses and government. For consistency with the CPI forecast derived from the Treasury-TIPS spread, which reflects only the prices paid by consumers, I use each agency's nominal GDP forecast deflated by its CPI forecast, rather than its GDP deflator forecast. Figure 26 summarizes the three agencies' real long-term per-capita GDP forecasts.

Figure 26. Real long-term per-capita GDP forecasts
Percent

		GDP				Nominal		CPI-deflated
Forecast	**Horizon**	Real	Deflator	Nominal	Population	**GDP pc**	**CPI**	**GDP pc**
CBO	2052	1.52	2.00	3.55	0.24	3.30	2.26	1.02
EIA	2050	1.99	2.28	4.32	0.33	3.98	2.40	1.55
SSA[142]	2100	NA	NA	4.09	0.42	3.65	2.40	1.22
Mean		1.76	2.14	3.99	0.33	3.64	2.35	1.26
+ Treasury-TIPS long-term inflation						**2.85**	1.57	

The average of the CBO, EIA, and SSA (the agencies) CPI-deflated long-term per-capita GDP growth rates is 1.26%. Adding the same long-term inflation expectation, 1.57%, used to estimate the terminal growth rate in the proxy group MS DCF in Section IV.D.3 above gives a nominal rate of 2.85%.[143] The corresponding average of the CBO, EIA, and SSA long-term

[139] Congressional Budget Office, *The 2022 Long-Term Budget Outlook*, (July 2022), https://www.cbo.gov/system/files/2022-07/57054-2022-07-LTBO.xlsx.
[140] Energy Info. Admin., *Annual Energy Outlook 2022*, (March 2022), https://www.eia.gov/outlooks/aeo/excel/aeotab20.xlsx.
[141] Soc. Sec. Admin., *The 2022 Annual Report of the Board of Trustees of the Federal Old-Age and Survivors Insurance and Federal Disability Insurance Trust Funds*, (June 2022) (https://www.ssa.gov/OACT/TR/2022/SingleYearTRTables_TR2022.xlsx).
[142] SSA does not forecast real GDP or the GDP deflator, only nominal GDP and CPI.
[143] Because these are compound growth rates, the geometric sum is used, $(1+g)(1+i)-1$.

per-capita nominal GDP growth rates is 3.64%. I use the market-implied long-term inflation rate rather than the agencies' for two reasons. First, although all three forecasts are the agencies' most recent, they are stale in comparison to the September 2022 average Treasury rates used to estimate inflation. Second, as demonstrated by the analysis of BCFF forecasts, market-derived data are generally considered less biased and more accurate indicators of investor expectations than expert forecasts.

Q. WHAT IS YOUR FORWARD-LOOKING MRP?

A. The S&P 500 MS DCF yields a forecast return of 6.43%. This result is consistent with the buy-side equity return forecasts summarized in Figure 3, which average 5.9% over the 10+-year horizon. Subtracting the current T30, 3.57%, gives an MRP of 2.87%.

Q. AND YOUR COMBINED MRP?

A. The average of my historical (4.86%) and forward-looking (2.87%) MRPs is 3.86%.

4. Implementing the CAPM with more rigorously estimated parameters yields COE estimates approximately one-third of Mr. Coyne's values.

Q. WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?

A. The Yahoo! Finance and Zacks 5-year monthly betas for the GPC proxy group, listed in Figure 20, are both 0.48. The corresponding COE is 5.41%,[144] approximately 40% of the 13.55% average of Mr. Coyne's estimates.[145]

Q. RECENT UTILITY BOND YIELDS ARE CLOSE TO, AND EVEN EXCEED, YOUR MS DCF AND CAPM RESULTS, 5.97% AND 5.41%, RESPECTIVELY. SHOULDN'T THE PREMIUM OVER BOND YIELDS BE GREATER?

