AUSTIN ENERGY 2022 BASE RATE REVIEW	§ § §	**BEFORE THE CITY OF AUSTIN IMPARTIAL HEARING EXAMINER**

INITIAL PRESENTATION

OF

CLARENCE L. JOHNSON

ON BEHALF OF

THE INDEPENDENT CONSUMER ADVOCATE

June 22, 2022

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Clarence Johnson. My address is 3707 Robinson Avenue, Austin, Texas 78722.

Q. WHAT IS YOUR ROLE WITH THE INDEPENDENT CONSUMER ADVOCATE?

A. I am self-employed as a consultant who provides technical analysis and advice regarding energy and utility regulatory issues. The City of Austin retained John B. Coffman LLC as the Independent Consumer Advocate (ICA) with the role of representing the interests of residential customers in this electric base rate review process. I have been retained by the ICA to provide technical analyses regarding Austin Energy's (AE) base rate increase request. The Party Position filed by the ICA in this proceeding includes presentations by myself and by Mr. David Effron.

Q. DO YOU HAVE PREVIOUS EXPERIENCE AS AN EXPERT ON REGULATED UTILITY MATTERS IN TEXAS?

A. Yes. I have approximately 38 years of experience as a professional regulatory analyst for the Texas Office of Public Utility Counsel ("OPUC") and as an independent expert witness in proceedings before the Public Utility Commission of Texas

("Commission"), Pennsylvania Public Utility Commission, Maryland Public Service Commission, and the Connecticut Department of Public Utilities.

Q. WHAT WERE YOUR RESPONSIBILITIES AT OPUC?

A. As OPUC's Director of Regulatory Analysis, I was the professional staff person with the primary responsibility for advising the OPUC on economic and regulatory policy issues. My responsibilities included reviewing utility rate applications, recommending actions or positions to be taken by the Office, preparing and presenting expert testimony, and working with other experts employed or retained by OPUC to coordinate the agency's technical evidentiary positions. I also held supervisory responsibilities with respect to OPUC's technical analysis staff. In addition, my responsibilities included providing technical assistance on legislative matters.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a B.S. in Political Science and a M.A. in Urban Studies from the University of Houston. My graduate degree is in an interdisciplinary program offered by the University of Houston's College of Social Science which incorporated substantial training in economics, including course work in the application of cost-benefit analysis to public policy. During my 25-year tenure at OPUC, I gained experience in virtually all phases of economic review required for the ratemaking process. I was chairman of the Economics and Finance Committee of the National Association of State Utility Consumer Advocates ("NASUCA") and served as a presenter for NASUCA's workshops and panels on cost allocation and rate design, Demand-Side Management ("DSM") incentives, market power and electric utility competition. Also, at various times, I have undergone training in specific subjects such as electric wholesale market design, cogeneration engineering and Electric Reliability Council of Texas ("ERCOT") operations. I have testified as an expert witness in approximately 170 utility rate proceedings.

Q. WHAT IS THE SUBJECT OF THIS PRESENTATION?

A. My testimony will address selected issues with respect to AE's requested base revenue increase, residential rate design, and class cost of service. Mr. Effron will address issues pertaining to AE's requested base revenue requirement.

I note that the ICA's review is necessarily limited by the relatively short time period (roughly two months) for reviewing and analyzing this request, as well as a limit placed on the number of requests for information each party could submit, according to the procedural guidelines for this matter.

Q. PLEASE SUMMARIZE YOUR TESTIMONY RECOMMENDATIONS.

A. My findings and conclusions are summarized below.

- AE's system base revenue increase is proposed to be $48.2 million or 7.6% The residential class increase would be $52.3 million or 17.6%. The residential increase would be $4.1 million more than the AE total system base revenue increase.

- AE proposes a 26% base revenue increase for Residential In City (Non-CAP) customers and a -7.6 base revenue decrease for Residential Outside City (Non-CAP) customers. The contrast between the outside city revenue reduction and the inside city revenue increase is due to AE's proposed changes in the residential rate structure, which indirectly shifts revenue responsibility among customers within the residential class.

- AE's proposed 150% increase in the residential customer charge ($25 proposed; $10 current) is outside the range of residential fixed rates charged by the other two largest municipal electric utilities in Texas (San Antonio and Lubbock).

- AE provided an estimate of $6.8 million for labor and benefits, overtime pay, and contract labor for Winter Storm Uri restoration, which is an extraordinary event. I recommend amortization of these expenses over five years.

- My recommendation is to reduce uncollectible expense by $1.4 million based on a three year average of bad debt. The COVID pandemic and Winter Storm Uri caused the test year to be unrepresentative for this category of expense. The three year average is preferable, given the difficulty of extracting all impacts of those events from the test year.

- My recommendation is to include an upward adjustment to late payment fee revenues based on the average late payment revenue in 2018 – 19. AE suspended late payment fees for specific periods of time due to COVID and Winter Storm Uri. The test year late payment fee revenue is not representative of the forward going level of late payment fees.

- An important part of ICA's assignment is a review of AE's class cost of service study (CCOSS) to determine if AE has reasonably and equitably assigned costs to customer classes. I performed an evaluation of AE's functional and class assignments of cost, recommending a number of adjustments to AE's CCOSS.

- The selection of an appropriate production demand methodology is one of the most important class allocation issues in this case. An examination of the underlying production plant characteristics is essential to this decision. AE's owned generation are plants with distinct fuel and operational characteristics that determine the hours that each plant will operate in the ERCOT market. Austin Energy incurred distinctly different generation plant investment to serve baseload, intermediate, and peak periods. AE's production demand method does not adequately recognize these characteristics. I recommend the Baseload-Intermediate-Peak (BIP) methodology for production demand allocation.

- I recommended functionalization, classification or allocation changes to the following costs in the CCOSS: generation O&M expense; uncollectible expense; meters and meter reading; services; administration & general expense (A&G), Accounts 920 and 930; customer service expense, load dispatch expense; and certain fees identified in Other Revenues.

- Contrary to AE's conclusion that the residential class is heavily subsidized by other customer classes, the revised CCOSS indicates that the residential class is approximately in an average cost position relative to other classes.

- The CCOSS is only a guide for determining the distribution of a system revenue increase among the customer classes. Non-cost and unquantifiable factors can be considered as part of this determination. A potential factor for consideration is the fact that two extreme events affected the test year—the COVID pandemic and Winter Storm Uri.

- My recommended method for assigning the base revenue increase to classes starts with the identification of two commercial classes that have a revenue surplus in the revised CCOSS. These two classes should receive 50% of the system percentage base revenue increase. The remaining revenue increase should be spread to the remaining classes on an equal percentage basis. With ICA's revenue requirement adjustments, the residential class receives a 1.2% base revenue increase.

- My recommendation for base revenue distribution is reasonable for small commercial customers by setting the Secondary <10 kW revenue increase at one-half system average. With ICA's revenue requirement changes, the base revenue increase for that class would be 0.5%.

- AE's proposed residential customer charge is more than 2.7 times higher than the average customer charges of Texas investor-owned electric utilities. AE's proposed 150% increase in the customer charge is unreasonable.

- I have developed basic residential customer costs, which should only be based on meters, services, and billing and collection costs which vary directly with the number of customers. I have estimated basic residential customer costs of $6.11 per month. The Company's proposed customer charge of $25.00 can be claimed as cost-based only by including substantial indirect costs, including general administration, general funds transfer, non-utility operations expense, and internal generation of funds for construction---none of which vary directly with the number of customers. In my view, a customer charge is sufficient and compensatory if it exceeds basic customer costs and provides some contribution to common costs.

- The current customer charge of $10.00 is reasonable because it exceeds the basic customer cost amount of $6.11. If the City decides to increase the customer charge, the increase should be commensurate with the overall revenue increase percentage. Under no circumstances should the residential customer charge exceed $13.00 in this case. An increase scaled to ICA's overall recommendation results in a $10.20 customer charge.

- AE overstates the role of the residential rate structure as a claimed cause of the proposed system revenue increase. AE's current residential rate structure was implemented with the goal of promoting energy conservation. AE's objection to the current rate structure is essentially that it has been too effective at promoting energy conservation. Furthermore, AE position ignores any potential long run reductions in utility cost which accompanies reduction in energy consumption. AE's changes to the overall rate structure (including the customer charge) are likely to weaken price signals that suppress excessive and wasteful use of electricity.

- My recommendation is to continue separate rates for outside city residential customers. The best approach at this time is to maintain the existing outside city residential tariff without change. Outside city customers consume much higher levels of electricity. Due to differences in the energy use characteristics of inside and outside city customers, imposition of a uniform rate structure is likely to cause excessive customer impacts for either set of residential customers. AE should develop load research data for outside city customers in the next rate case, so that an appropriate cost benchmark is available to set rates for those customers.

- I disagree with AE's proposed residential rate structure. The rate structure produces divergent customer impacts and is mis-aligned with energy conservation objectives. For inside city customers, low usage customers (<500 kWh) receive increases ranging from 51% - 84%. Medium usage customers (501 – 1,000 kWh) face increases ranging from 18% - 32%. 1,500 kWh and higher received decreases ranging from -5% - -26%.

- My proposed revisions to the residential rate structure would address AE's concerns regarding increased revenue stability without producing the customer impacts and divergence from energy conservation objectives associated with AE's three tier proposal. My recommendation is to reduce five tier structure to four tiers. The first two tiers would be 0-500 and 500-1300 kWh, which encompasses, on average, almost 90% of customer bills. The tiers at higher levels of consumption prevent the rate reductions for high electricity users.

II. OVERVIEW OF AE'S REQUEST

Q. WOULD AE'S PROPOSAL IMPOSE A SIGNIFICANT BASE RATE INCREASE ON THE RESIDENTIAL CLASS?

A. Yes. AE's proposal would have a more severe impact on the residential class than any other class. In addition, the AE proposal would significantly restructure residential rates in a manner that will cause more severe increases for certain groups of residential customers.

Q. PLEASE SUMMARIZE AE'S REQUESTED INCREASE IN BASE REVENUES.

A. AE's system base revenue increase is $48.2 million or 7.6% The residential class increase is $52.3 million or 17.6%. In effect, the residential class would pay an amount equal to the full system increase **plus** a contribution of $4.1 million toward the $11 million in revenue *reductions* proposed for large commercial and industrial classes.

Q. WHY DOES AE PROPOSE A RESIDENTIAL REVENUE INCREASE LARGER THAN THE SYSTEM INCREASE?

A. The process of rate setting utilizes a class cost of service study (CCOSS) as a guide for developing customer class revenue changes. AE contends that its CCOSS provides a justification for the sizeable residential rate increase in combination with rate reductions for certain commercial/industrial customer classes. For this reason, a thorough review of the AE's CCOSS methodology (as discussed in Sec.IV) is an important step in protecting the interests of residential customers.

Q. THE PROCEDURE FOR RATE REVIEW IS CONFINED TO BASE RATES. DOES THIS CAUSE CONCERN FOR EVALUATING A RESIDENTIAL INCREASE OF THIS SIZE?

A. Yes. The fuel and purchased power pass-through rates are not being reviewed in this hearing process, even though those rates could be adjusted by the end of the year. High natural gas prices and power prices in ERCOT which have been elevated could lead to a substantial increase in the pass-through rates. My concern is that a future pass-through rate increase could be "pancaked" on top of any base rate increase adopted in this proceeding, which would compound the severity of the residential revenue increase.

Q. CAN YOU PROVIDE DETAIL THAT BREAKS OUT THE PROPOSED REVENUE INCREASE AMONG DIFFERENT SEGMENTS OF THE RESIDENTIAL CLASS?

A. Yes. The residential revenue increase can be broken out among Inside City, Outside City, and CAP customers. As shown below, the 26% revenue increase for Inside City Non-CAP customers is particularly large. The revenue reduction for Outside City customers is not dictated by the CCOSS (outside city residential customers are not allocated costs as a separate class in the CCOSS). The contrast between the outside city revenue reduction and the inside city revenue increase is due to AE's proposed changes in the residential rate structure, which indirectly shifts revenue responsibility among customers within the residential class. Currently inside city and outside city residential customers have different rate schedules, but AE proposes to apply the same rate structure to both groups of residential customers.

AE Residential Rev. Increase

Residential Class	Current	Proposed	Rev. Change	Percent
Inside City	$206,793,386	$260,577,420	$53,784,034	26.0%
Outside City	$68,386,064	$63,314,366	($5,071,698)	-7.4%
CAP	$22,935,661	$26,556,422	$3,620,761	15.8%
Total	$298,115,111	$350,448,208	$52,333,097	17.6%

Q. PLEASE OUTLINE HOW AE APPLIES THE RESIDENTIAL REVENUE CHANGES TO RATE ELEMENTS?

A. The significant residential class revenue increase is not proposed to be applied evenly or proportionately to rate elements. This can be illustrated by the Inside City residential base rate changes. The residential basic customer charge is increased by 150%. The energy rates, cumulatively, are *reduced* by 9%. But, given AE's restructuring of the tiered energy rates, the reduction to energy rates is not consistent at different usage levels. Energy rate base revenues for residential customers using 500 or less kWh increase by 40% and energy rate base revenues for the remaining residential usage cumulatively *decrease* by 36%.

Q. AE STATES THAT THE PROPOSED 150% CUSTOMER CHARGE INCREASE ALIGNS AE'S FIXED CHARGE RECOVERY WITH OTHER AREA ELECTRIC UTILITIES. IS THIS A VALID JUSTIFICATION?

