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

POST-HEARING BRIEF OF THE

INDEPENDENT CONSUMER ADVOCATE

July 28, 2022

CITY OF AUSTIN 2016 BASE RATE REVIEW
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I. Introduction

The City of Austin retained an Independent Consumer Advocate ("ICA"), for the purpose of representing the interests of residential and small commercial electric consumers during the 2022 base rate review of Austin Energy ("AE" or "Utility"). In February 2022, the Austin City Council selected John B. Coffman LLC to serve as the Independent Consumer Advocate during this rate review proceeding. The ICA's testifying expert witnesses are David J. Effron and Clarence L. Johnson, both of whom have extensive experience in hundreds of utility rate cases These witnesses comprised the ICA's presentation during the on-the-record conference held in this matter on July 13-15, 2022, before the Impartial Hearing Examiner ("IHE").

In pursuit of its mission, the ICA independently reviewed and analyzed Austin Energy's entire proposal to change its electric rates from the perspective of the best interests of residential and small commercial customers. The ICA's recommendations are guided by accepted utility ratemaking principles, particularly with regard to the goals of maintaining affordability for all Austin ratepayers and ensuring that the electric rates are fair among the various customer classes, and within the residential class.

What made this task particularly difficult were the radical proposals of AE to shift cost responsibility from larger customer classes onto the residential and small business customer classes, and its proposal to further shift that cost responsibility onto the smallest users within the residential class. While AE originally proposed to increase its overall base rate revenue (revenue requirement) by $48.2 million or **7.6%,** AE's proposal for the residential class is more than double the impact, at $52.3 million or **17.6%**.[1] In fact, the revenue that AE wishes to collect from residential households alone is thus actually $4.1 million *more than* the AE's desired total system base revenue increase. In contrast, the ICA concludes that the comparable residential class base revenue increase should only be $6.5 million or **1.2%**.[2] ICA adjusted and corrected AE's cost study, and as a result of those corrections, ICA strongly disagrees with the contention that the residential class is being subsidized by large industry rates.

Within the residential customer class, one of AE's more radical and unreasonable proposals would be to increase the fixed monthly residential customer charge by 150% ($25 proposed; $10 current). An unavoidable fixed charge of $25.00 would be far outside the range of residential fixed rates currently charged by the other two largest municipal electric utilities in Texas, and would also be almost three times higher than the average of similar charges for Texas investor-owned electric utilities.[3] The customer charge of the three largest Texas municipal electric utilities is shown below:

San Antonio City Public Service $9.10
Austin Energy $10.00
Lubbock Power & Light $8.07
Austin Energy Proposed $25.00[4]

The ICA estimates that the basic residential customer costs are only $6.11 per month--far lower than AE's proposed $25.00 per month. Given these basic customer costs, the current

[1] Exhibit ICA-3, p. 1
[2] Exhibit ICA-1, p. 2.
[3] Exhibit ICA-2, p. 13.
[4] Exhibit ICA-2, p. 13.

customer charge of $10.00 is reasonable and does not need to be increased. Moreover, the ICA recommends that any residential customer charge increase should be commensurate with the overall revenue increase percentage. Under no circumstances should the residential customer charge exceed $13.00 in this case.[5]

The ICA further concludes that the combined effects of AE's proposed rate structure would produce wildly divergent customer impacts, as well as be mis-aligned with energy conservation objectives. Below is a comparison[6] of the bill impacts of the AE and ICA proposals at different usage levels, showing the radical shift that could occur under AE's proposed rate design:

	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%

When AE provided notice of its proposed rate increases, it did not inform its low usage customers that it was seeking rates that could impact residential customers that use less than the average among of electricity in the range of 30-50% on monthly bills. Such impacts would certainly constitute "rate shock" for those on the lower end of the usage spectrum.[7] Therefore, the ICA recommends that moderation and gradualism ultimately guide the final decision in this rate review proceeding.

[5] Exhibit ICA-2, p. 8
[6] Exhibit ICA-2, p. 73.
[7] According to AE's Brian. Murphy, a Residential class revenue increase of 25.7% would constitute "rate shock." Murphy Rebuttal, Exhibit AE-9 at p. 13, l. 14-15.

II. Revenue Requirement

A. Approach

The ICA analyzed AE's purported base rate revenue deficiency of $48,219,749, and proposes several revenue requirement adjustments and corrections, totaling $41,691,494. With these adjustments, the ICA calculates AE's revenue deficiency as $6,528,255.[8]

B. Cash Flow Methodology

1. Operation and Maintenance Expenses

a. 311 Call Center Staffing

As explained by AE in its response to ICA discovery questions, in February 2022, "the Austin City Council approved a new multi-term contract with Howroy-Wright Employment Agency Inc. d/b/a AppleOne Employment for temporary staffing services for the Austin Energy Customer Care team, for up to five years for a total contract not to exceed $68,800,000."[9] The annual cost of this contract is $5,382,525 greater than the actual call center staffing expense of $8,372,198 in Fiscal Year 2021. This expense adjustment is 64% over the actual Fiscal Year 2021 expense. The ICA disagrees with AE's contention that this excess is a "known and measurable" amount.[10]

AE's discovery response clearly states that "The quantities listed herein are *estimates* for year one of the contract. The City reserves the right to purchase more or less of these quantities as may be required during the Contract term" (emphasis added).[11] Although the hourly billing rates for the indicated labor classifications may be known, the quantities are not. the attachment to the response to

[8] Exhibit ICA-2, Schedule DJE-1.
[9] Exhibit ICA-2, p. 11.
[10] Exhibit ICA-2, p. 11.
[11] Exhibit ICA-2, p. 11-12.

