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

AUSTIN ENERGY'S CLOSING BRIEF

August 9, 2022

TABLE OF CONTENTS

Page

AUSTIN ENERGY'S	**§**	**BEFORE THE CITY OF AUSTIN**
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AUSTIN ENERGY'S CLOSING BRIEF

TO THE HONORABLE IMPARTIAL HEARING EXAMINER:

COMES NOW, Austin Energy (AE) and files this Closing Brief pursuant to Base Rate Review Procedural Guideline G2(c) and respectfully shows as follows:

I. INTRODUCTION

AE is a municipally owned utility (MOU) with a mission to safely provide clean, reliable, affordable energy and excellent customer service. AE takes pride in having served the community for over 125 years. To continue to meet its mission, AE must remain financially strong. Adoption of AE's proposals in this case will ensure that AE is able to fulfill this mission and continue to serve its customers and the growing community into the future.

Through this base rate review, AE is seeking to increase base rate revenue by $35.7 million. It also proposes revisions to its outdated residential rate design to stabilize revenues and more equitably recover its costs. These proposals are based on a Cost of Service (COS) Study that compares the base revenue requirement for the test year ending September 30, 2021, adjusted for known and measurable changes, to the revenue generated by current base rates, which were previously set based on a 2014 test year. AE then calculated the difference between these two balances to determine the proposed changes in AE's base rates. The COS Study confirmed that AE's base rates and base rate structures are not meeting the costs of serving its customers. In particular, current residential base rates do not appropriately recover costs.

AE initially proposed to increase its base rates by $48.2 million. After thoroughly vetting the cost of service and working with participants through the Base Rate Review process, AE made adjustments totaling $12.5 million.[1] As a result of these changes, AE has reduced its request to

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[1] As discussed in the rebuttal testimonies of AE witnesses Rabon and Gonzalez, adjustments were made to nuclear decommissioning expense, interest on nuclear decommissioning, late payment fees, GFT, and Build America Bond (BAB) subsidy, reducing AE's request to $35.7 million. In addition, AE agreed to functionalize new service connection revenues to the customer function, rather than demand.

$35.7 million. Additionally, the COS Study results suggest that changes to the current base rate class structures are both warranted and necessary. To address these findings and bring base rate financials back into balance, AE is proposing to:

- Increase base rate revenues by $35.7 million to account for higher costs and growth;
- Update an outdated residential base rate structure, which does not accurately recover the costs to serve customers;
- Better recover fixed costs by relying less on energy sales; and
- Bring customers closer to what it costs to serve them, establishing more equitable charges as the community continues to grow.

In this proceeding, AE is proposing to increase base rates for the first time since the 2012 Base Rate Review and only the second time since 1994.[2] The most recent Base Rate Review in 2016 was a decrease of $42.5 million. Additionally, since AE's last Base Rate Review, Fiscal Year (FY) 2014, prices, as measured monthly by the Consumer Price Index for All Urban Consumers: Fuels and Utilities from the St. Louis Federal Reserve, have increased 16.5 percent while rates have remained unchanged.[3] In the last 12 months alone, prices have increased 15 percent.[4]

Adoption of the proposed changes will ensure AE's financial stability, allowing the utility to continue delivering affordable, reliable electric service to its customers. As discussed by AE's witnesses, changes are needed for several reasons. First, AE has lost $90 million over the past two years in part due to an outdated base rate structure and declining average consumption in addition to rising costs in materials and equipment. Second, the current financial condition has resulted in less than 150 days of cash on hand in violation of the City's financial policies. Furthermore, in response to AE's deteriorating financial condition, on June 28, 2022, Fitch Credit Ratings downgraded AE from 'AA' to 'AA-.' Fitch cited AE's elevated leverage, which has steadily increased during the past three years, and weaker operating cash flows primarily driven by lower base rate revenues that contributed to the utility's rising leverage. Notably, this downgrade assumes approval of the original $48.2 million base rate increase proposal.

There are 14 participants in this case. Of those, ten filed position statements, and six took exception to AE's proposed revenue requirement. Those adjustments ranged from $11 million to

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[2] The 2012 Base Rate Review resulted in a 6.4 percent *increase*. In the 2016 Base Rate Review, base rates were *reduced* by 6.7 percent.

[3] AE Ex. 3 at 5.

[4] *Id*.

$41.7 million. Acceptance of the majority of the participants' adjustments to the revenue requirement would accelerate the deterioration of AE's financial position, decrease AE's operating cash flow, force AE to expend its cash and reserves, and increase its debt. Adoption of AE's base rate proposal is necessary to preserve AE's financial health.

In addition to the need for increased base revenues, it is also imperative to revise the current residential base rate design in order to stabilize revenues and more equitably recover costs. Accordingly, AE is proposing to:

- Reduce the number of residential base rate tiers from five to three and flatten the tiers;
- Eliminate the base rate differential between inside (inside-city) and outside City of Austin (outside-city) customers;
- Eliminate the billing unit adjustment that currently benefits low load factor commercial customers; and
- Increase fixed charges for revenue stability, including increasing the residential Customer Charge from $10 to $25.

These changes are necessitated by unprecedented customer growth, resulting in high infrastructure investment, combined with declining residential average energy sales. Despite the large increase in the number of customers, AE's load growth revenue has not kept pace.[5] Customer growth brings increased utility infrastructure investment and costs, but AE's base revenues have lagged. The disparity is due in part to customer demographic trends, including the increasing share of multi-family housing—such as downtown condos and apartments—as compared to single-family homes. Overall, the housing mix has increasingly become smaller and more energy efficient.

Declining average electric consumption has kept energy sales flat despite customer growth. Revenue growth is hampered by outdated base rate designs that rely too heavily on energy sales, particularly in the residential class. Most residential customers are billed on a steep five tier structure with each tier priced progressively higher. The first and second tiers are priced below cost and are subsidized by the fourth and fifth tiers that are above cost. More than 40 percent of residential customers are being subsidized by other residential customers.[6] Moreover, there are simply not enough customers with consumption in the higher tiers to make up the revenue deficit from the under recovery in the lower tiers as more and more customers use less energy due, in part,

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[5] AE Ex. 1 at 8.

[6] AE Ex. 3 at 12, *citing* AE Ex. 1 at 289.

to the evolving housing stock. Additionally, certain commercial customers are paying more than the costs to serve them. Accordingly, AE proposes moving these rate classes closer to COS. AE is mindful of rate impacts on customers and the need for gradualism. As such, AE proposes moving the residential class 50 percent to cost rather than moving them all at once.

In response to AE's proposed residential base rate design changes, participants present three basic recommendations: (1) leave the base rate design unchanged, (2) direct AE to develop a new proposal, or (3) make only minor changes to the current base rate design. These positions are not reasonable. AE's current residential base rate design is based on a 2009 test year. Residential consumption has changed greatly over the intervening 13 years. In this period, the number of customers with kilowatt hour (kWh) consumption in lower tiers, priced below COS, has increased. This change in consumption renders AE's current residential base rate design ineffective at recovering costs. Therefore, AE is proposing fundamental, necessary changes to the customer charge and the residential tier structure to address these deficiencies, and participants' recommendations are therefore unworkable.

