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July 30, 2020

VIA ELECTRONIC FILING

Mr. Joel H. Peck, Clerk
c/o Document Control Center
State Corporation Commission
Tyler Building – First Floor
1300 East Main Street
Richmond, Virginia 23219

RE: Application of Appalachian Power Company for a 2020 triennial review of its base rates, terms and conditions pursuant to § 56585.1 of the Code of Virginia

Case No. PUR-2020-00015

Dear Counsel:

Please find enclosed for filing in the above-referenced docket Direct Testimony of Justin Barnes, which is being submitted on behalf of Appalachian Voices ("Environmental Respondent"). Included with this testimony are Mr. Barnes' one-page summary and eleven attachments. This filing is being completed electronically, pursuant to the Commission's Electronic Document Filing system.

Pursuant to Rule 140 of the Commission's Rules of Practice and Procedure, Environmental Respondent is providing service of documents in this case exclusively via email unless parties request otherwise. Please let me know if you do not agree to electronic service and would like to receive hard copies of documents.

If you should have any questions regarding this filing, please contact me at (434) 977-4090.

Regards,

William C. Cleveland

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

APPALACHIAN POWER COMPANY	)	
	)	Case No. PUR-2020-00015
For a 2020 triennial review of its base	)	
rates, terms and conditions pursuant to	)	
§ 56-585.1 of the Code of Virginia	)	

SUMMARY OF

DIRECT TESTIMONY OF

JUSTIN R. BARNES

ON BEHALF OF

ENVIRONMENTAL RESPONDENT

July 30, 2020

Summary of the Testimony of Justin R. Barnes

My direct testimony covers three areas of the Company's Application: (1) the proposed increase in the residential basic service charge ("BSC"); (2) the Company's proposal to establish a winter tail block rate within Schedule R.S.; and (3) the Company's proposed Coal Amortization Recovery Rider ("Rider CAR").

In Section II of my testimony I discuss the Company's proposal to increase the BSC for most residential rates by $6.04/month from $7.96/month to $14.00/month. I recommend that the Commission reject the proposed increase because: (1) it conflicts with generally accepted ratemaking principles, including gradualism, cost causation, and the pursuit of economically efficient rates; and (2) the increase would be harmful to consumer incentives for energy efficiency. I recommend that the Commission retain the current residential BSC rate of $7.96/month, which is based generally on the costs that are classified as customer-related in the Company's cost of service study, with several small adjustments and refinements.

In Section III of my testimony I discuss the Company's proposal to establish a discounted rate within Schedule R.S. for electricity consumption above 1,100 kilowatt-hours ("kWh") from December through February. I recommend that the Commission reject the Company's proposal because it would encourage wasteful electricity use in conflict with Virginia's goal of improving energy efficiency, and instead adopt my alternative proposal to establish a discount applicable only to Schedule R.S. electric heating customers for electricity consumption up to 400 kWh/month during December through March. The discount, which I propose be set at $0.04713/kWh, is intended to recognize that a portion of winter electricity used by customers with electric heating is "essential use" that is completely non-discretionary and necessary for basic health and safety. I describe the reasons why my alternative proposal is superior to the Company's, which include its greater consistency with Virginia's state energy policies calling for building decarbonization and increased energy efficiency. I also discuss the broader need for attention to ratemaking and rate designs that support beneficial building electrification given Virginia's climate goals and recommend that the Commission further investigate the topic with a focus on mitigating energy burdens faced by lower-income customers.

In Section IV of my testimony I evaluate the Company's proposal to begin prospectively collecting revenue of up to $25 million annually via Rider CAR to buy-down the undepreciated basis of its existing coal generation portfolio in anticipation of the early retirement of those assets due to the 2020 Virginia Clean Economy Act ("VCEA"). I recommend that the Commission deny the Company's request to begin forward collection of these anticipated costs for several reasons: (1) Rider CAR is unnecessary because Commission possesses all of the flexibility it needs to appropriately address ratemaking treatment for early retirements of fossil fueled generation when the details of actual planned retirements become known; (2) it would exacerbate consumer electricity cost burdens during a time of unique economic uncertainty and distress; and (3) the forward collection under Rider CAR would not in fact reduce inter-generational inequities, as the Company claims it would, because future customers benefit from the early retirement of coal assets in the form of avoided operational costs and a cleaner generation mix.

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

APPALACHIAN POWER COMPANY	)	
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DIRECT TESTIMONY OF

JUSTIN R. BARNES

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ENVIRONMENTAL RESPONDENT

July 30, 2020

TABLE OF CONTENTS

I. INTRODUCTION

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

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

Q. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A. I am submitting testimony on behalf of Appalachian Voices (the "Environmental Respondent").

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE VIRGINIA STATE CORPORATION COMMISSION ("THE COMMISSION")?

A. Yes. I submitted testimony in Commission Case No. PUR-2019-00060 relating to Kentucky Utilities' most recent general rate case filing. I also assisted in the development of Environmental Respondent's comments on the Appalachian Power Company's proposal to establish a residential personal electric vehicle rate in Commission Case No. PUR-2019-00067.

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 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.

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

I have submitted testimony before utility regulatory commissions in Colorado, Hawaii, Georgia, New Hampshire, New York, North Carolina, Oklahoma, South Carolina, Texas, and Utah, as well as to the City Council of New Orleans, on various issues related to clean energy policy, rate design, and

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

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 Attachment JRB-1. It contains summaries of the subject matter I have addressed in each of these proceedings.

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY AND HOW IT IS ORGANIZED.

A. My testimony addresses several aspects of the rate increase application filed by the Appalachian Power Company ("APCo" or "the Company"), focused on aspects that relate to rate design. Specifically, I discuss and make recommendations to the Commission on the Company's proposals to:

- Increase the residential Basic Service Charge ("BSC" or "fixed charge") from $7.96/month to $14.00/month for most residential rate schedules. (Section II)
- Establish a winter tail block rate within Schedule R.S., the standard residential service rate, for energy use above 1,100 kWh per month during the months of December through February. (Section III)
- Establish a new Coal Amortization Recovery Rider ("Rider CAR") that would allow accelerated recovery of costs associated with its remaining coal-fired power plants. (Section IV)

In Section II of my testimony I provide my own recommendation for the amount of the residential BSC. In Section III, I present an alternative proposal for addressing energy cost burdens on electric heating customers and discuss a more

[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.

general need for consideration of rate designs that support building electrification while retaining accurate cost-based price signals and consumer efficiency incentives.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION ON THE COMPANY'S APPLICATION AND THE REASONS FOR THOSE RECOMMENDATIONS.

A. My recommendations are as follows:

- I recommend that the Commission deny the Company's request to increase the residential BSC to $14.00/month and instead leave the residential BSC at its current level of $7.96/month. My recommended charge is based on customer-related costs derived using the Basic Customer Method, which is the most common method used throughout the country to establish fixed charges.
- I recommend that the Commission deny the Company's request to establish a winter tail block rate within Schedule R.S. and instead adopt my alternative proposal that Schedule R.S. be modified to incorporate a rate discount only for customers with electric heating for electricity consumption up to 400 kWh/month during the months of December through March. The discount is intended to recognize that a portion of winter electricity use by customers with electric heating is "essential use" that is non-discretionary and necessary for basic health and safety. The use of a discount for essential winter heating use retains the actionable price signal provided by standard rates while also helping mitigate high and

volatile winter electricity bills for electric heating customers. Measures to address the high costs of electric heating are an aspect to encouraging electric heating, which in turn is a critical element of decarbonizing Virginia's energy system in line with the state's carbon emission reduction goals.

- I recommend that the Commission reject proposed Rider CAR because it is unnecessary given the Commission's newly established authority on the nature of coal asset cost recovery. Advanced cost recovery is particularly poorly-timed in light of the continuing economic impacts of COVID-19.

II. PROPOSED RESIDENTIAL BSC INCREASE

A. Context of APCo's Proposal

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSAL FOR THE RESIDENTIAL FIXED CHARGE.

A. The Company proposes to increase the residential BSC from $7.96/month to $14.00/month for most residential rate schedules, an increase of $6.04/month.[3]

Q. HOW DOES THE COMPANY DERIVE AND JUSTIFY THE $14.00/MONTH AMOUNT IT PROPOSES FOR THE RESIDENTIAL FIXED CHARGE?

A. The Company contends that this will help reduce intra-class subsidies that result from fixed costs being recovered via variable charges, which it states causes high usage customers to subsidize low usage customers. Company Witnesses Castle and Walsh point to electric heating customers in particular as subsidizing other

[3] Company Application at 18.

customers because electric heating customers tend to have higher than average electricity consumption.[4] They also contend that the proposal would benefit low-income customers and produce greater winter bill stability.[5]

The Company does not provide any specific reason for why it selected $14.00/month as the appropriate amount. Company Witness Walsh represents that a charge sufficient to recover the full amount of its fixed distribution costs required to connect a customer to the grid would be approximately $38/month.[6] In testimony, the Company chose $14.00/month to achieve the principle of "gradualism" in ratemaking.[7] It declined to elaborate on the specific amount in response to an information request.[8] Without any underlying analysis or specific justification, I take this to mean that the Company simply selected $14.00/month as a number between the present rate of $7.96/month and the purported $38.00/month amount.

Q. HOW DOES THE COMPANY DERIVE ITS "FULL-COST" RESIDENTIAL BSC OF $38/MONTH?

A. The amount is derived based on an assumption that each customer requires the same additional distribution infrastructure in order to be connected to the grid, in the form of an additional pole, conductor, a 15 kVA line transformer, a customer service drop, a meter, and related accessory equipment. It calculates the theoretical charge based on the costs of this additional equipment, a weighted

[4] Direct Testimony of Katharine I. Walsh ("Walsh Direct") at 10:1-22.

[5] Direct Testimony of William K. Castle ("Castle Direct") at 8:3-16.

[6] Walsh Direct at 14:20-21.

[7] Walsh Direct at 14:8-10.

[8] Company response to ER 2-4 included as Attachment JRB-2.

average lifetime, and a carrying charge.[9] Company Witness Walsh argues that this portion of distribution costs varies only with the number of customers and not their energy usage or demand.[10]

Q. PLEASE SUMMARIZE THE ELEMENTS OF GOOD RATEMAKING PRACTICE.

A. Good ratemaking is an exercise in balancing a suite of goals. The oft-cited work of Dr. James Bonbright offers valuable guidance on the criteria that should be used in the development of a sound rate structure, listing a set of eight principles to consider. I have paraphrased those principles below:

1. The "practical" attributes of simplicity, understandability, public acceptability and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers (*i.e.*, gradualism).
6. Fairness of the rates in apportioning the total cost of service among different consumers.
7. Avoidance of undue discrimination in rate relationships.
8. Efficiency of the rate classes and blocks in discouraging wasteful use of service (*i.e.*, economic efficiency) while promoting all justified types and amounts of use.[11]

The principles themselves are generally non-controversial. However, it is typically recognized that they sometimes conflict with one another and present a

[9] Walsh Direct, Schedule 1.

[10] Walsh Direct at 15:14-18

[11] James Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, p. 291.

need for subjective judgments as to interpretation (*e.g.*, the practical meaning of "stability" or "gradualism") and the relative weight each aspect should receive. The need to achieve balance is generally acknowledged, but disagreements will frequently arise as to what that balance should look like.

Q. DOES THE COMPANY'S RESIDENTIAL BSC PROPOSAL ACHIEVE A GOOD BALANCE OF SOUND RATEMAKING OBJECTIVES?

A. No. First and foremost, the Company's assessment of the costs that vary only by the number of customers is highly distorted and contradicted by the methodology used in its own cost of service study. That study takes a much narrower view of "customer-related" costs that excludes all aspects of the shared distribution system.[12] Beyond that, the Company's proposal effectively ignores gradualism, economic efficiency, customer acceptability, and fairness. While APCo has not proposed to increase the residential BSC to the full amount of its supposed "customer connection costs", using those costs as a benchmark for a "cost-based" residential BSC distorts the discussion of setting a reasonable residential BSC.

B. Cost Basis for APCo's Proposal

Q. WHAT TYPES OF COSTS ARE CLASSIFIED AS CUSTOMER-RELATED IN THE COMPANY'S COST OF SERVICE STUDY?

A. The customer-related costs include the costs of meters and services and related operations and maintenance ("O&M") as well as customer service and billing. They also include a share of general plant and overhead costs, such as Company offices, office equipment, and executive salaries that are not specifically

[12] Direct Testimony of Michael M. Spaeth ("Spaeth Direct"), Schedule 1.

attributable to another function. For the most part, it corresponds to a method that is sometimes referred to as the Basic Customer or Direct Customer Method, the primary distinguishing characteristic of which is the classification of all distribution plant beyond the customer's service drop as demand-related. Company Witness Spaeth includes a more detailed summary of the cost allocation methodology in Schedule 1 attached to his testimony.[13]

Q. WHY IS THE COMPANY'S REPORTED "CUSTOMER CONNECTION" AN INNAPPROPRIATE BENCHMARK FOR ESTABLISHING A COST-BASED RESIDENTIAL BSC?

A. First, the Company's residential so-called customer connection cost is driven by faulty assumptions that (1) each customer requires the exact same equipment additions regardless of the size of their load; and (2) multiple customers do not share any of this equipment. Neither is accurate, as the Company admits that factors such as proximity to other customers, the types of appliances in use (*e.g.*, electric heat, air conditioning), and geography all contribute to determining the equipment necessary to serve an individual customer and whether that equipment can be shared by multiple customers.[14] For instance, a 15 kVA line transformer might be able to serve only a single customer if that customer has a large two-story home with multiple electric heat pumps, while it could serve two or more mobile homes that have much lower demands due to reliance on small space heaters and window air-conditioning units. Quite simply, higher demand customers *should* pay more for electric service, and they do so under the current

[13] Spaeth Direct, Schedule 1.

[14] Company response to ER 2-7 included as Attachment JRB-3.

volumetric rate structure because higher demands translate to higher overall usage.

Second, the idea that such equipment is "customer-related" ignores the fact that a customer that has no demand for electricity would have no need to be connected to the distribution system. The Company's cost of service study accordingly and properly classifies all equipment beyond the customer service drop as demand-related because the customer's actual full demand, not the customer's existence, causes the need.[15]

The third problem with the Company's evaluation of customer connection costs is that it relies on *current* costs, whereas rates including the residential BSC are designed to recover the *embedded* costs incurred throughout the historic construction of the distribution system. In other words, the Company's estimate reflects a cost of effectively replacing all existing equipment with brand new equipment, which would significantly overcharge customers because the system was constructed at lower historic costs.

Q. IS IT TRUE THAT HIGHER USAGE CUSTOMERS SUCH AS ELECTRIC HEATING CUSTOMERS SUBSIDIZE LOWER USAGE CUSTOMERS?

A. In the system of cost-averaged ratemaking, no customer truly pays the exact cost of their service. By and large though, customers with higher usage will tend to have higher demands and thereby cause higher costs. In the specific example of electric heating it is easy to see how this would occur. A customer with a large

[15] Spaeth Direct, Schedule 1.

home on a large lot would require more and larger-sized dedicated facilities due to their heating load (*e.g.*, two heat pumps rather than none) and lack of close proximity to other customers that could permit the sharing of conductors, poles, and a transformer.

Likewise, the electric heating customer with large space conditioning needs (*e.g.*, 3,000 square feet) will typically have a larger heating load than one with a smaller amount of conditioned space (*e.g.*, 1,500 square feet). The larger customer will of course pay more under a volumetric rate because they use more electricity, but that is exactly what should occur according to cost causation.

Q. DOES A FIXED CHARGE THAT INCLUDES COSTS BEYOND THE BASIC SERVICE DROP DISADVANTAGE ANY SPECIFIC CUSTOMER SEGMENTS?

A. Yes. Customers that reside in multi-family buildings are likely to be the most disadvantaged from the perspective of their true cost of service. This is because they share a considerable amount of distribution infrastructure that is sized to serve the aggregate and diversified loads of a building. Multi-family unit residents would be charged as though each customer requires a dedicated, small line extension when in fact they share larger-sized distribution facilities that benefit from economies of scale. In addition, units in multi-unit housing tend on average to be smaller than single-family homes, and therefore have less space conditioning needs, resulting in lower usage.

In fact, even an assessment of customer-related costs under the Basic Customer Method likely overstates the true customer-related costs because multiple customers often share a single service drop, and meter banks housing multiple meters can be less costly than a collection of meters spread among single-family homes. As of 2018, the Company estimates that roughly 2.9% of its residential customers resided in buildings with four or more units, and an additional 6.6% resided in two-four unit buildings.[16]

Similarly, some rural customers that host farming operations have separately metered outbuildings or other loads that utilize the same distribution facilities, such as a common transformer and distribution service line, except for the service drop and meter. Those customers effectively pay twice for the same infrastructure because they pay separate BSCs for each metered account. Finally, small, single-family homes located in close proximity to one another, such as in mobile home parks, are likely to have considerable shared infrastructure that has a per-customer cost considerably lower than if each required a separate distribution line extension. Mobile homes in a mobile home park are also likely smaller on average than site-built homes and as a consequence more likely to have lower electricity demands and consumption.