A. To compare my COE results to utility bond yields, we must use the monthly average yield that corresponds to the proxy group's average credit-rating, Baa1, for September 2022,[146] the averaging period of the inputs to my MS DCF and CAPM. Moody's provides several widely referenced utility bond yield indexes, but not specifically for Baa1-rated utility bonds. Nonetheless, the Baa1 yield can be estimated by interpolating between Moody's Baa and A

[144] COE = 3.57% + 0.48 x 3.86% = 5.41%
[145] 2022 Rate Case Hr'g Tr. Vol. 1 at 662 (Sept. 28, 2022).
[146] M. Ellis analysis of S&P GMI data (last accessed October 16, 2022). S&P credit ratings are used; it is assumed that, on average, the ratings are comparable to Moody's.

monthly average utility bond yields for September 2022, 2/3 x 5.61% + 1/3 x 5.28% = 5.50% – higher than my CAPM result of 5.41%.[147]

But a utility COE estimate – an expected return on equity – cannot be directly compared to the corresponding utility bond yield. Reported bond yields are yields to maturity, assuming no default. Default risk for bonds with a Baa1 rating reduces their expected returns by approximately 0.46%. Similarly, bonds are not as liquid as stocks and attract a liquidity premium of approximately 0.33%.[148] Deducting the default and liquidity premia from the Baa1 utility bond yield to maturity reduces it to approximately 4.74%, 1.24% and 0.67% lower than my MS DCF and CAPM COE estimates, respectively.

There is no hard-and-fast rule for what the spread of equity returns over the corresponding cost of debt should be. My MS DCF and CAPM results are consistent with my forward-looking MRP and beta estimates, third-party forecasts for total market returns, and the widely recognized low risk profile of utilities.

G. Mr. Coyne's flotation cost adjustment is not analytically sound and is therefore unwarranted.

Q. MR. COYNE ADDS A FLOTATION COST ADJUSTMENT TO HIS ROE MODEL RESULTS. IS A FLOTATION COST ADJUSTMENT WARRANTED?

A. No. A flotation cost adjustment is not warranted. Mr. Coyne cites Roger Morin's *New Regulatory Finance* in support of adding a flotation cost adjustment,[149] but the application of the flotation cost adjustment provided in Morin's book is conceptually flawed. The math relied on by Mr. Coyne for his recommendation shows that shareholders make money from the issuance of new stock, so flotation cost adjustments are especially inappropriate.

[147] The ratings of Moody's A- and Baa-rated utility bond indexes are comparable to Moody's A2 and Baa2 ratings, respectively. The intermediate ratings are A3 and Baa1, so Georgia Power's Baa1 rating falls two-thirds of the way between A and Baa.

[148] Wolfgang Bühler and Monika Trapp, *Time-Varying Credit Risk and Liquidity Premia in Bond and CDS Markets*, CFR Working Papers 09-13, University of Cologne, Centre for Financial Research at 37 (2008), https://www.fdic.gov/analysis/cfr/2008/april/trapp-buhler.pdf.

[149] 2022 Rate Case Hr'g Tr. Vol. 1 at 669 (Sept. 28, 2022).

Mr. Morin's flotation cost adjustment assumes that the market price of the equity issued is equal to book value.[150] But, as shown in Figure 4 above, the average market-to-book ratio of the GPC proxy group is 2.1. As implied by the very formula provided by Mr. Morin, when the market price is greater than book value, new equity issuance is accretive to existing shareholders – that is, a share of the proceeds of the new issuance accrues to them.[151]

Morin derives the flotation cost adjustment from the formula for the extended DCF model under the assumption of continuous external stock financing:

$$k = \frac{D_1}{P} + br + sv,$$

where b is the earnings retention ratio, r is ROE, s is the annual rate of new equity issuance (expressed as a share of existing book equity), and v is the accretion factor, equal to $1 - \frac{B}{P}$. He then adjusts P for flotation costs, f, so that $1 - \frac{B}{P(1-f)}$.[152] But as long as $(1 - f)$ exceeds $\frac{B}{P}$, i.e., the reciprocal of the market-to-book ratio, existing shareholders *gain* from new share issuance. Mr. Coyne estimates flotation costs to be 2.47%, so $1 - f$ = 0.98, much greater than the reciprocal of the GPC proxy group average M/B ratio, 1/2.1 = 0.48.

Q. UNDER THE NARUC FAIRNESS PRINCIPLE, ROE SHOULD EQUAL THE ACTUAL COST OF EQUITY. THIS WOULD IMPLY THAT THE MARKET-TO-BOOK RATIO EQUALS 1.0, IN WHICH CASE NEW EQUITY ISSUANCE WOULD NOT BE ACCRETIVE. IF THE COMMISSION ADHERES TO THE NARUC FAIRNESS PRINCIPLE, SHOULD ROE BE ADJUSTED FOR FLOTATION COSTS?