AE's residential base rate proposal is compliant with its financial policies and bond covenants and is consistent with ratemaking principles, including gradualism. The higher Customer Charge removes most customer-related fixed-cost recovery from kWh sales. The new tier structure better reflects current customer consumption, while continuing to send efficiency signals. The proposal also reduces intra- and interclass subsidies, enhances revenue stability, and reduces customer bill volatility.

Finally, separate from base rates, AE is proposing a new approach that provides greater transparency and flexibility for its Value of Solar (VoS) rate design that fairly compensates customers for their onsite renewable energy production and adequately stimulates customer-sited solar adoption to help meet the City's Resource Generation and Climate Protection goals. Some components historically used to calculate the VoS rate are based on assumptions that no longer align with AE's underlying costs. Therefore, AE proposes a new methodology that more accurately allocates costs in accordance with standard utility ratemaking practices. AE remains committed to its goals, and with these changes AE will continue to be a national leader in the development of solar, demand-side management, and renewable energy initiatives.

AE's proposal carefully balances the interests of customers and the utility. As discussed in this brief, AE has met its burden of proof in seeking an increased revenue requirement and revised base rate design. AE's proposal should be adopted.

II. REVENUE REQUIREMENT

A. Approach

AE's revenue requirement is developed using actual historical costs from the most recent FY. Because a natural time lag exists between the end the historical test year and the time when a COS Study is performed, it is common industry practice to adjust historical test year information based on current concrete knowledge available at the time of the study. These adjustments reflect changes in system costs, revenues, or customer composition that are "known and measurable."[7] AE's budget facilitates certain known and measurable adjustments, such as personnel costs, equipment, or supply cost increases. These adjustments are made to historical accounting records to establish rates based on costs that reflect current operating conditions. In other instances, AE annualizes certain costs that were incurred for part of the historical year to reflect a full 12 months of operations.[8]

In a number of instances in this case, participants have taken issue with "known and measurable" adjustments proposed by AE. Significantly, they have not challenged the reasonableness of the actual test year expenses. As discussed below, each of the post-test year adjustments made by AE are quantifiable and reflect investment or expense that either is used and useful in the delivery of electric service or will become so prior to the effective date of the supporting base rate structure. Accordingly, the participants' recommended disallowances should not be adopted.

B. Cash Flow Methodology

AE uses the cash flow method to develop the return component of its total revenue requirement.[9] Under this method, the total revenue requirement includes the gross annual cash AE needs to operate, maintain, and capitalize the utility, including the cost of operations and

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[7] To make such an adjustment, the utility must show that (1) the adjustment is quantifiable and (2) the adjustment reflects investment or expense that either is used and useful in the delivery of electric service or will become so prior to the effective date of the supporting rate structure.

[8] AE Ex. 1 at 27.

[9] *Id.* at 28.

maintenance, transfers and shared services, cash funded capital, funding for decommissioning obligations, replenishment of reserve funds (if needed), annual debt service payments on bonds, satisfying debt covenants, and financial policies. For public power utilities like AE, the cash flow method is frequently used to develop the return component.

NXP Semiconductors, Inc. (NXP) witness Loy contends that AE's inclusion of depreciation and amortization in the development of the return under the cash flow approach was in error.[10] In fact, it is Mr. Loy who is incorrect. As Mr. Loy recognizes, the Public Utility Commission of Texas (Commission) has promulgated a Transmission Cost of Service Rate Filing Package for Non-Investor Owned Utilities.[11] The section discussing Schedule C-3 in this document contemplates use of the cash flow approach. There is also a section discussing Schedule E-1, which accounts for depreciation expense. Both are requirements of the rate filing package for non-investor owned utilities making a filing at the Commission. Because depreciation is a part of the expenses included by the utility, the cash flow approach must recognize this non-cash expense when developing the cash flow return, as AE has done.[12] AE's approach is consistent with every non-investor owned utility transmission rate filing at the Commission that has utilized the cash flow approach, including AE's last full filing.

While it was pointed out at the Final Conference that Brownsville Public Utilities Board filed a transmission rate filing at the Commission under the cash flow approach and did not include depreciation, this is not a common way to file such a request and it makes the resulting fallout rate of return incomparable with other non-investor owned utilities. In essence, Mr. Loy's approach places both the return of and the return on utility plant investment into the return amount. This makes the resulting return dissimilar from the returns of other utilities, which obtain return of investment through depreciation and return on investment through the calculated return.

As discussed in AE witness Rabon's rebuttal testimony, even if Mr. Loy were correct in removing depreciation and amortization from the development of the revenue requirement, the implied return on rate base would increase, but it would not have any impact on the overall revenue requirement.[13] This is because removal of depreciation and amortization amounts from the

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[10] NXP Ex. 1 at 51-54.

[11] *See* Instructions for Transmission Cost of Service Rate Filing Package for Non-Investor Owned Transmission Service Providers in the Electric Reliability Council of Texas (Non-IOU TCOS RFP) https://www.puc.texas.gov/industry/electric/forms/rfp/Non_IOU_TCOS_Instr.pdf.

[12] AE Ex. 6 at 21.

[13] *Id.* at 22.

analysis increases cash needs by the same amount. Thus, the resulting revenue requirement is unchanged.[14] This is in contrast to the utility basis relied upon by investor owned utilities (IOUs) to develop the revenue requirement, where the return on rate base would be relevant.

AE did not use the utility basis in developing the revenue requirement because it does not have a profit motive. AE is a not-for-profit entity, so the application of the utility basis can be complicated by difficulties in determining the appropriate return. The cash flow approach is better aligned with the key considerations for a MOU, such as AE. Given this situation, it is unclear why Mr. Loy is concerned with the implied return on rate base at all. He may want to make AE's request appear unreasonable by framing it in a way that is inconsistent with common utility practice, or he does not understand the cash flow approach. Regardless, Mr. Loy's recommendation is irrelevant and should be ignored.

1. **Operation and Maintenance Expenses**

a. **311 Call Center Staffing**

The 311 Call Center is the 24 hours per day, 365 days per year contact center to connect City of Austin residents and customers to city services and information.[15] The 311 Call Center also acts as a back-up for utility outage call support during storms/events and after hours.[16] The utility contact center operates Monday through Friday from 7 a.m. to 9 p.m., and on Saturdays from 9 a.m. to 1 p.m.[17] On weeknights, the 311 Call Center functions as the AE outage call handler for ten hours of each 24-hour period, from 9 p.m. to 7 a.m.[18] On weekends and holidays, the 311 Call Center handles outage calls from 1 p.m. on Saturday until the Utility Contact Center opens at 7 a.m. on Monday.[19] Costs associated with the 311 Call Center are allocated to city departments, including AE based on the total duration of all calls in minutes consistent with cost causation.[20]

Test year operations and maintenance (O&M) expenses for the staffing of AE City of Austin Utilities Contact Center and back office personnel as well as the 311 Call Center totaled \$8,372,198.[21] Austin City Council approved negotiation and execution of a new five-year staffing

[14] *Id.*
[15] AE Ex. 5 at 6.
[16] *Id.*
[17] *Id.*
[18] *Id.*
[19] *Id.*
[20] *Id.* at 7.
[21] *Id.* at 4.

contract for the call center in February 2022, which has an expected annual cost of $13,754,724, resulting in a known and measurable change to the test year in the amount of $5,382,525 (i.e. $8,372,198 + $5,382,525 = $13,754,724).[22]

Independent Consumer Advocate (ICA) witness Effron stated that the basis for AE's known and measurable adjustment is an estimate of the annual expense under the new contract and that the full staffing level outlined in the contract document has not been met at this point.[23] Mr. Effron reduced the AE known and measurable adjustment by $2,880,623 to reflect that, as of April 2022, AE had filled 185 of the 234 employees reflected in the supporting document for the call center staffing known and measurable adjustment.[24] As discussed in AE witness Galvan's testimony, Mr. Effron's adjustment should be rejected for at least two reasons. First, the new five-year staffing contract was executed in February 2022. Therefore, the contract is a known agreement. Second, AE has continued to fill positions and "anticipates meeting the full staffing level outlined in the contract by 2023, which would align with the timing of the implementation of the base rates approved from this Base Rate Review."[25] Therefore, the amounts in the contract are quantifiable and reflect expenses that would be incurred prior to the effective date of the supporting base rate structure.