ICA 2-9 includes 234 employees in the estimate of the annual cost of the new contract. Based on the response to ICA 4-5, the actual number of employees as of end of April 2022 was 185. Thus, the actual number of employees was 49 fewer than the number of employees assumed by AE in calculating the estimated annual cost of the new staffing contract. This equates to a difference of 20.9% in the number of employees. Therefore, the cost of the new staffing contract included in the AE revenue requirement should be reduced by 20.9%, or $2,880,623.[12] Despite further discovery, and cross examination at the conference, AE claimed that it will attempt to increase its staffing at the call center, but could not provide any actual updates to its staffing at the time of the conference.[13] Accepted rate making principles require that adjustments are known and measurable "with reasonable certainty."[14]

b. **Uncollectible Expense**

The actual test year (2021) amount of uncollectible expense claimed by AE is abnormally high at $13.9 million, almost three times the uncollectible expense for the previous fiscal year (2020). 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.[15]

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

[12] Exhibit ICA-2, p. 12, Schedule DJE-1.
[13] AE's Response to ICA 4-5 and 8-1.
[14] Texas PUC Order on Rehearing, Southwestern Public Service Co. Docket No. 43695 (2016), FOF No. 26B.
[15] Exhibit ICA-3, p. 15.

appropriate level of uncollectible expense.[16] This period is recent and excludes the conditions that affected FY 2021. The three-year average uncollectible amount is $4.574 million.[17] After AE's reduction of the test year expense for a known and measurable adjustment (pertaining to a single non-residential customer), 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. The ICA recommendation is to reduce uncollectible expense in the revenue requirement by $1.4 million.[18] AE has not demonstrated that the pandemic did not affect residential uncollectible amounts in 2021. Therefore, the appropriate remedy is to rely upon uncollectible experience in the previous three years.

c. **Heavy Equipment Lease**

AE's actual expense for heavy equipment in Fiscal Year 2021 was $5,338,897. Of this amount, $5,275,317 was charged to Account 593 Maintenance of Overhead Lines – Distribution. AE has adjusted the heavy equipment lease expense to reflect the *forecasted* three-year average expense for Fiscal Years 2023 – 2025. The effect of this adjustment is to increase test year distribution O&M expense by $7,407,652.[19]

However, AE has not demonstrated that this three-year average is known and measurable. In response to discovery, <u>AE acknowledged that the projected lease costs for FY 2023-2025 are not contractual obligations</u>.[20] Referring to the attachment in the response to ICA Request 2-8, it can be seen that the major increases in the forecasted heavy equipment lease expense are not expected to start

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[16] Exhibit ICA-3, p. 16.
[17] Calculation is based on data provided in response to ICA Request 4-8.
[18] Exhibit ICA-3, p. 16.
[19] AE Work Paper D-1.2.12
[20] AE response to ICA Request 4-4.

until May 2023, which are too remote from the Fiscal Year 2021 test year and too uncertain to be considered "known and measurable."[21]

In Fiscal Year 2022, the budgeted heavy equipment lease expense charged to distribution O&M is $5,338,896.96[22]—the only portion of this expense which is known and measurable. This is $7,344,072 less than the projected three-year average of $12,682,969 for Fiscal Years 2023 – 2025. That fiscal period extends four years beyond the test year. The time period used for expenses must match the time period used for revenues; a known and measurable adjustment which is based on forecasts beyond the test year will violate this matching principle.[23] Accordingly, the AE revenue requirement should be reduced by $7,344,072.[24]

d. **Non-Nuclear Decommissioning**

AE has included an annual contribution to the non-nuclear decommissioning reserve of $8,000,000 in its revenue requirement. This annual contribution is intended to fund the cost of demolition and removal of non-nuclear generation plants at the end of their useful lives. AE provided a study in support of the estimated cost of decommissioning its non-nuclear plants. However, there are no workpapers or calculations to show how the financial policies or the cost study estimates result in an annual contribution of $8,000,000.

Based on both the estimated cost of decommissioning documented in AE's study and the amount AE has already recovered in rates for non-nuclear decommissioning, $8,000,000 is well in

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[21] Exhibit ICA-2, pp. 9-10.
[22] AE response to ICA Request 2-8, Attachment Page 2.
[23] Application of Southwestern Public Service Co. Docket No. 43695 (2016) Order on Rehearing, FOF No. 24A.
[24] Exhibit ICA-2, Schedule DJE-1.

excess of the appropriate prospective annual allowance for non-nuclear decommissioning.[25] Mr. Effron summarized the estimated costs of decommissioning each of the non-nuclear generation plants.[26] He calculated a mid-point estimate, based on the average of the "Low Range Estimates" and "High Range Estimates" shown in the decommissioning study, resulting in a total of $62.8 million for three generation plants in the study, which is the best unbiased estimate and most appropriate starting point for the purpose of determining the appropriate annual contribution to the decommissioning reserve.[27]

The rates established in the 2016 Rate Review will have been in effect for six years when the rates in the present case go into effect. Thus, AE will have recovered in rates and funded $48 million (that is, 6 years times $8 million) of the non-nuclear decommissioning reserve as of January 1, 2023. At that time, approximately only $14.8 million of the estimated total decommissioning costs of $62.8 million will remain to be recovered.[28] Mr. Effron recommends that this $14.8 million be recovered over the remaining lives of the non-nuclear generation plants. On DJE-2, he calculated that the average remaining life, weighted by the estimated decommissioning cost of the plants, is approximately 9.4 years. This results in annual non-nuclear decommissioning expense of $1,570,000. To be conservative, he recommends that the calculated non-nuclear decommissioning expense of $1,570,000 be rounded up to $2,000,000 and that this amount be included in the test year revenue requirement. This proposed adjustment to the non-nuclear decommissioning expense reduces the test year AE revenue requirement by $6,000,000.

[25] Exhibit ICA-2, pp. 5-7.
[26] Exhibit ICA-2, Schedule DJE-2.
[27] Exhibit ICA-2, p. 5.
[28] Exhibit ICA-2, Schedule DJE-2.

AE complained in rebuttal testimony that previous decommissioning cost overruns portend that future decommissioning projects could be higher than expected. However, those previous cost overrun experiences have already been taken into account in the outside consultant's decommissioning study.[29] In the previous AE rate review, ICA supported a higher annual decommissioning amount; however, at that time there was no such fund, and now it has been created and substantially funded. Over-funding the decommissioning fund would lead to "intergenerational inequity".

AE has the burden of proving the reasonable amount of non-nuclear decommissioning expense, and ICA has relied on the only decommissioning study presented. AE has not presented a new study nor any additional analysis to support its position.

e. **Winter Strom Uri and COVID-19 Expenses**

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.[30] Given the deadly nature of this storm, restoration of electric service was a priority for AE, and it impacted several aspects of AE's operations. But although this event occurred during the test year, AE's cost of service is not adjusted for Winter Storm Uri. Notably, this event was not a routine or "normal" winter storm and should be considered abnormal for rate making purposes.[31]

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.[32] Mr.