A. No. Even if the M/B ratio is equal to 1.0, there is no reason to adjust the ROE for new equity issuance costs.

Purchasers of the newly issued equity know that a portion of proceeds will cover transaction costs, and the offering price reflects this information. There is no need to compensate new investors for issuance costs, which they knowingly pay when they purchase new shares, with an adjustment to the ROE. Similarly, existing shareholders know that the company may issue new equity over time. These costs, and their potential effect on expected

[150] ROGER A. MORIN, NEW REGULATORY FINANCE, PUB. UTIL. REPORTS at 328 (2006): "If P_0 is regarded as the proceeds per share actually received by the company from which dividends and earnings will be generated, that is, [if] P_0 equals B_0, the book value per share, …"

[151] MYRON J. GORDON, THE COST OF CAPITAL TO A PUBLIC UTILITY at 31-32 (1974).

[152] ROGER A. MORIN, NEW REGULATORY FINANCE, PUB. UTIL. REPORTS at 332-33 (2006).

returns, are likewise reflected in investors' willingness to buy, hold, or sell shares that determines share prices.

Mr. Coyne's flotation cost adjustment is small and is overwhelmed by the imprecision in his models. At 0.08%, it amounts to less than 2% of the 8.99%-13.55% range of Mr. Coyne's base ROE results.[153] To add a flotation cost adjustment is akin to the elementary school student, who, upon being asked what they learned during a field trip to the science museum, proudly says, "Earth is 4.5 billion years and [glancing at a clock] six hours and forty-three minutes old."

Mr. Coyne's flotation cost adjustment is conceptually flawed and not materially significant. It should be disregarded.

V. GEORGIA POWER'S ROE AND EQUITY RATIO SHOULD OPTIMALLY BALANCE CUSTOMER AND INVESTOR INTERESTS.

A. COE model results must be adjusted for differences in equity ratio.

Q. IN SECTION IV.B ABOVE, YOU DISCUSSED ADJUSTING COE MODEL RESULTS FOR DIFFERENCES IN EQUITY RATIOS AMONG THE PROXY GROUP MEMBERS. HOW DO YOU DO THAT?

A. The MS DCF and CAPM yield levered costs of equity. To account for differences in capital structure among the proxy group members, the COE results are unlevered to estimate the cost of equity assuming 100% equity financing.[154] The unlevered cost of equity, k_u, is typically expressed as an adjustment to beta in the CAPM:

$$k_u = r_f + \beta_u(r_m - r_f),$$[155]

where the unlevered beta, β_u, is expressed in terms of the levered equity beta, β_e:

[153] 2022 Rate Case Hr'g Tr. Vol. 1 at 668 (Sept. 28, 2022).

[154] The unlevered cost of equity differs from the weighted average cost of capital ("WACC"). The unlevered cost of capital assumes 100% equity financing; the WACC assumes the company's current capital structure. While under the Modigliani and Miller theorem of capital structure independence, the cost of capital should be the same regardless of capital structure, the WACC typically overstates the unlevered cost of equity because the *expected* return on corporate debt is lower than the yield due to default and liquidity risk.

[155] *See, e.g.*, ASWATH DAMODARAN, DAMODARAN ON VALUATION: SECURITY ANALYSIS FOR INVESTMENT AND CORPORATE FINANCE, WILEY 2ND ED. at 129 (2006).

$$\beta_u = \frac{E}{D+E}\beta_e.$$[156]

For consistency and comparability, I apply the same methodology – unlevering relative to the risk-free rate, not the company's cost of debt – to the MS DCF model results:

$$k_u = r_f + \frac{E}{D+E}\beta_l\left(r_m - r_f\right)$$

$$k_e - r_f = \beta_l\left(r_m - r_f\right)$$

$$k_u = r_f + \frac{E}{D+E}\left(k_e - r_f\right)$$

$$k_u = \frac{D}{D+E}r_f + \frac{E}{D+E}k_e,$$

where D and E refer to debt and equity, respectively. Best practice is to use market, not book, values for both debt and equity as market reflects investors' actual exposure; they buy and sell securities at market value, not book.[157] Market values for the debt carried by the proxy group members are not readily available, though, so book value is assumed.