2WR argues that the 311 Call Center is not a reasonable expense because AE has invested in digital meters, and thus there is no need for a call center for AE to learn of outages.[26] As noted in AE witness Galvan's rebuttal testimony, 2WR fails to recognize that the 311 Call Center provides services above and beyond the benefits of digital meters.[27] AE customers can call to report an outage and ask questions about an outage at a residence, a downed wire on a street, to request additional information on restoration efforts, and inquire about other matters or issues that cannot be addressed by information received from a digital meter.[28] Similarly, after-hours surcharge amounts should not be excluded from the annual operating costs of the 311 Call Center allocated to AE as asserted by 2WR.[29] Providing electricity is a 24-hour per day, seven days per week business, and customers need to be able to contact AE at any time. The 311 Call Center

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[22] *Id.* at 5.
[23] ICA Ex. 2 at 11-12.
[24] AE Ex. 5 at 10-17.
[25] *Id.* At 6.
[26] 2WR Brief at 5.
[27] AE Ex. 5 at 7.
[28] *Id.*
[29] 2WR Ex. 1 at 5-6.

provides that service for specific evening and weekend hours to ensure comprehensive service to customers. After-hours surcharges are necessary for staffing the 311 Call Center and are an appropriate cost to be included in the operation of the center.

2WR asserts that Mr. Galvan did not opine about the reasonableness of either the 311 Call Center costs or the Center's surcharge to AE.[30] In truth, Mr. Galvan provided very specific examples at the Final Conference demonstrating that AE should be responsible for the cost to handle after hour and weekend calls.[31] 2WR also complains about the allocation of 311 Call Center costs because "not all customers utilize this service, many don't."[32] While it is true that not all customers call the 311 Call Center, all customers have the ability to access the 311 Call Center if needed. As such, it is preferable public policy to recover the costs from all customers. Finally, it appears that 2WR may believe that costs unrelated to AE customers are being recovered in AE's base rates. While the 311 Call Center, in total, may benefit the community, the costs being requested in base rates are the costs of serving AE customers specifically—not a community benefit as alleged by 2WR.

b. Uncollectible Expense[33]

AE made a known and measurable adjustment to uncollectible expense of ($7,837,013).[34] This downward adjustment is related to the adjustment made to Other Revenues—Facilities Rental revenue, as addressed in Section II.B.9, below.

ICA witness Johnson proposes to reduce uncollectible expense by an additional $1,419,161. According to Mr. Johnson's testimony,[35] the uncollectible expense balance was influenced by the impact of COVID and Winter Storm Uri. Mr. Johnson proposes an adjustment because of the difficulty of determining the impact of COVID and Winter Storm Uri on the test year. As noted in AE witness Gonzalez' rebuttal testimony, there is no indication that a three-year average is more appropriate than the actual test year data.[36] In addition, the impact of the pandemic

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[30] 2WR Brief at 8.
[31] Tr. (July 15) at 6:7-33 (AE Rebuttal).
[32] 2WR Brief at 8.
[33] "Uncollectible Expense" may also be referred to as "Bad Debt."
[34] AE Ex. 1 at App. 127.
[35] ICA Ex. 3 at 15-16.
[36] AE Ex. 4 at 8.

is ongoing and neither AE nor any other participant can predict the end of the pandemic or the possibility of any future events.[37] For these reasons, Mr. Johnson's proposal should be rejected.

c. Heavy Equipment Lease

AE made a known and measurable adjustment of $7,421,233 to the heavy equipment lease test year expense amount.[38] In response, ICA witness Effron proposes a downward adjustment of $7,344,072 based on FY 2022 costs.[39] For the reasons discussed in Mr. Dombroski's rebuttal testimony, Mr. Effron's recommendation should be rejected.

The Altec lease has been the historical method by which AE acquires heavy equipment for operations and has been utilized since 2007. The current agreement is a fully executed lease contract. It provides annual extensions that are set out in the contract. Each August, City Council approves operating budgets on an annual basis that include the extensions. It has done so since the execution of the first lease agreement in 2007. Although City Council "authorizes" the extensions annually, the financial obligations are set out in the original binding contract. As such, the adjustment meets known and measurable criteria as set out in the executed contracts and extensions.

d. Non-Nuclear Decommissioning

City of Austin Financial Policy No. 21 requires AE to set aside funds to pay for the eventual retirement and decommissioning of the utility's non-nuclear generation fleet.[40] The non-nuclear fleet comprises the Decker Creek Power Station, the Fayette Power Plant (FPP), the Nacogdoches Power Plant (Nacogdoches), and the Sand Hill Energy Center. Funds must start accumulating no later than four years prior to commencement of decommissioning activities. In principle, AE would start collecting decommissioning funds as soon as a plant is energized; however, that has not been the practice to date. Thus, in the 2016 Base Rate Review, AE initially proposed to add $19.4 million of additional revenue to cover future decommissioning expenses. The cost estimates were developed and reported by NewGen Strategies and Solutions in a July 2015 study that examined the entirety of AE's reserved funds and policies. Ultimately, the 2016 case settled with

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[37] *Id*.
[38] AE Ex. 1 at 39.
[39] ICA Ex. 2 at 10.
[40] AE Ex. 1 at 371.

AE agreeing to include $8 million in base rates for non-nuclear decommissioning.[41] AE has reserved $8 million each year since that time.[42] Despite inflation and the acquisition of the Nacogdoches facility since the last case, AE proposes no change to the $8 million funding level approved six years ago.