[29] Exhibit ICA-2, p. 7.
[30] Exhibit ICA-2, p. 14.
[31] Exhibit ICA-2, p. 14.
[32] Response to ICA Request 4-12.

Clarence Johnson recommends amortizing 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 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.[33] AE opposes the adjustment, contending that regular labor and benefits should not be part of the adjustment, and that historical overtime and contract labor expense are in line with 2021 annual amounts. However, Mr. Johnson pointed out on cross-examination that utilities frequently include regular labor and benefit expense when they segregate extraordinary storm expense.[34] Indeed, as Mr. Johnson stated on cross-examination, AE's rebuttal testimony confirms that 2021 overtime and outside labor expense exceeds average historical experience by an amount approximately the same as the reported Uri restoration cost for those items.[35] If the 2017-2020 fiscal years in the two rebuttal charts (Maenius Rebuttal at 7) are averaged, the 2021 annual overtime and contract labor exceeds the historical average by $1.5 and $1.55 million, respectively.[36] These amounts are higher than the reported Uri restoration overtime and outside labor expense. Therefore, ICA's adjustment for Uri restoration is reasonable.

f. **Rate Case Expense**

[33] Exhibit ICA-2, p. 15.
[34] Tr. (7-14) page 88-89.
[35] Ibid. page 89-90.
[36] 2017-2020 annual averages for overtime and outside labor are $9.3 and $14.3 million respectively, compared to 2021 overtime and outside labor expense of $10.8 and 15.6 million, based upon the tables on page 7 of Maenius Rebuttal.

AE has included rate case expense of $597,000 in its revenue requirement. This amount was calculated by normalizing total estimated rate case costs of $1,791,000 over three years.[37] However, the last AE rate case was six years ago. Therefore, Mr. Effron recommends a normalization period of at least five years would be more appropriate. Normalizing total rate case costs of $1,791,000 over five years rather than over three years reduces the annual rate case expense by $238,800.[38]

5. General Fund Transfer

The General Fund Transfer (or "GFT") was calculated as 12% of the revenues, less power supply costs.[39] This calculation reflects the base rate revenue requirement as determined by AE. To the extent that other elements of the base rate revenue requirement are modified, the revenue base for the calculation of the General Fund Transfer must be modified accordingly. The General Fund Transfer is itself included in the base rate revenue requirement on which it is calculated. In other words, the total revenue requirement includes GFT on GFT. Therefore, to capture the effect of other revenue requirement adjustments and recognize the effect of the GFT on GFT, the 12% factor must be "grossed up." This can be accomplished by dividing the 12% by its complement, or 1-.12. Accordingly the grossed-up GFT factor is 12%/(1-.12), or 13.64%.[40] Mr. Effron applied the grossed-up GFT factor of 13.64% to the revenue requirement as adjusted by ICA, and calculated an adjustment of $5,002,979 to the General Fund Transfer included in the AE revenue requirement.[41] This adjustment is a fallout of

[37] AE Work Paper WP D-1.2.7.
[38] Exhibit ICA-2, p. 8; Schedule DJE-1.
[39] AE Work Paper WP C-3.2.1.
[40] Exhibit ICA-2, pp. 14-15.
[41] Exhibit ICA-2, Schedule DJE-1.

whatever revenue requirement adjustments are ultimately adopted in the final decision in this proceeding.

Beyond this fallout calculation, another potential adjustment to the GFT became apparent during the course of the hearing. AE's rate filing package did not use the three-year average method dictated by city council policy.[42] The city manager's budget request to the city council includes a $115 million GFT in 2022 and 2023, which is $6 million less than AE's known and measurable adjustment assumption.[43] Therefore, AE has not adequately supported its known and measurable adjustment to the GFT.

8. **Revenue Requirement Offsets**

a. **Late Payment Fees**

Late payment fee revenues are a reduction to customer costs in the cost of service study. 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.[44] Mr. Clarence Johnson recommends normalizing this expense using the average annual late payment fee revenue for 2018 and 2019 to set a revenue amount for the cost of service, because the late payment fee revenue in those years should be more representative of future revenues.[45]

AE's 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

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[42] Exhibit AE-11.
[43] Tr. Day 3 at 39.
[44] Exhibit ICA-3, pp. 16-17.
[45] Exhibit ICA-3, p. 17.

2020 is $5.55 million.[46] The test year amount of late payment fee revenues is $3.34 million.[47] Therefore, Mr. Johnson recommends an upward adjustment of $2.2 million to late payment fee revenue.[48] On rebuttal, AE proposed a $1.15 million adjustment which estimates late payment fees for months in which the fees were suspended. Although this represents movement in the right direction, ICA continues to support the $2.2 million adjustment because the more appropriate basis for estimating future late payment fees is the amount collected in the two-year period prior to the pandemic.

9. **Other Revenue (**Facilities Rentals**)**

AE adjusted the actual 2021 test year revenues for facilities rentals, which are included in "Other Revenues" by $1,836,826.[49] AE describes this adjustment as an adjustment to revenue to reflect a change in rental revenue from a particular customer.

In response to ICA Request 2-11[50], AE stated that "The adjustment to facilities rental is related to a disputed bill for pole attachments. Austin Energy does not expect to collect payment from this invoice." In response to ICA Request 4-6, AE said that it does not expect to collect payment from this customer: "This is due to the uncertainty of collecting on AT&T pole attachment bills due to an ongoing dispute and negotiations on an expired contract." AE has established that these bills are in dispute. However, this does not establish with a reasonable degree of certainty that there will be no recovery of

[46] AE Response to 2WR 1-11.
[47] WP E-5.1.
[48] Exhibit ICA-3, p. 17.
[49] AE Work Paper E-5.1.2.
[50] Exhibit ICA-2, Attachment ICA 4-6.

the balances due.[51] In fact, further discovery indicates that AE is still seeking to recover the amounts in dispute.[52]

AE has not shown that the disputed bills for facilities rentals will not be unrecoverable or that the ongoing revenues from this source will be zero prospectively. Accordingly, Mr. Effron recommends that the adjustment to reduce Other Revenues by $1,836,826 be eliminated.[53] The elimination of this adjustment reduces the AE base rate revenue requirement by $1,836,826.