A. No. AE compares its proposed residential customer charge to the fixed charges of Georgetown's municipal utility, and the Pedernales and Bluebonnet Electric Co-Ops.[1] AE omits any comparison to the fixed monthly charges of investor-owned electric utilities in Texas, which on average are lower than AE's current customer charge. Moreover, the customer charges of electric co-operatives typically are higher because those utilities serve rural areas, thus requiring longer service lines and serving lower population density than electric utilities like AE that serve major metropolitan areas. Instead of relying upon Georgetown, which is 4% of Austin's size, as a benchmark, AE could have compared its residential customer charge to similarly sized municipal

[1] Austin Energy Rate Filing Package at page 152, Table 10A.

utilities' monthly residential charge. The customer charge of the three largest Texas municipal electric utilities is shown below:

1. San Antonio City Public Service $9.10
2. Austin Energy $10.00
3. Lubbock Power & Light $8.07
4. **Austin Energy Proposed $25.00**

Q. PLEASE EXPLAIN HOW YOU WILL ADDRESS ISSUES PERTAINING TO AE'S PROPOSAL.

A. Subsequent sections of my presentation will address: (1) certain revenue requirements issues, which are in addition to those presented by Mr. Effron; (2) class cost allocation in the CCOSS; (3) the recommendation for assigning the system base revenue increase to customer classes; and (4) residential customer charge and rate structure.

Q. WILL YOU ADDRESS ANY REVENUE REQUIREMENT ISSUES?

A. Yes. I will address three revenue requirement issues: Winter Storm Uri expenses; uncollectible expense; and late fee revenues. Mr. Effron will present ICA's total revenue requirements position, and I have transmitted my recommendations on these three items for inclusion on his exhibits.

III. REVENUE REQUIREMENT ISSUES

Q. WHAT REGULATORY CONCEPTS ARE APPLICABLE TO YOUR RECOMMENDATION.

A. As AE recognizes in its filing, the test year data is intended to be representative of the conditions which will prevail in the future. Adjustment may be made to particular components of the revenue requirement reflecting normalized data, based on average conditions in the past. Furthermore, the impact of abnormal or non-recurring issues should be removed.

A. <u>Winter Storm Uri Expense</u>

Q. PLEASE PROVIDE BACKGROUND REGARDING WINTER STORM URI.

A. In February 2021, Winter Storm Uri struck most of Texas, including Austin. This was an extreme storm, rare in terms of intensity and duration. Over 220,000 customers in Austin experienced electric outages for 4 – 5 days. Given the deadly nature of this storm, restoration of electric service was a priority for AE. Although this event occurred during the test year, AE's cost of service is not adjusted for Winter Storm Uri.

Q. DID AE PROVIDE YOU EXPENSES RELATED TO WINTER STORM URI RESTORATION?

A. Yes. AE provided an estimate of $6.8 million for labor and benefits, overtime pay, and contract labor for Winter Storm Uri restoration, which AE said was recorded in March 2021.[2] Notably, this event was not a routine or "normal" winter storm and should be considered abnormal for rate making purposes.

Q. WHAT IS YOUR RECOMMENDATION FOR THE TREATMENT OF WINTER STORM URI RESTORATION EXPENSE?

A. My recommendation is to amortize this expense over five years. Regulatory authorities frequently amortize costs caused by extraordinary storms and hurricanes. Generally the amortization period is intended to represent the interval between events of similar magnitude. Given that the magnitude of Uri is quite rare in central Texas, that approach

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[2] Response to ICA Request 4-12. Note that this answer incorrectly states that the storm occurred in February 2020 with expenses recorded in March 2020. Presumably the answer intended to list February 2021 and March 2021.

would imply a lengthy amortization period. Because some normal level of storm restoration costs is likely to occur in the future, a five-year period is a reasonable balance. As a result, only $1.36 million of the $6.8 million test year amount should be included in cost of service. The difference is $5.44 million, which represents the reduction to cost of service.

B. Uncollectible Expense

Q. IS THE TEST YEAR UNCOLLECTIBLE EXPENSE ABNORMALLY HIGH?

A. Yes. The test year actual uncollectible expense is $13.9 million, which is almost three times the uncollectible expense for the previous fiscal year. AE makes a ($7.8 million) known and measurable adjustment to remove a non-recurring issue. [3] The cost of service amount is $5.99 million. AE provides no information on the nature of the non-recurring issue or the method of determining the known and measurable adjustment.

Q. ARE YOU AWARE OF UNUSUAL CONDITIONS WHICH WOULD CONTRIBUTE TO THE HIGH LEVEL OF UNCOLLECTIBLES?

A. Yes. The COVID pandemic began in March 2020 and continued through the end of 2020 and into 2021. The COVID pandemic caused severe dislocation among AE customers, including loss of employment, inability to work from employers' offices, closure of schools and universities, and staying at home. AE placed a moratorium on disconnections in March 2020, including reconnection of recently disconnected customers. The disconnection moratorium was extended into summer 2021. Furthermore, disconnections were suspended again after Winter Storm Uri.

[3] WP D -1.2.6.

Q. SHOULD THE TEST YEAR UNCOLLECTIBLE AMOUNT BE NORMALIZED BASED ON PRIOR YEARS UNCOLLECTIBLE DATA?

A. Yes. Given the extensive unusual conditions prevailing during the test year, a reasonable approach is to apply AE's three-year average uncollectible amount, FY2018 - FY2020, as the appropriate level of uncollectibles. This period is recent and excludes the conditions that affected FY 2021.

Q. PLEASE PROVIDE THE NORMALIZATION ADJUSTMENT.

A. The three-year average uncollectible amount is $4.574 million.[4] After AE's reduction of the test year expense for the known and measurable adjustment, the requested cost of service amount is $5.99 million. However, this amount is $1.4 million higher than the average for the prior three years. My recommendation is to reduce uncollectible expense by $1.4 million.

C. Late Payment Fees

Q. WHAT IS THE RATEMAKING EFFECT OF LATE PAYMENT FEE REVENUES?

A. Late payment fee revenues are a reduction to customer costs in the CCOSS.

Q. DO YOU RECOMMEND NORMALIZATION OF THE LATE PAYMENT FEE REVENUES?

A. Yes. Due to the COVID pandemic, late payment fees were suspended for most of 2020 and part of 2021. After late payment fees resumed in 2021, AE continued to encourage payment arrangements that included waiver of the late payment fee. I recommend using the average annual late payment fee revenue for 2018 and 2019 to set a revenue

[4] Calculation is based on data provided in response to ICA Request 4-8.

amount for cost of service. The late payment fee revenue in those years should be representative of future revenues.

Q. WHAT IS THE AMOUNT OF THE ADJUSTMENT IN "OTHER REVENUES?"

A. The late fee revenues declined sharply in 2020 and recovered somewhat in 2021, but not to the level of prior years. The average annual amount of late fee revenue in the two years prior to 2020 is $5.55 million.[5] The test year amount of late payment fee revenues is $3.34 million.[6] Therefore, I recommend an upward adjustment of $2.2 million to late payment fee revenue.

IV. CLASS COST OF SERVICE STUDY

A. Overview

Q. WHAT IS A CLASS COST OF SERVICE STUDY ("CCOSS")?

A. The CCOSS is a fully-allocated cost study that distributes the Company's costs to customer classes. The intent of the study is to allocate costs based on cost causation, generally resulting in a portion of costs allocated on causal measures and the remainder of indirect costs following those costs. The CCOSS is at best a broad benchmark for evaluating customer class cost responsibility. The CCOSS can provide guidance to the regulator, but considerations other than the CCOSS are also appropriate in determining the ultimate allocation of costs among customer classes.

Q. HOW IS THE COST CAUSATION CRITERION APPLIED IN THE CCOS?

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[5] AE Response to 2WR 1-11.
[6] WP E-5.1.

A. Some costs are incurred directly to serve only an individual customer or set of customers. But such directly assigned costs are relatively rare in the electric utility industry.

However, the provision of electric utility service is predominated by common and joint costs, which either support the overall enterprise or produce shared benefits for all or most customers. These costs often are assigned based upon indirect, and often weak, measures of causation. For example, overhead costs, such as Board of Director fees, might be allocated based upon measures as diverse as revenues, labor costs, energy sales, or rate base. No single objective economic basis supports the allocation of these costs; therefore, the allocation decisions are subjective or based on rate making conventions. Ideally, the analyst selects a method that best recognizes the manner in which customer classes' characteristics contributed to the incurrence of utility investments and expenses. The manner in which a utility plans and utilizes an investment often informs the analyst's evaluation of causal factors related to classification or allocation of the investment.

The three major steps of the embedded cost of service study are functionalization, classification, and allocation. Functionalization is the procedure for separating costs into functional segments, such as production, transmission, distribution and billing. The next two accounting steps, classification and allocation, facilitate the recognition of causation. The classification procedure, which pools costs into general categories of causation (i.e., demand, customer, energy) is an intermediate step in determining the allocation factors that are used to divide costs among customer classes.

Q. DO BUNDLED ELECTRIC UTILITIES LIKE AE HAVE MORE COMPLEX ALLOCATION ISSUES?

A. Yes. Bundled utilities provide both generation and delivery of electricity to end use customers. The classification of generation (production) costs is frequently disputed. Generation systems are complex and require minute to minute dispatch of generation resources in order to meet real time demand at the lowest cost. As part of the system planning process, the utility plans to acquire or install a mix of generation capacity and purchased power sufficient to meet the system reserve margin at the lowest projected present value of revenue requirements. Because the capital cost or capacity charge of generation generally varies inversely with the generation resource's running cost, the expected hourly output of the resource is an important determinant of system planning decisions. Both reliability and load duration are considerations in reflecting cost causation for generation. Reliability is recognized through class peak demands. Load duration is reflected through class energy use (average demand) or multiple hours of demand (such as the 12-month class peaks). Given the various weightings and combinations of methods to reflect reliability and load duration, the NARUC[7] Electric Utility Cost Allocation Manual (CAM) identifies approximately 30 different production cost allocation methodologies. AE is different from investor-owned electric utilities in Texas because it is a bundled utility operating in the Electric Reliability Council of Texas (ERCOT).[8] The nodal market in ERCOT dictates the dispatch of

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[7] National Association of Regulatory Utility Commissioners.

[8] Bundled investor-owned electric utilities in Texas (EPE, SPS, SWEPCO, ETI) operate in reliability. regions other than ERCOT.

AE's generation, a characteristic which should be considered in selecting a production allocation methodology.

Q. PLEASE DESCRIBE YOUR REVIEW OF AE'S CCOS STUDY.

A. I evaluated the study for consistency and accuracy in the allocation of costs among classes. The 1992 NARUC Electric Utility Cost Allocation Manual (CAM) and the 2020 Regulatory Assistance Project Cost Allocation Manual ("RAP CAM")[9] are helpful references for the evaluation. Based on my review, the allocation or classification of several cost elements were identified as insufficiently justified or warranting improvement. My analysis proposes modifications to the treatment of those costs in the CCOSS. My recommendations relate to changes in functionalization, classification, and class allocation factors.

B. <u>Production Demand Costs</u>

Q. WHAT ALLOCATION METHOD DOES AE'S CCOSS UTILIZE FOR PRODUCTION DEMAND COSTS?

A. The CCOSS uses the ERCOT 12 Coincident Peaks (12 CP) to allocate generation demand costs to customer classes. The 12 CP method is based on customer class kW contributions to the monthly ERCOT hours of peak demand.

Q. WHAT PRODUCTION DEMAND ALLOCATION METHOD DO YOU RECOMMEND FOR AE'S CCOSS?

A. My recommendation is to apply the Baseload-Intermediate-Peak (BIP) method, which separates production costs into generation serving base, intermediate, and peak time periods and develops different class allocation factors for each component.

[9] "Electric Utility Cost Allocation for A New Era: A Manual," January 2020.

Q. WHAT IS THE MOST SIGNIFICANT DEFICIENCY OF AE'S 12 CP METHOD?

A. AE's methodology does not recognize the existence of different types of generation facilities with varying cost characteristics that are critical to the planning and dispatch of generation capacity. AE's method uses 12 peak hours to assign a homogenous annual capacity cost to each month. In reality, generation capacity costs are not homogenous. AE's owned generation are plants with distinct fuel and operational characteristics that determine the hours that each plant will operate in the ERCOT market. Austin Energy incurred distinctly different generation plant investment to serve baseload, intermediate, and peak periods. Although the duration of annual energy output is a major determinant of production plant operations in ERCOT, the 12 CP method proposed by AE does not recognize the impact of average annual demand on the dispatch of its generation units.

(1) Background: Dimensions of Cost Causation for Production Plant

Q. HOW ARE COST CAUSAL CHARACTERISTICS RECOGNIZED BY PRODUCTION PLANT ALLOCATION METHODS?

A. Methodologies differ based on the extent that they recognize peak demand (with variations in the number of peak hours) and average annual energy use (Average Demand). Peak demand relates to the sizing of facilities. The megawatt capability of available generation plants constrains the level of instantaneous demand that can be accommodated. On the other hand, annual energy use (average demand) pertains to costs that are affected by the duration of usage. The 12 CP method used by AE is a pure peak demand method, which does not recognize the Average Demand dimension of causation. The current ERCOT paradigm (an energy only market) should lead to a greater emphasis on energy. If AE can buy power cheaper than its own plants on the hourly market, it can acquire ERCOT energy and reduce production cost. Furthermore, AE can go to the market to meet its hourly load requirements, even if it has owned generation that is subject to outage or unavailability.

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Q. PLEASE DISCUSS THE LONG RANGE PLANNING OF AE'S FUTURE GENERATION RESOURCES.

A. A municipal utility such as Austin Energy will consider several objectives in addition to the pure economics of generation technologies. The factors include environmental impact and climate change. In addition, the relative economics of available options will inform the recommendations of Austin Energy's planners. The primary planning assumption inputs for modeling future economic impacts are energy/fuel prices, forecasted system demands, ERCOT market price trends, and capital costs. Sensitivity studies can be conducted for different energy price and demand levels to evaluate the customer rate impact of various scenarios.