In response to AE's proposed decommissioning expense level, ICA witness Effron recommends reducing the amount of non-nuclear decommissioning to be recovered in base rates to $2 million.[43] Despite his significant reduction, during the Final Conference, Mr. Effron confirmed that he did virtually no examination of the facts to determine whether his recommendation is reasonable.[44] For example, in the 2016 Base Rate Review, the ICA recommended a total decommissioning expense level of $9.89 million.[45] Mr. Effron was unaware of this fact. Furthermore, he was unaware how many generating units are scheduled for decommissioning. Perhaps most troubling is the fact Mr. Effron was unaware of the existence of the Nacogdoches plant or the need to decommission it.[46]

Instead, Mr. Effron simply referenced the July 2015 decommissioning study performed for AE and then made a series of assumptions that arrived at a suggested $2 million reserve contribution. Mr. Effron's assumptions are unreasonable and unsupported. For example, his analysis starts by calculating a mid-point estimate of the cost of decommissioning each generation unit based on the low range and high range estimates from the 2015 decommissioning study.[47] This fails to recognize that the cost to decommission a generation unit has increased since 2015 due to inflation and that the decommissioning costs are estimate. Thus, the actual cost of decommissioning may be significantly higher. He also did not take into account AE's prior history with decommissioning the Holly Power Plant, which was longer, more extensive, and more expensive than originally estimated.[48] Regarding the decommissioning of the Holly Power Plant, it is instructive to note the original estimate was $19 million, but the total actual cost was approximately $32 million.[49] Further, AE is now planning for the eventual decommissioning of

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[41] AE Ex. 6 at 14.
[42] *Id.*
[43] ICA Ex. 2 at 5-7.
[44] Tr. (July 14) at 65:39-45−66:1-14 (Effron Cr.).
[45] The ICA in 2016 is the same individual acting as the ICA in the current case.
[46] Tr. (July 14) at 66:30-44 (Effron Cr.).
[47] ICA Ex. 2 at 4-7.
[48] AE Ex. 6 at 14-15.
[49] *Id.*

Nacogdoches, which was not included in the 2015 decommissioning study because AE did not own the facility at the time.[50] As noted, Mr. Effron's analysis does not capture this generation plant.

Because the actual future cost to decommission AE's non-nuclear plants is unknown, decommissioning funding is an estimate.[51] If the $8 million annual figure proves to be too low, AE will have to find additional funds, such as issuing debt, to pay for the decommissioning obligations for generation units at the time of retirement. This is likely to involve funding by future customers that may never have benefited from the generation units when they were in service. This presents an intergenerational equity issue. On the other hand, if the $8 million figure proves to be too high, AE can holdover funds to decommission the next non-nuclear unit to be decommissioned. If, in the future after retiring a unit, it appears that the $8 million per year is going to over-fund this obligation long-term, the amount can be reduced. However, there is currently no indication that $8 million annually is going to over-fund this obligation. Inflation and AE's past experience with the Holly Power Plant would suggest the $8 million figure will prove insufficient to fully fund this obligation. Fully funding the non-nuclear decommissioning reserve is the best way to mitigate intergenerational equity concerns. This allows current customers that benefit from the generation plants to bear some of the cost responsibility for decommissioning the plants. To the extent AE has insufficient funds to decommission generation plants at the end of their useful lives, it could necessitate charging future customers that do not benefit from the generation plants to pay for this expense.[52]

e. Winter Storm Uri and COVID Expenses

It is undisputed that Winter Storm Uri was an exceptional event. This fact does not mean, however, that storm costs associated with it were exceptional or abnormal. AE experiences storm outages every year and substantially all of the resources used in the Winter Storm Uri response are utilized in the normal course of the year, including regular storm response.[53] The power outage associated with Winter Storm Uri lasted over an extended period of time, but that was due primarily to Electric Reliability of Council of Texas (ERCOT)-directed load shed. While AE also

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[50] *Id*. at 14.
[51] *Id*.
[52] *Id*. at 16.
[53] AE Ex. 2 at 5.

experienced storm-related outages, the expenses associated with those outages were not exceptional as compared to other years.[54] Accordingly, AE did not adjust its revenue requirement for storm costs associated with Winter Storm Uri. In contrast, ICA witness Johnson, Texas Industrial Energy Consumers (TIEC) witness Pollock, and 2WR all propose adjustments to AE's revenue requirement for storm costs related to Winter Storm Uri. For the reasons stated in AE witness Maenius' rebuttal testimony and below, the participants' recommendations should be rejected.

ICA witness Johnson recommends amortizing $6.8 million dollars in Winter Storm Uri expense over five years and to include only one-fifth of that amount, or $1.36 million, in the test year revenue requirement.[55] Mr. Johnson stated that Winter Storm Uri was not a routine or "normal" winter storm and should be considered abnormal for ratemaking purposes.[56] As noted above, AE has storm outages on its system every year and substantially all of the resources used in the Winter Storm Uri response are utilized in the normal course of the year, including regular storm response. While AE experienced significant storm-related outages, the *expenses* associated with those outages were not exceptional as compared to other years.

ICA witness Johnson's recommendation is based on AE's response to ICA Request for Information (RFI) 4-12.[57] The $6.8 million in expenses he proposes to disallow are comprised of $4.3 million related to labor and benefits, $1.2 million related to overtime, and $1.3 million related to contract labor. In his rebuttal testimony, AE witness Maenius responded by explaining that AE regularly incurs labor, overtime, and contractual labor costs during the course of the year, including during periods of storm restoration. Mr. Maenius further addressed each of the three expenses comprising Mr. Johnson's disallowance.[58]

With respect to the $4.3 million in labor and benefits, Mr. Maenius testified that these "were regular wages and benefits paid to Austin Energy employees who would have been paid during the period that Winter Storm Uri occurred regardless of whether the storm had happened or not."[59] As such, these costs are part of normal operations and should not be removed from the COS. Similarly, Mr. Maenius explained that the $1.2 million in overtime costs are identical to

[54] *Id*.
[55] ICA Ex. 3 at 14-15.
[56] Mr. Johnson did not contest the reasonableness of the overall test year costs.
[57] AE Ex. 2 at 17.
[58] *Id*. at 6-8.
[59] *Id*. at 6.

those AE regularly incurs during normal operations and annual storm outages. As demonstrated by Mr. Maenius, overtime costs incurred by AE during the test year are consistent with historical overtime over the last five years, especially in light of yearly wage increases and rising job vacancies. Finally, Mr. Maenius explained that the $1.3 million in contractual labor costs during Winter Storm Uri restoration were attributable to vegetation management companies for their services. Notably, AE paid less to these contractors in total during the test year than in the previous year and not abnormally more than the two prior years.[60] Therefore, ICA witness Johnson's proposed adjustment should be rejected.

Notably, ICA witness Johnson provided no proof that restoration costs incurred during the test year are atypical. Instead, Mr. Johnson bases his recommendation on his assertion that Winter Storm Uri was not a normal storm. Although Winter Storm Uri was exceptional in many ways, its impact on AE's labor, overtime, and contract costs was similar to that experienced frequently on a yearly basis due to less extreme events. Even a cursory review of the costs shows that Mr. Johnson's recommendation is flawed when $4.3 million of the $6.8 million is associated with regular wages and benefits that would have been paid to AE employees regardless of whether Winter Storm Uri or any other storm would have occurred.