Q. HOW ARE RESIDENTIAL FIXED CHARGES SET IN OTHER STATES?

A. Many states confine the definition of "customer" costs to those costs that are directly attributable to a customer, such as metering and billing, excluding portions of the distribution system shared by multiple customers. A 2000 report developed by the Regulatory Assistance Project ("RAP") and published by the National Association of Regulatory Utility Commissioners ("NARUC") found

[16] Company response to ER 2-14, Attachment 1 included as Attachment JRB-4.

that this Basic Customer Method, which classifies distribution plant in FERC Accounts 364-368 as 100% demand-related, was the most common approach at the time of the report:

> There are a number of methods for differentiating between the customer and demand components of embedded distribution plant. The most common method used is the basic customer method, which classifies all poles, wires, and transformers as demand-related and meters, meter-reading, and billing as customer-related. This general approach is used in more than thirty states.[17]

Q. CAN THE COMMISSION RELY ON THIS REPORT AS AN ACCURATE ASSESSMENT OF DISTRIBUTION RATE DESIGN AT THE TIME IT WAS AUTHORED?

A. Yes. The list of authors is composed of several former utility regulators, including several former commissioners, each of which held positions on various NARUC boards and committees.[18]

Q. CAN YOU POINT TO SPECIFIC EXAMPLES WHERE THE BASIC CUSTOMER METHOD HAS BEEN ENDORSED FOR USE OR IS OTHERWISE USED IN COST OF SERVICE STUDIES OR FOR THE PURPOSE OF ESTABLISHING FIXED CHARGES?

A. Yes. In 2015, legislators in Connecticut directed the Public Utilities Regulatory Authority ("PURA") to utilize the Basic Customer Method for the purpose of

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[17] F. Weston, et al., *Charges for Distribution Service: Issues in Rate Design*, p. 29, REGULATORY ASSISTANCE PROJECT (2000), http://pubs.naruc.org/pub/536F0210-2354-D714-51CF-037E9E00A724.

[18] *See* the RAP website for biographies of the principal author Frederick Weston (former Vermont Public Service Board Economist and Hearing Officer) and contributors David Moskowvitz (former Maine Public Utilities Commission Commissioner) and Richard Cowart (former Vermont Public Service Board Chairman and Commissioner), https://www.raponline.org/about/.

establishing a maximum residential customer charge.[19] Likewise, in 2018, regulators in Colorado directed Black Hills Energy to eliminate the minimum-intercept method[20] entirely from its cost of service study in the utility's most recent general rate case.[21] Most recently, in a proceeding on grid modernization, the New Hampshire Public Utilities Commission made the following finding:

> <u>Customer Charges</u>: We find that customer charges should only be used to recover customer-related costs as identified in a cost of service study. Such costs include the cost of the ratepayer-funded investments required to serve the customer, which in the Commission's experience for residential customers are typically identified as the service drop, the portion of the meter directly related to billing for usage, and the costs of billing and collection.[22]

Additionally, South Carolina,[23] Texas,[24] and California[25] have expressly rejected including a customer-related component for shared distribution infrastructure in cost allocation or for the purpose of establishing customer charges. I am also aware that the cost of service studies used by Public Service New Mexico, Rocky Mountain Power in Utah, the Potomac Electric Power

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[19] Connecticut Public Act 15-5, June Special Session, https://www.cga.ct.gov/asp/cgabillstatus/CGAbillstatus.asp?selBillType=Bill&bill_num=1502&which_year=2015. The act requires PURA to "adjust each electric distribution company's residential fixed charge ... to recover only the fixed costs and operation and maintenance expenses directly related to metering, billing, service connections and the provision of customer service."

[20] The minimum intercept method is one type of analysis that utilities sometimes use to define a customer-related portion of the shared distribution system.

[21] Colorado Public Utilities Commission, Docket No. 17AL-0477E, Decision No. C18-0445 (June 15, 2018), https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=887641.

[22] New Hampshire Public Utilities Commission, Docket No. 15-296, Order No. 26,358 (May 22, 2020) https://www.puc.nh.gov/Regulatory/Docketbk/2015/15-296/ORDERS/15-296_2020-05-22_ORDER_26358.PDF

[23] South Carolina Public Service Commission, Docket No. 91-216-E, Order No. 91-1022 at 7 (Nov. 18, 1991).

[24] Public Utilities Commission of Texas, Docket No. 22344, Order No. 40 at 6 (Nov. 22, 2000).

[25] California Public Utilities Commission, Docket No. A.16-06-013, Decision No. 17-09-035 at 33, 40 (Sept. 28, 2017). The decision allows a portion of final line transformer costs consistent with a minimum-sized transformer to be included in a fixed charge.

Company and Baltimore Gas & Electric in Maryland, Entergy New Orleans, and Entergy Arkansas do not define any shared distribution costs as customer-related.

Finally, a letter from the Washington Utilities and Transportation Commission ("WUTC") to NARUC regarding the publication of the NARUC Electric Utility Cost Allocation Manual ("NARUC Manual") indicates that WUTC staff believed the Basic Customer Method to be the most common approach to establishing customer-related costs throughout the country, citing Arizona, Iowa, and Illinois as states that have explicitly rejected the practice of defining customer-related costs to include components of the shared distribution system.

Q. TO SUMMARIZE, HOW MANY STATES HAVE YOU CITED THAT HAVE ENDORSED THE BASIC CUSTOMER METHOD OR OTHERWISE USED IT IN A COST OF SERVICE STUDY OR FOR THE PURPOSE OF ESTABLISHING A FIXED CHARGE?

A. The number of states totals 14, including the six states that have explicitly rejected including shared distribution infrastructure as customer-related costs, four additional states referred to in the context of utility cost of service studies, and four more referred to by the WUTC letter (including Washington). In fact, there are even more states that utilize low customer charges that could only be arrived at by taking a narrow view of costs that are reasonable to include in a residential BSC, such as New Jersey, Michigan, and Idaho, and Massachusetts. I discuss the national landscape of residential fixed charges later in my testimony.

Q. WHY IS THE BASIC CUSTOMER METHOD PREFERRED IN MANY STATES FOR THE PURPOSE OF SETTING FIXED CHARGES?

A. There are several reasons. As I have already described, many states reject the concept that there is a customer-related aspect of the shared distribution system. Apart from that core reason, ratemaking must balance competing objectives, and thus there are typically multiple contributing factors. For instance, states that prioritize energy efficiency tend to utilize lower fixed charges, often derived using the Basic Customer Method, because high fixed charges reduce incentives for customers to conserve energy by decreasing the volumetric rate.[26] Fixed charges cannot be avoided by reducing energy consumption or demand for electricity. If one assumes the same total revenue requirement for a class of customers, a rate design weighted towards fixed charges produces a smaller customer incentive to pursue energy efficiency because collecting a larger amount of revenue via fixed charges lowers the amount to be collected from other charges. That produces lower rates for those other charges, reducing the amount of cost savings that customers can achieve by modifying their energy usage patterns or making investments in more efficient equipment. In simpler terms, fixed charges prevent customers from lowering their electric bills through smarter, more efficient load management. The Commission has often expressed concern about rising customer costs, and approving increased fixed charges limits a customer's ability to lower their costs.

[26] This is particularly relevant in Virginia given the Clean Economy Act's mandatory Energy Efficiency Resource Standard ("EERS"). Higher fixed costs will seriously hamper, and in fact may completely thwart, the bill savings the EERS is supposed to provide.

Economic efficiency (*i.e.*, discouraging wasteful use of service) is also a common consideration. Economic efficiency is supported by rate designs that are based on marginal costs. The basic customer method approximates the marginal cost of adding a new customer to system because it reflects only the costs that are directly related to the number of customers, not the demand-related costs that arise from a customer's use of the shared system up to the level of their full demand.

C. Negative Impacts on Energy Efficiency

Q. PLEASE EXPLAIN HOW THE AMOUNT OF A FIXED CHARGE AFFECTS CONSUMER INCENTIVES FOR ENERGY EFFICIENCY.

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

Long-run price elasticity tends to be higher than short-run price elasticity because, over longer time horizons, consumers become aware of more alternatives and those alternatives become more attractive. For example, replacing an aging appliance with a more efficient model is more attractive than replacing a new one.[27] The ideas that electricity consumption is affected by price and that long-run effects are greater than short-run effects are widely accepted. In fact, both are central to the rationale for time-differentiated rates.

Q. DOES VIRGINIA HAVE A POLICY OF SUPPORTING ENERGY EFFICIENCY?

A. Yes. In April 2020, Virginia enacted the Virginia Clean Economy Act ("VCEA") which establishes energy efficiency savings targets of 0.50% of 2019 retail sales by 2022 for APCo, rising by 0.5% each year to 2% of 2019 retail sales by 2025.[28] In addition, also in April 2020, Virginia adopted revisions to the Commonwealth Energy Policy, which among other things established a new objective of "Maximizing energy efficiency programs, which are the lowest-cost energy option to reduce greenhouse gas emissions, in order to produce electricity cost savings and to create jobs and economic opportunity from the energy efficiency service sector."[29]

Q. IS THE COMPANY'S PROPOSED INCREASE IN THE RESIDENTIAL BSC CONSISTENT WITH VIRGINIA'S PRIORITIZATION OF ENERGY EFFICIENCY?

A. No. Increasing fixed charges while also attempting to produce higher levels of energy efficiency savings is like driving with one foot on the gas and one foot on the brake.

[27] *See e.g.*, Electric Power Research Institute. 2008. *Price Elasticity of Demand for Electricity: A Primer and Synthesis.* epri.com/#/pages/product/1016264/?lang=en.

[28] 2020 Va. Acts ch. 1193.

[29] 2020 Va. Acts ch. 1191.

Q. HOW DOES A POLICY OF PRIORITIZING ENERGY EFFICIENCY TYPICALLY TRANSLATE TO DECISIONS ON SETTING FIXED CHARGES?

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

Q. HOW DOES THE COMPANY'S PROPOSED RESIDENTIAL BSC COMPARE TO THOSE CHARGED BY IOUS IN STATES WHERE ENERGY EFFICIENCY IS PRIORITIZED AS A RESOURCE?

A. The Company's proposed charge of $14/month is well in excess of those authorized in states that place a high priority on energy efficiency. Table 1 shows the average and median fixed charges for states ranked highly by the American Council for an Energy-Efficient Economy ("ACEEE"). The states were selected based on ACEEE's 2019 Energy Efficiency Scorecard rankings for utility sector energy efficiency policies.[30] Each IOU in those states was selected for the table.[31]

Table 1: Fixed Charges in Highly Ranked EE States

ACEEE State Rank	Average Charge	Median Charge
Top 5	$6.55	$7.00

[30] 2019 State Energy Efficiency Scorecard, ACEEE (Oct. 1, 2019),https://aceee.org/research-report/u1908.

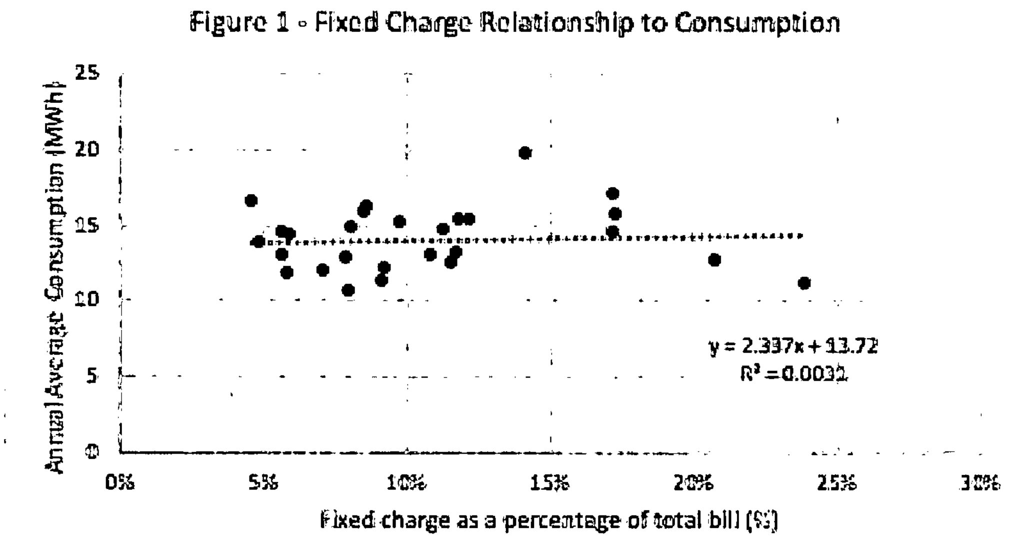
[31] These amounts are current as of June 23, 2020.

Top 10	$9.72	$8.01
Top 15	$9.97	$8.99
Top 20	$10.80	$9.60
Top 25	$10.10	$9.00

Q. DOES THE COMPANY PRESENT ANY EVIDENCE CONTRADICTING THE IDEA THAT FIXED CHARGES HARM CONSUMER EFFICIENCY INCENTIVES?

A. Company Witness Castle presents a graph depicting average residential energy usage compared to the percentage of a residential customer's bill among utilities in Virginia, which I have included below.[32]

Figure 1: Castle Figure 1



His graph depicts a linear trend line, which appears to show little relationship between the two by virtue of the trend line itself and a very low R-squared value. The R-squared value measures how well variations of one variable are explained by variations in another variable, where an R-squared value of 1

[32] Castle Direct, Figure 1 at 9.

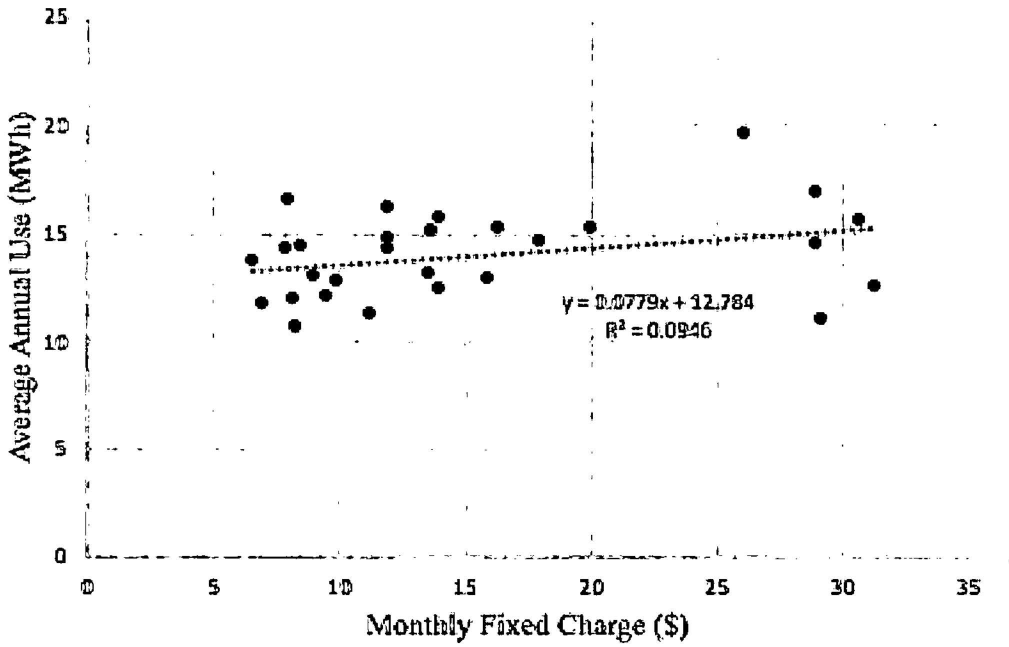
indicates perfect explanatory power (*i.e.*, 100% of the variation of one variable is explained by variation in another variable). In the graphic Company Witness Castle provides, the R-squared value is near zero, indicating that average residential energy use is not well explained by the percentage of a customer's bill that is attributable to fixed charges.

Q. DO YOU FIND THIS TO BE COMPELLING EVIDENCE THAT THE COMPANY'S PROPOSAL WOULD NOT ADVERSELY AFFECT ENERGY EFFICIENCY?

A. No. It is entirely unsurprising that an examination of only these two pieces of data in isolation would fail to provide a clear picture of the relationship between fixed charges and energy use. The representation simply indicates an obvious conclusion that there are likely many other factors that also influence residential energy use. Among those factors are the prevalence of electric heating, climate, the characteristics of housing stock, relative levels of consumer affluence, the prevalence of energy efficiency programs, and the duration for which the price relationship existed. Furthermore, the comparison itself is only one way to evaluate the relationship. A more direct comparison between the amount of the fixed charge and annual energy consumption shows that the amount of the fixed charge has greater explanatory power.