The economics of alternative portfolios of future generation resources will depend on critical trade-offs between each resource's capital cost and energy costs. High capital cost options have lower energy costs while less expensive capital cost options tend to have higher energy costs Renewable technologies, such as solar, and wind, typically have a relatively high cost per kilowatt of capacity, but in return they produce zero fuel cost. As a result, the renewable investment should be classified as primarily energy-related.[10] To the extent that de-carbonization objectives affect generation planning, the impact is primarily energy-related, because the harm caused by carbon and other pollutants depend on technology fuel type and load duration.

Q. IS IT YOUR POSITION THAT THE APPROPRIATE PRODUCTION DEMAND ALLOCATION METHOD IN THIS CASE SHOULD EFFECTIVELY REFLECT CUSTOMER CLASS ANNUAL AVERAGE ENERGY USE?

A. Yes. The dual importance of demand and energy in developing production demand allocation methods is recognized in the NARUC CAM:[11]

> There is evidence that energy loads are a major determinant of production plant costs. Thus, cost of service analysis may incorporate energy weighting into the treatment of production plant costs. One way to incorporate energy weighting is to classify part of the utility's production plant costs as energy-related and to allocate those costs to classes on the basis of class energy consumption.

The NARUC CAM cites the utility system planning process as justification:[12]

> Generally speaking, electric utilities conduct generation system planning by evaluating the need for additional capacity, then, having determined a need, choosing among the generation options available to it. These include purchases from a neighboring utility, the construction of its own peaking, intermediate or baseload capacity, load management, enhanced plant availability, and repowering among others.
>
> The utility can choose to construct one of a variety of plant-types: combustion turbines (CT), which are the least costly per KW of installed capacity, combined cycle (CC) units costing two to three times as much per KW as the CT, and base loaded units with a cost of four or more times as much as the CT per KW of installed capacity. The choice of unit depends on the

[10] RAP CAM at 132, Table 23.

[11] NARUC Electric Utility Cost Allocation Manual at 49.

[12] *Id.* at 53.

> energy load to be served. A peak load of relatively brief duration, for example, less than 1,500 hours per year, may be served most economically by a CT unit. A peak load of intermediate duration, of 1,500 to 4,000 hours per year, may be served most economically by a CC unit. A peak load of long annual duration may be served most economically by a baseload unit.

Q. PLEASE SUMMARIZE YOUR POSITION.

A. AE's ERCOT 12 CP method of production plant allocation is deficient because it fails to recognize the impact of energy use on cost causation. Furthermore, the other peak demand methods (including Average & Excess Demand) considered by AE do not *effectively* recognize annual energy use.

(2) Baseload-Intermediate-Peak (BIP) Methodology

Q. DO YOU RECOMMEND THE BIP METHOD FOR CLASS ALLOCATION OF PRODUCTION PLANT DEMAND?

A. My recommendation is to utilize the Base-Intermediate-Peak Method (BIP) for allocating production plant among customer classes. I have developed two variants of BIP which recognizes the specific characteristics of AE's generation investment. The NARUC CAM identifies BIP as an accepted production demand methodology which falls within the "time-differentiated" category of methodologies.[13] The RAP CAM rates the BIP method as providing a "High" level of accuracy for cost causality.[14] BIP utilizes three time periods—Base, Intermediate, and Peak hours—and is based on the premise that baseload, intermediate, and peaking generation technologies and fuel types were incurred primarily to serve each of those time periods, respectively.

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[13] NARUC CAM at 60-62.
[14] RAP CAM at 129, Table 19.

Q. HOW DID YOU USE THE TWO VARIANTS OF BIP?

A. BIP separates production plant into base, intermediate, peak based on the load durations that the plants primarily serve. The first method (BIP-P), which is used in my CCOSS recommendation, establishes weightings for the three time periods based on the original cost of plants assigned as base, intermediate, or peak. The second method (BIP-E) reflects the current operation of the plants in the ERCOT market, estimates relative margins earned by the baseload, intermediate, and peak plants, which establishes weightings for the baseload, intermediate, and peak period. I utilize the BIP-E results as illustrative, in order to confirm the reasonableness of the BIP-P results. The two variants produce closely similar class allocation results.[15]

Q. PLEASE DESCRIBE THE GENERATION PLANT ASSIGNED TO BASE, INTERMEDIATE, AND PEAK UTILIZATION.

A. The BIP method identifies the plant investment assignable to base, intermediate, and peak utilization. South Texas Project (nuclear) and Fayette Power Plant (coal) are assigned as baseload, because these units are operated at high capacity factors throughout the year. AE reports an average capacity factor of 89% for STP and 60% for FPP.[16] From an economic perspective, the objective of STP and FPP management is to maximize the capacity factor for these two plants in order to take advantage of their relatively low variable costs. The combined cycle gas unit at Sand Hill Energy Center is assigned as intermediate generation; AE reported a 39% capacity factor for

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[15] See Schedule CJ-1.
[16] Technical Conference-1., Attachment ICA TC 1-8C.

this plant.[17] Typically intermediate generation will have capacity factors ranging from 20% - 50%, depending on their variable costs and market conditions. Intermediate periods frequently include shoulder demands. The gas generation consisting of simple cycle combustion turbines at the Decker and Sand Hill sites and are assigned to Peak. AE refers to these units as "quick dispatch" because the units can be started quickly in order to meet loads of short duration.

Q. PLEASE EXPLAIN HOW CLASS ALLOCATION FACTORS ARE DEVELOPED FOR BIP.

A. The Base capacity is allocated on class Average Demand factors, because baseload generation is operated at a high capacity factor in order to achieve maximum energy value throughout the year. The Intermediate period is allocated partially on an energy basis and partly on the basis of 12 CP (ERCOT), because intermediate generation has a role which is a mixture of Peak and Baseload characteristics.[18] The capacity factor of these units is used to separate the portion of intermediate plant cost which is energy-related. Based on the reported capacity factor for AE's combined cycle plant, 39% of Intermediate is allocated on energy and 61% is allocated on a 12 CP basis. The Peak capacity is allocated on the basis of the ERCOT 4 summer coincident peaks (4CP). The summer peaks provide higher prices which justify the operation of high variable cost generators. This reflects the role of quick start peak generation in meeting the primary peak demands. I developed two variations of BIP class allocation factors. My

[17] Ibid.

[18] This is essentially Average & Peak 12 CP, with capacity factor substituted for load factor.

development of BIP is consistent with the classification of generation plants shown in the RAP CAM (Table 23, page 132).

Q. PLEASE DESCRIBE THE BASIC DIFFERENCE BETWEEN THE TWO VARIANTS.

A. BIP-P establishes base, intermediate, and peak weightings based on the gross plant cost of Austin's share of STP and FPP (Base), Sand Hill Combined Cycle (Intermediate), and Decker and Sand Hill Combustion Turbines (Peak). BIP-E establishes base, intermediate, and peak weightings based on a simplified estimate of the relative margins generated by each type of plant. Margin is defined as the market price in excess of the unit's fuel cost plus dispatchable variable expense. In the ERCOT paradigm, the margin earned by AE's owned generation can be used to offset the cost of acquiring ERCOT energy to meet AE's customer load. In this case, I use BIP-E to confirm the reasonableness of the BIP-P results. I do not object to utilizing the BIP-E factors for production allocation. But I have chosen the BIP-P class allocation factors for the CCOSS because this variant is less complex than BIP-E. The allocation factor weightings for each variant are shown below.

Allocation Weightings

	BIP-P	BIP-E
Base	79.8%	76.6%
Intermediate	9.4%	9.4%
Peak	10.8%	13.9%

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Q. PLEASE DESCRIBE HOW YOU DEVELOPED THE ERCOT MARGIN ANALYSIS.

A. ERCOT prices are based on the 2019-2020 average of location weighted settlement prices for each type of generation plant (Nuclear, Coal, Combined Cycle, Combustion Turbine) as determined by ERCOT's Independent Market Monitor.[19] WP D-1.1.1.1 of the RFP provides fuel costs for FPP and STP. Gas plant fuel costs are based on estimated heat rates and the average summer Henry Hub gas spot price for 2019-2020. Variable energy expense for each plant type is derived from Energy Information Administration (EIA) generic data.[20] Plant output is based on the capacity factors reported in Attachment ICA TC 1-8C.

Q. DOES THE ERCOT MARGIN VARIANT OF BIP ILLUSTRATE CONSISTENCY WITH AE'S PARTICIPATION IN ERCOT?

A. Yes. In the ERCOT market structure, generators (including AE) submit real time or day ahead pricing bids into the ERCOT market, and ERCOT dispatches generation on a five minute or less basis, utilizing the market clearing price for the demand level at that instant. Under ordinary conditions, generators are expected to submit bids close to the generation unit's variable cost in order to ensure that the unit operates when it is economic to do so. As a result, generating unit's annual hours of operation will depend on its variable cost. And, as noted previously, higher capital cost plants tend to have lower variable cost, and vice versa. By confirming the reasonableness of the BIP

[19] ERCOT State of the Market Report 2020, Independent Market Monitor, Table 7.
[20] EIA Cost and Performance Characteristics of Generation Technologies at page 2, 2022 Annual Energy Outlook, March 2022.

allocation factors used in my CCOSS, the BIP-E analysis demonstrates that the method is appropriate for an ERCOT market participant.

Q. DOES THE BIP-E ANALYSIS ILLUSTRATE THE GENERATION COST TRADE-OFFS THAT YOU HAVE DISCUSSED.

A. Yes. The gas generation produced about 20% of margins, even though the market prices were much higher for those units' operation. The average settlement prices for Combined Cycle and Combustion Turbine plants were 10% and 200% higher than settlement prices for coal and nuclear power, but the gas plants operated in a much more limited number of hours. The coal and nuclear capacity earn lower average prices because they operate in a large number of hours, including low priced hours. This reflects the lower variable cost of the solid fuel plants compared to gas generation, which permits the solid fuel plants to operate in more hours.

Q. HAS AE PREVIOUSLY RECOGNIZED THAT THE BIP METHOD BETTER REFLECTS THE ERCOT MARKET?

A. Yes. AE previously considered the BIP methodology and, therefore, is aware that it represents a reasonable methodology for the AE system. AE's rate filing package for the 2016 rate case included a sub-functionalization of production costs for use in a BIP method. [21]AE's previous cost of service consultant, R.W. Beck (later called "SAIC"), recommended BIP during the public involvement (PIC) process for the 2011 rate

[21] 2016 COSS WP F-2.3

request.[22] The consultant pointed out that BIP is consistent with the characteristics of ERCOT market dispatch.[23]

Q. PLEASE SUMMARIZE YOUR POSITION.

A. The BIP methodology represents a more reasonable approach to allocating production demand costs. This approach also reflects a method which more reasonably balances the interests of AE's customer base by recognizing both reliability and economics. Furthermore, BIP recognizes the prevalence of meeting ERCOT loads of short or medium duration with combustion turbine and combined cycle generation. Schedule CJ-1 presents allocation factors for both variants of BIP.

C. Production Non-Fuel O&M Expense Classification

Q. DO YOU AGREE WITH AE'S CLASSIFICATION OF PRODUCTION NON-FUEL O&M ACCOUNTS?

A. No. AE classified all production base rate O&M expense as demand-related.[24] The customary approach is to split these expenses between demand and energy. Although I sometimes disagree with the demand/energy split for generation O&M applied by other utilities, I cannot recall another bundled electric utility which owned multiple generating units that applied a 100% demand classification to the expenses. Among current bundled electric utilities in Texas, SWEPCO, SPS, and El Paso Electric Co. (EPE) classify a significant portion of production non-fuel O&M expense as energy-

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[22] 2016 rate case. AE Response to ICA Request 7-11.

[23] R.W. Beck concluded that BIP mirrored the Probability of Dispatch method (POD) by "maintaining a link between resource dispatch and load requirements, but in a manner more consistent with the ERCOT nodal market design." Ibid.

[24] AE classifies Nacogdoches Plant O&M expense as Energy, but includes these costs in the PSA.

related. The NARUC CAM specifies a methodology for defining the demand and energy portion of each account; this is a reasonable convention for evaluating the classification of generation O&M expense.[25]

Q. DO YOU USE THE NARUC METHOD TO CLASSIFY PRODUCTION NON-FUEL O&M EXPENSE?

A. Yes. This method represents an accepted convention and has been adopted by the Texas PUC in the past. In this case, the methodology is applied to STP and FPP O&M expense. AE's gas generation non-fuel O&M expense is recorded in Other Power Generation accounts which is classified as demand-related.

Q. PLEASE DESCRIBE THE NARUC COST ALLOCATION MANUAL'S METHOD FOR CLASSIFYING PRODUCTION NON-FUEL EXPENSE.

A. Some accounts are classified entirely as either energy or demand. However, most accounts are split between energy and demand in proportion to the labor and materials cost in the account. For these accounts, labor costs are considered more fixed in nature, and are classified as demand-related, while materials (consumables) are considered more variable in nature and are classified as energy-related. AE does not separate STP and FPP labor and materials cost in the rate filing package. However, AE provided those percentages in responses to the technical conference and requests for information.[26] I applied the labor/materials percentages as specified by the NARUC CAM.

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[25] NARUC CAM at 35-41, Table labeled "Exhibit 4-1."
[26] Response to ICA Request 1-7, and Attachment ICA TC 1-8B.

Q. WHY IS A SUBSTANTIAL PORTION OF GENERATION MAINTENANCE EXPENSE ENERGY-RELATED?

A. Like most mechanical devices, the frequency of maintenance for production facilities is generally a function of the wear and tear associated with the duration of operating the facilities. It is not reasonable to assign causal responsibility for maintenance costs solely to peak hours during the year.