[*Remainder of page intentionally left blank.*]

[156] Unlevered beta is sometimes adjusted for taxes (the "Hamada" adjustment). As explained in Damondaran in *Valuation*, when the capital structure is constant over time, as it is with utilities, then the value of tax shields tracks the value of operating assets. Thus, the risk of tax shields will mirror the risk of operating assets and have the same discount rate, i.e., the unlevered cost of equity. *Id*. at 790-93.

[157] *See, e.g.*, TIM KOLLER, MARC GOEDHART ET AL., VALUATION, 5TH ED. MCKINSEY & CO. 35 at 204 (2010): "Where possible, you should estimate *market* values of the elements of the current capital structure" (emphasis added).

Figure 27. Proxy group levered COEs, equity ratios, and unlevered COEs[158]
Percent, as of September 2022

	Levered COE				
Utility	MSDCF	CAPM	Average	**Equity ratio**	**Unlevered COE**
ALLETE	8.25	5.92	7.08	56	5.52
Alliant	5.50	5.36	5.43	65	4.78
Ameren	5.36	4.93	5.15	61	4.53
AEP	5.92	4.87	5.40	57	4.61
Duke	6.70	4.91	5.81	52	4.73
Edison Int'l	6.61	6.17	6.39	42	4.75
Entergy	6.50	5.76	6.13	47	4.76
Evergy	6.00	5.41	5.71	56	4.77
Hawaiian Electric	5.73	4.80	5.26	62	4.62
IDACORP	4.78	5.72	5.25	74	4.81
NextEra	5.03	5.34	5.18	71	4.71
OGE	5.96	6.11	6.03	62	5.09
Portland General	5.93	5.55	5.74	56	4.78
Xcel	5.37	4.89	5.13	61	4.52
Mean	**5.97**	**5.41**	**5.69**	**59**	**4.78**
Standard deviation	*0.87*	*0.48*	*0.57*		*0.25*
High	*8.25*	*6.17*	*7.08*		*5.52*
Low	*4.78*	*4.80*	*5.13*		*4.52*
High – low	*3.47*	*1.37*	*1.95*		*1.00*

The variation in the unlevered COE estimates is much lower than in the levered COEs, with approximately half the standard deviation (0.25 vs 0.57) and range (1.00 vs. 1.95). The underlying businesses of the proxy group members are very similar, so their risk profiles and corresponding overall costs of capital are expected to be similar as well. Their equity ratios vary considerably, though, from 42% to 74%, which introduces variation in their levered costs of equity. This variation due to differences in equity ratios makes levered COEs an inappropriate basis for determining the ROE of a target company, like Georgia Power, which will likely have a different equity ratio.

Q. HOW DO YOU USE THE PROXY GROUP AVERAGE UNLEVERED COE TO DETERMINE YOUR RECOMMENDATION FOR GEORGIA POWER'S ROE, WHICH IS LEVERED?

A. The unlevered COE is "relevered" using the same formula described above, the terms of which can be rearranged as:

$$k_e = \frac{D+E}{E} k_u + \frac{D+E}{D} r_f.$$

[158] M. Ellis analysis of S&P GMI data; market equity ratio based on September 2022 average.

In Section III above, I explained that the equity ratio depends on ROE. ROE, in turn, depends on the equity ratio. They can be determined jointly, in an iterative calculation process that is easily performed in common spreadsheet software like Microsoft Excel or Google Sheets.

B. ROE and equity ratio should be optimized to minimize customer costs while meeting investor requirements.

Q. IN SECTION III.A ABOVE, YOU PROVIDED AN ILLUSTRATIVE ANALYSIS OF THE INTER-RELATIONSHIPS BETWEEN EQUITY RATIO, ROE, AND CREDIT QUALITY. CAN YOU CONDUCT THAT ANALYSIS SPECIFICALLY FOR GEORGIA POWER?

A. Yes. Such an analysis can be conducted for Georgia Power using data provided in Moody's most recent credit update.[159]

Figure 28 applies the analysis illustrated in Figure 8 above to the financial data provided in Moody's October 2021 credit update for Georgia Power. As before, different levels of ROE are represented by the upward curving lines. As the equity ratio increases along the horizontal axis, so does the cash flow-to-debt ratio, depicted on the vertical axis. Here, cash flow from operations (CFO) is used instead of FFO, for consistency with Moody's preferred metric.[160] Black dashed horizontal lines have been added at the CFO/debt levels that correspond to potential target credit ratings: Georgia Power's current Baa1 ([redacted]% CFO/debt) and an upgrade to A3 ([redacted]%).[161]

The dark gray dot on the upper of the two ROE arcs represents Georgia Power's proposed 11.00% ROE and 56% equity ratio. The corresponding CFO/debt ratio is indicated by the

[159] GPC data request response STF-NEC-1-1 Attachment AG: Moody's Investors Service, "Georgia Power Company: Update to credit analysis" (October 13, 2021). Data from Moody's is used, not the financial data in GPC's regulatory filing, because Moody's makes various adjustments to GPC's reported financials that are not explained in sufficient detail to replicate using GPC's data.