Figure 2 uses the same information used by Company Witness Castle in a more direct way, comparing the amounts of monthly fixed charges to average annual residential energy consumption. Figure 2 shows that higher fixed charges tend to be associated with higher electricity consumption, and that the amount of the fixed charge has greater explanatory power with respect to electricity use than the way Witness Castle conducted the comparison. This makes sense; if your electric bill does not fluctuate based on your use, you have no incentive to consume less because no price signal tells you to consume less.

Figure 2: Fixed Charge vs. Annual Electricity Use



Q. HOW SHOULD THE COMMISSION VIEW WITNESS CASTLE'S ANALYSIS IN LIGHT OF THE EVIDENCE YOU HAVE PRESENTED?

A. Witness Castle's analysis is limited and superficial, and is contradicted by a basic and well accepted economic principle supported by numerous more comprehensive analyses. I urge the Commission to reject this overly simplistic analysis.

D. National Fixed Charge Landscape and Gradualism

Q. HOW DOES APCO'S PROPOSED RESIDENTIAL BSC COMPARE TO THOSE CHARGED BY OTHER IOUS ON A NATIONAL LEVEL?

A. The Company's proposed rate would place it well above the national average and even more above the national median. The amount of the increase in both monetary and percentage terms is also well-above typical increases. Table 2 compares the proposed rate to the average and median fixed charges among 172 IOUs in 49 states and the District of Columbia.[33] The utilities in this survey encompass all major IOUs and nearly all smaller IOUs in each state. Accordingly, the survey presents a comprehensive national picture. It is current as of June 23, 2020. A table providing all current approved IOU residential fixed charges for the 172 IOUs examined in this survey is provided in Attachment JRB-5.

Table 2: National Fixed Charges Comparison

Basis of Comparison	Fixed Charge ($)	APCo Above ($)	APCo Above (%)
National Average Fixed Charge	$10.71	$3.29	30.7%
National Median Fixed Charge	$10.00	$4.00	40.0%
[redacted]			
APCo Proposed	$14.00		

Table 3 shows how APCo's proposal compares to typical increases in residential fixed charges based on a review of adopted increases for IOU general rate case applications filed since July 2014. A total of 223 general rate cases are

[33] Nebraska is the only state not represented in this survey. Nebraska is unique in that it is the only state served entirely by consumer-owned utilities not subject to external rate regulation.

represented in this sample, though the total number of utilities is lower because several utilities had multiple rate cases during this time frame (and thus the sample of adopted increases reflects these utilities more than once). It is current for rate cases decided through the end of May 2020. A table providing each existing (*i.e.*, at the time the rate case was filed) and ultimately approved IOU residential fixed charge used in this sample, and the associated nominal and percentage changes that were approved in each case, is provided in Attachment JRB-6.

Table 3: National Fixed Charge Increases Comparison

Basis of Comparison	Fixed Charge ($)	APCo Above ($)	APCo Above (%)
National Average Increase ($)	$0.94	$5.10	543.9%
National Median Increase ($)	$0.25	$5.79	2316.0%
National Average Increase (%)	12.9%		63.0%
National Median Increase (%)	3.8%		72.1%
APCo Increase ($)	$6.04		
APCo Increase (%)	75.9%		

Q. PLEASE EXPLAIN THE RELEVANCE OF THE COMPARISONS YOU HAVE PRESENTED TO APCO'S PROPOSED RESIDENTIAL BSC.

A. While the most important metric is that APCo's proposed charge is not justified based on APCo's own costs, the national comparison is useful to place the

Company in the context of other IOUs generally. The amounts of current fixed charges and adopted increases are objective indicators of how gradualism is practiced for the purpose of setting residential fixed charges. Whether one considers the statistical means or medians the proper measure, the results are similar. The comparison to utilities in states that prioritize energy efficiency as a resource presented in the prior section add a policy "modifier" into the assessment that illustrates how consideration of other policy goals affects outcomes.

Q. **WHY IS IT SIGNIFICANT THAT THE MEDIAN AMOUNTS PRESENTED IN TABLES 2 AND 3 ARE LOWER THAN THE AVERAGES?**

A. The median of dataset specifies the data point at which the number of values above it equal the number below it. When the average differs from the median, it indicates that there may be outliers (*i.e.,* unusually high or low values) that exert a disproportionate influence on the average. In this case, in both Tables 2 and 3, the average is above the median, indicating that the average is being skewed higher by a small number of data points that are the furthest from the "center." In other words, fixed charges and fixed charge increases that are *below* the averages are more common than those that are above the averages and the median could be seen as a better measure of what is the "typical" with respect to gradualism.

Q. HOW DOES THE COMPANY'S PROPOSED INCREASE COMPARE TO THE INDIVIDUAL DATA POINTS THAT FORM THE BASIS OF TABLE 3 ON ADOPTED INCREASES?

A. The Company's proposed increase of $6.04/month would rank as the 5th highest out of the 223 values in the sample in monetary terms. It would rank 8th of out 223 data points in terms of percentage of increase.

E. Impacts on Customers

Q. HOW WOULD THE COMPANY'S RATE PROPOSAL GENERALLY AFFECT CUSTOMERS WITH DIFFERENT LEVELS OF USAGE?

A. Fixed charge increases by nature result in greater percentage bill increases for lower usage customers than higher usage customers. Any customer with usage below the class average is made worse off while those with usage above the class average are better off when fixed charges are increased. The further a customer is from the class average, the greater the impact becomes.

Additionally, the difference in percentage bill impacts is sensitive to the percentage of any revenue increase that is recovered via a fixed charge. For instance, if the Commission were to approve a lower revenue requirement than what APCo has requested and implement that reduction entirely as a reduction in the volumetric rate (*i.e.*, adopt the proposed $14.00/month fixed charge), the spread of percentage bill impacts would increase between low and high usage customers.

Q. WHAT IS THE BREAKDOWN BETWEEN CUSTOMERS THAT BENEFIT FROM FIXED CHARGE INCREASES VERSUS CUSTOMERS THAT ARE NEGATIVELY IMPACTED BY FIXED CHARGE INCREASES?

A. For 2019 the residential class average usage was 1,133 kWh/month.[34] As noted above, the class average defines the customer indifference point with respect to fixed charges. The Company's bill frequency analysis shows that 51.71% of residential customers had average monthly usage below 1,100 kWh during 2019.[35] Assuming that the relationship between average usage and bill frequency during 2019 is representative of any given year, fixed charges are bad for roughly 53-54% of customers while 46-47% benefit from them.[36]

Q. RETURNING TO THE BONBRIGHT PRINCIPLES, HAS THE COMPANY PROVIDED EVIDENCE OF THE "ACCEPTABILITY" OF A LARGE FIXED CHARGE INCREASE TO ITS RESIDENTIAL CUSTOMERS?

A. No. The Company's testimony supporting its application does not address customer preferences. It stands to reason that higher usage customers would find it acceptable in general since they benefit, though the Company has not presented any research showing that, for instance, customers prefer bill stability over their ability to exercise greater control over their bills.

[34] Walsh Direct at 13:12.

[35] Company response to Staff 6-202, Attachment 1 – Bill Frequency RS Tariffs included as Attachment JRB-7.

[36] Based on an interpolation between the cumulative percentage of customers below 1,100 kWh and those below 1,200 kWh.

Q. HAS THE COMPANY EVALUATED HOW ITS PROPOSAL WOULD AFFECT CUSTOMERS WITH DIFFERENT LEVELS OF INCOME?

A. Not really. The Company suggests that low-income customers would benefit from the proposal because customers that receive lower-income energy assistance tend to have usage above the class average and that those same customers are slightly more likely than the average customer to rely on electric heating (*i.e.*, a factor that would typically increase average usage).

Q. DOES THIS ANALYSIS PRESENT A COMPLETE PICTURE OF HOW INCREASES IN THE RESIDENTIAL BSC WOULD AFFECT LOW-INCOME CUSTOMERS?

A. No. The Company's statistics are limited to customers that have elected to participate in the lower income energy assistance program, not all lower income customers. APCo states that it did not utilize and cannot easily obtain information on customer income that would permit an evaluation to be extended to all customers, not just those in the energy assistance program.[37] Accordingly, the Company's evaluation of the issue is incomplete and cannot be relied upon.

Given the lack of available information, it is not possible for me to specifically say what such a broader analysis would reveal in terms of the association between customer income and energy usage. However, it would not be surprising that usage by assistance program participants would be relatively high because the need for assistance is a product of *both* a customer's income and their electricity bill. Stated another way, the sample may be biased by the fact that

[37] Company response to ER 2-8(b) included as Attachment JRB-8.

those customers most in need of assistance are those low income customers with higher usage and higher bills in the first place.

In addition, the Company's sample may be biased in another way because APCo excluded customers with annual usage of less than 4,800 kWh (400 kWh/month).[38] The exclusion of the accounts with lower average usage would of course skew the average higher. APCo states that it excluded these data points in order to eliminate accounts with only a partial year of data.[39] While some amount of data cleaning of this type is likely necessary, a blanket exclusion of all lower usage accounts is inappropriate. A better approach would exclude only those accounts known to represent a partial year of data.

Finally, the Company's supporting data raises questions about the role that electric heating actually plays as a driver of usage among customers receiving energy assistance. In both years of the Company's sample (2018 and 2019), average usage among energy assistance recipients was *higher* among non-heating customers than electric heating customers.[40] In 2019 average monthly use by non-heating energy assistance customers was 1,220 kWh/month vs. 1,195 kWh/month for heating customers.[41] In 2018 the averages were 1,258 kWh/month for non-heating customers and 1,235 kWh/month for heating customers.[42] This oddity defies an easy explanation and creates questions about the reliability of the data.

[38] Company response to ER 3-2(b) included as Attachment JRB-9.

[39] *Id.*

[40] *See* Company response to Walmart 1-2, Walsh Direct Testimony Workpapers ("Walsh Workpapers") titled RS Usage 2018 and RS Usage 2019 included as Attachment JRB-10.

[41] Derived from Walsh Workpapers, RS Usage 2019.

[42] Derived from Walsh Workpapers, RS Usage 2018.

Q. IN SUMMARY, WHAT DO YOU MAKE OF THE COMPANY'S CLAIM THAT HIGHER FIXED CHARGES ARE GOOD FOR LOW INCOME CUSTOMERS?

A. The data does not support that conclusion. The data simply indicate that some lower income customers have high bills and experience difficulty paying their bills. It is not possible to conclude any more than that.

Q. ARE THERE BETTER SOLUTIONS FOR ADDRESSING THE NEEDS OF LOWER INCOME CUSTOMERS THAN FIXED CHARGE INCREASES?

A. Yes. Increasing fixed charges are a highly imprecise solution for addressing the needs of the segment of customers with both lower incomes and relatively high electricity usage. For one, no matter how you slice it, fixed charge increases will harm the significant percentage of lower income customers that are also lower usage customers.

Second, it fails to address the cause of high usage in the first place. As the Company observes, in instances where lower income customers have higher than average usage, it is "because they often do not have the resources to invest in weatherization and energy efficient appliances . . . ."[43] That is, an inability to invest in energy efficiency offsets the fact that we would expect them to have smaller homes with lower space conditioning needs and fewer appliances. A better solution is to seek out ways to improve the efficiency of their residences

[43] Walsh Direct at 13:7-8

through targeted energy efficiency programs. Establishing a general, non-targeted rate subsidy amounts to throwing good money after bad.

As I discuss in Section 3(c) of my testimony, there is a need to pursue beneficial building electrification in Virginia given the state's ambitious climate goals. A part of this effort should focus on low income customer needs, including, but not limited to, measures that support greater efficiency in electric heating.

F. Residential BSC Recommendation

Q. WHAT ARE THE COMPANY'S CUSTOMER-RELATED COSTS AS INDICATED BY ITS COST OF SERVICE STUDY?

A. The Company's cost of service study produces a residential class customer-related unit cost of $6.33/month at fully equalized rates or $5.76/month at proposed rates.[44] These amounts represent the monthly per customer costs for all costs that are classified as customer-related in the Company's cost of service study. As I have previously described, those costs include the costs of meters, service drops, customer service, billing, and a portion of general and overhead costs. The fully equalized rate represents full "cost of service," unaffected by adjustments to class revenues reflected in proposed rates.

However, due to some idiosyncrasies in deriving the annual residential customer-related revenue requirement that forms the basis of this calculation, it may understate residential customer-related costs. Under an alternative calculation that I performed, the residential customer-related cost comes to $8.53/month, or $8.19/month once a few small expense items that I do not believe

[44] Based on the spreadsheet version of Schedule 40C of the Company's Application, in the tab labeled "D Unit Cost". The Company's spreadsheet contains a formula error that I have corrected for the purpose of this calculation.

should be classified as customer-related have been excluded. The methodology that I used for this estimate is generally aligned with a similar calculation made by Commission Staff in APCo's last rate case.[45] The calculation essentially reflects the sum of the utility's return on customer-related net plant, income taxes, depreciation expenses on customer-related plant, and customer-related O&M expenses. My methodology differs slightly from Staff's 2014 methodology in the following ways:

- Staff's 2014 calculation appears to include only meters and services in the calculation of customer-related plant, while my own calculation includes the share of general and intangible plant that the Company classifies as customer-related.
- As noted above, the $8.19/month amount excludes several expense items that I do not believe should be classified as customer-related.
- I have deducted the other non-sales revenue that the Company classifies as customer-related from the revenue requirement.

Q. **PLEASE DESCRIBE THE EXCLUSIONS YOU MADE IN ARRIVING AT THE $8.19/MONTH AMOUNT FOR RESIDENTIAL CUSTOMER-RELATED COSTS.**

A. I consider it inappropriate to classify the costs listed below as customer-related based on the account level descriptions used in the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts.

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[45] Direct Testimony of Gregory L. Abbot, Attachment GLA-3, Ex., 68, *Appalachian Power Company for a 2014 biennial review of the rates, terms and conditions of the provision of generation, distribution and transmission services pursuant to § 56-585.1 A of the Code of Virginia*, Case No. PUE-2014-00026 (Aug. 20, 2014), https://scc.virginia.gov/docketsearch/DOCS/2yvj01!.PDF.

- Customer Installations Operation Expenses (FERC Account 587): This account relates to expenses associated with customer installations, including property leased to customers and contained in FERC Account 372. Neither relate to costs that are directly associated with connecting a customer to the grid.
- Miscellaneous Distribution O&M (FERC Accounts 588 and 598): These accounts are catch-alls for costs that cannot be directly attributed to a more specific purpose. If these costs were truly customer-related they would be included in other applicable accounts (*e.g.*, metering expenses).
- Uncollectable Accounts (FERC Account 904): Uncollectables are a general cost of doing business that have no relationship to the customer's connection to the grid. Any direct labor associated with collection activities would be contained in FERC Account 903, which I did not adjust.
- Miscellaneous Sales Expenses (FERC Account 916): This account contains sales expenses not assigned to another more specific account. Sales expenses include activities such as the promotion of the sale of electricity, customer retention, and other work for sales purposes. While they may appear to be superficially related to customer service, direct customer service and assistance is logged in other accounts. Promoting the sale of electricity should not be considered a customer-related cost.

Q. ARE THERE ANY OTHER ADJUSTMENTS TO THE COMPANY'S CLASSIFICATION OF CUSTOMER-RELATED COSTS THAT WOULD BE REASONABLE?

A. Yes. the Company classifies all metering costs as customer-related. While this classification has historically been well-justified, the advent of advance metering infrastructure ("AMI") suggests a more nuanced treatment because AMI, and related advanced billing systems, when deployed properly, accomplish far more than just the basic task of measuring customer usage. AMI is deployed, at least in part, with a goal of supporting energy and demand cost reduction, therefore the incremental cost of AMI metering and related systems beyond legacy metering can be seen as having energy and demand components that are not traditionally recovered through a fixed customer charge.

Q. WHAT IS YOUR RECOMMENDATION FOR A COST-BASED RESIDENTIAL BSC?

A. The current rate of $7.96/month is reasonable as a cost-based residential BSC. While I have derived an amount of $8.19/month based on the Company's cost of service study, with minor adjustments, this amount fails to capture the energy and demand-related components of AMI metering and related systems. In this case I have not been able to obtain the information necessary to quantify the amount of metering costs that should be considered non-customer-related, but a small deduction would be appropriate nevertheless. Given the small deduction ($0.23/month) between my calculated amount and the current rate, I believe the current rate of \$7.96/month to be an acceptable amount for the purposes of the instant proceeding.

In the alternative, should the Commission decide to depart from a cost-based methodology for setting the residential BSC, I recommend that the increase be limited to no more than \$1.00/month. This amount would reflect a reasonable exercise of gradualism on the part of the Commission based on what is typical in other states. As shown in Table 2, the increases adopted by regulators in other states for IOUs average \$0.94/month in monetary terms and 12.9% in percentage terms, the equivalent of approximately \$1.03/month from the current rate.

III. PROPOSED RESIDENTIAL WINTER TAIL BLOCK RATE

A. Recommendation on APCo's Proposal

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSAL FOR A WINTER TAIL BLOCK RESIDENTIAL RATE.