Q. IS SOME PORTION OF PRODUCTION OPERATION EXPENSE PROPERLY CLASSIFIED AS ENERGY-RELATED?

A. Yes. Certain expenses such as coolants, lubricants, nuclear fuel moderation fluids, and other consumable supplies vary with the annual generation of the production facilities. Moreover, baseload facility operating expenses obviously are needed to support operations throughout the year.

Q. SUMMARIZE THE ENERGY CLASSIFICATION PERCENTAGES APPLIED TO PARTICULAR ACCOUNTS.

A. The following FERC Accounts were classified as 100% Energy: 512 – 514. The following FERC Accounts were classified to Energy in the following percentages: 500 (70%), 502 (72%), 505 (95%), 510 (58%), 517 (65%), 519 (43%), 520 (56%), 520 (15%). The remainder of these accounts are demand-related.

Q. HOW DOES THE O&M EXPENSE CLASSIFICATION AFFECT THE ALLOCATION OF PRODUCTION EXPENSE TO CUSTOMER CLASSES?

A. Demand classified O&M are allocated on the production demand allocation factor, and Energy classified O&M are allocated on the generation level kWh allocation factor.

D. Classification of A&G Accounts 920 and 930

Q. DESCRIBE ADMINISTRATIVE & GENERAL ("A&G") ACCOUNT 920?

A. As a matter of accounting definition, Account 920 contains salaries and wages which cannot be attributed to any particular function of the utility. Examples of typical expenses include the utility's chief executive, general utility officers, the treasury and finance departments, the human resources department, strategic planning, budgeting, and the like.

Q. DOES AE UTILIZE AN INDIRECT ALLOCATOR TO FUNCTIONALIZE MOST OF THE A&G SALARIES IN A920 TO PRODUCTION, TRANSMISSION, DISTRIBUTION, AND CUSTOMER FUNCTIONS?

A. Yes. AE identifies 5.5% of A&G salaries related to FPP and STP oversight, which are directly assigned to production. The remainder of A920, after known and measurable adjustment, is functionalized based on the proportion of payroll within each function (LABOR functionalization). It should be noted that other indirect functionalization factors, such as net plant, revenue requirement, or O&M expense, could also be justified as a general method to prorate A&G salary to the functions. There is no objective economic rationale for selecting particular functionalization factors of A920. The labor functionalization method is consistent with the NARUC CAM.

Q. HOW SHOULD THE RESULTS OF AN INDIRECT FACTOR BE EVALUATED?

A. Because none of the potential indirect methods are strongly related in a causal sense to this A&G accounts, an evaluation of the results should focus on the extent to which the allocator spreads corporate overhead broadly and equitably across corporate functions. A920 activities support the overall enterprise. A reasonable general allocator should not be tilted in a direction that is out of proportion to the overall composition of costs. In this case, the labor allocator does not produce balanced results.

Q. WHY IS THE LABOR ALLOCATOR IN THIS CASE ABERRANT?

A. The composition of AE's labor allocator produces incongruent results, which justifies either rejecting the labor method for A920 salaries or correcting the deficiency in the method. Because AE is a co-owner of the STP and Fayette power plants, AE's share of the on-site payroll for both plants is not included in the development of the Payroll functionalization factor. Although STP and FPP constitute approximately 67% of non-fuel production O&M expense, the STP and FPP on-site labor expense is not included in the payroll allocator. As a result, the labor allocation will understate the magnitude of the production function relative to AE's overall cost structure. Therefore, I have corrected the payroll functionalization factors applied to A920.

Q. PLEASE EXPLAIN HOW YOU CORRECTED THE PAYROLL FUNCTIONALIZATION APPLIED TO ACCOUNT 920.

A. I re-calculated the payroll functionalization factor for Production based on including AE's share of STP and FPP on-site labor.[27] Next I determined the difference between AE's allocation of 920 expense to Production and the allocation based on the corrected payroll functionalization factor. In order to avoid changing the payroll functionalization factor, which is applied to other accounts in the CCOSS, I made a

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[27] AE provided its share of STP and FPP on-site payroll in response to ICA Request 1-7, and Attachment ICA TC 1-8B.

direct assignment of $10.4 million from A920 to Production before applying AE's payroll factor to the remaining expense in A920. Both of these steps result in a composite allocation equal to the corrected Payroll factor.

Q. CAN YOU DEMONSTRATE THAT THE OMISSION OF STP AND FPP PAYROLL FROM THE PAYROLL ALLOCATOR DISTORTS THE RELATIVE IMPORTANCE OF PRODUCTION?

A. Yes. Customer classes are responsible for varying proportions of the four functions. All customer classes pay for production costs, but transmission voltage classes are not responsible for most distribution costs, and customer costs are mostly borne by classes with numerous customers (i.e., the residential and small secondary classes). Allocating a lower proportion of indirect costs to production tends to favor large industrial customers because a larger part of their bundled rate is generation. If STP and FPP on-site labor is included in the payroll functionalization, 37.5**%** of allocable cost in Account 920 is functionalized to Production. By comparison, the Company's payroll factor functionalizes **19.7%** of allocable Account 920 cost to Production. By contrast, Production is 39.8% of non-fuel O&M, 40.8% of Gross Plant, and 32.3% of Revenue Requirement.

Q. DO YOU PROPOSE A FUNCTIONALIZATION CHANGE TO A&G ACCOUNT 930-GENERAL EXPENSES?

A. Yes. This account contains miscellaneous general expenses. Less than 1% of this FERC Account consists of salaries. AE functionalizes this account on Payroll. My recommendation is to use the non-fuel O&M functionalization factor. This will result in a more balanced spread of the cost to the Production, Transmission, Distribution, and Customer functions. Given the diverse variety of A&G expenditures recorded to this account, AE's functionalization of the largest amount of cost (40%) to the Customer function is unreasonable. I recommend the O&M excluding A&G factor[28]; this is consistent with the three-factor allocation for A930 set out in the NARUC CAM. This is also the same functionalization method as AE applies to A&G outside services (A923). The RAP CAM states that "best practices" for A&G accounts is to "ensure broad sharing …based on usage metrics."[29] AE's payroll method does not meet this criterion, given the large allocation to Customer.

Q. DO YOU CARRY THROUGH THE A930 CHANGE TO THE DISTRIBUTION SUB-FUNCTIONALIZATION LEVEL?

A. Yes. A930 expenses functionalized to Distribution are spread to the sub-functions on the basis of distribution O&M instead of distribution payroll.

Q. PLEASE DISCUSS THE DIVERSITY OF EXPENSES IN ACCOUNT 930.

A. The largest single expenditure is for Information Technology Business & Quality Management.[30] But the business units involved in the numerous expenditures are diverse: for example, Security Management Services, State and Federal Government Relations, Strategic Planning and Technology, Advanced Grid Technologies, and Disaster Restoration. I have seen no evidence that these expenses are directly related to payroll in the same manner as pensions and benefits, for instance.

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[28] " O&MxA&G" factor.
[29] RAP CAM at 19.
[30] A listing of A930 expenses is provided in Attachment ICA 3-2, AE Response to ICA Request 3-2.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION ON A&G EXPENSE.

A. I propose to modify the functionalization of A920 (Salaries) by correcting the payroll functionalization to include STP and FPP. For A930 (Miscellaneous General), I recommend replacing the payroll functionalization with non-fuel O&M functionalization.

E. Classification of Revenues from Customer-Related Fees

Q. PLEASE DISCUSS THE CLASSIFICATION OF "OTHER REVENUES" PRODUCED BY NON-RECURRING FEES AND CHARGES.

A. Rate Filing Package WP E-5.1 sets out the revenue and functionalization for numerous fees charged by AE. Each type of fee is functionalized among Production, Distribution, and Customer functions. The revenue from each fee is used as an offset to revenue requirements for the assigned function. Based on my review of WP E-5.1, some of the fees which were assigned to Distribution should have been functionalized to Customer.

Q. PLEASE SPECIFY THE FEE REVENUE ITEMS WHICH SHOULD HAVE BEEN CLASSIFIED TO CUSTOMER.

A. My recommendation assigns the following fees (which AE functionalized to Distribution) to the Customer function: meter damage and breakage, meter broken seal fee, after hours connection, and new service connections (service initiation fees). The incidence of each of these fees is more likely to vary with the number of customers than the demand of customer classes. Revenues assigned to Distribution will be allocated to classes on the basis of class non-coincident peak demand (NCP), and revenues assigned to Customer will be allocated based on the number of customers in the class. My recommendation increases the "Other Revenues" functionalized to Customer by $2.8 million.

Q. WHICH OF THESE FUNCTIONALIZATION RECOMMENDATIONS IS MOST IMPORTANT?

A. Service connection and reconnection (Service Initiation Fee) comprises $2.39 million of the $2.8 million change in revenues functionalized to Customer. This fee is for ordering the initiation of new service and does not involve the physical costs of connecting a structure.[31] AE states that it cannot identify the proportion of this fee revenue by customer class or type of structure.[32] However, it is apparent that residential customers pay the overwhelming proportion of the $20 service initiation fee. In FY2021 97% of new customers were in the residential class.[33] Clearly a customer allocation (87% Residential) is a better proxy for that proportion than an NCP demand allocation (45% Residential).

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION REGARDING FUNCTIONALIZATION OF NON-RECURRING FEES?

A. The amount of fees on Rate Filing Package WP E-5.1 classified as Customer should be increased by $2.8 million.[34] This results in a larger offset to the component of revenue requirement allocated to classes on the basis of customers and would produce a decrease in AE's proposed residential customer charge.

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[31] In most cases, AE can remotely activate service through smart meters.
[32] Response to ICA Request 3-4; Technical Conference-1.
[33] Attachment NXP 3-10C at 397.
[34] This does not include my proposed revenue requirement adjustment to Late Payment Fees, which AE has properly classified as Customer.

F. Class Allocation of Uncollectible Expense

Q. HOW DOES AE'S COST OF SERVICE STUDY ALLOCATE UNCOLLECTIBLE EXPENSE AMONG CUSTOMER CLASSES?

A. AE allocates uncollectible expense to customer classes based upon the proportion of bad debt expense occurring within residential and non-residential classes during the prior three-year period. This type of method is sometimes referred to as a direct assignment, although it does not strictly fit that label.

Q. DO YOU AGREE WITH DIRECT ASSIGNMENT OF UNCOLLECTIBLE EXPENSE?

A. No. A more reasonable method is to allocate uncollectible expense in proportion to a revenue requirement allocation factor, sometimes called a "revenue allocation." I agree with the order of the Texas Public Utility Commission on this issue in Entergy Docket No 16705. The order in Docket No. 16705 succinctly explained the reasoning for rejecting the direct assignment proposed by Entergy, in favor of a revenue allocation:

> Just as it may seem unfair to have the industrial customers absorb the bad debts of a few individuals, it is just as unfair to have the great majority of dutiful residential ratepayers pay those debts. The passing on of such costs to others is generally factored into the cost of doing business. It is a cost that is better absorbed by the many. Therefore, uncollectible expense should be allocated at both the jurisdictional and class levels on the basis of jurisdictional and class operating revenues.[35]

As recognized in this finding of fact quoted above, the Texas PUC has recognized uncollectibles as a social cost that must be absorbed on an equitable basis

[35] *Application of Entergy Gulf States, Inc. for Approval of its Transition to Competition Plan and the*

across classes, because the cost causers are no longer on the system. Direct assignment of the cost does not allocate the expense to cost causers, because the non-payers, by definition, are not paying customers.

Q. IS THE ENTERGY DECISION CITED ABOVE CONSISTENT WITH TEXAS PUC PRECEDENT FOR INTEGRATED ELECTRIC UTILITIES?

A. Yes. Based upon my experience, the Texas PUC's use of a revenue allocation for uncollectible is one of the most consistent allocation practices historically approved or ordered by the Commission.[36] [37] The Texas PUC discussed the precedent in a 2016 order. Direct assignment vs. revenue allocation was litigated in the Southwestern Public Service Co. (SPS) Docket No. 43695. the decision in that case adopts a revenue allocation of uncollectibles based on the following findings:

> SPS reasonably allocated Uncollectible Account expense in FERC Account 904 on the basis of present base rate sales by class.
>
> Uncollectible expenses are caused by non-paying customers, and the current customers in a particular class are not the cause of uncollectible expense created by other members of that class.[38]

Tariffs Implementing the Plan, and for the Authority to Reconcile Fuel Costs, to Set Revised Fuel Factors, and to Recover a Surcharge for Underrecovered Fuel Costs, Docket No. 16705, Second Order on Rehearing at Finding of Fact No. 231 (Oct. 14, 1998).

[36] For example, *see Application of El Paso Electric Company for Authority to Change Rates*, Docket No. 9945, 18 P.U.C. BULL. 9 (Feb. 1992); *Application of Houston Lighting & Power Company for Authority to Change Rates*, Docket No. 6765, 13 P.U.C. BULL. 1 (Nov. 1986); *Application of Gulf States Utilities Company for Authority to Change Rates*, Docket No. 7195, 14 P.U.C. BULL. 1943, 2425 (1989) (May 1988); *Application of Texas Utilities Electric Company for Authority to Change Rates*, Docket No. 11735, Order on Rehearing, Finding of Fact No. 162 (Apr. 20, 1994).

[37] The nature of uncollectible expense is somewhat different in a retail competition environment. Retail uncollectibles are the responsibility of Retail Electric Providers (REPs). Any uncollectible expense incurred by an unbundled TDU would arise due to a default by particular REPs.

[38] *Application of Southwestern Public Service Co. for Authority to Change Rates*, Docket No. 43695, Order, FOF 310 and 311.