III. Cost Allocation

A. Background

Mr. Clarence Johnson evaluated AE's proposed CCOSS for consistency and accuracy in the allocation of costs among classes; he relied upon the 1992 NARUC Cost Allocation Manual ("NARUC CAM") and the 2020 Regulatory Assistance Project Cost Allocation Manual ("RAP CAM") to inform his analysis.[54]

A 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[55], generally resulting in a portion of costs allocated on causal measures and the remainder of indirect costs following those costs. A CCOSS is at best a broad benchmark for evaluating customer class cost responsibility and can provide guidance to the decisionmaker, but considerations other than the CCOSS are also appropriate in determining the ultimate allocation of costs among customer classes.

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[51] Exhibit ICA-2, p. 13.
[52] See Response to ICA Request 8-3.
[53] Exhibit ICA-2, p. 13-14.
[54] "Electric Utility Cost Allocation for A New Era: A Manual," January 2020.
[55] See Exhibit ICA-13, NARUC CAM, Production "Cost Causation", pp. 38-39.

B. Functionalization

1. Production Function

2. Transmission Function

3. Distribution Function

4. Customer Service Function

a. 311 Call Center

b. Bad Debt

Bad debt expense should not be functionalized to customer service because uncollectible expense is a system cost of doing business. AE inappropriately assigns this overhead expense as a customer cost. (Please see the discussion below in Subsection III.D.6.) The NARUC CAM specifically excludes bad debt from the customer classification.[56]

c. Functionalization and Allocation of Services and Meters

i. Smart Meter Allocation

AE develops a weighted customer allocation which reflects the cost of different meter sizes installed by customer class, which is appropriate and standard, for 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.[57]

[56] Exhibit ICA-3 at 61.
[57] Exhibit ICA-3, pp. 42-45.

The cost of 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. Thus ICA witness Mr. Johnson 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, in order to recognize that Smart Meters perform both traditional billing functions and functions that provide system benefits.[58] Furthermore, the revised Weighted Meter allocation factor should be applied to meter reading expense, which should be considered part of the Meter sub-function.[59] (Inexplicably. AE has not applied its own meter class allocation factor to meter reading costs.)

As justification for its Smart Meter upgrades over the last five years, AE emphasized system benefits for modernizing the grid, acquiring information, developing revenue and usage reports, revenue protection, and communicating with customers.[60] 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. AE recognizes most of these functions and continues to activate meter functions which enable these benefits.[61]

[58] Exhibit ICA-3, 43.
[59] 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.
[60] AE Presentations provided in response to ICA TC 1-12B.
[61] Exhibit ICA-3, p. 44.

The 2020 RAP CAM recognizes the deployment of automated meter investment and concludes that a traditional customer allocation is inadequate.[62] 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."[63] In addition, as documented by Mr. Johnson, state commissions, such as the Maryland PSC, have started to recognize that part of the smart meter cost should be allocated similar to production costs due to system and regional benefits.[64]

ii. Services

Services, also called service drops, are lines attached to the customer premises which connect the distribution line to the end use customer. The "loaded cost" of AE services is negative because many service lines are old, and the plant account is almost fully depreciated as a result, the services sub-function is a reduction to revenue requirement.[65]

AE classifies services as Demand and allocates the cost on NCP demand. As a result, the negative average cost position of services does not reduce net customer costs, nor does it affect the customer charge. The NARUC CAM specifies that services are properly classified as customer-related. In Mr. Johnson's experience, other electric utilities treat services as customer-related, and he recommends the classification of services as a customer cost and its inclusion in the calculation of the customer charge.[66]

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[62] Regulatory Assistance Project CAM, "Electric Cost Allocation for a New Era" at 157.
[63] Ibid.
[64] Exhibit ICA-3, p. 44-45.
[65] Exhibit ICA-3, p. 45.
[66] Exhibit ICA-3, p. 46.

Contrary to its CCOSS, AE's Rate Filing Package narrative defines customer-related costs as "the cost of meters, service drops, 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.[67] Thus the ICA recommendation is to classify services as customer-related, and to apply a weighted customer allocation factor which combines a 12NCP weighting with the customer allocation factors.

C. Classification

2. Energy-Related Costs

Production Non-Fuel O&M Expense. AE classified all production base rate O&M expense as demand-related.[68] Mr. Johnson could not 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-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.[69] This method represents an accepted convention that has been adopted by the Texas PUC in the past.[70]

Classification of a substantial portion of generation maintenance as energy-related is reasonable. Like most mechanical devices, the frequency of maintenance for production facilities

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[67] AE Rate Filing Package, p. 57
[68] AE classifies Nacogdoches Plant O&M expense as Energy, but includes these costs in the PSA.
[69] NARUC CAM at 35-41, Table labeled "Exhibit 4-1."
[70] Exhibit ICA-3, pp. 30-32.

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.[71] Likewise, some portion of production operation expense is properly classified as energy-related, because 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.[72] The NARUC method should be used to classify non-fuel O&M expense, as set out by Mr. Johnson.[73]

3. Customer-Related Costs

The classification of "other revenues" from non-recurring customer-related fees was corrected by ICA witness Johnson. Based on the ICA's review of WP E-5.1, some of the fees which were assigned to Distribution should have been functionalized to Customer. Mr. Johnson 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. The ICA recommendation increases the "Other Revenues" functionalized to Customer by $2.8 million.

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

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[71] Exhibit ICA-3, p. 32.
[72] Exhibit ICA-3, p. 32.
[73] Exhibit ICA-3, p. 32.

initiation of new service and does not involve the physical costs of connecting a structure.[74] AE's rebuttal testimony accepted the classification of Service Initiation Fee as customer-related.[75]

The amount of fees classified as Customer should be increased by $2.8 million.[76] 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.