A. APCo proposes a \$0.04/kWh nominal discount for electricity usage above 1,100 kWh during the months of December – February for customers that take service on Schedule R.S. In order to recover the foregone revenue associated with this discount, the non-blocked rate for all other consumption would increase by \$0.00567/kWh. This results in an effective discount of \$0.03433/kWh (*i.e.,* the nominal discount minus the revenue true-up increase). The Company reflects the discount in the Generation portion of the unbundled rate.[46]

[46] Company's Application Schedule 42 Workpaper 3, Tab RS.

Q. HOW DOES THE COMPANY JUSTIFY ITS WINTER TAIL BLOCK RATE PROPOSAL?

A. APCo argues that high usage customers, electric heating customers most specifically, subsidize non-electric heating customers because electric heating customers require the same basic distribution infrastructure and cause the Company to incur the same fixed costs of service, but pay greater amounts in rates under the prevailing rate structure.[47] The Company also argues that its proposal would reduce winter bill volatility and that it holds particular benefits for low income customers because customers that receive energy assistance tend to have higher usage on average and are slightly more likely than the broader customer base to be electric heating customers (66% vs. 60%).[48] The Company's arguments in favor of a winter tail block rate are more or less identical to its arguments in favor of a large increase in the residential BSC.

Q. HOW DOES THE COMPANY JUSTIFY THE SPECIFICS OF ITS PROPOSAL, A $0.04/KWH DISCOUNT AND THE 1,100 KWH THRESHOLD?

A. The Company did not provide a specific justification for the amount of the discount. With respect to the 1,100 kWh threshold, APCo states that it is appropriate because electric heating customers use 1,100 kWh on average during non-winter months, meaning that "it can be assumed that any average usage over 1,100 kWh for those customers is attributable to winter electric heating."[49]

[47] *See* Walsh Direct at 10-11.

[48] Walsh Direct at 12-13.

[49] Company response to Staff 6-200 included as Attachment JRB-11.

Q. HOW DO YOU RESPOND TO THE COMPANY'S CONTENTION THAT LOW USAGE CUSTOMERS ARE BEING SUBSIDIZED BY HIGH USAGE CUSTOMERS?

A. Leaving aside distribution costs, which I have discussed in Section II of my testimony, the Company's cost of service study does not support Company Witness Walsh's assertion that the supposed intra-class subsidy between non-electric and electric heating customers "is true for the Company's fixed costs of generation service."[50] Company Witness Spaeth's workpapers demonstrate that the allocation of production costs to the residential class is heavily weighted towards coincident peak demands during December – February, which are undoubtedly associated with electric heating load. In other words, residential electric heating customers cause significant additional costs to be allocated to the residential class beyond what would be the case if they did not use electric heat.

By way of explanation, the Company bases production plant cost allocation on the average of six coincident peak demands ("6CP") for the months of December – February and June – August.[51] Class coincident peak demand during each month carries equal weight in this methodology. The average coincident peak for the residential class during December – February is roughly 2,036 MW while the average for June – August is roughly 1,175 MW. This produces a 6CP allocation factor for the residential class of 56.66%.[52] By contrast, if the allocation was based only on the June – August period, the residential class

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[50] Walsh Direct at 10:14-15

[51] Spaeth Direct, Schedule 1.

[52] Company response to Walmart 1-002, Spaeth - APCo VA Demand and Energy, Loss Factor 2019.xls

allocation would be 50.19%.[53] Alternatively if one assumed that the residential December – February coincident peak contribution was the same as the June – August contribution while all other classes remained the same, the residential class allocation of generation costs would be 48.90%.[54]

Clearly, residential electric heating customers contribute significantly to generation costs allocated to the residential class by virtue of the fact that they use electric heat. The assertion that "fixed" generation costs caused by residential electric heating customers are equivalent to those caused by non-heating customers is highly inaccurate. While it is not possible to determine precisely how much electric heating increases costs allocated to the residential class with available data, the amount is considerable, almost certainly in excess of $10 million.

Q. DO YOU AGREE THAT WINTER BILL VOLATILITY AMONG ELECTRIC HEATING CUSTOMERS IS AN ISSUE THAT NEEDS TO BE ADDRESSED?

A. Yes, but I disagree with some of the ways that the Company characterizes the issue and its preferred solutions of increasing the residential BSC across the board and instituting a winter tail block rate. One overarching fact that I urge the Commission to consider throughout this discussion is that a customer's total winter *energy* burden is the combination of electric *and gas or other fuel costs.* Direct comparisons of winter electric bills for electric heating customers to the

[53] Derived from Company response to Walmart 1-002, Spaeth - APCo VA Demand and Energy, Loss Factor 2019.xls

[54] *Id.* Calculated by using 1,176 MW as the residential class coincident peak and dividing by the system peak minus the difference between the 6CP residential class peak (1,606 MW) and the 1,176 MW amount.

electric-only bills of customers that heat with other fuels are inherently flawed. This is not to say that energy cost burdens among electric heating customers are not considerable or not worth addressing, but the mismatch embodied in thinking only about electric costs needs to be recognized.

Q. WHAT ARE THE DRAWBACKS OF ESTABLISHING A WINTER TAIL BLOCK RATE?

A. Tail-block rates erode consumer incentives for energy efficiency and reward customers with the highest levels of usage the most. As I discussed in the prior section of my testimony, price elasticity of electricity demand is a well-established concept. Though the exact amount of increased/decreased usage produced by a lower/higher price is challenging to define, the direction of the effect is widely accepted. Furthermore, a tail block rate provides the greatest discount to customers that use the largest amounts of electricity. Given the strong tie between the square footage of conditioned space and the energy necessary to heat that space, the Company's proposal would offer the greatest benefits to customers with the largest residences, who are in turn likely to be the most affluent customers.

A winter tail block rate also fails to get at the core issue present for electric heating customers, that a certain amount of usage is effectively unavoidable because a certain amount of heating energy will always be necessary to protect the basic health and well-being of a customer and their residence. Rather than acknowledge that this minimum level of "essential usage" is unavoidable and cannot be responsive to price signals (*i.e.*, an elasticity of zero), a winter tail block rewards the much more discretionary highest tranche of usage. The Company's proposal in the instant proceeding exacerbates the erosion of consumer efficiency incentives by applying the discount to all customers, not just those whose high winter usage is in part attributable to electric heating.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION ON THE COMPANY'S WINTER TAIL BLOCK RATE PROPOSAL?

A. I respectfully ask the Commission to reject the Company's proposal and instead adopt an alternative proposal that I have developed that better achieves the Company's goal of relieving pressure on electric heat customers. The Commission should also seek to find further ratemaking and other solutions to support building electrification, including the increased adoption of electric heating, in a manner that is consistent with meeting Virginia's climate goals, supports increased energy efficiency, and addresses the energy cost burdens faced by lower income ratepayers.

B. Alternative Electric Heating Rate Proposal

Q. HOW COULD AN ALTERNATIVE RATE DESIGN BE FORMULATED TO ADDRESS THE NEGATIVE ASPECTS OF A WINTER TAIL BLOCK RATE WHILE ALSO PRODUCING WINTER BILL RELIEF FOR ELECTRIC HEATING CUSTOMERS?

A. A better option would be to establish a decrement to the Schedule R.S. rate, but only for electric heating customers for usage up to a threshold that represents essential winter heating usage. Essentially, electric heating customers can cover their very basic electric heating needs at a discount, and all usage above that amount is priced at normal rates. This alternative—essentially the opposite of what the Company proposes—solves many of the problems created by the tail block. In contrast to a tail block design, this design preserves economic efficiency by correctly assuming that usage below the essential use threshold is entirely unresponsive to the rate, while usage above that threshold has a progressively increasing discretionary nature (*i.e.*, a non-zero elasticity).

Q. PLEASE DESCRIBE THE SPECIFIC PARAMETERS OF YOUR ALTERNATIVE PROPOSAL.

A. I recommend that the Commission direct APCo to establish a rate for residential electric heating customers that provides a nominal discount of $0.04713/kWh for electric usage up to 400 kWh per month from December – March. The effective discount would be $0.04375/kWh relative to a fully flat rate due to the need to increase the non-discounted rate to achieve the same amount of revenue.

Q. PLEASE EXPLAIN WHY YOU SELECTED THE 400 KWH AS THE THRESHOLD FOR WINTER ELECTRIC HEATING ESSENTIAL USAGE.

A. This amount corresponds to the approximate difference in monthly usage by electric heating customers compared to non-electric heating customers from December – March (519 kWh/month more by heating customers) minus the difference in usage between the two groups from May – October (117 kWh/month more by electric heating customers).[55] The December – March time frame comprises the bulk of the heating season while the May – October time period

[55] Derived from the Company's response to Staff 6-200, Attachment 1 – Winter Tail Block.

represents a time frame where little to no electric heating use takes place. Accordingly, the measure of essential heating electricity usage is the difference between average use during heating months and the difference during non-heating months. The subtraction of non-heating month excess usage corrects for the fact that this portion of higher usage cannot be attributed to electric heating. The specific result of this equation is 402 kWh, which I have rounded to 400 kWh.

Q. PLEASE EXPLAIN HOW YOU ARRIVED AT THE RECOMMENDED RATE DECREMENT.

A. I used the Company's proposed tail block rate as a starting point. The Company's proposal produces a revenue deficit of approximately $34 million, which is then made up through an increase in the rate for the first block. Because my proposal would only apply to electric heating customers, which are roughly 60% of residential customers, I reduced the revenue decrement by approximately 40% to $20.4 million.[56] I then divided this targeted revenue by the total amount of usage by electric heating customers for the 4-month window (*i.e.*, 1,600 kWh per electric heating customer).

Q. WHY DO YOU RECOMMEND ADDING THE MONTH OF MARCH AS A WINTER MONTH IN YOUR ALTERNATIVE PROPOSAL?

A. The month of March still shows a considerable difference in monthly electric consumption between electric heating and non-electric heating customers. Electric heating customers used 456 kWh more electricity on average than non-electric

[56] This reduction also reflects my observation that electric heating is a significant factor in production cost allocation to the residential class. As I previously noted I do not possess the information to fully quantify the added cost contribution, but by reducing the revenue decrement by roughly $14 million relative to the Company's proposal helps address the issue.

heating customers in March 2019, which is nearly identical to the 457 kWh difference in December 2019. The difference in heating vs. non-heating consumption drops considerably after March. Furthermore, the Company's 2019 bill frequency analysis shows that during March 2019, roughly 54% of customers had usage in excess of 1,100 kWh, the rough residential monthly average.[57] Both of these characteristics indicate that March is more like a winter month with considerable electric heating load than a non-winter month with minimal or no electric heating load.

Q. HOW MUCH SAVINGS WOULD AN ELECTRIC HEATING CUSTOMER EXPERIENCE UNDER THE DESIGN YOU PROPOSE?

A. Each electric heating customer would have an initial maximum monthly savings amount of $17.50/month relative to an entirely flat rate. This savings would decline with each incremental kWh a customer uses above the 400 kWh threshold because keeping total class revenue constant requires an increase in the generally applicable rate, roughly 0.34 cents/kWh. A hypothetical electric heating customer with monthly usage of 1,500 kWh on average during the winter months would still see a winter monthly bill decrease of $13.79/month. At 2,500 kWh per month of winter consumption, on average, the savings would still be $10.42/month.

The actual effective savings on an annual basis would depend on usage both during the winter months and the remainder of the year. An electric heating customer with average monthly use for the entire year of roughly 1,860 kWh per month would essentially be indifferent because their savings under the lower

[57] Company response to Staff 6-202, Attachment 1 – Bill Frequency RS Tariffs included as Attachment JRB-7.

winter tier rate would be offset by their costs for usage that is not subject to the discounted rate. This amount is roughly 64% more than class average use and 36% more than average use among residential heating customers according to the Company's 2019 usage data.[58] The key feature of this design is that it rewards lower usage customers the most. It also does not unduly penalize customers with above average usage, as net bill increases only occur for heating customers with well above average usage.

Q. HOW WOULD NON-ELECTRIC HEATING RESIDENTIAL CUSTOMERS BE AFFECTED BY YOUR PROPOSED RATE DESIGN.

A. Non-electric heating customers would see an increase in costs, the magnitude of which would depend on how much electricity they use. The same is actually true under APCo's proposal, but under my alternative the added cost is lower because the discount is more targeted and results in a lower revenue deficit recovered under the non-discounted portion of the rate.

Q. PLEASE DESCRIBE HOW YOUR ALTERNATIVE PROPOSAL FORWARDS THE OBJECTIVES OF VIRGINIA'S ENERGY POLICY.

A. As discussed in Section 2, the General Assembly passed a new law stating that maximizing energy efficiency is a state policy objective.[59] Moreover, this same law provides:

- A legislative finding stating "Climate change is an urgent and pressing challenge for Virginia. Swift decarbonization and a transition to clean energy are required to meet the urgency of the challenge"; and

[58] Derived from Walsh Workpapers, RS Usage 2019.

[59] 2020 Va. Acts ch. 1191.

- A further objective of "Establishing greenhouse gas emissions reduction goals across Virginia's economy sufficient to reach net-zero emissions by 2045, including the electric power, transportation, industrial, agricultural, building, and infrastructure sectors".[60]

Collectively, these goals and findings point to a need to pursue building decarbonization while not compromising consumer energy efficiency motivations, including those provided through residential electric rates. I have designed my alternative proposal to do just that. My proposed rate design produces cost savings for electric heating customers while ensuring that the source of those cost savings is limited to entirely non-discretionary usage that cannot respond to a price signal in rates.

Q. DOES THE COMPANY POSSESS THE INFORMATION NECESSARY TO IMPLEMENT A RATE SPECIFIC TO ELECTRIC HEATING CUSTOMERS?

A. Yes. The Company has stated that it maintains an electric heating and non-electric heating classification in its customer records based on information recorded at the time service was initiated.[61]

[60] 2020 Va. Acts ch. 1191.

[61] Company response to ER 3-2 (c) and (d) included as Attachment JRB-9.

C. Need for Action on Beneficial Electrification

Q. WHY IS IT IMPORTANT FOR THE COMMISSION TO ACT WITH URGENCY ON THE ISSUE OF RATE DESIGNS TO SUPPORT BUILDING ELECTRIFICATION, SUCH AS RESIDENTIAL ELECTRIC HEATING?

A. A net-zero carbon economy requires building electrification, but the building electrification transition is a long process. Transitioning the space heating end-use to electricity is particularly challenging because heating systems tend to have a long service life and gas heating is often less costly. A typical residential heating system has a service life of around 15 years, meaning that less than 7% of heating systems are likely to require replacement during any given year. Some systems may remain operable for 20 years or more. Yet, the end of service life replacement cycle constitutes the best opportunity to pursue fuel switching on a least-cost basis. Accordingly, if one considers that some systems may last 20 years or longer, the window for ensuring that all system replacements involve a switch to electric-only is quickly closing. The Commission needs to act with urgency in order to ensure that fuel switching takes place along a reasonable glide path and that the current penetration is not eroded by fuel switching to natural gas based on present economics.

Q. **IS THE RESIDENTIAL ELECTRIC HEATING RATE PROPOSAL YOU HAVE MADE SUFFICIENT FOR THE PURPOSE OF ACHIEVING FULL RESIDENTIAL ELECTRIFICATION?**

A. No. The intent of my proposal is to supply an alternative that is more consistent with Virginia's energy goals than the Company's proposal. It is a reasonable starting point for addressing the near-term energy cost burdens faced by residential electric heating customers, but it does not address all non-electric end uses, nor should it be viewed as an end-point even for residential heating. A considerable amount of further work is necessary to realize Virginia's decarbonization goals. This includes a more general evolution of rate structure(s) to support building electrification, consideration of how to do so without eroding consumer energy efficiency incentives and preserving cost-causation principles, the use of energy efficiency programs themselves to support electrification, and the place that efforts and programs targeting the energy burden faced by lower income customers has in this process.

Q. **FROM THE STANDPOINT OF RATEMAKING, WHAT FURTHER ACTIONS DO YOU RECOMMEND THAT THE COMMISSION TAKE?**

A. I have two primary recommendations focused on ratemaking and rate design. First, I recommend that the Commission undertake an investigation of the nature of essential electric usage among residential customers. I have endeavored to define a reasonable measure of essential winter electric heating usage by residential customers but there are other end uses that could be considered "essential" and therefore insulated from being affected by price signals in rates.

Furthermore, the nature of essential residential heating usage itself would benefit from further study because I possessed limited data for this purpose and there are many other factors that might be considered as a part of such a study (*e.g.*, conditioned area, climate zone, building stock age, efficiency of the heating system). The results of such a study should be used to inform rate designs that support electrification while preserving the economic efficiency of price signals.

Second, I recommend that the Commission begin developing further information on the rate options that can be used to support beneficial electrification. APCo's winter tail block rate proposal could be seen as an electrification-supportive rate, but as I have already discussed it has considerable drawbacks and is not aligned with beneficial electrification. A further exploration of the options at the Commission's disposal is needed to identify the best path forward.