2WR and TIEC witness Pollock also discuss Winter Storm Uri. Mr. Pollock's testimony on Winter Storm Uri addresses proposed changes to test year billing determinants, which is addressed in the rebuttal testimony of AE witness Murphy and in Section II.C below. 2WR makes a recommendation concerning late payment fees associated with Winter Storm Uri, which is addressed in the rebuttal testimony of AE witness Gonzalez and in Section II.B.8.a.

f. Rate Case Expense

AE proposes to collect $1,791,000 in rate cases expense associated with this proceeding over a three year amortization period (i.e. $597,015 x 3 years = $1,791,000).[61] No participant has objected to the reasonableness of the requested amount. However, ICA witness Effron[62] and 2WR[63] propose a five-year amortization period for the recovery of rate case expenses. Under the City of Austin's Financial Policy No. 17 "[a] rate adequacy review shall be completed every five

[60] AE Ex. 2 at 7.
[61] AE Ex. 1 at App. 129.
[62] ICA Ex. 2 at 8.
[63] 2WR Ex. 11 at 5.

years, at a minimum, through performing a cost of service study."[64] The policy does not prohibit AE from conducting a COS study in a shorter timeframe, and a three-year amortization period helps ensure that there is not an over-lapping of rate case expense recovery periods between filings.[65]

A three-year amortization is typical of the period over which other utilities collect rate case expenses. This is reasonable because it balances the interests of the utility in obtaining cost recovery with the interests of ratepayers by mitigating rate impacts and spreading the cost over the period that rates are likely to be in effect. This is important because AE's proposal avoids expense recovery from one proceeding overlapping with the recovery of expenses from a subsequent rate case. This is particularly important for AE because, although it has a financial policy to conduct a COS study at least every five years, the policy does not prohibit AE from conducting one on a shorter timeframe. Furthermore, preparation of a COS study and rate application, conducting public outreach, and the formal Impartial Hearing Examiner (IHE) process typically takes well over a year. Rate case expenses are incurred throughout this period. For these reasons, a three-year amortization period for rate case expenses is the most appropriate and should be adopted.

g. Town Lake Center

The Town Lake Center (TLC) is a commercial building on Barton Springs Road purchased by AE in 1989 and used as a headquarters building until April 2021, when AE acquired a new building in the Mueller Development to use as its headquarters. AE continues to maintain certain information technology equipment at TLC. According to Mr. Dombroski's rebuttal testimony, AE anticipates that it will transfer use of TLC to the City of Austin Financial Services Division (FSD) for general municipal purposes in FY 2023, but has not finalized the terms of the transfer nor executed a memorandum of understanding for the transfer.[66] Because TLC is currently owned by AE, no adjustment to the revenue requirement was made to reflect potential proceeds from the sale of the facility.[67] Despite the fact TLC has not been transferred to the FSD, 2WR proposes to amortize $30.5 million as an offset to AE's revenue requirement.[68] 2WR's proposal should be

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[64] AE Ex. 1 at App. 21.

[65] Ironically, in the 2016 Base Rate Review, ICA witness Johnson proposed that AE conduct COS studies more frequently than the five years prescribed in the financial policy.

[66] AE Ex. 3 at 20.

[67] AE has removed all operating costs of TLC from the revenue requirement and therefore no costs have been allocated to base rates.

[68] 2WR Ex. 1 at 5.

rejected for several reasons detailed in Mr. Dombroski's rebuttal testimony. First, AE and FSD have not entered into or agreed to a memorandum of understanding for the sale and transfer of TLC. Second, AE and FSD have not specified the amortization period, interest rate, or payment schedule.[69] Therefore, 2WR's proposal does not meet the criteria of a known and measurable adjustment and must be rejected.[70]

h. Other Expenses

FPP is a coal fired generation unit in Fayette County. AE jointly owns FPP units 1 and 2 with the Lower Colorado River Authority (LCRA). It is widely known that AE has attempted to exit its share of FPP, but so far has been unable to reach a mutually acceptable agreement with LCRA to do so.[71] As such, the plant is expected to continue to remain in service generating electricity for the foreseeable future. Significantly, AE's obligations under the City's participation agreement with LCRA continue. Nevertheless, counsel for Sierra Club, Public Citizen, and Solar United Neighbors (SCPC/SUN) devoted considerable time at the Final Conference suggesting that it is "ironic" that costs associated with FPP remain in base rates. Although it is unclear, it appears that SCPC/SUN's recommendation to disallow FPP costs is based more on environmental policy rationale as opposed to applying appropriate ratemaking principles.[72] In its brief, SCPC/SUN takes this argument further claiming that all of the costs of FPP should be disallowed because "there is no evidence in the record supporting the prudence of the utility's continued investment in th[e] plant."[73]

Excluding the costs associated with AE's continued ownership and operation of FPP from base rates would be confiscatory and at odds with basic ratemaking principles. Until AE is able to exit its share of FPP, AE has obligations under the Participation Agreement with LCRA.[74] FPP is operational and provides benefit to AE's customers and the ERCOT grid. Costs to operate and

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[69] AE Ex. 3 at 21.

[70] If, however, an adjustment would be made as a result of the proceeds, then a reduction would be made to internally generated funds for construction in Schedule C-3.

[71] *See* Austin Energy Announces Update to Generation Portfolio (Nov. 1, 2021) https://austinenergy.com/ae/about/news/news-releases/2021.

[72] This assumption is consistent with a statement attributed to Public Citizen in an Austin Monitor article dated July 1, 2022. *See* https://www.austinmonitor.com/stories/2022/07/environmental-advocates-say-fayette-coal-plant-is-poisoning-residents-push-city-to-test-water/.

[73] SCPC/SUN Brief at 2, 5-10.

[74] AE Ex. 3 at 68.

maintain FPP included in the revenue requirement are reasonable and necessary based on ratemaking and cost recovery principles and should be approved.

Contrary to SCPC/SUN's claims, AE presented evidence supporting the reasonableness of the costs. For example, at page 29 of the Base Rate Filing Package (RFP) it states that "O&M expenses reflect all the costs required to operate and maintain the utility; provide efficient and reliable electric service to customers, including providing excellent customer service; and all maintenance and repair of utility assets."[75] On the following page, AE singled out power production costs which include FPP fuel, labor, routine maintenance, system control, and dispatch costs.[76] The O&M expenses for FPP were not separately identified in the RFP because AE did not make an adjustment to the historical FY 2021 amount. AE also provided the capital spending for FPP in the RFP as seen below:[77]

Fund Acct	Description	Actual FY 2019	Actual FY 2020	Actual FY 2021	Three-Year Average
		(A)	(B)	(C)	(D)
Fund 3080	Fayette Power Plant (FPP)	601,521	4,255,880	763,099	1,873,500

As can be seen in the chart above, the test year amount was based on the three-year average of *actual* historical expenses. Finally, AE is not the sole owner of FPP and, in fact, does not directly operate the plant. Although AE has some oversight responsibilities as a participant, the day-to-day spending decisions are made by the operator (i.e. LCRA) and AE has a contractual obligation to pay its allocated share of these costs. Thus, AE cannot unilaterally decide that it wants to spend less on FPP as it can on other generation that it owns. In summary, the costs associated with FPP are supported by the evidence. So long as the plant remains used and useful, it is appropriate for the costs associated with the plant to remain in AE's rates.

In his Statement of Position, participant Paul Robbins proposed that lowering the cost of Nacogdoches be analyzed.[78] In his brief, Mr. Robbins proposed "2 potential points of savings" associated with the plant.[79] Mr. Robbins conditioned his recommendation on the plant being included in base rates. In response, AE witness Dombroski testified that costs associated with

[75] AE Ex. 1 at 29.
[76] *Id.* at 30.
[77] AE Ex. 1 at App. 93.
[78] P. Robbins Ex. 1 at 11.
[79] P. Robbins Brief at 10.

Nacogdoches are *not* included in base rates. They are recovered through the Power Supply Adjustment (PSA), which is outside the scope of this rate review. The purpose of the rate review is not to explore whether gains in efficiency for specific power generation assets are attainable. Consequently, Mr. Robbins' recommendations are not ripe for consideration in this case.