[160] *See* GPC data request response STF-NEC-1-1 Attachment AG: Moody's Investors Service, *Georgia Power Company: Update to credit analysis* (October 13, 2021). Moody's preferred cash flow metric is cash flow from operations (CFO), not FFO, and the analysis is based on Moody's CFO/debt data. The basic definition of CFO is net income + depreciation and amortization + changes in working capital, i.e., FFO + changes in working capital. *See* Corporate Finance Institute, *How to Calculate FCFE from CFO?* (Dec. 16, 2020) https://corporatefinanceinstitute.com/resources/knowledge/accounting/how-to-calculate-fcfe-from-cfo/.

[161] In the Moody's credit analysis provided in GPC data request Trade Secret response STF-NEC-1-1 Attachment AG, Moody's provides CFO/debt thresholds for up- and downgrades of [redacted]% and [redacted]%, respectively. The threshold for GPC's current rating is estimated as the midpoint, [redacted]%.

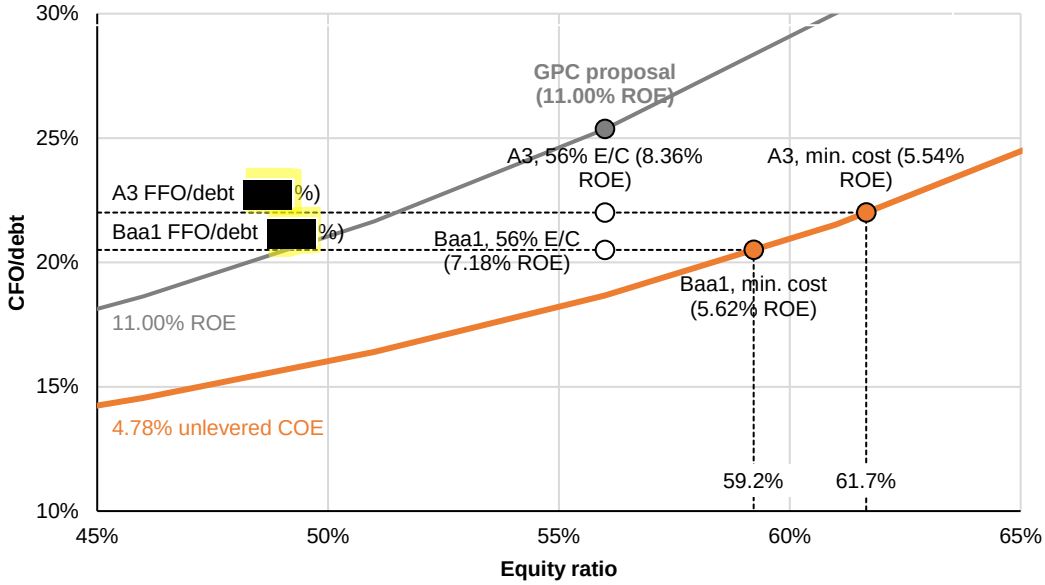
height of the dot on the vertical axis, [redacted]% – well above the [redacted]% required to maintain Georgia Power's current Baa1 credit rating. Either or both of Georgia Power's proposed ROE and equity ratio can be reduced to lower customer costs while still satisfying investor demands.

The lower of the two ROE arcs represents Georgia Power's 4.78% unlevered (100% equity) COE. As discussed previously, the corresponding levered ROE will increase as the equity ratio declines. To maintain Georgia Power's current Baa1 rating would require an equity ratio of 59.2%, slightly higher than GPC's proposal, and an ROE of 5.62%. If instead a higher A3 credit rating is targeted, the equity ratio and ROE would need to be 61.7% and 5.54%, respectively. The trade-off, in terms of customer costs, associated with these higher equity ratios will be quantified below.