6. A&G Expense and Indirect Costs

ICA disagrees with AE's classification of A&G Expense accounts 920 and 930. As a matter of accounting definition, Account 920 (Administrative & General) 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, and budgeting.[77] Account 930 (general expense) contains little if any labor cost, but instead aggregates a multitude of miscellaneous expenses from all functions of the utility. Both A920 and 930 are classified to functions based on an indirect allocator based on payroll within each function. There is no objective economic rationale for selecting particular classification factors to assign A920 and 930.[78]

The ICA disagrees with the classification of A920 and 930, because none of the potential indirect methods are strongly related in a causal sense to the underlying expenses in these 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

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[74] In most cases, AE can remotely activate service through smart meters.
[75] AE Rebuttal testimony, Rabon, p. 8.
[76] Late Payment Fees is an exception, where AE properly classified those as Customer-related.
[77] Exhibit ICA-3, p. 33.
[78] Exhibit ICA-3, p. 33.

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.[79] The composition of AE's labor allocator produces incongruent results for A920 because nuclear and coal plant on-site labor is excluded; this justifies either rejecting the labor method for A920 salaries or correcting the deficiency in the method. Mr. Johnson corrected the payroll functionalization factors applied to A920.[80] Mr. Johnson modified the functionalization of A920 (Salaries) by correcting the payroll functionalization to include the STP and FPP power plant on site labor. For A930 (Miscellaneous General), he recommends replacing the payroll method with non-fuel O&M factors.[81] Again, the non-fuel O&M classification produces a more balanced assignment of miscellaneous expenses across Production, Transmission, Distribution, and Customer functions than the payroll classification method. Moreover, A930 includes virtually no payroll expense, further confirming that a payroll classification is inappropriate. In Mr. Johnson's opinion, AE's classification of A920 and A930 expense artificially inflates customer costs.[82]

C. Class Allocation

1. Demand-Related Costs

a. Production-Demand

AE uses a CCOSS based on the ERCOT 12 Coincident Peaks (12 CP) to allocate generation demand costs to customer classes. The 12 CP method is based on customer class contributions to

[79] Exhibit ICA-3, p. 34, 36; RAP CAM: A&G classification should "ensure broad sharing" among functions.
[80] Exhibit ICA-3, pp. 34-35.
[81] Exhibit ICA-3, pp. 35-37.
[82] Exhibit ICA-3, pp.35-36.

the ERCOT monthly peak hours. In contrast, on behalf of the ICA, Mr. Johnson applied the Baseload-Intermediate-Peak (BIP) method; this method separates production costs into generation serving base, intermediate, and peak time periods and develops different class allocation factors for each component.[83] The BIP method is an accepted production allocation method in both the NARUC CAM and the RAP CAM.

The primary deficiency of AE's methodology is that it 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.[84]

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).[85] The Texas PUC has never addressed the appropriate production plant allocation method for the current ERCOT market structure. The nodal market in ERCOT dictates the dispatch of AE's generation, a characteristic

[83] Exhibit ICA-3, pp. 20-30.
[84] Exhibit ICA-3, p. 21.
[85] Bundled investor-owned electric utilities in Texas (EPE, SPS, SWEPCO, ETI) operate in reliability. regions other than ERCOT.

which should be considered in selecting a production allocation methodology.[86] The hourly dispatch within ERCOT is driven by generation unit variable cost characteristics, which in turn depends upon the type of generation facility (baseload, intermediate, peak). Therefore, BIP allocation is consistent with the ERCOT market structure. Moreover, the ERCOT market structure differs from the regional market structures faced by other bundled investor-owned utilities, such as SPS, SWEPCO, and EPE, which additionally confirms the need for a different production allocation applied to AE. [87]

Production plant allocation 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). 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.[88]

The dual importance of demand and energy in developing production demand allocation methods is recognized in the NARUC CAM.[89] 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.

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[86] Exhibit ICA-3, pp. 19-20.
[87] Exhibit ICA-4, pp. 4-5.
[88] Exhibit ICA-3, pp. 22-23.
[89] NARUC Electric Utility Cost Allocation Manual at 49.

Furthermore, the other peak demand methods (including Average & Excess Demand) proposed by industrial intervenors do not *effectively* recognize annual energy use.[90]

Mr. Johnson developed two variants of the BIP methodology which recognizes the specific characteristics of AE's generation investment.[91] The NARUC CAM identifies BIP as an accepted production demand methodology which falls within the "time-differentiated" category of methodologies.[92] The RAP CAM rates the BIP method as providing a "High" level of accuracy for cost causality.[93] 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.[94]

. Mr. Johnson prepared a secondary BIP method to confirm that his primary BIP formulation is consistent with the current operation of the plants in the ERCOT market. This process estimates relative margins earned by the baseload, intermediate, and peak plants in the ERCOT market, which demonstrates that the plants' profits in the ERCOT market produce results consistent with the primary BIP method. This exercise proves the consistency of BIP with AE's participation in ERCOT and shows that the two approaches to BIP produce closely similar class allocation results.[95]

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

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[90] Exhibit ICA-3, p. 24. Exhibit ICA-4, p. 6-7.
[91] Exhibit ICA-3, pp. 24-25.
[92] NARUC CAM at 60-62.
[93] RAP CAM at 129, Table 19.
[94] Exhibit ICA-3, p. 25.
[95] See Exhibit ICA-3, p. 27-29; Schedule CJ-1.

included a sub-functionalization of production costs for use in a BIP method. [96]AE's previous cost of service consultant, R.W. Beck, recommended BIP during the public involvement (PIC) process for the 2011 rate request.[97] The consultant pointed out that BIP is consistent with the characteristics of ERCOT market dispatch.[98] This conclusion contradicts Mr. Burnham's rebuttal testimony which claimed that BIP is not appropriate for utilities that operate in the ERCOT market. Moreover, Mr. Burnham fails to consider or even mention that Mr. Johnson performed a version of BIP based on an analysis of ERCOT market margins to verify the appropriateness of BIP.