I also note that the Commission has recently expressed interest on the subject of electric vehicle ("EV") rates, EV rate design, and related issues in Case No. PUR-2020-00051, and I urge it to also seek further information on the topic of building electrification. Transportation electrification and building electrification have common issues from the standpoint of ratemaking and common goals from the standpoint of Virginia's decarbonization goals. Beneficial electrification as a general concept encompasses both, and Virginia would benefit from a comprehensive effort that addresses their similarities, differences, and interconnected nature.

For instance, the use of time-varying marginal cost pricing for incremental load could be applied to both, but adaptability to time-varying price signals may differ between EV load and building load. Likewise, there is reason to consider what building and transportation electrification in concert with one another mean for the distribution grid and for the rates charged to different customer segments. The costs for providing distribution service for a large single-family home with large heating needs and multiple EVs are likely to differ considerably from those associated with smaller multi-family units housing residents that rely on public transportation or separate EV charging stations. Equity issues are likely to become more rather than less pronounced with the proliferation of electrification.

Q. WHAT OTHER ACTIONS DO YOU RECOMMEND THE COMMISSION TAKE ON THE ISSUE OF BUILDING ELECTRIFICATION?

A. Supporting electrification through ratemaking needs to be accompanied by efforts to increase energy efficiency more generally, particularly in areas with older housing stocks and a heavy reliance on resistance electric heating, as well as facilitate fuel switching during the end of life replacement cycle. I recognize that energy efficiency programs are outside of the scope of the instance proceeding, but I recommend that the Commission devote considerable attention to how programmatic efforts can be combined with ratemaking actions in a synergistic fashion.

APCo's dual proposals for a large increase in the residential BSC and the establishment of a winter tail block rate highlight the choices that the Commission is facing with respect to cost attribution, rate design, and the energy burdens faced by lower income customers, which are made even more pronounced by the prospect, and need for, a shift to broad electrification. All of these issues are ripe for the Commission to address. While the Company's specific proposals are ill-suited for the purpose of meeting Virginia's energy goals, I do not disagree that Commission action is warranted on multiple fronts.

IV. PROPOSED RIDER CAR

Q. PLEASE DECRIBE THE PURPOSE OF PROPOSED RIDER CAR.

A. The Company's Rider CAR proposal contemplates the implications of VCEA on its remaining coal fleet, the Amos Plant and the Mountaineer Plant. Company Witness Castle observes that due to the VCEA it will be increasingly unable to use these plants to meet Virginia load and that "the Commission may wish to address the remaining plant balances" associated with both plants.[62] APCo proposes to use Rider CAR to collect money from current ratepayers to buy-down those remaining plant balances, accelerating its recovery of the plant balances alongside a corresponding reduction in the remaining rate base. Effectively, this results in current customers paying more of the costs and future customers paying less of the costs.

Witness Castle explains that the proposal is intended to "provide the Commission flexibility with regard to future asset disposition decisions" based on an "[u]nderstanding that both the Company and the Commission wish to avoid or minimize any potential cost burden on future customers . . . ."[63] The Company

[62] Castle Direct at 17:11-13.

[63] *Id.* at 17:15-19.

proposes this buy-down take place at $25 million annually, or up to $15 million annually if the Commission does not grant the entire increase it seeks.[64]

Q. DOES THE COMPANY EXPLAIN WHY IT BELIEVES THE COMMISSION NEEDS THE "FLEXIBILITY" PROVIDED BY ITS PROPOSAL?

A. Company Witness Vaughn describes Rider CAR as "superior to normal base rate recovery in that it is far more flexible and can be updated annually rather than every three years in the Triennial review proceedings." Witness Vaughn also states that Rider CAR should be viewed "as a tool that it and the Company can utilize to make adjustments to net book value (plant investment) recovery of APCo's aging coal plants and avoid large remaining balances and generational subsidies if, in the future, it cannot use these resources to serve its Virginia customers."[65]

Q. DO YOU AGREE WITH WITNESS VAUGHN THAT THE COMMISSION REQUIRES THIS FLEXIBILITY?

A. No. Under House Bill 528 ("HB528"), which passed in the 2020 legislative session, the Commission possesses unrestricted authority to determine the amortization period for early retirements of coal or natural gas units. In doing so it must:

- Perform an independent analysis of the remaining undepreciated capital costs;
- Establish a recovery period that best serves ratepayers; and

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[64] *Id.* at 18:1-5.

[65] Direct Testimony of at Alex E. Vaughn ("Vaughn Direct") at 13:8-13.

- Allow for the recovery of any carrying costs that the Commission deems appropriate.[66]

The authority granted to the Commission under HB528 provides the Commission with all the flexibility it needs to establish a recovery mechanism that properly balances ratepayer and Company interests, including but not limited to how it views so-called "generational subsidies" and weighs the merits of shorter or longer amortization periods. The Company's proposal is simply unnecessary, and poorly timed given the ongoing economic uncertainty caused by COVID-19.[67]

Q. PLEASE ELABORATE ON HOW THE COMPANY'S PROPOSAL IS "POORLY TIMED".

A. There may be certain circumstances where it would be *necessary* to authorize rate increases even when a utility's customers are facing unexpected economic challenges, such as those created by the COVID-19 pandemic. This, however, is not one of those circumstances. APCo's proposal is entirely discretionary because: (1) the Company has not even determined when its remaining coal assets will be retired, and (2) the Commission possesses unfettered authority to address cost recovery for those assets under HB528. The discretionary nature of the proposal argues against its approval since it would exacerbate energy cost burdens on customers during a time of extraordinary economic upheaval of an uncertain magnitude and duration. The Commission would be entirely justified in rejecting it for this reason alone.

[66] 2020 Va. Acts ch. 662.

[67] The proposal likely made much more sense (and in fact APCo likely conceived of it) prior to the 2020 legislative session. In 2018, the Commission was stripped of its ability to amortize stranded asset costs, and the current proposal was arguably a way to remedy that issue. Now that HB 528 has restored the Commission's proper power, however, the proposal is unnecessary.

Q. DO YOU AGREE WITH THE COMPANY'S PREMISE THAT PRE-COLLECTION OF COSTS IS NECESSARY TO ADDRESS SO-CALLED "GENERATIONAL SUBSIDIES"?

A. No. The Company does not elaborate on precisely what it means by this phrase. I interpret it as suggesting that the Commission should avoid or minimize placing cost recovery for retired assets on future ratepayers that did not "use" the resource during the time it was in service (*e.g.*, through an amortization mechanism). It is my observation that the existence of a generational subsidy under these circumstances is very much a matter of perspective that depends on how one views the "benefits" of retiring the coal units.

Future ratepayers can be seen as benefiting from coal retirements because they will receive service from a cleaner electricity system with lower carbon and other emissions. They also benefit from avoiding operations and maintenance expenses on the units and a reduction in the risk of future environmental costs. To the extent that the units become uneconomic to operate, as Company Witness Vaughn observes could be the case in the future,[68] future ratepayers benefit from their retirement. The idea that future ratepayers are being disadvantaged simply because they never "used" the coal plants is an oversimplification of the matter.

[68] Vaughn Direct at 13:17—14:2

Q. ARE YOU AWARE OF ANY EXAMPLES FROM OTHER STATES WHERE REGULATORS HAVE ALLOWED A PRE-COLLECTION MECHANISM FOR EARLY COAL ASSET RETIREMENTS?

A. No. Typical practice has been to update depreciation rates once retirement dates are known, oftentimes accompanied by guardrails such as capital expenditure limitations and auditing protocols. Some Commissions have adopted measures to mitigate the rate impacts of accelerated depreciation such as using existing deferred balances to offset the costs to ratepayers that are associated with accelerated depreciation. If APCo truly intends to retire Amos and Mountaineer early, it should formally impair them and adjust the depreciation schedule accordingly. The current proposal is like having your cake and eating it too: pre-collecting on potential stranded asset costs without actually impairing the asset.

One could view the use of balances owed to ratepayers to effectively buy down higher depreciation costs as a variety of pre-collection. However, this analogy is misleading because those deferred balances are actually amounts owed to current and *past* ratepayers due to historic overcollection. The practical effect is to reduce collections from current ratepayers by accelerating the return of balances owed to them, in recognition that past overpayments should be repaid to those customers that made them rather than future customers. APCo's proposal is actually the reverse of this practice as it charges current customers more than future customers.

Q. WOULD THE ADOPTION OF RIDER CAR BE CONSISISTENT WITH THE LEGISLATURE'S DIRECTIVES TO THE COMMISSION UNDER HB528?

A. While HB528 affords the Commission a fair amount of discretion, I do not believe that Rider CAR is consistent with the new law. In particular, HB528 requires that the Commission perform an independent analysis of the remaining undepreciated costs and establish a recovery period that "best serves" ratepayers. Since the retirement dates have not been established,[69] the Commission cannot perform such an analysis. In addition, assigning a recovery period that is in the best interest of ratepayers seems equally impossible because the Commission lacks the information on what the remaining undepreciated costs will be at the time of retirement and the factors affecting the best interests of ratepayers at the time this information becomes known.

In other words, the best interests of ratepayers cannot be judged without considering all factors in play and all potential options that exist when complete information is known. Furthermore, the adoption of Rider CAR would define the start of the recovery period, not the end, to coincide with a period of unique economic distress and uncertainty for ratepayers. I do not see how the Commission could possibly conclude that commencement of the recovery period right now "best serves" ratepayers, especially since the actual retirement dates are unknown.

[69] APCo could, of course, formally announce plans to retire these plants, which would then allow APCo to impair the assets and enable the Commission to establish a proper amortization period based on the impairment.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION ON APCO'S RIDER CAR PROPOSAL?

A. The Commission should reject Rider CAR and address the issue of coal retirement cost recovery according to the specific facts and circumstances present when firm retirement dates become known.

V. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION ON THE COMPANY'S APPLICATION.

A. First, I recommend that the Commission deny the Company's request to increase the residential BSC to $14.00/month. Based on customer-related costs derived using the Basic Customer Method—the most common method used through the country to establish fixed charges—the residential BSC should remain at its current level of $7.96/month.

Second, I recommend that the Commission deny the Company request to establish a winter tail block. Instead of the Company's approach, I recommend an alternative proposal that would apply a rate discount only to customers with electric heating for consumption of up to 400 kWh/month during the months of December through March. This proposal will better target customers most in need of assistance with basic electric needs for health and safety, while maintaining price signals to reduce electricity consumption.

Third, I recommend that the Commission reject proposed Rider CAR. It is unnecessary given the Commission's newly granted amortization authority, and especially inappropriate given the ongoing economic impacts of COVID-19.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that the following have been served with a true and accurate copy of the foregoing via electronic service:

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DATED: July 30, 2020

Part 2

Virginia State Corporation Commission
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Environmental Respondent Testimony

Part 2

Attachment JRB-1

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EDUCATION

Michigan Technological University — Houghton, Michigan
Master of Science, Environmental Policy, August 2006
Graduate-level work in Energy Policy.

University of Oklahoma — Norman, Oklahoma
Bachelor of Science, Geography, December 2003
Area of concentration in Physical Geography.

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

North Carolina Utilities Commission. Docket No. E-7 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 201500271. 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 Master's Thesis Awards (2007)
- Sustainable Futures Institute Graduate Scholar Michigan Tech University (2005-2006)

200740079

Attachment JRB-2

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2020-00015
Interrogatories and Requests for the Production
of Documents by the ENVIRONMENTAL RESPONDENTS
ER Set 2
To Appalachian Power Company

Interrogatory ER 2-4:

Refer to the Direct Testimony of Witness Katharine I. Walsh at 9:15 proposing a residential basic service charge of $14/month. Please explain in detail the reasons why the Company proposes to set the basic service charge at this specific level, including any relationship that exists to the amount of customer-related costs indicated by the Company's Class Cost of Service Study.

Response ER 2-4:

Please see the same direct testimony at page 14 line 1-11 through page 15 line 3. Although the Company can support a basic service charge higher than $14, the Company is considering the principle of gradualism when introducing a rate change such as this.

The foregoing response is made by Katharine I. Walsh, Reg Pricing & Analysis Mgr, on behalf of Appalachian Power Company.

200740079

Attachment JRB-3

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2020-00015
Interrogatories and Requests for the Production
of Documents by the ENVIRONMENTAL RESPONDENTS
ER Set 2
To Appalachian Power Company

Interrogatory ER 2-7:

Refer to Schedule 1 of the Direct Testimony of Witness Katharine I. Walsh.
a) How many residential customers would the 15 kVA transformer listed under FERC Account 368 typically serve?
b) What is the maximum number of residential customers that might be served by a 15 kVA transformer?
c) Does the single 40 foot Class 4 secondary distribution pole listed under FERC Account 364 typically serve a single customer service drop?
d) Are there instances where a single 40 foot Class 4 secondary distribution pole hosts service drops leading to multiple residential customers?
e) What is the maximum number of residential customers that might be served by a single 40 foot Class 4 secondary distribution pole?
f) Would the 400 foot secondary conductor extension listed under FERC Account 365 typically serve a single residential customer or multiple residential customers?
g) What is the maximum number of residential customers that might be served by a 400 foot secondary conductor extension?

Response ER 2-7:

(a, b, c) It depends on each residential customer's load, location, and geography. Does the customer have certain appliances, like air conditioner(s), heat pump(s), electric or gas heat. What is the distance from the pole & transformer to the home? What is the local geography of the area (urban, rural, apartments, duplex, hilly, hollows, etc.)?
(d) It depends upon how close multiple customers are to the pole, plus each residential customers' load.
(f, g) The Company would not make a 400 foot secondary conductor extension because of voltage drops. It would install a 400 foot primary conductor extension typically for a single residential customer.

The foregoing response is made by Philip A. Wright, VP Dist Region Opers, and Katharine I. Walsh, Reg Pricing & Analysis Mgr, on behalf of Appalachian Power Company.

Attachment JRB-4

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2020-00015
Interrogatories and Requests for the Production
of Documents by the ENVIRONMENTAL RESPONDENTS
ER Set 2
To Appalachian Power Company

Interrogatory ER 2-14:

Does the Company possess data showing the number of its residential customers that reside in multi-unit dwellings? If so, please provide residential customer numbers for multi-unit customers and single-family dwelling customers. If the Company does not possess this data, please so state.

Response ER 2-14:

Please see ER 2-14 Attachment 1 for the requested information.

The foregoing response is made by Katharine I. Walsh, Reg Pricing & Analysis Mgr, on behalf of Appalachian Power Company.

What one type best describes your home?