The two white dots immediately below GPC's proposal illustrate scenarios in which an equity ratio constraint is imposed, here equal to GPC's proposed 56%. To maintain target credit ratings of Baa1 or A3, the ROE would need to be increased to 7.18% and 8.36%, respectively. The trade-off, in terms of customer costs, associated with an equity ratio constraint will also be quantified below.

[*Remainder of page intentionally left blank.*]

Figure 28. Relationship between equity ratio, ROE, and credit quality for Georgia Power



C. An optimized ROE and equity ratio can significantly reduce customer costs while meeting the demands of both equity and debt investors.

Q. HOW WOULD AN OPTIMIZED ROE AND EQUITY RATIO IMPACT CUSTOMER COSTS?

A. Figure 29 compares the revenue requirement (pre-tax) weighted average rate of return for the five scenarios depicted in Figure 28. The ROE optimized for a Baa1 rating, 5.62%, is 49% lower than Mr. Coyne's proposed ROE of 11.00% (line 2). Even with the higher 59.2% equity ratio, after grossing up for taxes, the revenue requirement ROR, 5.92%, is 40% lower than GPC's 9.83% (lines 6-7). If a higher A3 credit rating is targeted, the additional cost of the required higher 61.7% equity ratio is almost completely offset by the lower levered ROE of 5.54%,[162] and the revenue requirement ROR increases only slightly to 5.95%.

Figure 29 also shows the average annual total revenue requirement under each of the five scenarios (line 8). Based on analysis of Georgia Power's general rate case filings, its proposed combined rate of return for both debt and equity, the latter grossed up for taxes, accounts for

[162] It is assumed that there is no change in the cost of debt at the higher A1 credit rating over the 2023-25 period. New issuance accounts for approximately 18% of Georgia Power's net long-term debt at the end of 2025. The difference in yield between A3- and Baa1-rated utility bonds is approximately 0.11%. The change in interest costs would therefore be approximately 18% x 0.11% = 0.02% by the end of the forecast period. M. Ellis analysis of data in Ex. APA SPA ADH MBR-3, Schedule 3, Workpaper 4.

more than 25% of its revenue requirement.[163] The total revenue requirement under GPC's proposal averages $9.14 billion per year from 2023 through 2025. Optimized ROEs and equity ratios, under either the Baa1 or A3 target credit rating, reduce total customer costs by over 11% (line 10) or more than $1.0 billion per year (line 9).

An equity ratio constraint would impose fairly substantial costs on customers, increasing the revenue requirement ROR to 6.96% and 7.84% under Baa1 and A3 credit rating targets, respectively – an increase of nearly 100 and 200 basis points relative to the corresponding minimum-cost scenarios. While total customer costs are lower than under GPC's proposal, they are only 50% to 70% of the reduction without an equity ratio constraint. These results further demonstrate the flaw in the "leverage up" (reduce the equity ratio) argument described in Section III.A above. It is much more cost effective to use any spare credit capacity to reduce ROE than to increase debt.

Figure 29. Revenue requirement (pre-tax) rate of return under different weighted under GPC proposal, minimum cost, and equity ratio constraint scenarios
Percent (except lines 8 and 9)

		GPC proposal	Minimum cost		Equity ratio constraint	
			Baa1	A3	Baa1C	A3
1	Equity ratio	56.0	59.2	61.7	56.0	56.0
2	ROE	11.00	5.62	5.54	7.18	8.36
3	Cost of debt	3.59	3.59	3.59	3.59	3.59
4	Rate of return	7.74	4.79	4.79	5.60	6.26
5	Tax rate	25.3	25.3	25.3	25.3	25.3
6	**Rev. requirement rate**	**9.83**	**5.92**	**5.95**	**6.96**	**7.84**
7	*ΔGPC proposal*		*-40*	*-39*	*-29*	*-20*
8	**Rev. requirement ($ B)**	**9.14**	**8.09**	**8.10**	**8.37**	**8.61**
9	Customer savings ($ billion per year)		-1.05	-1.04	-0.77	-0.53
10	*ΔGPC proposal*		*-11.5%*	*-11.4%*	*-8.4%*	*-5.8%*

Q. WHAT ARE THE IMPLICATIONS OF AN OPTIMIZED ROE AND EQUITY RATIO ON RESIDENTIAL CUSTOMER BILLS?

A. Average residential customer bills can be estimated from Georgia Power's total retail base rate revenue and sales of electricity forecast for the 12 months ending July 31, 2023,[164] and Budget

[163] M. Ellis analysis of data in Ex. APA-SPA-ADH-MBR-1, Schedule 1.
[164] 2022 Rate Case, Georgia Power Document Filing No. 190559, App. Ex. 1-2 Workpaper 1 (June 24, 2022).