Q. IS DIRECT ASSIGNMENT ADEQUATE TO REFLECT THE COMPANY'S EXPOSURE ON A CLASS BASIS?

A. Probably not. If one accepts the direct assignment concept, the class allocations should reflect the future risk exposure posed by each customer class. The direct assignments tend to be based on experience over a relatively short period of time. The magnitude of the uncollectible expense in a given period is affected not only by the frequency of customer accounts which are written off during a period, but also by the size of bills within each particular customer class. For example, the bad debt risk for a class with a small number of customers of varying sizes may not be adequately measured over a short duration period. In addition, the *potential* for significant impact from individual large accounts should be considered. For instance, if an industrial or large business customer goes out of business due to bankruptcy, that individual default would result in a disproportionate increase in the amount of uncollectible expense. This event is likely a low probability/high consequence exposure. The allocation of an uncollectible allowance should reflect the broader exposure if a very large customer defaults. The more reasonable methodology is to allocate uncollectible expense as a cost of doing business which should be spread proportionately to all customer classes.

Q. IS YOUR POSITION CONSISTENT WITH COST ALLOCATION PRINCIPLES?

A. Yes. The RAP CAM supports the use of a class revenue allocation for uncollectible expense.[39] As stated by that manual, direct assignment will not reflect that "these costs are not caused by any current customer in any particular class… Although certain

[39] Regulatory Assistance Project, "Electric Cost Allocation in a New Era" at 162 – 163.

accounts have unpaid electric bills, those accounts are former customers who are no longer members of any class."[40] The manual states that a revenue allocation factor is appropriate because the size of a customer class's bills affect the risk of bad debt, and "if the customer had shut down or left before rates were set, most of the costs reflected in the uncollectible bills would have been allocated to the remaining customers."[41]

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. AE's proposed direct assignment of uncollectible expense should be rejected. Instead, uncollectible expense should be allocated on the basis of revenues (Rev Req allocation).

G. <u>Class Allocation of Smart Meters</u>

Q. HOW ARE METERS ALLOCATED IN THE AE CCOS STUDY?

A. AE develops a weighted customer allocation which reflects the cost of different meter sizes installed by customer class. This method is appropriate and standard, as far as it pertains to the traditional meter function. However, AE has been aggressive in the sophistication of the meters it deploys, and the implication of these advancements is that substantial meter investment cost has been expended to access meter functions which transcend the standard billing and collection measurement role. The allocation method for the meter sub-function should take into account the incremental cost of enabling additional system benefits.

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[40] Ibid.
[41] Ibid.

Q. WHAT IS THE INCREMENTAL COST OF INSTALLING SMART METERS OVER STANDARD MANUAL METERS?

A. The cost of an installed manual residential meter is $105, and the cost of a comparable installed smart meter is $214. [42] Thus, the manual meter is approximately 49% of the cost of the smart meter. The remaining 51% of the smart meter cost represents investment incurred for functions which cannot be performed by a manual meter.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE CLASS ALLOCATION OF SMART METERS?

A. I revised the weighted meter allocation factor to apply 49% of the allocation on the basis of class meter investment and 51% on the basis of class revenue requirement (Rev Req x Serv Area Light). 49% represents standard meter functions and 51% represents the additional functions provided by Smart Meters. In my view, the combined allocation factor recognizes that Smart Meters perform both traditional billing functions and functions that provide system benefits. Furthermore, the revised Weighted Meter allocation factor should be applied to meter reading, which should be considered part of the Meter sub-function.[43]

Q. WHAT ADDITIONAL FUNCTIONS CAN BE ACCESSED AS A RESULT OF THE INCREMENTAL INVESTMENT FOR SMART METERS?

A. As justification for Smart Meter upgrades over the last five years, AE emphasized system benefits for modernizing the grid, acquiring information, developing revenue

[42] Response to ICA Request 1-6.

[43] Because meter reading is accomplished through the network communications architecture of AMI, the expense should allocated be on the same basis as the underlying AMI investment.

and usage reports, revenue protection, and communicating with customers.[44] Additional utility benefits involve the reliability function, enabling improved outage detection, restoring service, repairing faults and system wide recovery. Societal benefits arise from direct load control, demand response, and integration of distributed generation, which reduces energy and demand, thereby applying downward pressure on energy prices in ERCOT markets and reducing the need for new generation. Enabling shared solar generation is an example of a smart meter feature pursued by AE. Customers benefits arise from enhanced ability to manage energy costs, shift loads, communicate with appliances and identify wasteful uses of electricity. AE recognizes most of these functions and continues to activate meter functions which enable these benefits.[45]

Q. IS IT REASONABLE TO EXPECT COST ALLOCATION PRACTICE TO REFLECT MODERNIZATION OF METERS AND THE GRID?

A. Yes. The NARUC CAM supports the use of a traditional weighted customer allocation. However, this manual was published in 1992, prior to the development of Smart Meters. The 2020 RAP CAM recognizes the deployment of automated meter investment and concludes that a traditional customer allocation is inadequate.[46] The manual states that the cost must be allocated over a wider range of activities that reflects generation and distribution functions, because "these new (automated meter) systems are… largely justified by services other than billing." As an example, the Maryland Public Service Commission allocates smart meters 25% to weighted customer, 37.5%

[44] AE Presentations provided in response to ICA TC 1-12B.
[45] Ibid.
[46] Regulatory Assistance Project, "Electric Cost Allocation for a New Era" at 157.

to NCP demand, and 37.5% to energy.[47] As a rationale, "the Commission specifically cites the capacity revenues, capacity price mitigation, energy revenue, energy price mitigation and energy conservation benefits enabled by AMI meters."[48] Such broad allocations accomplish a similar purpose to the revised meter allocation I recommend in this case.

H. Classification and Class Allocation of Services

Q. WHAT ARE SERVICES?

A. Services, also called service drops, are lines attached to the customer premises which connect the distribution line to the end use customer.

Q. WHAT IS UNUSUAL ABOUT SERVICES IN THIS CASE?

A. The "loaded cost" of AE services is negative. Many service lines are old, and the plant account is almost fully depreciated. In addition, many new service lines are prepaid by developers in the form of contributions in aid of construction. The bottom line is that the services sub-function is a reduction to revenue requirement.

Q. HOW DOES AE CLASSIFY AND ALLOCATE SERVICES?

A. AE classifies services as Demand and allocates the cost on 12 NCP demand. As a result, the negative average cost position of services does not reduce customer costs, nor does it affect the customer charge. The NARUC CAM specifies that services are properly classified as customer-related. In my experience, other electric utilities treat services as customer-related. My recommendation is to change the classification of

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[47] BGE Docket No. 9610, Direct Testimony of David Hoppock for the Maryland PSC Staff at 15.
[48] Ibid.

services to customer. Furthermore, the services sub-function should be included in the calculation of the customer charge.

Q. IS AE'S TREATMENT OF SERVICES INCONSISTENT WITH ITS DISCUSSION OF CUSTOMER COSTS IN THE RATE FILING PACKAGE.

A. Yes. Page 57 of the Rate Filing Package defines customer-related costs as "the cost of meters, <u>service drops</u>, meter reading, meter maintenance, and billing," noting that "they vary with the addition or subtraction of customers, not usage," and are therefore not demand-related. At Technical Conference-1, AE regulatory personnel justified the demand classification of services, stating that services are designed for distribution demand.

Q. WHAT IS YOUR RECOMMENDATION FOR THE CLASS ALLOCATION OF SERVICES?

A. My recommendation is to apply a weighted customer allocation factor which combines a 12NCP weighting with the customer allocation factors. Many utilities utilize a weighted customer allocation factor for services which is weighted for the sizing and length of service drops for various customer classes. Because AE does not have a services weighting study, I have developed a services weighted customer allocation which is 50% 12 NCP and 50% class customer count. In addition, I have included the Services sub-function in the development of the customer charge.

I. <u>Class Allocation of Load Dispatch Expense</u>

Q. HOW DOES AE ALLOCATE DISTRIBUTIION LOAD DISPATCH EXPENSE?

A. AE allocates distribution load dispatch expense to customer classes based on 12 NCP demand. My recommendation is to allocate the expense on the basis of average demand because load dispatch is important in every hour of the year.

Q. WHAT IS LOAD DISPATCH?

A. Load dispatch is the process of tracking real time electricity demand and dispatching a cost-effective combination of generation resources to match customer usage. Because changes in real time demand vary on a locational basis, this process involves transmission and distribution operations, in addition to production personnel. Because generation and transmission load dispatch is included in pass through rates, the load dispatch at issue in base rates pertains to the distribution system. Load dispatch incorporates a multitude of information in making dispatch decision, including the status of transmission and distribution constraints, current and forecasted weather conditions, and demand in various parts of the service area.

Q. DO ANY TEXAS PUC DECISIONS ADDRESS THE APPROPRIATE ALLOCATION OF LOAD DISPATCH?

A. This issue was subject to contested litigation is SPS Docket No. 43695. In that case, SPS allocated production load dispatch based on 12 coincident peak demand (12 CP), and transmission and distribution dispatch expense based on average demand. Although several intervenor witnesses contested the SPS allocation, the Commission found that SPS' allocation was reasonable. The PFD in that case points out that "it is without question that load dispatching occurs every hour of every day," and goes on to state, "peak demand does not occur nearly as often as typical average demands, and that the peak demand usages are included in each class's average demand over the course of a year."[49] In discussing the use of average demand for load dispatch, the PFD cites the SPS witness' statement that line loss adjusted annual kilowatt-hour energy "(a) reflects that SPS dispatches load all year, at the high-peak, low-peak, and all times in between, to ensure reliability, and (b) represents each class's use of SPS's system over the course of a year." [50]

Q. ARE SUMMER PEAK HOURS MORE IMPORTANT TO LOAD DISPATCH THAN OTHER HOURS?

A. I am not aware of any evidence to support an assumption that load dispatchers are only or primarily concerned with the summer peak hours. Faults and outages on distribution lines could occur at any hour, thereby requiring immediate action by load dispatch personnel. Furthermore, winter storm conditions, like the severe Winter Storm Uri, occurred outside the summer peak hours and affected continuous hours of use (and not just the expected February class peaks). Average Demand appropriately recognizes that load dispatch monitors the distribution system in all hours of the year.

J. <u>Class Allocation of Customer Service Expense</u>

Q. HOW DOES AE ALLOCATE CUSTOMER SERVICE EXPENSE TO CUSTOMER CLASSES?

A. FERC Accounts 907-917 are customer service accounts. With the exception of key account expense, AE allocates customer service accounts based on class customer count.

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[49] Application of Southwestern Public Service Co. for Authority to Change Rates, Docket No 43695, Proposal for Decision at 246 – 247.
[50] Ibid.

Q. DO YOU AGREE WITH AE'S ALLOCATION OF THESE ACCOUNTS TO CUSTOMER CLASSES?

A. No. The customer service accounts include advertising and dissemination of information. The FERC account descriptors indicate that A907 – A910 include advertising and information related to the safe and efficient use of electricity. The FERC account description for A911 – A917 includes advertising aimed at promoting and retaining the use of electricity and marketing the utility's services. The expenses in A911 – A917 are related to system objectives which affect all functions and not solely the customer function. My recommendation is to allocate expenses in A911 – A917 broadly across functions. FERC Accounts 911 – 917 comprise 61% of the total Customer Service expense ($20 Million). Therefore, I revised the Customer Service allocation factor to reflect a 61% weighting to the Revenue Requirement allocation and 39% weighting to the Customer allocation factor.

Q. IS YOUR RECOMMENDATION SUPPORTED BY COST ALLOCATION MANUALS?

A. Yes. Both the NARUC CAM and the RAP CAM advise against the use of an unweighted customer allocation factor for Customer Service expense. There is no reason to believe that the costs of achieving general system objectives will vary in proportion to the number of customers. The expenditures represent a general cost of doing business and are more property treated as an overhead. The RAP manual states, "Since the purpose of these costs (A911 – A917) is to increase contributions to margin from new or existing customers, thereby reducing the need for future rate increases, the costs should be allocated by base rate revenue or another broad allocation factor such as rate base."[51] For A911 – 917, the NARUC CAM states:

> Allocation of these costs, however, should be based upon some general allocation scheme, not numbers of customers. Although these costs are incurred to influence the usage decisions of customers, they cannot property be said to vary with the number of customers. These costs should be either directly assigned to each customer class when data are available or allocated based upon the overall revenue responsibility of each class.[52]

Q. IS YOUR RECOMMENDED ALLOCATION FACTOR CONSERVATIVE?

A. Yes. My recommendation for FERC Accounts 911 – 917 is consistent with the allocation stated by the NARUC CAM and RAP CAM. However, my acceptance of an unweighted customer allocation for FERC Accounts 907 – 910 is conservative. Both cost allocation manuals recommend additional analysis of the expenses in those accounts to create a weighted customer allocation factor for A907 – 910. Likely some information dissemination expenses in A907 – A910 promote objectives which are not solely customer related. Since I have not attempted to separate those expense amounts from A907 – A910, I have limited my allocation factor adjustment to A911 – A917.

K. Results of Class Cost of Service Study

Q. DO YOUR PROPOSED CHANGES TO AE'S CCOSS SIGNIFICANTLY ALTER THE INTER-CLASS RELATIONSHIP BETWEEN RESIDENTIAL CLASS AND THE OTHER CUSTOMER CLASSES?

A. Yes. Austin Energy claims that the residential class currently receives significant subsidies from other classes. As a result, AE proposes that the residential class should

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[51] Regulatory Assistance Project, "Electric Cost Allocation for a New Era" at 164.