2. Depreciation Expenses and Amortization of Contributions in Aid of Construction

Contributions in Aid of Construction (CIAC) are contributions from customers that offset the cost of building infrastructure. CIAC revenues reduce the revenue requirement of a utility. AE has reflected CIAC it has received on Schedule C-3 and the associated workpapers in the RFP.[80] Despite this transparency, 2WR states that it "has yet to receive answer to how AE books and tracks the CIAC funded capital or how it is treated in the COS.[81] AE responded to 2WR's questions about CIAC at both the second technical conference[82] and in its response to 2WR RFI 3-7.[83] Furthermore, CIAC and its impact on base rates is discussed in Section 4.2.2 of the RFP.[84]

2WR and Paul Robbins raised issues related to CIAC. 2WR recommends that AE be required to track its capital paid for with CIAC for purposes of rate setting and that the IHE recommend City Council direct the Electric Utility Commission (EUC) to supervise a study addressing growth.[85] Mr. Robbins takes the position that AE is not following City Council's policy to have growth pay for itself. Both 2WR and Mr. Robbins misunderstand or mischaracterize the facts.

In 2014, City Council adopted a resolution (City Council Resolution No. 20140612-057) directing the City Manager to "plan for full cost recovery of line extensions, with an exception for certain affordable housing," which AE has done. Additionally, at its June 13, 2022 meeting, the EUC discussed the CIAC policy and the allocation of system growth costs. The EUC voted that City Council should review the CIAC policy and AE should provide a presentation to the EUC regarding the CIAC policy. Therefore, 2WR's recommendations are unnecessary as the EUC will be reviewing the CIAC policy over the next few months and making recommendations to City Council on possible revisions.

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[80] AE Ex. 1 at App. 86, 93-94, 97-98.
[81] 2WR Ex. 1 at 3.
[82] AE Responses to Questions Related to Technical Conference #2 at 22-24 (Bates 53-55) (May 27, 2022).
[83] AE Response to 2WR Third Request for Information at 48 (Jun. 22, 2022).
[84] AE Ex. 1 at 31.
[85] 2WR Ex. 1 at 3.

With respect to Mr. Robbins' argument, AE's CIAC policy as reflected in the design manual requires collection of 100 percent of the costs for line extensions and new infrastructure associated with requests for new electric service, with an exemption for certain affordable housing. A customer applying for new service will be charged all estimated costs for labor and material required to modify existing infrastructure and to extend service from AE's existing infrastructure to the customer's point of service to serve the requested load. This includes the service drop and meter. Mr. Robbins has provided no evidence that AE is not following the intent of City Council.

3. Capital Expenditures

Discussion of capital expenditures related to FPP may be found in Section II.B.1.h above.

4. Internally Generated Funds for Construction

Like most utilities, AE funds capital projects through a combination of cash (i.e. equity) and debt. Internally Generated Funds for Construction (IGFFC) represent the cash component available to help fund such projects. AE attempts to fund capital projects using a combination of 50/50 cash and debt.[86] This approach reduces overall carrying costs associated with higher levels of debt and is consistent with AE's financial policies. Specifically, Financial Policy No. 14 states that capital projects should be financed through a combination of cash and debt and that "[a]n equity contribution ratio between 35 percent and 60 percent is desirable."[87]

NXP witness Loy suggests AE change the IGFFC level so that it targets 35 percent rather than the 50 percent used by AE.[88] Although Mr. Loy's recommendation falls within the lower end of the range set out in Financial Policy No. 14, his recommendation fails to take into account other relevant considerations. First, the range of potentially acceptable funding in Financial Policy No. 14 has to be balanced with the other financial policies, such as Financial Policy No. 6, as well as AE's objective to maintain its credit rating. Further, AE was instructed, at the conclusion of the 2012 Base Rate Review,[89] to prospectively implement a policy of 50 percent funding for IGFFC. Thus, adopting Mr. Loy's suggestion would be contrary to the direction of City Council. Additionally, on June 28, 2022 Fitch downgraded AE to 'AA-.' Fitch cited AE's elevated leverage, which has steadily increased during the past three years, and weaker operating cash flows

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[86] AE Ex. 6 at 23.
[87] AE Ex. 1 at App. 21.
[88] NXP Ex. 1 at 54-56.
[89] *See* City of Austin Ordinance No. 20120607-055, Part 7 (Jun. 7, 2012).

primarily driven by lower base rate revenues that contributed to the utility's rising leverage.[90] Adoption of Mr. Loy's recommendation would result in even greater levels of debt and put AE at risk for additional downgrades.

TIEC witness LaConte observes that AE's financial policies do not mandate a particular IGFFC. Ms. LaConte suggests that IGFFC be reduced to 40 percent.[91] Although accurate, this observation overlooks City Council direction on this point. As discussed above, in 2012 the City Council approved a policy dictating that AE implement a policy of 50 percent funding for IGFFC. Further, this directive is in alignment with AE's other financial objectives. Therefore, the fact that the financial policies do not mandate a particular level of IGFFC is insignificant.

5. **General Fund Transfer**

Consistent with standard practice among MOUs and Texas Government Code § 1502.059, AE transfers a percentage of revenues to the City. AE makes transfers to the City's general fund in lieu of paying franchise fees, taxes, dividends; and also in lieu of earning a return on investment as is done with IOUs. The transfer payment from AE to the City is invested directly back into the local community, rather than flowing to outside investors, which is a benefit to residents in Austin and those in surrounding communities. AE's Financial Policy Nos. 12, 13, and 17 provide for and prescribe how the General Fund Transfer (GFT) is determined. Per Financial Policy No. 13, the GFT is based on 12 percent of AE's three-year average revenues using the current year estimate and the previous two years' actual revenues less power supply and district cooling revenues. The GFT is not based on earnings, margins, or profits.[92] The GFT is calculated and determined during the City's budget process. AE has made a GFT to the City since at least 1946.[93]

Coalition for Clean, Affordable and Reliable Energy (CCARE), Homeowners United for Rate Fairness (HURF), 2WR, NXP, and TIEC all presented arguments regarding the GFT. 2WR suggested that AE's proposed residential customer charge is inflated by the inclusion of the GFT, which 2WR describes as a "profit." 2WR also suggested that the GFT be allocated based on revenues.[94] The GFT is an expense to AE and not a profit. Thus, it is a real cost of doing business that must be recovered from customers. Cost elements become revenue requirement and are

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[90] AE Ex. 3 at 6.
[91] TIEC Ex. 3 at 13-15.
[92] AE Ex. 1 at App. 21.
[93] AE Ex. 3 at 16.
[94] 2WR Ex. 1 at 9-10.

therefore included in the GFT calculation. As the revenue requirement increases, so does the amount of the GFT.[95] Second, the GFT is functionalized based on revenue requirement (excluding PSA costs and non-electric costs) and then, for the portion that is functionalized to the customer function, sub-functionalized based on revenue requirement.[96] Thus, the portion of the GFT that ends-up in the customer charge has been allocated based on the revenue requirement.

TIEC witness Pollock suggests reducing the GFT in the test year revenue requirement to the average amount of the actual GFT in FY 2018, FY 2019, and FY 2020.[97] CCARE and NXP support Mr. Pollock's recommendation. Mr. Pollock misunderstands the way the GFT is calculated. As previously stated, AE does not have the discretion to reduce the GFT rate. Thus, AE cannot summarily change the GFT amount to a historical level. As such, Mr. Pollock's suggestions on the GFT must be rejected.