	2013 Survey	2016 Survey	2018 Survey
Mfd/Mobile Home	70,272	51,101	62,664
Apt./Condo/TH (2-4 units)	16,913	34,837	27,778
Apt./Condo/TH (> 4 units)	31,151	27,119	12,084
Single-Family Home	317,849	322,086	315,827
Total Responses	**436,185**	**435,144**	**418,353**

Attachment JRB-5

Attachment JRB-5 – Current IOU Residential Fixed Charges

State	Utility	Existing Fixed Charge
Mississippi	Mississippi Power	$26.16
Wyoming	Montana-Dakota Utilities	$23.39
Florida	Florida Public Utilities	$23.35
New York	RG&E	$22.10
Wisconsin	Wisconsin Public Service	$21.00
Alaska	Alaska Power Company	$20.00
Oklahoma	PSO	$20.00
Wyoming	Rocky Mountain Power	$20.00
New York	Central Hudson Gas & Electric	$20.00
New York	Orange & Rockland Utilities	$19.50
Florida	Gulf Power	$19.47
Wisconsin	MGE	$19.00
Indiana	IP&L	$17.00
New York	National Grid	$17.00
Wisconsin	Xcel Energy	$17.00
New Hampshire	Unitil	$16.22
Kentucky	Kentucky Utilities	$16.12
New York	Con Edison	$16.00
Wisconsin	We Energies	$15.99
New York	NYSEG	$15.92
Wyoming	Black Hills Power	$15.50
Nevada	Sierra Pacific Power Company	$15.25
Illinois	Commonwealth Edison	$15.22
District of Columbia	Pepco	$15.09
Florida	Tampa Electric	$15.05
Arizona	Arizona Public Service	$15.00
Arizona	UniSource Energy Services	$15.00
Indiana	Indiana Michigan Power	$15.00
Michigan	Upper Peninsula Power Company	$15.00
Wisconsin	Alliant Energy	$15.00
Vermont	Green Mountain Power	$14.97
New Hampshire	Liberty Utilities	$14.74
Alabama	Alabama Power	$14.50
Kansas	Westar Energy	$14.50
North Dakota	Xcel Energy	$14.50
Kansas	Empire District Electric	$14.25
Kansas	KCP&L	$14.25
Pennsylvania	PPL Electric Utilities	$14.09
Kentucky	Kentucky Power	$14.00
North Carolina	Duke Energy Carolinas	$14.00
North Carolina	Duke Energy Progress	$14.00
North Dakota	Otter Tail Power Company	$14.00
North Dakota	Montana-Dakota Utilities	$13.99
Illinois	Ameren Illinois	$13.98
New Hampshire	Eversource	$13.81

Attachment JRB-5 – Current IOU Residential Fixed Charges

Kentucky	LG&E	$13.69
Indiana	NIPSCO	$13.50
Arizona	Tucson Electric Power	$13.00
Iowa	Alliant Energy	$13.00
Missouri	Empire District Electric	$13.00
Oklahoma	Oklahoma Gas & Electric	$13.00
Pennsylvania	Citizens' Electric Company	$13.00
Wisconsin	North Central Power	$13.00
Wyoming	Black Hills Energy	$13.00
Connecticut	United Illuminating	$12.84
Maine	Central Maine Power	$12.76
Tennessee	Kingsport Power (AEP AppCo)	$12.63
Kentucky	Duke Energy Kentucky	$12.60
Nevada	Nevada Power Company	$12.50
Oklahoma	Empire District Electric	$12.50
Pennsylvania	Duquesne Light	$12.50
Michigan	Wisconsin Public Service	$12.00
Pennsylvania	Wellsboro Electric Company	$12.00
South Dakota	Black Hills Power	$12.00
Virginia	Kentucky Utilities	$12.00
West Virginia	Appalachian Power Company	$12.00
South Carolina	Duke Energy Carolinas	$11.96
South Carolina	Duke Energy Progress	$11.78
Delaware	Delmarva Power	$11.70
Hawaii	Hawaii Electric Light (HELCO)	$11.50
Hawaii	Hawaiian Electric (HECO)	$11.50
Hawaii	Maui Electric (MECO)	$11.50
Missouri	KCP&L	$11.47
Missouri	KCP&L Greater Missouri Operations	$11.47
Pennsylvania	Met-Ed	$11.25
Pennsylvania	Penelec	$11.25
Arkansas	Empire District Electric	$11.04
Indiana	Vectren Indiana	$11.00
Oregon	Portland General Electric	$11.00
Pennsylvania	Penn Power	$11.00
Wisconsin	Northwestern Wisconsin Electric Company	$11.00
North Carolina	Dominion North Carolina Power	$10.91
Florida	Duke Energy Florida	$10.58
Arkansas	SWEPCO	$10.00
South Dakota	Otter Tail Power Company	$10.00
Texas	Entergy Texas	$10.00
Texas	Xcel Energy	$10.00
Pennsylvania	PECO	$9.98
Georgia	Georgia Power Company	$9.97
Arkansas	Oklahoma Gas & Electric	$9.75
Minnesota	Otter Tail Power Company	$9.75
Connecticut	Eversource	$9.62

Attachment JRB-5 – Current IOU Residential Fixed Charges

Michigan	Upper Michigan Energy Resources	$9.60
New Mexico	Xcel Energy (SPS)	$9.60
Oregon	Pacific Power	$9.50
California	Liberty Utilities	$9.02
Indiana	Duke Energy Indiana	$9.01
Louisiana	Cleco	$9.00
Michigan	Xcel Energy	$9.00
Missouri	Ameren Missouri	$9.00
South Carolina	SCE&G (Dominion SC)	$9.00
Washington	Avista Utilities	$9.00
Wisconsin	Superior Water Light & Power	$9.00
Illinois	MidAmerican Energy	$8.97
Colorado	Black Hills Energy	$8.77
Pennsylvania	UGI Electric	$8.74
Alaska	Alaska Electric Light & Power	$8.60
Iowa	MidAmerican Energy	$8.50
Arkansas	Entergy Arkansas	$8.40
Ohio	Ohio Power Company	$8.40
Florida	Florida Power & Light	$8.34
Maryland	Delmarva Power	$8.30
South Dakota	Xcel Energy	$8.25
Texas	El Paso Electric	$8.25
Louisiana	Entergy New Orleans	$8.07
Maryland	Pepco	$8.01
Maryland	BGE	$8.00
Minnesota	Minnesota Power	$8.00
Minnesota	Xcel Energy	$8.00
Oregon	Idaho Power Company	$8.00
South Dakota	MidAmerican Energy	$8.00
Texas	SWEPCO	$8.00
Virginia	Appalachian Power Company	$7.96
Texas	Texas-New Mexico Power	$7.85
Washington	Pacific Power	$7.75
South Dakota	Montana-Dakota Utilities	$7.51
Michigan	Consumers Energy	$7.50
Michigan	DTE	$7.50
New York	Penelec	$7.49
Washington	Puget Sound Energy	$7.49
Pennsylvania	West Penn Power	$7.44
Michigan	Indiana Michigan Power	$7.25
California	Pacific Power	$7.20
New Mexico	PNM	$7.11
Louisiana	Entergy Louisiana	$7.04
Massachusetts	Eversource Eastern	$7.00
Massachusetts	Eversource Western	$7.00
Massachusetts	National Grid	$7.00
Massachusetts	Unitil	$7.00
New Mexico	El Paso Electric	$7.00

Attachment JRB-5 – Current IOU Residential Fixed Charges

Ohio	Dayton Power & Light	$7.00
Mississippi	Entergy Mississippi	$6.75
Virginia	Dominion Virginia	$6.58
California	Bear Valley Electric Service	$6.39
Maine	Emera Maine	$6.36
Idaho	Avista Utilities	$6.00
Ohio	Duke Energy Ohio	$6.00
Rhode Island	National Grid	$6.00
South Dakota	NorthWestern Energy	$6.00
Utah	Rocky Mountain Power	$6.00
Montana	Montana-Dakota Utilities	$5.78
New Jersey	Atlantic City Electric	$5.77
Maryland	Potomac Edison	$5.70
Louisiana	SWEPCO	$5.49
Colorado	Xcel Energy	$5.47
New Jersey	Rockland Electric	$5.07
Idaho	Idaho Power Company	$5.00
Idaho	Rocky Mountain Power	$5.00
Michigan	Alpena Power Company	$5.00
West Virginia	First Energy Utilities	$5.00
Texas	AEP Texas Central	$4.79
Texas	AEP Texas North	$4.79
New Jersey	PSE&G	$4.64
Louisiana	Entergy Gulf States	$4.46
Texas	Centerpoint Energy	$4.39
Montana	Northwestern Energy	$4.00
Ohio	First Energy Utilities	$4.00
Texas	Oncor	$3.42
New Jersey	JCP&L	$2.78
California	SCE	$0.93
California	PG&E	$0.00
California	SDG&E	$0.00

Average	**$10.71**
Median	**$10.00**

Attachment JRB-6

Attachment JRB-6 – Fixed Charge Increases Adopted in General Rate Cases

State	Utility	Existing Fixed Charge	Approved Fixed Charge	$ Increase Approved	Approved % Increase
Alaska	Alaska Power	$12.31	$20.00	$7.69	62.5%
Wisconsin	Alliant Energy	$7.67	$15.00	$7.33	95.6%
Kentucky	Duke Energy Kentucky	$4.50	$11.00	$6.50	144.4%
Arizona	Arizona Public Service	$8.67	$15.00	$6.33	73.0%
Wisconsin	Xcel Energy	$8.00	$14.00	$6.00	75.0%
Indiana	IP&L	$11.00	$17.00	$6.00	54.5%
North Dakota	Otter Tail Power Company	$8.00	$14.00	$6.00	75.0%
Tennessee	Kingsport Power	$7.30	$12.63	$5.33	73.0%
Arizona	UniSource Energy Services	$10.00	$15.00	$5.00	50.0%
New Hampshire	Unitil	$10.27	$15.24	$4.97	48.4%
Indiana	Indiana Michigan Power	$10.50	$15.00	$4.50	42.9%
Georgia	Georgia Power	$9.97	$14.00	$4.03	40.4%
West Virginia	Appalachian Power	$8.00	$12.00	$4.00	50.0%
Kentucky	Kentucky Utilities	$12.25	$16.12	$3.87	31.6%
South Carolina	Duke Energy Carolinas	$8.29	$11.96	$3.67	44.3%
Pennsylvania	Citizens' Electric Company	$8.00	$11.50	$3.50	43.8%
Wisconsin	NW Wisconsin Electric Company	$7.50	$11.00	$3.50	46.7%
North Dakota	Montana-Dakota Utilities	$10.65	$13.99	$3.34	31.4%
Kansas	KCP&L	$10.71	$14.00	$3.29	30.7%
Pennsylvania	UGI Electric	$5.50	$8.74	$3.24	58.9%
Indiana	Indiana Michigan Power	$7.30	$10.50	$3.20	43.8%
Michigan	Wisconsin Public Service	$9.00	$12.00	$3.00	33.3%
Kentucky	Kentucky Power	$8.00	$11.00	$3.00	37.5%
Indiana	NIPSCO	$11.00	$14.00	$3.00	27.3%
Michigan	Upper Peninsula Power Company	$12.00	$15.00	$3.00	25.0%
Arizona	Tucson Electric Power	$10.00	$13.00	$3.00	30.0%
Wisconsin	Xcel Energy	$14.00	$17.00	$3.00	21.4%
Kentucky	Kentucky Power	$11.00	$14.00	$3.00	27.3%
Texas	Entergy Texas	$7.00	$10.00	$3.00	42.9%
Hawaii	Maui Electric (MECO)	$8.50	$11.50	$3.00	35.3%
Missouri	KCP&L	$9.00	$11.88	$2.88	32.0%
North Carolina	Duke Energy Progress	$11.13	$14.00	$2.87	25.8%

Attachment JRB-6 – Fixed Charge Increases Adopted in General Rate Cases

New Hampshire	Liberty Utilities	$11.79	$14.54	$2.75	23.3%
Ohio	Dayton Power & Light	$4.25	$7.00	$2.75	64.7%
South Carolina	Duke Energy Progress	$9.06	$11.78	$2.72	30.0%
Texas	Texas-New Mexico Power	$5.25	$7.85	$2.60	49.5%
Maine	Central Maine Power	$10.17	$12.76	$2.59	25.5%
South Carolina	Duke Energy Progress	$6.50	$9.06	$2.56	39.4%
Kansas	Westar Energy	$12.00	$14.50	$2.50	20.8%
Hawaii	Hawaiian Electric (HECO)	$9.00	$11.50	$2.50	27.8%
Pennsylvania	Duquesne Light	$10.00	$12.50	$2.50	25.0%
New Jersey	PSE&G	$2.27	$4.64	$2.37	104.4%
Arkansas	SWEPCO	$7.75	$10.00	$2.25	29.0%
North Carolina	Duke Energy Carolinas	$11.80	$14.00	$2.20	18.6%
Pennsylvania	Met-Ed	$8.11	$10.25	$2.14	26.4%
District of Columbia	Pepco	$13.00	$15.09	$2.09	16.1%
Pennsylvania	Penelec	$7.98	$9.99	$2.01	25.2%
Wisconsin	Wisconsin Public Service	$19.00	$21.00	$2.00	10.5%
New Mexico	PNM	$5.00	$7.00	$2.00	40.0%
Wisconsin	SWL&P	$7.00	$9.00	$2.00	28.6%
South Dakota	Otter Tail Power Company	$8.00	$10.00	$2.00	25.0%
Pennsylvania	Penn Power	$8.89	$10.85	$1.96	22.0%
Texas	Xcel Energy	$7.60	$9.50	$1.90	25.0%
Texas	El Paso Electric	$5.00	$6.90	$1.90	38.0%
Arkansas	Oklahoma Gas & Electric	$7.94	$9.75	$1.81	22.8%
Pennsylvania	Citizens' Electric Company	$11.24	$13.00	$1.76	15.7%
Wisconsin	North Central Power	$11.25	$13.00	$1.75	15.6%
Pennsylvania	West Penn Power	$5.81	$7.44	$1.63	28.1%
Kentucky	Duke Energy Kentucky	$11.00	$12.60	$1.60	14.5%
Pennsylvania	PECO	$8.45	$10.00	$1.55	18.3%
North Carolina	Dominion North Carolina Power	$10.40	$11.92	$1.52	14.6%
South Dakota	Montana-Dakota Utilities	$6.00	$7.51	$1.51	25.2%
Massachusetts	National Grid	$4.00	$5.50	$1.50	37.5%
Michigan	DTE	$6.00	$7.50	$1.50	25.0%
Kentucky	Kentucky Utilities	$10.75	$12.25	$1.50	14.0%
Kentucky	LG&E	$10.75	$12.25	$1.50	14.0%

Attachment JRB-6 – Fixed Charge Increases Adopted in General Rate Cases

Massachusetts	National Grid	$5.50	$7.00	$1.50	27.3%
Iowa	Alliant Energy	$11.50	$13.00	$1.50	13.0%
Arkansas	Entergy Arkansas	$6.96	$8.40	$1.44	20.7%
Kentucky	LG&E	$12.25	$13.69	$1.44	11.8%
Texas	El Paso Electric	$6.90	$8.25	$1.35	19.6%
Pennsylvania	PECO	$7.12	$8.45	$1.33	18.7%
Pennsylvania	Penelec	$9.99	$11.25	$1.26	12.6%
Minnesota	Otter Tail Power Company	$8.50	$9.75	$1.25	14.7%
Pennsylvania	Wellsboro Electric Company	$10.79	$12.00	$1.21	11.2%
Pennsylvania	Wellsboro Electric Company	$9.75	$10.95	$1.20	12.3%
New York	Penelec	$6.36	$7.49	$1.13	17.8%
New Jersey	JCP&L	$1.92	$2.98	$1.06	55.2%
Missouri	KCP&L GMO	$10.43	$11.47	$1.04	10.0%
South Dakota	MidAmerican Energy	$7.00	$8.00	$1.00	14.3%
South Dakota	NorthWestern Energy	$5.00	$6.00	$1.00	20.0%
Pennsylvania	Met-Ed	$10.25	$11.25	$1.00	9.8%
Missouri	Ameren Missouri	$8.00	$9.00	$1.00	12.5%
Iowa	Alliant Energy	$10.50	$11.50	$1.00	9.5%
Hawaii	Hawaii Electric Light (HELCO)	$10.50	$11.50	$1.00	9.5%
Rhode Island	National Grid	$5.00	$6.00	$1.00	20.0%
New Jersey	Atlantic City Electric	$4.83	$5.77	$0.94	19.5%
Florida	Gulf Power	$18.85	$19.77	$0.92	4.9%
Missouri	KCP&L GMO	$9.54	$10.43	$0.89	9.3%
New Mexico	Xcel Energy (SPS)	$8.75	$9.60	$0.85	9.7%
Pennsylvania	West Penn Power	$5.00	$5.81	$0.81	16.2%
Missouri	KCP&L	$11.88	$12.62	$0.74	6.2%
Vermont	Green Mountain Power	$13.17	$13.89	$0.72	5.5%
Vermont	Green Mountain Power	$13.89	$14.60	$0.71	5.1%
Maryland	Potomac Edison	$5.00	$5.70	$0.70	14.0%
Montana	Montana-Dakota Utilities	$5.17	$5.78	$0.61	11.8%
New Mexico	Xcel Energy (SPS)	$7.90	$8.50	$0.60	7.6%
New Jersey	Atlantic City Electric	$4.44	$5.00	$0.56	12.6%
New Jersey	Rockland Electric	$4.53	$5.07	$0.54	11.9%
Oregon	Portland General Electric	$10.00	$10.50	$0.50	5.0%

Attachment JRB-6 – Fixed Charge Increases Adopted in General Rate Cases

Idaho	Avista Utilities	$5.25	$5.75	$0.50	9.5%
Texas	Xcel Energy	$9.50	$10.00	$0.50	5.3%
Oregon	Portland General Electric	$10.50	$11.00	$0.50	4.8%
Washington	Avista Utilities	$8.50	$9.00	$0.50	5.9%
Michigan	Consumers Energy	$7.00	$7.50	$0.50	7.1%
Missouri	Empire District Electric	$12.52	$13.00	$0.48	3.8%
New Jersey	Atlantic City Electric	$4.00	$4.44	$0.44	11.0%
Texas	Oncor	$3.06	$3.49	$0.43	14.1%
Maryland	BGE	$7.50	$7.90	$0.40	5.3%
Alaska	Alaska Electric Light & Power	$8.88	$9.22	$0.34	3.8%
Maine	Emera Maine	$6.04	$6.36	$0.32	5.3%
Idaho	Avista Utilities	$5.75	$6.00	$0.25	4.3%
Michigan	Xcel Energy	$8.75	$9.00	$0.25	2.9%
New Mexico	Xcel Energy (SPS)	$8.50	$8.75	$0.25	2.9%
Kansas	KCP&L	$14.00	$14.25	$0.25	1.8%
Kansas	Empire District Electric	$14.00	$14.25	$0.25	1.8%
New York	Con Edison	$15.76	$16.00	$0.24	1.5%
Maryland	Delmarva Power	$7.94	$8.17	$0.23	2.9%
Maine	Emera Maine	$5.82	$6.04	$0.22	3.8%
Maryland	Pepco	$7.39	$7.60	$0.21	2.8%
Maryland	Pepco	$7.80	$8.01	$0.21	2.7%
Maryland	Pepco	$7.60	$7.80	$0.20	2.6%
Pennsylvania	Penn Power	$10.85	$11.00	$0.15	1.4%
Massachusetts	Eversource Energy	$6.86	$7.00	$0.14	2.0%
Maryland	Delmarva Power	$8.17	$8.30	$0.13	1.6%
New Mexico	PNM	$7.00	$7.11	$0.11	1.6%
Montana	NorthWestern Energy	$4.10	$4.20	$0.10	2.4%
Michigan	Xcel Energy	$8.65	$8.75	$0.10	1.2%
New Jersey	Rockland Electric	$4.44	$4.54	$0.10	2.3%
Maryland	BGE	$7.90	$8.00	$0.10	1.3%
Maryland	BGE	$7.50	$7.50	$0.00	0.0%
Missouri	Ameren Missouri	$8.00	$8.00	$0.00	0.0%
New York	Central Hudson Gas & Electric	$24.00	$24.00	$0.00	0.0%
New York	Con Edison	$15.76	$15.76	$0.00	0.0%