The BIP methodology represents a more reasonable approach to allocating production demand costs than the 12CP or the A&E-4CP methods. The BIP is a method which more reasonably balances the interests of AE's customer base by recognizing both reliability and economics.[99] Furthermore, BIP recognizes the prevalence of meeting ERCOT loads of short or medium duration with combustion turbine and combined cycle generation.

b. Distribution-Demand

(i) 12 NCP

The 12 NCP approach is within the range of reason for the allocation of distribution costs. Class non-coincident demands (NCP) normally are used to allocate most demand related distribution costs. Austin Energy applies the 12 NCP (12 monthly class peaks) method to allocate

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[96] 2016 COSS WP F-2.3
[97] Exhibit ICA-15 (RW Beck Report), p. 198-203.
[98] 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., p. 199-200.
[99] Industrial witnesses claim that BIP involves an inconsistency between base rate and fuel cost recovery. However, on cross-examination, Mr. Johnson pointed out that AE could readily address this issue during the reconciliation of power supply adjustment costs. Transcript, Day 2, p.83.

poles, conductors, and substations, and TIEC proposes to replace this allocator with an NCP allocator limited to the single peak hour for each class. The 12 NCP method used by AE is an average of class NCP for each of the 12 months. The purpose of the NCP demand method is to recognize load diversity and the localized nature of distribution planning. Compared to 12 NCP, TIEC's single hour NCP method dilutes the recognition of both factors.[100]

Load diversity is an important economy of scope in the electric utility industry. When class loads have a similar profile, increased demand imposes higher costs on distribution facilities. However, as more and different types of loads are combined within a local area served by distribution facilities, diversity benefits reduce the cost associated with additional new load. Distinct types of loads can be complementary, with the peak of one profile occurring outside the peak of the other type of load. By restricting the NCP demand to one hour for each class, TIEC's recommendation limits the recognition of diversity of loads between classes, because classes with significant demands outside the single hour peak (for instance, winter heating loads) are insulated from the allocation of distribution costs associated with high demand periods which do not drive the single peak hour. In this respect, 12 NCP is superior for recognizing class load diversity.[101]

If in fact the TIEC change is made, the ICA recommends an additional modification be made. In that scenario, the ICA recommends including a partial allocation based on class energy use in the range of 10% - 30%. This would be consistent with the recommendations of the Regulatory Assistance Project 2020 cost allocation manual[102], and would recognize that

[100] Exhibit ICA-4, p. 8.
[101] Exhibit ICA-4, pp. 8-9.
[102] RAP, "Electric Utility Cost Allocation for A New Era: A Manual," January 2020.

distribution planning must build the system to account for line losses which may occur throughout the year.[103]

(ii) **Load Dispatch Expense**

AE allocates distribution load dispatch expense to customer classes based on 12 NCP demand. In contrast, the ICA recommends allocating the expense on the basis of average demand because load dispatch is important in every hour of the year.[104]

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.

This issue was subject to contested litigation is SPS Docket No. 43695. In that case, SPS allocated 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."[105] 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." [106]

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[103] Exhibit ICA-4, p. 9.
[104] Exhibit ICA-3, pp. 46-48.
[105] Southwestern Public Service Co., Docket No 43695, Proposal for Decision at 246 – 247.
[106] Ibid.

Summer hours are not more important to load dispatch than other 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.[107]

c. Primary Distribution Demand-Related Costs (Primary Substation Issue)

With regard to TIEC's primary substation issue, ICA contends that the industrials' proposal for a substation class should be denied. If some form of substation rate is adopted, the ICA recommends that any revenue shifting in the proposal should be confined within the primary voltage classes. Costs should be allocated in full to primary voltage classes, and any revenue loss caused by discounts to substation customers should be recovered within those primary classes.[108]

2. Energy-Related Cost

The ICA disagrees with AE's classification of Production Non-Fuel O&M Accounts. See the discussion in Subsection III.C.2 of this brief.

3. Customer-Related Cost

AE allocates customer service expense (FERC Accounts 907-917) based on class customer count. The ICA disagrees. The customer service accounts include advertising and dissemination of information, and the A911-A917 expenditures are intended to influence system energy

[107] Exhibit ICA-3, p. 48.
[108] Exhibit ICA-4, p. 10.

consumption. 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. The ICA recommendation is to allocate expenses in A911 – A917 broadly across functions, as recommended by NARUC and RAP manuals. FERC Accounts 911 – 917 comprise 61% of the total Customer Service expense Therefore, the Customer Service allocation factor should reflect a 61% weighting to the Revenue Requirement allocation and 39% weighting to the Customer allocation factor.[109] Although NXP criticized the 61% ratio because it allegedly included key accounts, that view is unfounded because (as shown by Schedule G-5) AE's RFP segregates customer service expense and key account expense.[110]

Both the NARUC CAM and the RAP CAM advise against the use of an unweighted customer allocation factor for Customer Service expense. 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."[111] 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

[109] Exhibit ICA-3, pp. 49-50.
[110] Daniels cross, Tr. Day 2 at 51.
[111] Regulatory Assistance Project, "Electric Cost Allocation for a New Era" at 164.

> customer class when data are available or allocated based upon the overall revenue responsibility of each class.[112]

4. Revenue-Related Costs

5. Service Area Street Lighting

6. Direct Assignments

AE assigns 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. The ICA believes that a more reasonable method is to allocate uncollectible expense in proportion to a revenue requirement allocation factor, sometimes called a "revenue allocation." Mr. Johnson's testimony cites Texas PUC precedent supporting his recommendation.[113] The order in the Texas PUC 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.[114]

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

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[112] NARUC CAM at 104; Exhibit ICA-11.

[113] Exhibit ICA-3, p. 40, footnotes 36, 38.

[114] Entergy Gulf States, Inc., Docket No. 16705, Second Order on Rehearing at Finding of Fact No. 231 (Oct. 14, 1998).

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. This reasoning was more recently recognized in a 2016 Texas PUC contested case which rejected direct assignment of uncollectible expense.[115]

The RAP CAM also supports the use of a class revenue allocation for uncollectible expense.[116] 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 accounts have unpaid electric bills, those accounts are former customers who are no longer members of any class."[117] 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."[118] Therefore, 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).

E. Cost of Service Results

Austin Energy claims that the residential class currently receives significant subsidies from other classes. As a result, AE proposes that the residential class should receive a percentage base revenue increase almost 2.5 times the requested 7.6% system base revenue percent. However, the ICA's proposed CCOSS shows that the residential class relative cost position is *not* above system

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[115] Application of Southwestern Public Service Co. for Authority to Change Rates, Docket No. 43695, Order, FOF 310 and 311.
[116] Regulatory Assistance Project CAM, "Electric Cost Allocation in a New Era" at 162 – 163.
[117] Ibid.
[118] Ibid.

average.[119] This suggests that AE's proposed base revenue increase vastly overstates the residential class proportion of increased revenues, casting considerable doubt on AE's claim that the residential class is heavily subsidized. Therefore, CCOSS results are only used as a guide in evaluating how any base revenue increase is distributed among classes.