[52] NARUC CAM at 104.

receive a percentage base revenue increase almost 2.5 times the requested 7.6% system base revenue percent. However, if AE's CCOSS is revised for my proposed CCOSS cost allocation changes, the residential class relative cost position is *not* above system average. This suggests that AE's proposed base revenue increase vastly overstates the residential class proportion of increased revenues. This casts considerable doubt on AE's claim that the residential class is heavily subsidized. Schedule CJ-2 provides the revised CCOSS results for each class if AE's requested increase in total base revenues were accepted. The CCOSS results are only used as a guide in evaluating how any base revenue increase is distributed among classes. Schedule CJ-7 provides references to changes that were made to the Rate Filing Package CCOSS model.

Q. DO YOUR CCOSS RESULTS INCLUDE THE IMPACT OF ICA'S PROPOSED REDUCTION TO AE'S REQUESTED TOTAL REVENUE REQUIREMENT?

A. No. Given time constraints resulting from the accelerated procedural schedule in this case, I have not incorporated Mr. Effron' s revenue requirement revisions[53] into AE's CCOSS model. However, this is not an impediment to recommending class revenue changes. The CCOSS should only be used as a general benchmark, and I do not intend on setting the class revenue increases in lockstep with class results from the CCOSS. The revised CCOSS provides sufficient information to inform the process of spreading any revenue increase among customer classes.

Q. CAN YOU PRESENT THE IMPACT OF THE REVISIONS?

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[53] Mr. Effron' s total reductions to the system base revenue increase includes the revenue requirement issues discussed in Sec. III.

A. Yes. AE did not request a residential increase equal to the results indicated by its CCOSS, But the residential cost deficit shown in the study provided the basis for AE's proposal to require the residential class to pay an increase larger than the total system increase. Therefore, a comparison of the impact of the revisions is informative.

Q. PLEASE QUANTIFY THE DIFFERENCE FOR THE RESIDENTIAL CLASS BETWEEN AE'S CCOSS AND ICA'S REVISED CCOSS.

A. The Residential CCOSS results shown below do not include the reduction in total revenue requirement recommended by ICA. However, this comparison shows the magnitude of changes in the Residential cost study position. As shown below, ICA's proposed cost allocation revisions reduce a substantial amount of the costs assigned to the Residential class by AE's CCOSS.

Revised CCOSS Results
With AE Requested Total Increase

	System Incr.	Res. Incr.
As Revised	$ 48,219,749	$22,399,804
Percent	7.55%	7.51%
AE CCOSS	$ 48,219,749	$76,513,391
	7.55%	25.66%
Difference		(54,113,587)

Q. WHAT IS THE NEXT STEP AFTER THE CCOSS?

A. The next step is to apportion the total base revenue increase among customer classes. The revised CCOSS will inform my proposal for distribution of the system base revenue increase among customer classes.

V. <u>CLASS REVENUE DISTRIBUTION</u>

Q. PLEASE DESCRIBE THE ISSUES REGARDING CLASS REVENUE DISTRIBUTION.

A. Rate design involves the following major decisions: (1) distribution of the ultimately approved rate change among customer classes; and (2) the rate components used to collect revenues from each customer class. The CCOS is only one piece of information to be considered in the distribution of the revenue increase among customer classes. Rate impact, non-cost considerations, promoting efficient behavior, and public policy are also relevant factors. The second area (rate components) will be discussed in subsequent sections pertaining to the customer charge and residential rate structure.

Q. IS RATE MODERATION NECESSARY FOR THE APPORTIONMENT OF REVENUE INCREASES AMONG CUSTOMER CLASSES IN THIS CASE?

A. Yes. Extreme variations in revenue-cost positions exist among the customer classes in this case. Furthermore, the later stages of the COVID pandemic, which produced significant economic impacts, are embedded in the test year. The COVID pandemic is an exceptional circumstance, which could affect many customers' ability to pay and constrain growth in billing determinants for some classes. As a result, the potential arises that future customer class composition and capacity for revenue generation will vary significantly from test year conditions.

Q. WHAT IS THE APPROPRIATE ROLE OF THE EMBEDDED CCOS STUDY RESULTS IN DETERMINING CLASS REVENUE INCREASES?

A. The CCOSS provides useful information for developing the class revenue increases, but it should not be the sole consideration. Non-cost considerations are appropriate in mitigating pure CCOS results. This principle has been recognized in longstanding regulatory texts, such as Dr. James Bonbright's seminal *Principles of Public Utility Rates*.[54] The RAP CAM discusses the widespread practice of regulators departing from strict adherence to CCOSS results.[55] From its earliest history, the Texas PUC has recognized the principle that cost study results are subject to rate mitigation.

CCOS studies are imprecise instruments. The studies will allocate costs to a multiple decimal point level, but this may provide a false sense of security about the accuracy of the studies. This conclusion is based on two general reservations regarding embedded CCOS studies. First, some of the costs are classified and allocated on a disputable causal basis, and subjective judgment enters into the selection and development of allocation methods. The CCOS results may be quite sensitive to alternative classification or allocation decisions that are within the range of reasonable choices. As a result, it may be more appropriate to characterize the CCOS in the form of a range of acceptable relative rates of return instead of a single point estimate.

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[54] James Bonbright, *Principles of Public Utility Rates*, Chapter 16, "Criteria for A Sound Rate Structure," (Columbia Press) (1961).

[55] "Electric Utility Cost Allocation for a New Era" at 237 – 238, Regulatory Assistance Project.

Second, CCOS studies are a static snapshot of the dynamic relationship between supply and demand. Both costs and class usage characteristics will change over various time periods. For these reasons, some degree of judgment may be appropriate in applying the CCOS study to class revenue increases. "Cost based rates" are best viewed as representing a reasonable band around the CCOS results, rather than exact price points. The RAP CAM suggests that regulators may examine the results of multiple different CCOS studies to arrive at a range of reasonableness.[56] Third, the varying business risks of serving various customer classes can be a non-quantifiable factor which the regulator may consider in determining the appropriate distribution of revenue increases.[57]

Q. HAVE CUSTOMER CLASS ALLOCATION FACTORS CHANGED SIGNIFICANTLY SINCE THE 2016 RATE CASE?

A. Yes. The most striking changes occurred in the Residential class and Secondary commercial classes. The Residential energy allocation factor increased 9.4% and the Secondary energy allocation factors cumulatively declined 10.2%. The 12 CP demand allocation factor for Residential increased by 6.3% and the Secondary cumulative 12 CP demand factor declined by 8.9%.[58] This is consistent with S&P Global Credit's assessment that AE's commercial sales declined and residential sales increased as a result of the pandemic.[59] An increase in the CCOSS Residential allocation factor accompanied by a decrease in the Secondary allocation factors would shift costs from

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[56] Ibid.
[57] Notably, bond rating agencies generally consider the size and growth of AE's residential customer base as a positive risk factor, adding stability to the utility's risk profile. See, for example, S&P Global Credit Rating Report, AE Response to TIEC 4th Requests, Attachment 4-3I page 3 of 7.
[58]This is based on a comparison of allocation factors (Schedule F-6) in AE's 2016 CCOSS and the 2021 CCOSS.
[59] "For fiscal 2020, a decline in commercial customer sales due to the pandemic was offset by increased residential sales and continued customer growth, which increased total electric sales by 1%." Attachment 4 TIEC 4-3I at page 6.

commercial classes to the Residential class. The question arises regarding the extent that any COVID impact on classes' allocation factors recedes in the future. But it seems reasonable to expect some reversal of these changes in the future. Potentially this provides additional support for gradualism in the distribution of the revenue increase among classes.

Q. DO YOU DISAGREE WITH THE AE'S APPROACH TO CLASS REVENUE DISTRIBUTION?

A. Yes. First, for the Residential class, AE proposes a "times system average" base revenue percentage of 233% (17.6% Residential increase / 7.6% System increase). In my view, this is excessive and produces an immense impact on households in the AE service area. Although AE attempts moderation (compared to the AE CCOSS result), AE does not provide a coherent justification for a 233% limiter. Second, I do not agree with assigning revenue reductions to some classes at the same time overall revenues increase. In my view, given the circumstances in this case, the most equitable approach precludes a revenue reduction for any class when the overall retail system faces a significant revenue increase. Selected revenue reductions compound the severity of revenue increases confronting most customers.

Q. PLEASE DESCRIBE THE PROCEDURE YOU APPLIED FOR DISTRIBUTING THE REVENUE INCREASE AMONG CUSTOMER CLASSES.

A. My recommendation is to use a relatively simple approach to class rate moderation. The first step is to apply a percentage increase one half the system average to customer classes which otherwise would receive a revenue reduction. The second step is to distribute the remainder of the base revenue increase on an equal percentage basis to the remaining customer classes. Based on ICA's revisions to the CCOSS, Secondary classes <10 kW and 10 – 300 kW would otherwise receive a revenue reduction. Schedule CJ-3 provides the application of this procedure for AE's requested system base revenue increase, and Schedule CJ-4 provides the revenue distribution based on ICA's system base revenue increase set out in Mr. Effron' s testimony. This approach suppresses large impacts, broadly shares the revenue increase, and recognizes classes with revenues substantially above cost.

Q. WHAT IS THE IMPACT OF ICA'S OVERALL RECOMMENDATION ON RESIDENTIAL CUSTOMERS?

A. The system revenue increase is 1%, compared to AE's requested 7.6%. The residential class increase is 1.2% compared to AE's requested 17.6%.

VI. RATE DESIGN

A. Residential Rate Structure

1. Customer Charge

Q. HOW HAS THE COMPANY PROPOSED TO INCREASE THE RESIDENTIAL CUSTOMER CHARGE?

A. AE proposes to increase the residential monthly customer charge from $10.00 to $25.00. The 150% percent proposed increase in the fixed customer charge is excessive. The proposal is extraordinarily high compared to the fixed monthly charge of electric utilities under the jurisdiction of the Texas PUC. The AE proposed residential fixed monthly charge would be $13 higher than the highest regulated customer charge in Texas.

Q. PLEASE PROVIDE DETAILS ON THE COMPARISON TO TEXAS INVESTOR-OWNED UTILITY (IOU) CUSTOMER CHARGES.

A. Schedule CJ-5 shows the residential fixed monthly charges for each electric utility. The ERCOT electric utilities are unbundled, and the customer charge is the sum of the meter and customer service charges. The non-ERCOT electric utilities are bundled electric utilities like AE and charge a single monthly customer charge. In my view, it is reasonable to include the unbundled utilities in the comparison. The difference between unbundled and bundled electric utilities in Texas is that the generation function is not part of the unbundled TDUs. But the generation function does not include customer costs and would not affect the customer charge. [60] The account components of the customer charge are functionally the same for TDUs and bundled electric utilities. The IOU averages are summarized below.

Texas IOU Electric Utilities
Residential Fixed Monthly Charge

ERCOT Average	**$ 5.11**
Non-ERCOT Average	**$ 9.77**
Average all Texas IOU Electrics	**$ 7.44**

[60] Although unbundled utilities operate call centers, it is possible this function is smaller than those operated by bundled utilities, because REPs may also operate a call center. However, total call center costs for bundled utilities are typically less than $1.00 per month.

Q. WHAT IS THE POLICY OBJECTIVE OF PRICING THE FIXED MONTHLY CUSTOMER CHARGE?

A. The customer charge should only recover costs that vary directly with the number of customers. [61] Generally, the costs that vary directly with customer count consist of meters, service lines, meter reading, and customer billing. Although AE asserts that the customer unit cost in its CCOSS justify a 150% customer charge increase, the unit cost includes costs that are not directly associated with customers, and do not vary with the number of customers. The CCOSS customer unit cost includes a portion of general overhead costs, such as A&G expense and general plant, which do not vary with changes in the number of customers. The CCOSS also layers part of General Fund Transfer (GFT), non-utility operations expense and internally generated funds for construction onto the customer charge.[62] These expenditures are not directly driven by the number of customers; instead, this is a circuitous pathway for recovering costs that cannot be directly recovered through specific charges for GFT, non-utility operations or construction cost. For example, the actual customer accounting expense is $5.6 million before loading with indirect costs. After the indirect costs are added to this customer accounting expense, the Customer Accounting function has grown to $58.5 million, essentially a ten-fold increase.

[61] See, Docket No. 22344, Generic Issues Associated with Applications for Approval of Unbundled Cost of Service, Order No. 40 at 6, Interim Order Establishing Generic Customer Classification and Rate Design, "Specifically, the customer charge shall be comprised of costs that vary by customer such as metering, billing and customer service."
[62] RFP Schedule G-6.

Q. HAVE YOU CALCULATED A RESIDENTIAL CUSTOMER CHARGE FOR AE BASED ONLY ON COSTS WHICH VARY WITH TO THE NUMBER OF CUSTOMERS?

A. Yes. My estimate of the residential customer charge directly related to the number of customers is $6.11. Since the existing customer charge is $10.00, the current customer charge is more than compensatory for direct customer costs. The calculation includes O&M expense for meters, services, meter reading, and customer accounting, and also encompasses the return, depreciation, and carrying charges associated with meter and service investment, minus credits for other customer-related revenues.[63] My calculation is consistent with the historic Texas PUC practice for evaluating the customer charge level of bundled electric utilities.[64] The calculation is set out on Schedule CJ-6. To the extent that the current customer charge exceeds the direct customer costs, the existing monthly fixed rate recovers direct customer costs plus a contribution to utility common costs. The customer charge calculation in Schedule CJ-6 is also known as the "Basic Customer Method." The RAP CAM concludes that the Basic Customer Method is "by far the most equitable solution" for the vast majority of electric utilities.[65]

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[63] My calculation also includes a portion of pensions and benefits (Account 926) associated with the O&M expense in the customer charge.

[64] *See* for example *Application of Houston Lighting & Power Company*, Docket No. 8425, Examiners' Report at 264, 16 P.U.C. Bull. 2199, 2488 (June 20, 1990).