2022 Load and Energy Forecast customer count projection.[165] Assuming the 11% cost reduction under either of the optimized ROE/equity ratio scenarios applies uniformly across customer classes, Georgia Power residential customers would save approximately $135 per year.

Q. WHAT ARE YOUR ROE AND EQUITY RATIO RECOMMENDATIONS FOR GEORGIA POWER?

A. I recommend the A3 target credit rating scenario for Georgia Power, 5.54% ROE and 61.7% equity ratio, for several reasons. Both the A3 and Baa1 scenarios are consistent with the Supreme Court's guidance provided in *Hope Natural Gas* to set "just and reasonable rates" through a "balancing of the investor and the consumer interests." In contrast, Mr. Coyne's recommendation and the two equity ratio-constrained scenarios are overly generous to investors at the expense of customers and therefore fail the *Hope* standard.

The A3 and Baa1 scenarios have the same estimated cost to customers over the 2023-25 timeframe. This is largely because the analysis assumes the improved credit rating does not materially reduce Georgia Power's average cost of debt during the 2023-25 timeframe. Beyond 2025, though, the average cost of debt would be materially lower under the A3 scenario, reducing customer costs relative to the Baa1 scenario. Figure 30 summarizes my COE analysis and ROE and equity ratio recommendations.

[*Remainder of page intentionally left blank.*]

[165] 2022 IRP, Georgia Power Document Filing No. 188519, PD Vol. 1, 4 PD Load and Energy Forecast, PD B2022 Load and Energy Forecast 2022 to 2041 at 18, Section 2 (January 31, 2022).

Figure 30. Summary of Georgia Power COE analysis and recommended ROE and equity ratio
Percent

Model	COE	Key assumptions
DCF	**5.97**	
Dividend yield	3.36	Most recent quarterly dividend divided by one-month trailing price history (~21 trading days)
Initial growth rate	5.49	Analysts' EPS growth rates for three years to mitigate upward bias
Terminal growth rate	1.57	Based on long-term historical utility DPS growth rate equal to inflation
CAPM	**5.41**	
Risk-free rate	3.56	Current (one-month trailing average) 30-year Treasury
Beta	0.48	5-year monthly balances long-term historical trend and current market conditions
Market risk premium • Historical • Forward	3.86 4.86 2.87	Average of forward-looking using MS DCF and long-term historical average; MS DCF long-term growth rate equal to pre-capita GDP
Mean COE – Levered	**5.69**	
– Unlevered	4.78	59% proxy group average *market* equity ratio
Equity ratio	**61.7**	
Relevered COE/ recommended ROE	**5.54**	

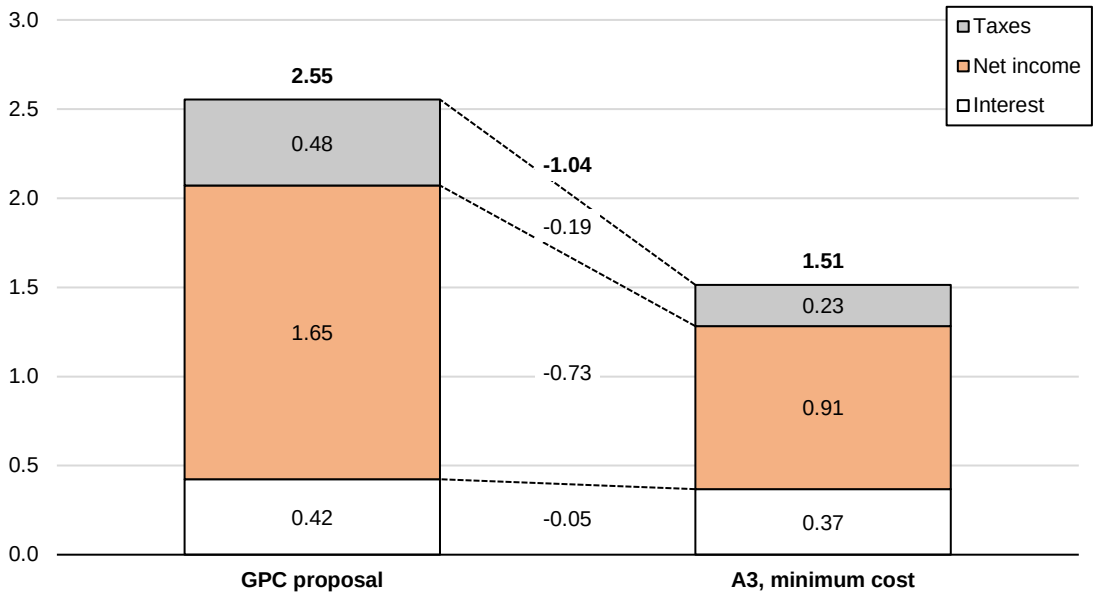
Q. IF THE COMMISSION ADOPTS YOUR ROE AND EQUITY RATIO RECOMMENDATIONS, HOW WOULD THE SOUTHERN COMPANY'S SHAREHOLDERS BE AFFECTED?