The Residential CCOSS results shown in the table 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)

[119] Exhibit ICA-3, Schedule CJ-2.

IV. Class Revenue Distribution

The CCOSS 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. Rate moderation is essential for the proper apportionment of revenue increases among the various customer classes.

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 2021 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. While the CCOSS provides useful information for developing the class revenue increases, it should not be the sole consideration. Non-cost considerations are appropriate in mitigating pure CCOSS results. This principle has been recognized in longstanding regulatory texts, such as Dr. James Bonbright's seminal *Principles of Public Utility Rates*.[120] The RAP CAM also discusses the widespread practice of regulators departing from strict adherence to CCOSS results.[121]

From its earliest history, the Texas PUC has recognized the principle that cost study results need to be subject to rate mitigation.[122] 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 three general reservations: (1) some of

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[120] James Bonbright, *Principles of Public Utility Rates*, Chapter 16, "Criteria for A Sound Rate Structure," (Columbia Press) (1961).
[121] "Electric Utility Cost Allocation for a New Era" at 237 – 238, Regulatory Assistance Project.
[122] Exhibit ICA-3 at 54.

the costs are classified and allocated on a disputable causal basis; (2) CCOS results may be quite sensitive to alternative classification or allocation decisions that are within the range of reasonable choices and (3) 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 is appropriate in applying the CCOS study to class revenue increases.[123] The RAP CAM suggests that regulators may examine the results of multiple different CCOS studies to arrive at a range of reasonableness.[124] 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.[125]

Customer class allocation factors have changed significantly since the 2016 AE rate review, with 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%.[126] The 12 CP demand allocation factor for Residential increased by 6.3% and the Secondary cumulative 12 CP demand factor declined by 8.9%.[127] 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.[128] An increase in the CCOSS Residential allocation factor accompanied by a decrease in the Secondary allocation factors would shift costs from commercial classes to the Residential class. However, this may not reflect future

[123] Exhibit ICA-3, pp. 53.
[124] Ibid.
[125] 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.
[126] Exhibit ICA-3, p. 55.
[127]This is based on a comparison of allocation factors (Schedule F-6) in AE's 2016 CCOSS and the 2021 CCOSS.
[128] "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.

class relationships to the extent that COVID impacts on class allocation factors are likely to recedes in the future.[129] This provides additional support for gradualism in the distribution of the revenue increase among classes.[130]

AE's attempt at customer class revenue distribution severely impacts the residential class. First, for the Residential class, AE proposes a "times system average" base revenue percentage of 233% (17.6% Residential increase / 7.6% System increase). This is excessive and produces an immense impact on households in the AE service area.[131] Second, the assigning of revenue *reductions* to some classes while overall revenues *increase* is a violation of the principles of moderation and public acceptability. In the ICA's 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 for some customers compound the severity of revenue increases confronting most customers.

The ICA proposes 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.[132] This approach suppresses large impacts, broadly shares the revenue increase, and recognizes classes with revenues substantially above cost.

V. Rate Design

[129] Exhibit ICA-3, pp. 55-56.
[130] The fact that commercial classes' customers and sales declined between 2020 and 2021 appears to validate the potential impact of COVID on the CCOSS results. Transcript, Day 3 pp. 2-4.
[131] Exhibit ICA-3, p. 56.
[132] Exhibit ICA-3, Schedules CJ-3 and CJ-4.

A. Residential Rate Structure

1. Customer Charge

AE proposes to increase the residential monthly customer charge from $10.00 to $25.00. This 150% percent proposed increase in the fixed customer charge is excessive. The proposal is extraordinarily high compared to the fixed monthly charge of both bundled and unbundled 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.[133]

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.[134] The ERCOT average customer charge represents unbundled electric utilities, and the Non-ERCOT average represents bundled utilities like AE. The IOU average of customer charges 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**

[133] Exhibit ICA-3, Schedule CJ-5.

[134] 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.

The residential customer charge should only recover costs that vary directly with the number of customers. [135] 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 in its calculation includes costs that are not directly associated with customers, and that do not vary with the number of customers. The main problem with AE's CCOSS is that its 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 then also layers part of General Fund Transfer (GFT), non-utility operations expense and internally generated funds for construction onto the customer charge.[136] These overhead expenditures are not directly driven by the number of customers; instead, is the customer charge becomes a circuitous pathway for recovering costs that cannot be recovered through other 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. However, after the indirect/overhead costs are added to this customer accounting expense, the Customer Accounting function has grown to $58.5 million, essentially a ten-fold increase.[137] AE has distorted the true amount of customer-specific costs through a piling on of overheads, and overheads on top of overheads.

The ICA has calculated a residential customer charge directly related to the number of customers ($6.11).[138] The calculation includes O&M expense for meters, services, meter reading,

[135] 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."
[136] RFP Schedule G-5 and G-6 (Exhibit ICA-12).
[137] Exhibit ICA-3, p. 59.
[138] Exhibit ICA-3, p. 60; Schedule CJ-6.