[65] "Electric Utility Cost Allocation for a New Era" at 145, Regulatory Assistance Project.

Q. DO YOU AGREE WITH AE'S REQUEST TO RECOVER UNCOLLECTIBLE EXPENSE IN THE RESIDENTIAL CUSTOMER CHARGE?

A. No. There is no logical rationale for recovering all uncollectible expense through the monthly customer charge.[66] AE recovers $7.0 million of the $7.6 million total uncollectible expense through the residential customer charge.[67] The amount of uncollectible expense is determined by the size of customer bills which are unpaid and does not vary directly with the number of customers. Presumably AE assigned uncollectibles to the customer charge because the expense is recorded in customer accounting; however, the act of recording the expense in a customer account does not mean that the cost varies directly with number of customers. Moreover, uncollectible expense is comprised of, for the most part, unpaid variable charges, because variable rates comprise 78% of residential base revenues. And most likely, unpaid variable charges are the primary driver of uncollectible expense.[68] The Company's inclusion of the full residential uncollectible expense demonstrates how indirect costs are loaded into the Company's proposed customer charge. The Basic Customer Charge presented in Schedule CJ-6 does not include uncollectible expense.

Q. WHAT ARE THE POLICY REASONS FOR ENSURING THE RESIDENTIAL CUSTOMER CHARGE IS NOT EXCESSIVE?

A. An excessive customer charge can distort appropriate price signals for residential customers. The dominant economic function of a customer charge is to ration access

[66] The NARUC Electric Utility Cost Allocation Manual (CAM) specifically excludes uncollectible expense from the customer classification. NARUC CAM at 103.

[67] This is the fully loaded cost of uncollectible expense, after adding GFT and non-utility operation expense.

[68] High bills, caused by high usage, are more likely to be unpaid.

to the utility system. That objective conflicts with the policy basis for regulating monopolies and is counter to the concept of electricity as an essential service. With the exception of its role in rationing access to the system, the customer charge provides no meaningful price signal that is relevant to resource allocation. Because the electric utility's cost structure is dominated by costs that vary with changes in demand and energy usage, the usage-sensitive rate is the primary source of meaningful price signals. A lower customer charge ensures a greater proportion of costs are recovered through a usage-sensitive price (i.e., kWh charges). That result is more consistent with energy conservation goals and provides pricing policies appropriate for consumption of finite natural resources. In addition, a policy that minimizes the customer charge is more equitable to low-usage residential customers.

Q. WHAT IS THE EFFECT OF AN EXCESSIVE CUSTOMER CHARGE ON ENERGY EFFICIENCY?

A. A high customer charge tends to inhibit energy conservation. Minimizing the customer charge provides the ratepayers with a greater ability to control their bill on the basis of usage. At a time when electric utilities spend millions of dollars on energy efficiency programs, maintaining the fixed monthly charge at a reasonable level is a relatively inexpensive action to incentivize energy conservation. But the long-term tendency for utility management to seek increases in the customer charge can inhibit the attractiveness of energy savings measures, because a larger portion of the rate structure becomes invariant with energy usage. This can adversely affect the payback period and net bill savings available to customers who purchase high efficiency appliances.

Q. YOU REFER TO MAKING A LARGER PORTION OF THE RESIDENTIAL RATE STRUCTURE INVARIANT WITH ENERGY USE. IS THIS AE'S OBJECTIVE?

A. Apparently so. The residential basic customer charge is increased by 150%. The energy rates, cumulatively, are *reduced* by 9%. The result will be a significant weakening of the price signal for energy conservation. In my view, this is contrary to AE's record and goals for conserving energy.

Q. SHOULD THE SERVICES FUNCTION BE INCLUDED IN THE CUSTOMER CHARGE?

A. Yes. The Services function is negative, but AE opted to exclude this function from the customer charge. As I suggested in Sec. IV (H), this is contrary to the AE Rate Filing Package's description of services as part of the customer charge.

Q. IF THE CCOSS ADJUSTMENTS PROPOSED IN SEC. IV ARE ADOPTED, WOULD AE'S CUSTOMER CHARGE METHOD PRODUCE A LOWER FIXED MONTHLY CHARGE?

A. Yes. Even if one accepts AE's inclusion of indirect costs in the customer charge, the amount of the indicated customer charge is sensitive to the choice of functionalization and classification factors for assigning the overhead. If my CCOSS adjustments are adopted (and the services function is included), AE's method would specify a residential customer charge of $15.39, rather than the $25.00 requested by AE.

Q. WHAT IS YOUR RECOMMENDATION FOR SETTING THE RESIDENTIAL CUSTOMER CHARGE?

A. Given that the current $10.00 customer charges exceed the Basic Customer Costs shown on Schedule CJ-6, maintaining the existing customer charge level is not unreasonable (particularly at relatively low residential base revenue increase percentages). However, the combined effect of the customer charge with the tier block energy charge rate structure is an additional consideration. A reasonable approach might seek roughly to maintain the existing relationship between customer charge and energy charge revenues. I recommend limiting the customer charge increase based on the residential base revenue increase ultimately adopted. I recommend a maximum residential customer charge of $13.00, which would be applicable only if AE's proposed residential revenue increase is adopted.[69] However, ICA objects to both AE's proposed system increase and AE's allocation of an excessive share of the system increase to the residential class. If ICA's recommended 1.2% base revenue increase for the residential class is adopted. I would scale back the maximum customer charge to $10.20. The 20-cent increase in the customer charge would reasonably match the percentage increase for energy charge revenue.

2. Overview of AE's Position Regarding Tiered Rate Structure

Q. DESCRIBE THE CURRENT RESIDENTIAL RATE STRUCTURE.

A. The current residential rate structure consists of a $10 customer charge and five tiers or blocks of energy charges. This structure is sometimes referred to as an inverted block

[69] As noted previously, AE's proposal imposes a 26% base revenue increase on inside city customers.

rate, because energy charges for each tier increase as the customer's total kWh usage increases. The objective of this rate structure is to promote energy conservation.

Q. WHAT IS AE'S POSITION REGARDING THIS RATE STRUCTURE?

A. AE proposes to increase the fixed monthly charge by 150% and reduce total revenues recovered from energy charges. Furthermore, AE proposes to reduce the number of energy charge tiers from five to three. As a result of this restructuring, low usage customers will pay a substantial increase in rates, and higher usage customers will receive revenue reductions. AE posits that the problem with its residential rates is that reductions in customer usage caused revenues to remain flat or decline and thereby fall behind the increase in utility costs. According to AE, revenue deficits in 2020 and 2021 caused the utility to rely on cash from its reserves.

Q. THE AE RATE FILING PACKAGE STATES (PAGE 101) THAT THE RATE STRUCTURE IS "UNSUSTAINABLE." WHAT IS YOUR REACTION TO THIS STATEMENT?

A. In context, the use of the word "unsustainable" is an overstatement of the situation. Most utilities requesting rate relief would claim that their current financial position is unsustainable—but that does not make it so. The pertinent claim is that AE contends that its future revenues are insufficient to recover future costs, That is not an uncommon position. That is why rate cases exist. The purpose of the rate case is to increase rates to cover any gap between future revenues and costs. ICA disagrees with AE that the gap between future revenues and costs is as large as AE claims. ICA's position on revenue deficiency is set out in Mr. Effron' s testimony, which concludes that a revenue deficiency is in the range of 1%. Rate levels in any rate structure are not intended to remain the same over a lengthy period, and thus the "unsustainable" characterization is overblown. The fact that Austin has a policy of periodic rate review as frequently as every three years should permit corrections of the amount of revenues generated by the rate structure. Moreover, focusing on rate structure as the "problem" detracts from a critical review of rising costs and whether additional cost control is necessary.

Q. DOES AE PROVIDE AN ILLUSTRATION OF THE GAP BETWEEN REVENUE AND COSTS IN FIGURE 7.22 AND 7.23 ON PAGES 101 – 102 OF ITS RATE FILING PACKAGE?

A. Yes. However, this is not a definitive demonstration of either rate structure problems or expectations regarding the future. The figures contain data which is unadjusted and is not normalized for weather or any other non-recurring events.[70] Moreover, the gap in these figures primarily pertains to 2020 and 2021. Yet both 2020 and 2021 are affected by extraordinary events—the COVID pandemic in both years, and Winter Storm Uri. The COVID pandemic caused a national economic shock which is unprecedented in history. Besides any potential impact on customers' power usage, AE responded to COVID by increasing funds for customer relief, additional discounts for the CAP program, ceasing disconnections, waiving late payment fees, and rates for the top two tiers in the residential rate structure. Winter Storm Uri resulted in lost revenues from 220,000 customers suffering more or less continuous outages for five consecutive days. In addition, AE subsequently gave credits to its customers and made other billing adjustments. AE has not quantified most of these amounts because the

[70] AE Response to 2WR Request Nos. 1-15 and 1-16.

CCOSS relies upon normalized billing determinants. But these issues can affect the actual revenues and costs shown in the figures.

Q. IS A $25 CUSTOMER CHARGE NECESSARY TO AVOID UNSUSTAINABLE FINANCIAL CONDITIONS?

A. No. As discussed previously, AE's current customer charge is higher than the average customer charge for IOUs in Texas, as well as the customer charge of the other two large municipal electric utilities in the state. Thus, the other major electric utilities in Texas have maintained their financial integrity without charging a $25 fixed customer charge.

Q. WHAT IS YOUR REACTION TO THE GENERAL ARGUMENT MADE BY AE?

A. AE's position is paradoxical. AE recognizes that the purpose of the five tier structure is to promote reduced power usage and energy efficiency.[71] AE lauds its energy efficiency programs and the city building codes. However, AE's objection to the five tier rate structure is essentially that it has been too effective at promoting energy conservation. Furthermore, AE position ignores any potential long run reductions in utility cost which accompanies reduction in energy consumption.[72] Despite AE's

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[71] AE's web site advises customers: "Austin Energy has a five-tier rate structure that rewards customers who use less electricity with lower rates. With the five-tier rate structure, you can see how lowering your electric use can result in lower bills. You can lower your electric usage by modifying your energy use or by making energy-efficiency improvements to your home." https://austinenergy.com/ae/rates/residential-rates/residential-electric-rates-and-line-items

[72] The RAP CAM at 157 states:" Energy efficiency costs are typically caused by the opportunity to reduce total costs to consumers. For most costs, revenue requirements would be lower if customers did less to require the utility to incur those costs."

recognition of the City's goal of energy conservation, the effort to re-structure the residential rates is likely to increase future electricity consumption.

3. Outside City Residential Rates

Q. DESCRIBE THE AE PROPOSAL FOR OUTSIDE CITY RESIDENTIAL CUSTOMERS.

A. Currently residential customers residing outside the city limits pay a different rate schedule than Inside City residential customers. AE proposes to end this distinction and utilize a uniform residential tariff for both sets of customers. Outside City customers currently pay a $10 customer charge with a three tier block rate. AE's proposal for the uniform residential rate is a three-tier rate structure plus a $25 customer charge. The result tends to shift revenue responsibility from the Outside City customers to the Inside City customers. AE proposal applies the following base revenue change to the two sets of customers.

AE PROPOSED BASE REVENUE CHANGE

INSIDE CITY (NON-CAP) $53.8 million 26%

OUTSIDE CITY (NON -CAP) -5.1 million -7.4%

Q. WHY DOES THE OUTSIDE CITY PORTION OF THE CLASS RECEIVE A RATE REDUCTION WHILE THE INSIDE CITY RESIDENTIAL CUSTOMERS RECEIVE A LARGE REVENUE INCREASE?

A. This is a consequence of AE's rate structure changes and its decision to eliminate a separate tariff for Outside City residential. Rate structure changes, by their nature, result in shifting of intra-class revenue responsibility. The housing stock, residential density, and energy use per customer outside the city differs from Inside City residential customers. Therefore, adopting a higher proportion of rate recovery in the fixed customer charge and adopting a rate structure which provides rate reductions for high use customers causes this shifting of revenue recovery. On average, outside city residences use 86% more electricity than inside city customers.

Q. WHAT IS YOUR RECOMMENDATION?

A. Given the differences in usage characteristics, designing a uniform tariff is likely to produce significant rate impacts on either Inside City or Outside City residential customers. My recommendation is to leave the Outside City residential tariff unchanged. This will eliminate the revenue reduction for those customers, which may appear unfair to inside city customers. Another alternative is to establish a separate tariff for Outside City residential customers which is based on a specific base revenue percentage (such as the system average). However, this approach is relatively arbitrary since no cost benchmark exists for Outside City residential customers. If my recommendation is adopted, AE should treat Outside City as a sub-class of Residential in the next rate case and develop a cost of service study or similar cost analysis to the sub-class. This would enable AE to determine a revenue requirement for the sub-class. This would require load research analysis of the Outside City residential customers.

4. Rate Structure Evaluation and Recommendation

Q. DO YOU DISAGREE WITH AE'S PROPOSED RESTRUCTURED TIER RATES?

A. Yes. I disagree with the restructuring due both to customer impacts and mis-alignment with energy conservation objectives. The base revenue changes in energy charges by tier for the Inside City (Non-CAP) customers are shown below. The change in energy charge revenues is followed by a summation of the change in both customer and energy revenues.