In HURF's brief it argues that the settlement agreement in PUC Docket No. 40627, the appeal of AE's 2012 Base Rate Review, precludes outside-city customers from being subject to the GFT.[98] This is incorrect. The settlement in Docket No. 40627[99] was a negotiated, "black-box" settlement that did not specifically address the GFT. The base rate reduction provided to outside-city customers in 2012 was through a general reduction to the revenue requirement, not through a reduction in GFT. The final settlement in PUC Docket No. 40627 section (25 [E]) goes on to say that "the Signatories agree that their request that the Commission enter an order consistent with the Agreement is the result of negotiation and is not intended to have precedential value with respect to any particular principle, treatment, or methodology that may underlie the Agreement." That agreement no longer creates an obligation on AE. Therefore, HURF's proposed reductions to rates for outside-city customers should be rejected.

HURF is also incorrect in claiming that the GFT should not apply to outside-city calculations.[100] The GFT is calculated in accordance with AE's Financial Policy No. 13.[101] Since revenue from outside-city customers is included in the calculation of the GFT, cost causation dictates that outside-city customers are allocated their share of this cost. Texas Government Code

95 AE Ex. 3 at 16.

96 Per AE Financial Policy No. 13, this is the basis for the calculation of the GFT.

97 TIEC Ex. 1 at 9.

98 HURF Brief at 1.

99 *Petition By Homeowners United for Rate Fairness to Review Austin Rate Ordinance No. 20120607-055*, Docket No. 40627, Final Order (Apr. 29, 2013).

100 HURF Ex. 1 at 1.

101 AE Ex. 1 at App. 21.

§ 1502.059, which specifically authorizes the transfer of revenue of any MOU to the municipality's general fund, does not distinguish between inside-and outside-city customers. Finally, HURF is misplaced in arguing that participants agreed in 2012 that outside-city customers derive no benefit from the City's expenditures of those funds.[102] While AE believes that all customers benefit from services resulting from the GFT, there is no requirement that AE be required to demonstrate any direct benefit to customers.[103] Additionally, HURF has provided no evidence to support its position that outside-city customers derive no benefit from the City's expenditure of the GFT.

During the Final Conference and in brief, certain participants referenced the GFT amount within the context of the City's ongoing budget process. In particular, certain participants noted that the City's proposed budget for 2022-2023 includes a GFT of $115 million in 2023 rather than the $121 million initially proposed by AE in this Base Rate Review. As discussed below, the correct GFT amount for purposes of this Base Rate Review is now $120 million after accounting for the other adjustments AE has already accepted.

The proposed FY 2023 budgeted GFT of $115 million is based on 12 percent of the three-year average revenues, minus revenues from PSA and District Cooling for FY 2020, FY 2021 and estimated revenues for FY 2022. The revenues for those years utilize existing base rates and not the proposed base rates, which would not be in effect until FY 2023. As shown on Work Paper C-3.2.1 of the RFP, the GFT amount of $121 million included in the Base Rate Review as originally filed is based on 12 percent of operating revenues, minus revenues from the PSA and non-electric business (rounded to the nearest $1 million).[104] However, rather than take a three-year average (two actual and one estimate) of revenue, as is done when establishing the GFT annually, the amount of the GFT in the Base Rate Review relied on the amount of revenue that is estimated from the test year only. This aligns the amount of the GFT with the base rates proposed. Because the GFT is recovered in base rates that may be in place for five years (or perhaps longer), it is important for the amount of the GFT to be paid during the time the proposed rates are in effect. The budget process is separate from the rate setting process. The budgeted GFT is calculated

[102] HURF Ex. 1 at 1.

[103] By way of comparison, IOUs pay dividends to shareholders regardless of their location without having an obligation to demonstrate its customers benefit from those payments. In contrast, the GFT is used to fund City services. For the purposes of allocating the GFT, it is irrelevant whether inside-city or outside-city customers directly benefit from these services.

[104] In AE's rebuttal case the GFT was reduced to $120 million as a result of the reduction in the overall revenue requirement.

pursuant to financial policies. The $120 million GFT is the amount AE would expect to pay over the tenure the proposed base rates are in effect. Failure to align the GFT with base rates could result in AE under-recovering this cost. The amount of GFT ultimately included in the revenue requirement will be based on the final revenue requirement adopted by City Council in November 2022.

6. **Debt**

a. Debt Service Coverage Ratio

Debt service coverage ratio is the ratio of cash available for servicing interest, principal, and lease payments to the total annual debt payments the utility is required to make. Significantly, the debt service coverage ratio does not impact the revenue requirement. Pursuant to Financial Policy No. 6, AE must target a debt service coverage ratio of not less than 2.0x on electric utility revenue bonds. Traditionally, utilities with lower debt ratios (i.e. less leverage) and higher debt service coverage ratios have higher credit ratings. Higher credit ratings result in lower borrowing costs for the utility, a savings that can be passed on to customers through lower annual debt service payments. In addition, a 2.0x coverage ratio aligns with debt service coverage ratios of other public power utilities across the country.

In her testimony, TIEC witness LaConte took issue with AE's service coverage ratio. Specifically, Ms. LaConte prepared a calculation that resulted in a debt service coverage calculation of 2.50x.[105] In order to reach her recommendation, Ms. LaConte removed non-electric revenue and expenses from her calculation. AE uses revenue bonds for its capital financing. These bonds are secured by all of AE's revenues, regardless of source. Therefore, it is inappropriate to exclude a source of revenue and its associated expenses from the debt service coverage ratio calculation.

AE's methodology to calculate debt service coverage is consistent with and complies with its financial policies and bond covenants. However, credit rating agencies, such as Fitch, make additional adjustments, resulting in a range of 0.90x-3.96x.[106] Ms. LaConte relies upon this range to substantiate her recommended debt service coverage ratio. As noted in AE witness Dombroski's rebuttal testimony, however, Ms. LaConte's comparison is an apples-to-oranges calculation. Her

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[105] TIEC Ex. 3 at 9; *See* Exhibit BSL-1.
[106] AE Ex. 3 at 27.

proposed debt service coverage calculation is inappropriate because it does not include all revenues and expenses as discussed above. Second, Fitch makes adjustments to its debt service coverage ratio that include items such as power purchase agreements and transfers.[107] Moreover, AE's rates are calculated in accordance with AE's financial policies and bond covenants, not by relying upon the Fitch Report.[108]

Finally, Ms. LaConte recommends that AE's return is unnecessarily high by calculating a return on equity and comparing that to regulated entities as a benchmark. She does this despite admitting that AE does not earn a return on equity.[109] It is inappropriate to calculate a theoretical return based on IOU methodology, which has a different capital structure than an MOU. This fact renders Ms. LaConte's analysis flawed. Nevertheless, Ms. LaConte calculates a 12.0 percent return on equity versus a benchmark of 9.38 percent.[110] Even assuming Ms. LaConte's methodology was appropriate, AE's implied return on rate base of 7.9 percent using the cash flow methodology is significantly lower that Ms. LaConte's calculation.[111] For all of these reasons, Ms. LaConte's recommendation should be rejected.

b. Credit Rating

AE's rates are calculated in accordance with the AE financial policies and bond covenants.[112] AE uses the cash flow methodology as outlined in Section 4.2 of the RFP and discussed in Section II.B above.[113] As noted in AE witness Dombroski's rebuttal testimony, AE does not set rates to achieve a certain credit rating. AE's credit rating is the result of prudent management and favorable market conditions and not a product of applying criteria for a specific credit rating in its ratemaking.[114] In addition, Financial Policy No. 6 stipulates that AE set its rates using the cash flow methodology which shall produce a minimum of a 2.0x debt service coverage;[115] however, AE made no adjustment to increase or decrease the proposed revenue requirement to achieve a specific level of debt service coverage.