Attachment JRB-6 – Fixed Charge Increases Adopted in General Rate Cases

Missouri	Empire District Electric	$12.52	$12.52	$0.00	0.0%
Kentucky	Kentucky Utilities	$10.75	$10.75	$0.00	0.0%
Kentucky	LG&E	$10.75	$10.75	$0.00	0.0%
Michigan	Indiana Michigan Power	$7.25	$7.25	$0.00	0.0%
New York	Orange & Rockland Utilities	$20.00	$20.00	$0.00	0.0%
Michigan	Consumers Energy	$7.00	$7.00	$0.00	0.0%
Pennsylvania	PPL Electric Utilities	$14.09	$14.09	$0.00	0.0%
Mississippi	Mississippi Power	$23.73	$23.73	$0.00	0.0%
Michigan	DTE	$6.00	$6.00	$0.00	0.0%
Idaho	Avista Utilities	$5.25	$5.25	$0.00	0.0%
Wyoming	Rocky Mountain Power	$20.00	$20.00	$0.00	0.0%
Washington	Avista Utilities	$8.50	$8.50	$0.00	0.0%
Virginia	Kentucky Utilities	$12.00	$12.00	$0.00	0.0%
Montana	Montana-Dakota Utilities	$5.47	$5.47	$0.00	0.0%
Massachusetts	Unitil	$7.00	$7.00	$0.00	0.0%
New Mexico	El Paso Electric	$7.00	$7.00	$0.00	0.0%
New York	NYSEG	$15.92	$15.92	$0.00	0.0%
New York	RG&E	$22.10	$22.10	$0.00	0.0%
Oklahoma	PSO	$20.00	$20.00	$0.00	0.0%
Florida	Florida Power & Light	$7.87	$7.87	$0.00	0.0%
Wisconsin	Xcel Energy	$14.00	$14.00	$0.00	0.0%
Washington	Avista Utilities	$8.50	$8.50	$0.00	0.0%
Wisconsin	MGE	$19.00	$19.00	$0.00	0.0%
Colorado	Black Hills Energy	$16.50	$16.50	$0.00	0.0%
North Carolina	Dominion North Carolina Power	$10.96	$10.96	$0.00	0.0%
Nevada	Sierra Pacific Power	$15.25	$15.25	$0.00	0.0%
New York	Con Edison	$15.76	$15.76	$0.00	0.0%
Michigan	Consumers Energy	$7.00	$7.00	$0.00	0.0%
Oklahoma	Oklahoma Gas & Electric	$13.00	$13.00	$0.00	0.0%
Wyoming	Montana-Dakota Utilities	$25.00	$25.00	$0.00	0.0%
Minnesota	Xcel Energy	$8.00	$8.00	$0.00	0.0%
Delaware	Delmarva Power	$11.70	$11.70	$0.00	0.0%
Oklahoma	Empire District Electric	$12.50	$12.50	$0.00	0.0%
California	SDG&E	$0.00	$0.00	$0.00	0.0%

Attachment JRB-6 – Fixed Charge Increases Adopted in General Rate Cases

Michigan	Alpena Power Company	$5.00	$5.00	$0.00	0.0%
Washington	Puget Sound Energy	$7.49	$7.49	$0.00	0.0%
Texas	SWEPCO	$8.00	$8.00	$0.00	0.0%
Minnesota	Minnesota Power	$8.00	$8.00	$0.00	0.0%
Oklahoma	PSO	$20.00	$20.00	$0.00	0.0%
New York	National Grid	$17.00	$17.00	$0.00	0.0%
Michigan	Consumers Energy	$7.00	$7.00	$0.00	0.0%
Michigan	Indiana Michigan Power	$7.25	$7.25	$0.00	0.0%
Michigan	DTE	$7.50	$7.50	$0.00	0.0%
Virginia	Kentucky Utilities	$12.00	$12.00	$0.00	0.0%
Maryland	Pepco	$7.80	$7.80	$0.00	0.0%
Oklahoma	Oklahoma Gas & Electric	$13.00	$13.00	$0.00	0.0%
District of Columbia	Pepco	$15.09	$15.09	$0.00	0.0%
California	PG&E	$0.00	$0.00	$0.00	0.0%
Delaware	Delmarva Power	$11.70	$11.70	$0.00	0.0%
Wisconsin	Alliant Energy	$15.00	$15.00	$0.00	0.0%
Kansas	Westar Energy	$14.50	$14.50	$0.00	0.0%
Wisconsin	MGE	$19.00	$19.00	$0.00	0.0%
Indiana	IP&L	$17.00	$17.00	$0.00	0.0%
California	SCE	$0.93	$0.93	$0.00	0.0%
Texas	Xcel Energy	$10.00	$10.00	$0.00	0.0%
Oregon	Portland General Electric	$11.00	$11.00	$0.00	0.0%
Ohio	Duke Energy Ohio	$6.00	$6.00	$0.00	0.0%
Wisconsin	SWL&P	$9.00	$9.00	$0.00	0.0%
Oklahoma	PSO	$20.00	$20.00	$0.00	0.0%
Michigan	DTE	$7.50	$7.50	$0.00	0.0%
Michigan	Upper Peninsula Power	$15.00	$15.00	$0.00	0.0%
California	Bear Valley Electric Service	$6.39	$6.39	$0.00	0.0%
Oklahoma	Oklahoma Gas & Electric	$13.00	$13.00	$0.00	0.0%
Oklahoma	Empire District Electric	$12.50	$12.50	$0.00	0.0%
Louisiana	Entergy New Orleans	$8.07	$8.07	$0.00	0.0%
Idaho	Avista Utilities	$6.00	$6.00	$0.00	0.0%
Wisconsin	Xcel Energy	$17.00	$17.00	$0.00	0.0%
Wisconsin	We Energies	$15.99	$15.99	$0.00	0.0%

Attachment JRB-6 – Fixed Charge Increases Adopted in General Rate Cases

Wisconsin	Wisconsin Public Service	$21.00	$21.00	$0.00	0.0%
Nevada	Sierra Pacific Power	$15.25	$15.25	$0.00	0.0%
Michigan	Indiana Michigan Power	$7.25	$7.25	$0.00	0.0%
California	Pacific Power	$7.20	$7.20	$0.00	0.0%
Mississippi	Mississippi Power	$26.16	$26.16	$0.00	0.0%
Missouri	Ameren Missouri	$9.00	$9.00	$0.00	0.0%
Washington	Avista Utilities	$9.00	$9.00	$0.00	0.0%
Virginia	Kentucky Utilities	$12.00	$12.00	$0.00	0.0%
Michigan	DTE	$7.50	$7.50	$0.00	0.0%
Nevada	Nevada Power	$12.75	$12.50	-$0.25	-2.0%
New York	Orange & Rockland Utilities	$20.00	$19.50	-$0.50	-2.5%
Indiana	NIPSCO	$14.00	$13.50	-$0.50	-3.6%
California	Liberty Utilities	$7.10	$6.56	-$0.54	-7.6%
Texas	CenterPoint Energy	$5.47	$4.39	-$1.08	-19.7%
Missouri	KCP&L	$12.62	$11.47	-$1.15	-9.1%
Texas	AEP Texas	$6.04	$4.79	-$1.25	-20.7%
Colorado	Xcel Energy	$6.75	$5.39	-$1.36	-20.1%
New York	Central Hudson Gas & Electric	$24.00	$19.50	-$4.50	-18.8%
Connecticut	United Illuminating	$17.25	$9.67	-$7.58	-43.9%
Colorado	Black Hills Energy	$16.50	$8.77	-$7.73	-46.8%
Connecticut	Eversource	$19.25	$9.21	-$10.04	-52.2%
			Average	$0.94	12.9%
			Median	$0.25	3.8%

Attachment JRB-7

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2020-00015
Interrogatories and Requests for the Production
of Documents by the STAFF OF THE STATE CORPORATION COMMISSION
Staff Set 6
To Appalachian Power Company

Interrogatory 6-202:

Please provide a detailed monthly and annual bill frequency analysis for Rate R.S. during the test year. In this response, please provide consumption blocks of 100 kWh for each of the first 1,100 kWh and then in blocks of 250 kWh thereafter. In this response, please provide the number of bills and kWh in each block as well as cumulative bills and kWh. Please provide in executable electronic format (Excel preferred)

Response 6-202:

Please see Staff 6-202 Attachment 1 - Bill Frequency RS Tariffs for the requested information.

The foregoing response is made by Katharine I. Walsh, Reg Pricing & Analysis Mgr, on behalf of Appalachian Power Company.

APPALACHIAN POWER COMPANY - VIRGINIA
TYE DECEMBER 31, 2019
Total DS Frequency Distribution Report (011, 015, 020, 030, 051)

Summary - Distribution of kWh Based on Metered kWh	Jan - 2019	Feb - 2019	Mar - 2019	Apr - 2019	May - 2019	Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	Total
Total KWH	729,945,818	719,510,531	597,233,548	460,479,850	359,918,274	412,765,545	482,174,820	497,933,014	475,279,036	404,713,367	413,742,009	638,701,009	6,192,396,821
KWH - <= 0 KWH	[illegible]	(1,459)	(9,577)	(57,833)	(134,331)	[illegible]	(61,722)	(56,937)	[illegible]	[illegible]	(31,704)	(3,264)	[illegible]
KWH - > 0 and <= 100 KWH	602,754	587,813	679,189	826,964	1,026,707	970,662	858,248	816,809	749,931	863,853	846,807	643,548	9,473,285
KWH - > 100 and <= 200 KWH	1,581,829	1,522,741	1,879,853	2,406,525	3,016,440	2,770,856	2,399,721	2,266,048	2,163,099	2,522,761	2,679,422	1,758,265	26,967,560
KWH - > 200 and <= 300 KWH	2,737,999	3,078,653	3,724,248	4,817,323	6,158,995	5,321,116	4,353,231	4,100,662	4,060,346	5,176,833	5,462,605	3,299,709	52,291,720
KWH - > 300 and <= 400 KWH	4,510,449	5,179,772	6,284,825	8,308,019	10,784,902	8,981,879	7,135,178	6,517,869	6,919,553	9,074,585	9,390,694	5,475,249	88,566,974
KWH - > 400 and <= 500 KWH	6,709,735	7,585,828	8,985,896	11,803,853	16,228,985	13,230,664	10,390,494	9,582,918	10,456,012	13,741,273	13,845,395	8,116,641	130,677,694
KWH - > 500 and <= 600 KWH	8,992,859	9,611,835	11,375,842	15,246,896	21,509,723	17,629,388	14,210,984	13,199,745	14,394,662	18,870,732	18,265,054	10,501,885	173,809,605
KWH - > 600 and <= 700 KWH	10,893,062	11,524,739	13,309,169	18,622,513	25,983,031	21,922,155	17,941,673	16,780,066	18,519,030	23,553,883	22,441,295	12,675,777	214,166,393
KWH - > 700 and <= 800 KWH	12,737,486	12,894,619	15,331,261	21,711,554	29,241,603	25,522,203	21,373,503	20,719,322	22,804,899	27,050,179	25,402,010	14,505,215	249,283,854
KWH - > 800 and <= 900 KWH	14,079,323	14,312,326	17,073,662	24,514,125	30,928,026	28,216,320	24,806,225	23,977,941	25,917,278	29,962,065	27,954,071	16,477,141	278,218,503
KWH - > 900 and <= 1000 KWH	15,710,273	15,472,627	19,158,285	27,023,222	31,039,167	29,562,581	27,203,716	27,158,222	28,582,957	31,113,982	29,554,038	18,471,494	300,050,565
KWH - > 1000 and <= 1100 KWH	17,148,370	16,990,503	21,276,617	28,283,882	28,650,032	29,868,355	28,829,435	29,265,130	30,438,984	30,297,481	29,410,369	20,476,308	310,935,466
KWH - > 1100 and <= 1200 KWH	18,507,906	18,134,550	23,746,856	28,662,177	26,002,660	29,040,702	30,231,244	30,688,367	30,940,304	29,115,657	27,933,294	22,796,823	315,800,540
KWH - > 1200 and <= 1300 KWH	20,610,846	19,686,524	25,214,758	28,399,065	22,382,860	26,974,090	29,622,848	30,900,590	30,930,821	26,490,994	26,289,791	24,708,384	312,211,571
KWH - > 1300 and <= 1400 KWH	22,163,215	21,736,721	27,148,981	27,510,120	19,547,477	24,589,988	28,585,002	30,053,826	29,394,165	23,783,545	23,596,376	25,989,577	304,098,993
KWH - > 1400 and <= 1500 KWH	24,033,099	23,336,361	28,072,128	25,581,325	16,013,488	21,765,339	26,980,019	28,548,145	27,339,979	20,680,720	21,292,456	27,771,615	291,414,674
KWH - > 1500 and <= 1600 KWH	25,367,777	24,501,240	28,368,418	23,534,649	13,268,508	19,098,330	24,833,273	26,671,874	24,802,671	17,543,778	18,801,914	28,486,808	275,279,240
KWH - > 1600 and <= 1700 KWH	26,922,157	25,875,345	28,623,257	21,375,829	10,614,235	16,257,872	22,422,850	24,455,009	22,532,362	15,032,450	16,343,533	28,378,336	258,833,235
KWH - > 1700 and <= 1800 KWH	27,832,429	26,505,276	27,830,056	18,835,128	8,553,077	13,895,941	20,650,840	22,126,587	19,941,279	12,571,834	13,920,491	28,286,690	240,949,628
KWH - > 1800 and <= 1900 KWH	28,220,952	27,477,267	26,733,489	16,609,181	6,939,673	11,831,586	18,167,514	19,712,088	17,671,244	10,744,021	11,965,830	27,707,027	223,779,872
KWH - > 1900 and <= 2000 KWH	28,345,694	27,825,306	25,515,309	14,699,392	5,603,921	9,824,996	15,995,151	17,478,164	14,869,615	8,961,028	10,209,961	26,383,384	205,711,921
KWH - > 2000 and <= 2500 KWH	133,874,313	130,114,381	99,630,576	48,295,051	15,097,640	30,254,866	53,420,792	58,148,413	48,470,761	26,445,484	31,075,341	110,121,285	784,948,903
KWH - > 2500 and <= 3000 KWH	100,773,999	98,335,400	60,135,300	22,368,553	5,565,492	12,517,870	25,321,518	26,915,504	21,763,954	10,420,767	13,715,716	72,100,094	469,934,167
KWH - > 3000 and <= 3500 KWH	66,473,068	66,682,621	33,470,496	10,040,749	2,430,081	5,537,166	12,216,418	13,098,796	10,154,882	4,742,238	6,097,656	42,114,129	273,057,800
KWH - > 3500 and <= 4000 KWH	41,718,957	40,927,467	18,333,234	5,009,576	1,163,826	2,672,622	5,639,184	6,231,809	4,734,094	2,309,605	2,821,908	24,616,459	156,178,741
KWH - > 4000 and <= 4500 KWH	25,695,776	25,971,521	9,992,068	2,414,027	597,953	1,499,391	3,169,299	3,259,528	2,425,494	1,154,923	1,612,771	14,055,476	91,848,227
KWH - > 4500 and <= 5000 KWH	15,572,145	15,274,174	5,771,142	1,280,708	372,150	791,702	1,701,909	1,739,922	1,323,513	648,901	910,501	8,002,436	53,389,203
KWH - > 5000 KWH	28,129,426	28,376,380	9,574,209	2,366,777	1,332,003	2,325,467	3,776,273	3,577,147	3,036,755	1,892,031	1,934,494	14,784,518	101,105,480

APPALACHIAN POWER COMPANY - VIRGINIA
TYE DECEMBER 31, 2019
Total RS Frequency Distribution Report (011, 015, 020, 030, 051)