Inside City Base Revenue Change

TIER	Rev Increase	Percent
0-300 kWh	$12,721,758	34%
300-500	$10,045,583	52%
500-1000	(14,636,668)	-56%
1000-1200	(6,186,107)	-45%
> 1200 kWh	(17,109,890)	-47%
Sub Total Energy	(15,165,326)	-9%
Cust + Energy	$53,784,034	26.0%

Q. PLEASE ELABORATE ON YOUR CONCERN REGARDING THE TWIN OBJECTIVES OF MODERATING CUSTOMER IMPACT AND ENERGY CONSERVATION.

A. For Inside City (Non CAP) Residential, total bill impact for AE's proposal, by usage level is shown on WP H-3.1.1.1 in the Rate Filing Package. Low usage customers (<500 kWh) receive increases ranging from 51% - 84%. Medium usage customers (501 – 1,000 kWh) face increases ranging from 18% - 32%. 1,500 kWh and higher received decreases ranging from -5% - -26%. The range of impacts by usage level are quite divergent. In particular, the bill impact at low usage levels is large in percentage terms. The percentage impact of bill reductions at the high usage levels is incongruent with the large percentage bill increases among low usage customers. As noted previously, the objective of the five tier rate structure is to promote energy conservation. Significantly increasing rates for low usage customers and significantly decreasing rates for high usage customers runs counter to that objective.

Q. DO YOU CONTEND THAT RATE STRUCTURE CAN AFFECT CUSTOMERS' ENERGY EFFICIENCY?

A. Yes, energy rates can and should be used to send price signals to customers. Based upon my experience in the field of regulatory economics, I would expect that the Tier rate structure is more likely to affect residential usage over time. Most customers probably do not track their usage against tier levels. However, over time customers may become aware that their total electric bill is too high and become more inclined to engage in energy efficiency activities, such as lowering thermostats, installing more efficient HVAC, increasing insulation, and so forth. This is consistent with the accepted view that residential electricity demand is more elastic (responsive to price) in the long term than the short run.[73] Given that the tier structure may affect appliance payback periods, the inverted block structure can work in combination with energy efficiency programs to achieve higher penetration levels.

Q. DO YOU AGREE WITH AE THAT THE FIVE TIER RATE STRUCTURE MAY HAVE SOME DEFICIENCIES.

[73] El Paso Electric Company has used a demand elasticity of -.065, which implies a 6.5% reduction in electricity demand for each 10% increase in price. Docket No. 52195, EPE Response to CEP Request No. 9-3.

A. Yes. An inverted block rate structure can create more year-to-year revenue volatility than an energy rate structure with fewer blocks. This may occur if weather conditions cause customers to use more or less power than expected, and the customers' usage moves above or below their normal usage tier. The five tier structure may be susceptible to this problem. However, in my opinion, this can be adequately addressed without adopting the three tier structure proposed by AE.

Q. HOW DO YOU PROPOSE TO ADDRESS THE REVENUE VOLATILITY ISSUE FOR THE INSIDE CITY RESIDENTIAL TARIFF.

A. I recommend two changes. First, I propose to reduce the number of tiers from five to four. This is a compromise between AE's three tier proposal and the current five tier structure. Eliminating one tier should be sufficient to mitigate revenue volatility. Furthermore, the three tier structure is an impediment to limiting rate reductions in the upper usage tiers. Therefore, compared to AE's three tiers, the four tier structure addresses the energy conservation objective. Second, I recommend a Tier 2 that broadly covers 500 kWh – 1,300 kWh. Tier 1 and Tier 2 would encompass, on average, almost 90% of residential bills, which should increase revenue stability.

Q. HAVE YOU PREPARED TIER RATES FOR AN ALTERNATIVE RATE STRUCTURE CONSISTENT WITH THOSE TWO PRINCIPLES?

A. Yes. I have prepared TIER rates for a rate structure based on ICA's revenue requirements recommendation and ICA class revenue distribution recommendation. I have also prepared TIER rates for a rate structure based on AE's revenue requirements case and ICA's class revenue distribution recommendation. The $10.20 customer charge for the former example is scaled up to $12.00 in the latter example.

TIER	ICA Incr. ICA Rev Dist.	AE Rev Req ICA Rev Dist.
0-500 kWh	0.02850	0.03000
500-1300 kWh	0.06200	0.06519
1300-2500	0.09176	0.09691
>2500 kWh	0.11317	0.11913
Cust Charge	**$10.20**	**$12.00**

Q. CAN YOU PROVIDE AN ILLUSTRATION OF THE BILL IMPACT BASED ON ICA'S RECOMMENDATION?

A. Yes. The comparison below is based on bills at varying residential usage levels. ICA-1 provides the ICA proposal based on Mr. Effron' s revenue requirements analysis and my proposed class revenue distribution. "AE Filed" shows the bill impacts based on AE's rate filing package proposal. The ICA proposal demonstrates the importance of all elements of the ICA technical analysis: reducing revenue requirements, analyzing the CCOSS and developing class revenue distribution, and developing a more balanced residential rate structure.

	ICA- 1		**AE Filed**	
kWh	Increase	Percent	Increase	Percent
375	$ 0.59	1.56%	19.16	50.75%
625	$ 1.24	2.07%	19.15	31.90%
875	$ 2.30	2.67%	$ 15.34	17.81%
1,625	$ 0.88	0.49%	(8.20)	-4.59%
3,250	$ 4.34	1.04%	(92.63)	-22.2%

Q. DO YOU AGREE WITH AE'S ANALYSIS THAT HIGH USAGE TIERS ARE PAYING ABOVE COST WHILE LOW USAGE TIERS ARE PAYING BELOW COST?

A. Not necessarily. This appears to be an attempt to use the CCOS study to define whether customers of various usage levels are above or below cost. In my opinion, this is not an appropriate use of the CCOS study. The CCOS allocates costs to customer classes, not to individual customers or customers at various tier levels. The allocation factors for assigning costs to classes are not the same measures as the rate components within the rate structure. In my view, the attempt to graft CCOSS results to individual customer usage levels could produce serious inaccuracies. In essence, an assumption is made that energy use has a strict linear relationship with the various demand allocators in the CCOS, which may not be correct. Moreover, a more appropriate cost analysis for rate design purposes would involve marginal costs rather than embedded costs, because marginal cost is more relevant to evaluating a tiered rate structure. Finally, AE's intra-class cost analysis does not account for the differing customer density of low energy users and high energy users. All else equal, higher customer density (generally associated with lower customer energy use) should reduce utility infrastructure cost.

Q. DOES THIS CONCLUDE YOUR PRESENTATION AT THIS TIME?

A. Yes.

Baseload-Intermediate-Peak Production Factors

	RES	S 1	S 2	S 3	P 1	P 2	P 3	T 1	T 2	Lt 1	Lt 2	Lt 3	Lt 4	Total
BIP -P	**38.26%**	**2.26%**	**20.68%**	**16.55%**	**2.38%**	**6.93%**	**10.79%**	**0.21%**	**1.57%**	**0.27%**	**0.07%**	**0.01%**	**0.03%**	**100.00%**
BIP-E	**38.55%**	**2.25%**	**20.71%**	**16.46%**	**2.37%**	**6.85%**	**10.67%**	**0.22%**	**1.55%**	**0.26%**	**0.07%**	**0.01%**	**0.03%**	**100.00%**

ICA Revised CCOSS Results
AE PROPOSED REV REQUIREMENT

	Total Company	Residential	Sec <10	Sec ≥ 10 < 300	Sec ≥ 300 kW	Prim < 3 MW	Primary ≥ 3 < 20 MW
Current Base Revenues	$ 638,623,744	$ 298,139,951	$ 22,062,516	$ 146,379,682	$ 97,431,981	$ 8,571,888	$ 24,590,380
Base Revenues at Cost	$ 686,843,493	$ 320,539,755	$ 21,188,350	$ 130,570,030	$ 102,847,051	$ 12,532,862	$ 35,412,718
Revenue Deficiency (Surplus)	$ 48,219,749	$ 22,399,804	$ (874,166)	$ (15,809,652)	$ 5,415,070	$ 3,960,974	$ 10,822,338
Pct. Base Revenue Increase	7.6%	7.5%	-4.0%	-10.8%	5.6%	46.2%	44.0%

	Primary ≥ 20 MW	Transmission	Trans ≥ 20 MW	City Outdoor Lt	Cust Unmetered	Cust Metered Light
Current Base Revenues	$ 33,906,126	$ 801,058	$ 4,236,381	$ 2,141,558	$ 45,878	$ 316,344
Base Revenues at Cost	$ 52,452,753	$ 948,717	$ 5,426,694	$ 4,327,241	$ 90,296	$ 507,025
Revenue Deficiency (Surplus)	$ 18,546,627	$ 147,660	$ 1,190,313	$ 2,185,683	$ 44,419	$ 190,681
Pct. Base Revenue Increase	54.7%	18.4%	28.1%	102.1%	96.8%	60.3%

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RECOMMENDED BASE REVENUE DISTRIBUTION (AE PROPOSED SYSTEM REVENUE REQUIREMENT)

	Total Company	Residential	Sec <10	Sec ≥ 10 < 300	Sec ≥ 300 kW	Prim < 3 MW	Primary ≥ 3 < 20 MW
Current Base Revenues	$ 638,623,744	$ 298,139,951	$ 22,062,516	$ 146,379,682	$ 97,431,981	$ 8,571,888	$ 24,590,380
Proposed Incr.	$ 48,219,749						
Step 1 Increase	$ 41,860,574	$ 22,511,273	$ 832,923	$ 5,526,252	$ 7,356,672	$ 647,227	$ 1,856,714
Step 2 Total Increase	$ 48,219,749	$ 26,543,597	$ 832,923	$ 5,526,252	$ 8,674,434	$ 763,161	$ 2,189,298
Pct. Base Revenue Increase	7.6%	8.9%	3.8%	3.8%	8.9%	8.9%	8.9%

	Primary ≥ 20 MW	Transmission	Trans ≥ 20 MW	City Outdoor Lt	Cust Unmetered	Cust Metered Light
Current Base Revenues	$ 33,906,126	$ 801,058	$ 4,236,381	$ 2,141,558	$ 45,878	$ 316,344
Step 1 Increase	$ 2,560,107	$ 60,484	$ 319,871	$ 161,700	$ 3,464	$ 23,886
Step 2 Total Increase	$ 3,018,685	$ 71,319	$ 377,168	$ 190,664	$ 4,085	$ 28,164
	8.9%	8.9%	8.9%	8.9%	8.9%	8.9%

RECOMMENDED BASE REVENUE DISTRIBUTION (ICA Revenue Requirement)

	Total Company	Residential	Sec <10	Sec ≥ 10 < 300	Sec ≥ 300 kW	Prim < 3 MW	Primary ≥ 3 < 20 MW
Current Base Revenues	$ 638,623,744	$ 298,139,951	$ 22,062,516	$ 146,379,682	$ 97,431,981	$ 8,571,888	$ 24,590,380
Proposed Incr.	$ 6,528,255						
Step 1 Increase	$ 5,667,315	$ 3,047,700	$ 112,766	$ 748,174	$ 995,987	$ 87,625	$ 251,372
Step 2 Total Increase	$ 6,528,255	$ 3,593,618	$ 112,766	$ 748,174	$ 1,174,393	$ 103,321	$ 296,399
Pct. Base Revenue Increase	1.0%	1.2%	0.5%	0.5%	1.2%	1.2%	1.2%

	Primary ≥ 20 MW	Transmission	Trans ≥ 20 MW	City Outdoor Lt	Cust Unmetered	Cust Metered Light
Current Base Revenues	$ 33,906,126	$ 801,058	$ 4,236,381	$ 2,141,558	$ 45,878	$ 316,344
Step 1 Increase	$ 346,601	$ 8,189	$ 43,306	$ 21,892	$ 469	$ 3,234
Step 2 Total Increase	$ 408,686	$ 9,656	$ 51,063	$ 25,813	$ 553	$ 3,813
	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%

#

Comparison to Current Customer Charges
Texas Investor Owned Electric Utilities

Electric Utility	Cus Ch	Meter Ch	Monthly
CenterPoint Electric	2.30	2.09	$ 4.39
Oncor Electric	0.90	2.52	$ 3.42
AEP TX	1.40	3.39	$ 4.79
Texas-New Mexico	1.13	6.72	$ 7.85
Southwestern Public Service			$ 11.40
SWEPCO			$ 9.42
Entergy Texas Inc.			$ 10.00
El Paso Electric Co.			$ 8.25
Average			**$ 7.44**
Austin Energy Increase as % of Average			*236%*
Austin Energy Current			*$ 10.00*
Austin Energy Proposed			*$ 25.00*
Austin Energy Percent Increase			*150%*

Residential Basic Customer Costs
For AE Customer Charge

Services & Meters

Res Meters Per AE	$	10,884,972
Res Services Per AE	$	(1,440,292)
Sub-Total	$	9,444,680

O&M Expense

Meter Reading	$	10,356,510
Customer Accounting A901-903	$	4,951,432
Prorated pension & benefit		10,291,757
Total Expense	$	25,599,698
Total Customer Charge Costs	**$**	**35,044,378**
Residential Customers (annual)		5,736,564
Monthly Customer Charge	**$**	**6.11**

Changes Made To RFP CCOSS

Tab	Cells With Changes	comment
Schedule G-8	D198…T198	customer charge w/services
WP-G 10.2	E19..E21	Compare CCOSS results
Schedule G-6	G41…G43k, G26 G27	
Schedule G-4	F51	
Schedule G-2	F535..537, F22…F24	
Schedule G-2	F38 F40..F42 F29	
Schedule F-6	B26..S27	
Schedule F-6	J8..S8 , C58..S58	
Schedule F-6	T76..AK77 , T79..AK79	develop combination factors
Schedule F-6	T82…AK84	develop combination factors
Schedule F-2	F15..F17, F20	
Schedule F-2	B32..F35	New classificaiton factors
WP E-5.1	I43, I 59, I18 , I19, I15	
WP-D-2.1	F8	
WP D-2	I16	

Note: Procedural rule requires identification of cells modified in AEP Model.