A. ROEs in excess of the cost of equity resembles a zero-sum game, with the interests of shareholders and customers in direct opposition. If the Commission adopted my recommended ROE and equity ratio, I would expect The Southern Company share price to experience a one-time downward adjustment as investors reset their expectations about future returns. Southern would still be able to access the equity markets, because Georgia Power's ROE, based on its actual cost of equity, i.e., investors' *expected* return,[166] would be sufficient to satisfy investors' demands. Investors who purchase shares after the one-time adjustment would earn returns comparable to the return current Southern shareholders expect.

[166] "Cost of equity" and "*expected* return on equity" are synonymous. *See supra* footnote 11.

I said that ROE above the cost of equity *resembles* a zero-sum game between shareholders and customers. It is not quite zero-sum between these two parties, though, because there is a third party: the tax authorities. ROE is grossed-up for taxes; to the extent ROE is reduced, taxes are also reduced. In aggregate, a lower ROE provides approximately one-third more benefit to customers than shareholders lose in foregone profit.[167] As shown in Figure 31, of the $1.04-billion reduction in revenue requirement return under the A3 scenario (Figure 29, line 9), the decline in Georgia Power's net income accounts for $740 million; $190 million is foregone taxes, of which approximately $150 million (77.5%) is Federal.[168]

Figure 31. Interest, ROE, and income tax revenue requirement under GPC proposal and A3 minimum cost scenario
$ billion



It is important to recognize that *Hope* established that regulators are not obligated to maintain utility stock market valuations, and that such an obligation would make a nonsense of regulators' consumer protection mandate:

> Ratemaking is indeed but one species of price-fixing. The fixing of prices, like other applications of the police power, may reduce the value of the property which is being regulated. But the fact

[167] Georgia Power's marginal tax rate is approximately 25%. The tax gross-up is 1/(1 – 25%) = $1^{1}/_{3}$. *See* Ex. APA-SPA-ADH-MBR-1, Schedule 1 Total Company.

[168] Georgia corporate income tax rate of 5.75%, Federal, 21%. After deducting state taxes, the net Federal rate is (1 – 5.75%) x 21% = 19.79%; 19.79% / (19.79% + 5.75%) = 77.49%.

> that the value is reduced does not mean that the regulation is invalid. It does, however, indicate that "fair value" is the end product of the process of ratemaking, not the starting point, as the Circuit Court of Appeals held. The heart of the matter is that rates cannot be made to depend upon "fair value" when the value of the going enterprise depends on earnings under whatever rates may be anticipated.[169]

The impact on Southern's stock price should not factor at all into the Commission's determination of the appropriate ROE and equity ratio.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

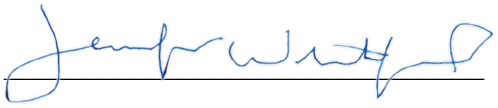
A. Yes.

[*Remainder of page intentionally left blank.*]

[169] 320 U.S. 591, 601.

CERTIFICATE OF SERVICE

I certify that the foregoing **Direct Testimony of Justin Barnes and Direct Testimony of Mark E. Ellis on behalf of Georgia Interfaith Power & Light** in Docket No. 44280 was filed with the Public Service Commission by electronic delivery on the 20th of October, 2022. An electronic copy of same was served upon all parties listed below by electronic mail as follows:



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