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.[139] This method is 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.[140]

The Basic Customer Method is also consistent with the historic Texas PUC practice for evaluating the customer charge level of bundled electric utilities.[141] Since AE's existing customer charge is $10.00, the current customer charge is more than compensatory for direct customer costs.[142]

There is no logical rationale for recovering all uncollectible expense through the monthly customer charge.[143] AE recovers $7.0 million of the $7.6 million total uncollectible expense through the residential customer charge.[144] 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.[145]

There are numerous important policy reasons to ensure that the residential customer charge is not excessive. An excessive customer charge can distort appropriate price signals for

[139] The calculation also includes a portion of pensions and benefits (Account 926) associated with the O&M expense in the customer charge.
[140] "Electric Utility Cost Allocation for a New Era" at 145, Regulatory Assistance Project.
[141] *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).
[142] Exhibit ICA-3, p. 60.
[143] The NARUC Electric Utility Cost Allocation Manual (CAM) specifically excludes uncollectible expense from the customer classification. NARUC CAM at 103. Exhibit ICA-3 at 61.
[144] This is the fully loaded cost of uncollectible expense, after adding GFT and non-utility operation expense.
[145] Exhibit ICA-3, p. 61.

residential customers. The dominant economic function of a customer charge is to ration access 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.[146] 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 Minimizing the customer charge provides the ratepayers with a greater ability to control their bill on the basis of usage. [147]

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.[148] AE desires to increase the residential basic customer charge by 150%. The energy rates, cumulatively, are *reduced* by 9%. The result will be a significant weakening of the price signal for energy conservation. This is contrary to AE's record and goals for conserving energy.[149]

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[146] Exhibit ICA-3, p. 62.
[147] Exhibit ICA-3, pp. 61-62.
[148] Exhibit ICA-3, p. 63.
[149] Exhibit ICA-3, p. 64.

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 would seek to maintain the existing relationship between customer charge and energy charge revenues, and thus the ICA recommends limiting the customer charge increase based on the residential base revenue increase ultimately adopted. A maximum residential customer charge of no higher than $13.00 would be reasonable, which would be applicable only if AE's proposed residential revenue increase is adopted.[150]

2. Tiers

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 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. [151] 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, for inside city customers, low usage customers will pay a substantial increase in rates (34% - 52%), and higher usage customers will receive revenue reductions with a magnitude as high as -47%. AE's witness Mr. Murphy attempts to justify the changes as cost-based, but this is

[150] As noted previously, AE's proposal imposes a 26% base revenue increase on inside city customers.
[151] Exhibit ICA-9. AE's public information website describes the residential 5 tier rate structure's energy conservation objective.

a serious misuse of the CCOSS.[152] The CCOSS estimates costs for *classes* of customers, not tiers within the class. Mr. Murphy's claim requires an assumption that energy use at various usage levels has a strict linear relationship with the various demand allocators in the CCOSS—without any evidence to support the premise.[153] ICA contends that the principle of gradualism should override flawed assertions of a cost basis. Therefore, ICA recommends tier rates with less extreme disparities in the rate change percentages.

The ICA's proposed rate design would be a more moderate change that includes four tiers. 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 obstacle to limiting absolute rate reductions in the upper usage tiers. As a matter of logic, reducing rates for upper tier customers is not a path for solving a class revenue deficiency. Furthermore, compared to AE's three tiers, the four tier structure addresses the energy conservation objective. Finally, ICA's proposed Tier 2 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[154]

4. Outside City 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

[152] ICA Ex. 3 at 74.
[153] Ibid. Note that we do not have coincident and non-coincident peak demands for each tier level.
[154] ICA Ex. 3 at 72.

Inside City customers. AE's proposal applies the following base revenue change to the two sets of customers.

<u>AE PROPOSED BASE REVENUE CHANGE</u>

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

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

These results are 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.[155] On average, outside city residences use 86% more electricity than inside city customers.[156] 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. Notably, the 26% revenue increase to inside city residential customers is higher than the 25.7% class increase which AE witness Murphy deemed to be "rate shock."[157]

Given the differences in usage characteristics, the ICA recommends leaving the Outside City residential tariff unchanged. This will eliminate the revenue reduction for those customers, which on the surface would appear unfair to Inside City customers. Moreover, this also preclude the possibility that other rate design changes, such as ICA's four tier proposal, would impose large rate increases on outside city residential customers. Factually, AE can provide no cost information which supports a significant change in outside city residential rates. Without data regarding the

[155] Exhibit ICA-3, p. 68.
[156] Exhibit ICA-3, p. 69.
[157] Murphy Rebuttal at 13.

coincident and non-coincident demands of outside city customers, we can only speculate on the cost of serving these customers. ICA recommends that AE develop load research for outside city residential customers which would inform the rate review process in its next rate case.

VII. Additional Issues

Current Rate Design Inappropriately Blamed for Utility Financial Performance

AE's claim that its current rate structure is "unsustainable" is an exaggeration. Rate levels in any rate structure are not intended to remain the same over a lengthy period, and thus the "unsustainable" characterization is inappropriate. The fact that Austin has a policy of periodic rate review as frequently as every three years should permit corrections of the rate structure billing units. Moreover, focusing on rate structure as the "problem" detracts from a critical review of rising costs and whether additional cost control is necessary.[158]

AE expresses concern that 2020 and 2021 required it to rely upon cash reserves. 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

[158] Exhibit ICA-3, pp. 65-66.

its customers and made other billing adjustments. AE has not quantified most of these amounts because the CCOSS relies upon normalized billing determinants. But these issues can affect the actual revenues and costs shown in the data that AE uses to tie its claim of financial stress to the residential rate design.[159]

AE's position is paradoxical. AE recognizes that the purpose of the five-tier structure is to promote reduced power usage and energy efficiency.[160] 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.[161] Despite AE's recognition of the City's goal of energy conservation, the effort to re-structure the residential rates is likely to increase future electricity consumption.

VIII. Conclusion

In addition to the record of the proceeding taking place at the Final Conference, the ICA urges the IHE and the City Council to fully review the public comments received in the official record.[162] These are comments from the individuals that will be paying the rates and bills resulting from this rate review, and their voices deserve to be heard.

[159] Exhibit ICA-3, pp. 66-67.

[160] 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

[161] 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."

[162] Exhibit ICA-5.

In these times of rising inflation and cost of living concerns for residents of the City of Austin, the ICA recommends that its proposals be seriously considered, and that the final decision in this matter be mindful of avoiding unintended or dramatic rate impacts for *any* segment of the ratepaying customer base. The ICA believes that its proposals in this matter are just and reasonable, and carefully designed to minimize disparate rate changes among customers.

The ICA respectfully requests that the Impartial Hearing Examiner issues a report that contains findings and recommendations consistent with those contain in this post-hearing brief.

Respectfully submitted,

John B. Coffman
Independent Consumer Advocate

Submitted this date: July 28, 2022

CERTIFICATE OF SERVICE

The forgoing filing has been served upon all of the email addresses contained in the official Service List for this proceeding as found on the website for the Office of the City Clerk's website on this 28th day of July, 2022.