Summary - Distribution of Customers Based on Metered kWh	Jan - 2019	Feb - 2019	Mar - 2019	Apr - 2019	May - 2019	Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	Total
Total Customer Count	456,197	456,183	456,760	456,611	456,619	457,068	457,779	458,023	456,445	456,147	456,276	456,846	5,480,954
CUST - <= 0 KWH	6,220	6,412	6,486	6,406	6,336	6,112	5,869	5,819	5,877	5,912	5,761	5,963	73,173
CUST - > 0 and <= 100 KWH	14,946	15,002	16,555	19,080	21,996	20,788	18,545	17,827	16,605	18,481	18,408	15,216	213,449
CUST - > 100 and <= 200 KWH	10,499	10,025	12,393	15,862	19,941	18,415	15,967	15,077	14,350	16,647	17,650	11,622	178,448
CUST - > 200 and <= 300 KWH	10,888	12,232	14,763	19,096	24,366	21,103	17,280	16,905	16,097	20,487	21,630	13,091	207,338
CUST - > 300 and <= 400 KWH	12,818	14,698	17,255	23,631	30,625	25,521	20,292	18,536	19,669	25,774	26,699	15,554	251,672
CUST - > 400 and <= 500 KWH	14,858	16,800	19,916	26,180	35,938	29,313	22,997	21,227	23,152	30,419	30,676	17,976	289,452
CUST - > 500 and <= 600 KWH	16,331	17,459	20,664	27,682	39,038	31,994	25,792	23,932	26,100	34,221	33,150	19,066	315,429
CUST - > 600 and <= 700 KWH	16,747	17,718	20,456	28,617	39,949	33,707	27,562	25,775	28,439	36,192	34,491	19,487	329,140
CUST - > 700 and <= 800 KWH	16,978	17,167	20,429	28,929	38,980	34,015	28,468	27,588	30,383	36,043	33,846	19,323	332,149
CUST - > 800 and <= 900 KWH	16,556	16,833	20,077	28,832	36,391	33,191	29,172	28,193	30,471	35,235	32,891	19,375	327,217
CUST - > 900 and <= 1000 KWH	16,525	16,281	20,152	28,439	32,698	31,119	28,630	28,574	30,070	32,757	31,112	19,435	315,792
CUST - > 1000 and <= 1100 KWH	16,324	16,179	20,253	26,935	27,313	28,453	27,457	27,868	28,979	28,868	28,027	19,489	296,145
CUST - > 1100 and <= 1200 KWH	16,086	15,761	20,642	24,923	22,639	25,266	26,288	26,683	26,908	25,330	24,307	19,808	274,641
CUST - > 1200 and <= 1300 KWH	16,481	15,742	20,168	22,734	17,924	21,593	23,710	24,726	24,754	21,211	21,043	19,759	249,845
CUST - > 1300 and <= 1400 KWH	16,410	16,095	20,106	20,385	14,496	18,230	21,182	22,265	21,782	17,633	17,494	19,248	225,326
CUST - > 1400 and <= 1500 KWH	16,560	16,086	19,356	17,654	11,059	15,023	18,617	19,694	18,870	14,278	14,695	19,148	201,040
CUST - > 1500 and <= 1600 KWH	16,361	15,802	18,303	15,184	8,566	12,335	16,027	17,216	16,010	11,327	12,142	18,379	177,662
CUST - > 1600 and <= 1700 KWH	16,314	15,677	17,350	12,967	6,439	9,861	13,598	14,829	13,666	9,118	9,916	17,196	156,931
CUST - > 1700 and <= 1800 KWH	15,902	15,145	15,903	10,765	4,893	7,945	11,803	12,648	11,399	7,191	7,959	16,165	137,718
CUST - > 1800 and <= 1900 KWH	15,249	14,852	14,454	8,983	3,755	6,399	9,825	10,658	9,558	5,813	6,473	14,983	121,002
CUST - > 1900 and <= 2000 KWH	14,537	14,269	13,088	7,541	2,876	5,042	8,207	8,970	7,629	4,601	5,238	13,530	105,528
CUST - > 2000 and <= 2500 KWH	59,928	58,231	44,819	21,862	6,874	13,731	24,158	26,273	21,928	12,002	14,092	49,453	353,351
CUST - > 2500 and <= 3000 KWH	36,943	36,037	22,105	8,249	2,059	4,622	9,348	9,930	8,030	3,846	5,058	26,484	172,711
CUST - > 3000 and <= 3500 KWH	20,611	20,664	10,398	3,123	757	1,722	3,800	4,073	3,160	1,476	1,899	13,072	84,755
CUST - > 3500 and <= 4000 KWH	11,200	10,994	4,927	1,347	312	721	1,519	1,677	1,273	620	759	6,614	41,963
CUST - > 4000 and <= 4500 KWH	6,082	6,148	2,367	572	142	355	751	771	575	274	382	3,328	21,747
CUST - > 4500 and <= 5000 KWH	3,293	3,234	1,223	271	79	167	360	368	280	137	193	1,691	11,296
CUST - > 5000 KWH	4,550	4,640	1,552	352	178	325	555	521	431	254	285	2,391	16,034

APPALACHIAN POWER COMPANY - VIRGINIA

TYE DECEMBER 31, 2019

Total RS Frequency Distribution Report (011, 015, 020, 030, 051)

Summary - Distribution of Avg kWh Based on Avg Metered kWh	Dec - 2019
Total AVG KWH	517,069,320
AVG KWH - <= 0 KWH	(7,981)
AVG KWH - > 0 and <= 100 KWH	560,468
AVG KWH - > 100 and <= 200 KWH	1,505,823
AVG KWH - > 200 and <= 300 KWH	3,098,571
AVG KWH - > 300 and <= 400 KWH	5,657,767
AVG KWH - > 400 and <= 500 KWH	8,923,410
AVG KWH - > 500 and <= 600 KWH	12,563,828
AVG KWH - > 600 and <= 700 KWH	16,393,907
AVG KWH - > 700 and <= 800 KWH	20,435,753
AVG KWH - > 800 and <= 900 KWH	24,335,903
AVG KWH - > 900 and <= 1000 KWH	27,936,499
AVG KWH - > 1000 and <= 1100 KWH	30,804,092
AVG KWH - > 1100 and <= 1200 KWH	33,144,215
AVG KWH - > 1200 and <= 1300 KWH	34,157,297
AVG KWH - > 1300 and <= 1400 KWH	34,149,540
AVG KWH - > 1400 and <= 1500 KWH	32,810,761
AVG KWH - > 1500 and <= 1600 KWH	30,995,044
AVG KWH - > 1600 and <= 1700 KWH	28,452,214
AVG KWH - > 1700 and <= 1800 KWH	24,954,239
AVG KWH - > 1800 and <= 1900 KWH	22,058,412
AVG KWH - > 1900 and <= 2000 KWH	19,267,766
AVG KWH - > 2000 and <= 2500 KWH	60,006,360
AVG KWH - > 2500 and <= 3000 KWH	24,533,307
AVG KWH - > 3000 and <= 3500 KWH	10,187,584
AVG KWH - > 3500 and <= 4000 KWH	4,456,542
AVG KWH - > 4000 and <= 4500 KWH	2,219,529
AVG KWH - > 4500 and <= 5000 KWH	1,114,686
AVG KWH - > 5000 KWH	2,353,784

APPALACHIAN POWER COMPANY - VIRGINIA

TYE DECEMBER 31, 2019

Total RS Frequency Distribution Report (011, 015, 020, 030, 051)

Summary - Distribution of Customers Based on Avg Metered kWh	Dec - 2019
Total AVG Customer Count	453,915
AVG CUST - <= 0 KWH	43
AVG CUST - > 0 and <= 100 KWH	13,975
AVG CUST - > 100 and <= 200 KWH	9,997
AVG CUST - > 200 and <= 300 KWH	12,263
AVG CUST - > 300 and <= 400 KWH	16,081
AVG CUST - > 400 and <= 500 KWH	19,773
AVG CUST - > 500 and <= 600 KWH	22,806
AVG CUST - > 600 and <= 700 KWH	25,186
AVG CUST - > 700 and <= 800 KWH	27,229
AVG CUST - > 800 and <= 900 KWH	28,617
AVG CUST - > 900 and <= 1000 KWH	29,401
AVG CUST - > 1000 and <= 1100 KWH	29,328
AVG CUST - > 1100 and <= 1200 KWH	28,826
AVG CUST - > 1200 and <= 1300 KWH	27,330
AVG CUST - > 1300 and <= 1400 KWH	25,311
AVG CUST - > 1400 and <= 1500 KWH	22,643
AVG CUST - > 1500 and <= 1600 KWH	20,010
AVG CUST - > 1600 and <= 1700 KWH	17,262
AVG CUST - > 1700 and <= 1800 KWH	14,274
AVG CUST - > 1800 and <= 1900 KWH	11,934
AVG CUST - > 1900 and <= 2000 KWH	9,887
AVG CUST - > 2000 and <= 2500 KWH	27,188
AVG CUST - > 2500 and <= 3000 KWH	9,071
AVG CUST - > 3000 and <= 3500 KWH	3,174
AVG CUST - > 3500 and <= 4000 KWH	1,202
AVG CUST - > 4000 and <= 4500 KWH	525
AVG CUST - > 4500 and <= 5000 KWH	236
AVG CUST - > 5000 KWH	343

Attachment JRB-8

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2020-00015
Interrogatories and Requests for the Production
of Documents by the ENVIRONMENTAL RESPONDENTS
ER Set 2
To Appalachian Power Company

Interrogatory ER 2-8:

Refer to the Direct Testimony of Witness Katharine I. Walsh at 13:5-19 relating statistics on electricity usage by low-income customers that receive energy assistance.
a) Please provide all data and workpapers used by Witness Walsh in developing these numbers in executable spreadsheet format with all formulas and file linkages intact, and describe in detail all associated data sources and any assumptions used by Witness Walsh.
b) Did the Company perform an equivalent analysis for low-income customers that did not receive energy assistance? If so, please provide the results of that analysis and all associated workpapers.
c) If the Company did not perform the analysis referred to in subpart b of this question, please provide all of the data that would be necessary to produce such an analysis.

Response ER 2-8:

a) Please see the Company's response to Walmart 1-002, specifically workbooks Walsh Direct Testimony - RS Usage 2018 and Walsh Direct Testimony - RS Usage 2019. All "HEAP" or "Assistance" customers are active customers who participated in Low Income Home Energy Assistance Programs (LIHEAP) over the previous 12 months.
b) No. The Company did not utilize, nor can it easily obtain, customer account information related to income levels. The assistance customer data referenced in part a are those customers who elected to participate in LIHEAP.
c) The Company does not have such data as requested.

The foregoing response is made by Katharine I. Walsh, Reg Pricing & Analysis Mgr, on behalf of Appalachian Power Company.

Attachment JRB-9

20074079

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2020-00015
Interrogatories and Requests for the Production
of Documents by the ENVIRONMENTAL RESPONDENTS
ER Set 3
To Appalachian Power Company

Interrogatory ER 3-2:

Refer to the Company's response to ER 2-8 (a), referring to Company Witness Walsh's workpapers titled RS Usage 2018 and RS Usage 2019.
a) Please explain the meaning of the figures (10) and (20) within the column labeled Revenue Class at rows 8 and 9 and rows 11 and 12.
b) Please explain the meaning of the notes labeled 1), 2), and 3) located in column A rows 16-18 of the spreadsheets. Specifically, does note "1) 12 month kWh >= 4800" denote that this sample only includes customers with annual usage above 4,800 kWh?
c) Please clarify whether the customer numbers listed in column labeled "Number of Premises" refer to individual metered accounts, and if so, why the sum of HEAP Customers and All Other Customers is less than the total number of customers listed in cell G26.
d) Do the customer count numbers for electric heating customers refer to an estimate or actual electric heating customer counts based on customer-specific information?
1) If your response is that these amounts are based on actual electric heating customer counts, does this mean that the Company can reliably identify electric heating customers at the customer-specific level?
2) If your response is that these amounts are estimates, please describe in detail how the estimate was developed and provide all of the associated workpapers.

Response ER 3-2:

a) (10) and (20) denote those customers who utilize electric heating (20) and those who do not (10).
b) Yes, the sample includes customers whose annual use is equal to or greater than 4,800 kWh (400 kWh per month on average). These parameters (1 & 2) are intended to capture only active customers with 12 months worth of usage and exclude partial year data. 3) HEAP or "assistance" customers must have participated in assistance programs over the past 12 months.
c) Yes, number of premises refers to individual accounts. The data in the table includes the previously mentioned parameters and will therefore be less than Company billing record data.
d) The customer counts refer to actual electric heating customers based on customer records recorded at the time of service initiation.
1) Yes, the Company maintains electric heating and non-electric heating classification as previously described. The Company also periodically conducts a customer appliance survey; the results of which are consistent with customer records in aggregate.
2) Not applicable.

The foregoing response is made by Katharine I. Walsh, Reg Pricing & Analysis Mgr, on behalf of Appalachian Power Company.

Attachment JRB-10

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2020-00015
Interrogatories and Requests for the Production of Documents by the WALMART
Walmart Set 1
To Appalachian Power Company

Interrogatory Walmart 1-002:

Please provide all workpapers, in electronic spreadsheet format with formulas intact, where available, supporting each of the figures, tables, and exhibits accompanying the APCo's filing and supporting testimony.

Response Walmart 1-002:

Electronic copies of the Company's workpapers are available at https://www.imanageshare.com/, and access has been provided to Walmart's counsel. Please note that one attachment is confidential and is provided pursuant to the Hearing Examiner's April 15, 2020 Protective Ruling.

The foregoing response is made by William K. Castle, Dir Regulatory Svcs, on behalf of Appalachian Power Company.

Appalachian Power Company - Virginia
Comparison of 12-Month Residential Customer kWh Consumption
By Revenue Class and HEAP Participation

	Revenue Class	12 Months Ending December 2018 Number of Premises	12 Months Ending December 2018 Average kWh Usage	TME December 2018 kWh
HEAP Customers	Non-electric Heat (10)	6,276	15,093	
	Electric Heat (20)	11,999	14,824	177,873,176
	Total	18,275	14,916	272,589,900
All Other Customers	Non-electric Heat (10)	114,375	14,356	
	Electric Heat (20)	190,855	17,391	3,319,159,305
	Total	305,230	16,254	4,961,208,420

1) 12-month kWh >=4800
2) Active
3) HEAP recipient in 12-month p

	2018 B&A 12 month Tariff Summary (RS only)	Number of Customers		Average Monthly kWh
11 RS-LMWH	21,098,550	1,084		
15 RS	6,391,120,052	449,519		
20 RS EMP	26,768,807	1,548		
30 RS-TOD	3,243,036	192		
51 RS-LMWH	170,174	9		
	6,442,400,619	452,352	14,242	1,187

	2018 (kWh)	
Total Residential Average Use	1,187	1,187
Residential Electric Heating Average Use	1,437	1,437
LIHEAP Average Use	1,243	1,243
% of HEAP that uses Electric Heat	66%	66%

Appalachian Power Company - Virginia
Comparison of 12-Month Residential Customer kWh Consumption
By Revenue Class and HEAP Participation

		12 months ending December 2019		
	Revenue Class	Number of premises	Average kWh Usage	
HEAP	non electric heat (10)	7,038	14,651	103,111,508
	electric heat (20)	13,878	14,340	199,012,717
	Total	20,916	14,445	
All Other Customers	non electric heat (10)	122,683	13,929	1,708,893,930
	electric heat (20)	205,682	16,578	3,409,775,274
	Total	328,365		

		2019 B&A 12 month Tariff Summary (RS only)	Number of Customers		Average Monthly kWh
11	RS-LMWH	18,978,430	997		
15	RS	6,115,230,935	450,621		
20	RS EMP	24,722,675	1,496		
30	RS-TOD	3,201,017	194		
51	RS-LMWH	164,583	9		
		6,162,297,640	453,317	13,594	1,133

	2019 (kWh)
Total Residential Average Use	1,133
Residential Electric Heating Average	1,370
LIHEAP Average Use	1,204
% of HEAP that uses Electric Heat	66%

Attachment JRB-11

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. PUR-2020-00015
Interrogatories and Requests for the Production of Documents by the STAFF OF THE STATE CORPORATION COMMISSION
Staff Set 6
To Appalachian Power Company

Interrogatory 6-200:

Please provide all workpapers and analyses showing the basis for, and development of, the Company's proposed Residential Winter tail-block rate. Please provide in executable electronic (Excel) format.

Response 6-200:

Please see Staff 6-200 Attachment 1 - Winter Tail Block. This file provides usage characteristics for residential customers who use electric heating versus those who do not. Cell P29 demonstrates that 1,100 kWh is an appropriate threshold for the winter tail block as electric heating customers use, on average, just under 1,100 kWh during non-winter months. Therefore it can be assumed that any average usage over 1,100 kWh for those customers is attributable to winter electric heating.
Please see Schedule 42 Workpaper 3 particularly tab "RS" on the excel version (provided with the filing made on March 31) for the winter tail block rate design beginning on row 156.

The foregoing response is made by Katharine I. Walsh, Reg Pricing & Analysis Mgr, on behalf of Appalachian Power Company.