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[107] AE Ex. 1 at App. 572-599.
[108] *Id*. at App. 20-22.
[109] TIEC Ex. 3 at 10.
[110] *Id*.
[111] AE Ex. 1 at App. 35.
[112] *Id*. at 20-22.
[113] *Id*. at 28-29.
[114] AE Ex. 3 at 23.
[115] AE Ex. 1 at App. 20.

In her testimony, TIEC witness LaConte took issue with AE's credit rating. By comparing AE's credit rating to four vertically integrated IOUs,[116] Ms. LaConte determined that AE is above investment grade status with a credit rating much higher than the four vertically integrated IOUs.[117] Based upon this analysis, Ms. LaConte takes the unusual position that it is not prudent for AE to have an 'AA' rating. Unfortunately, Ms. LaConte's testimony demonstrates a misunderstanding of how a MOU operates as related to its credit rating and debt service coverage. AE is an MOU and not an IOU. MOUs and IOUs have very distinct capital structures. AE does not have access to equity investments that IOUs enjoy. Ms. LaConte acknowledged this fact at the Final Conference.[118] MOUs rely upon cash from customers and retail rates as well as the sale of long-term debt (bonds) to fund capital needs. Therefore, the credit rating on debt is much more critical for an MOU than an IOU.

A lower credit rating would be harmful to ratepayers in a number of ways. The most obvious impact is that it would increase costs. According to Ms. LaConte's calculation, if AE were downgraded to an 'A' rating, AE's annual debt service cost would increase by $3.6 million per year.[119] A lower credit rating will also increase the cash collateral requirements on AE from its energy trading counterparties. A lower credit rating may also impact the favorable terms and conditions in vendor contracts. Not only would a lower credit rating raise costs, it is also contrary to the ratings of most utilities.[120] AE's former 'AA' rating was well within the norm of retail public power providers according to the Fitch Peer Review.[121] There are 80 total retail public power providers in the Fitch 2021 peer review.[122] Of those 80, 51 (or 64 percent) are rated between 'AA+' to 'AA-,' with 21 being 'AA.'[123] There are only eight (or 10 percent) retail public providers with ratings between 'A-' and 'BBB,'[124] which is the range of LaConte's IOUs.

7. **Cash Margin**

Not addressed.

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[116] TIEC Ex. 3 at 6.
[117] *Id*. at 7.
[118] Tr. (July 14) at 5:40-46-6:3-10 (LaConte Cr.).
[119] TIEC Ex. 3 at 8.
[120] AE Ex. 3 at 25.
[121] *Id., citing* AE Ex. 1 at App. 572-599.
[122] *Id*. at 576-580.
[123] *Id*.
[124] *Id*.

8. **Revenue Requirement Offsets**

a. **Late Payment Fees**

Late payment fees are revenues AE receives from customers who have been late in paying their electric bills. These revenues provide an offset to the revenue requirement. AE made no adjustment to test year late payment fee amount in the RFP. ICA witness Johnson proposed an upward adjustment of $2.2 million[125] and 2WR proposed a similar adjustment.[126] Specifically, Mr. Johnson excludes FY 2020 and FY 2021 due to the COVID pandemic and instead proposes an average of FY 2018 and FY 2019 to arrive at this late payment fees adjustment. As discussed in AE witness Gonzalez' rebuttal testimony, it is improper to use FY 2018 and FY 2019 because those are two years prior to the current test year of FY 2021 and will be four years prior to the FY once base rates approved in this proceeding become effective (FY 2023). 2WR's recommendation is similar in that they propose averaging of prior year late payment fees. These proposals should not be adopted because they do not accurately reflect the test year or more recent experience.

In her rebuttal testimony, AE witness Gonzalez acknowledged that the test year included only eight months of late fees due to AE waiving them in response to COVID and Winter Storm Uri.[127] As a result, Ms. Gonzales revised her recommendation to include a known and measurable adjustment to late payment fess of $1,154,575.[128] This was derived using a 12-month total of late payment fees billed beginning May 2021 through April 2022, which is after the expiration of COVID and Winter Storm Uri policies that temporarily eliminated late payment fees.[129]

9. **Other Revenue**

AE made three adjustments to Other Revenues including reducing Facility Rentals by $1,836,826[130] to reflect an adjustment for pole attachment revenue that it does not expect to collect from a customer. The revenue has been disputed by the customer for more than a year, and AE does not expect that the amount will be recovered. In contrast, ICA witness Effron proposes that no adjustment be made to Other Revenues for Facility Rentals.[131]

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[125] ICA Ex. 3 at 16-17.
[126] 2WR Ex. 1 at 5.
[127] AE Ex. 4 at 7.
[128] *Id.*
[129] *Id.*
[130] AE Ex. 1 at App. 172.
[131] ICA Ex. 2 at 12-13.

AE follows Generally Accepted Accounting Principles, which require AE to reduce receivables not expected to be collected. Because AE does not expect to collect this amount, it is required to adjust its revenues. As such, the $1,836,826 revenue was negated in AE's financial statements as uncollectible, subject to an independent external audit for FY 2021.[132]

10. **Pass-Through Items**

Although this is a base rate case, AE's COS Study includes pass-through costs in its analysis. This allows the entirety of AE's business operations to be represented, ensuring that no cost has been missed or duplicated, which ensures transparency. Further, it allows AE to represent estimated electric utility bills for different customers. Having only base costs in the COS makes it difficult to represent the entire bill. In the end, as illustrated in the schedules contained within the RFP, all pass-through costs were quantified and only base costs were included for recovery through AE's proposed base rates.[133]

TIEC witness Pollock contends that pass-through costs should not be included in the COS analysis. Further, he suggests that having pass-through costs represented in the COS impacts the allocation of service area lighting. Therefore, he developed a version of the COS with pass-through costs removed.[134] As noted above, AE agrees that pass-through costs should not impact the COS. However, including pass-through costs represented in the analysis does not cause the recovery of service area lighting costs to be impacted.

Service area lighting costs are allocated to customer classes based on revenue requirement (including pass-through costs). However, service area lighting for the City of Austin is a pass-through cost, which is not being addressed in this Base Rate Review. Thus, although there is an allocation shown on Schedules G-6 and G-7, these allocations are not proposals for how to recover this cost. Because the service area lighting pass-through charge is not being set in this Base Rate Review, AE did not develop a special allocator for service area lighting that accounted for all of the various limitations on the recovery of this cost. Further, no matter how service area lighting costs are allocated to customer classes in the RFP, it will have no impact on the base COS or resulting proposed base rates. As long as the allocator for service area lighting is the same between

[132] AE Ex. 4 at 5.
[133] AE Ex. 6 at 27.
[134] TIEC Ex. 1 at 17-19.

these two schedules, meaning there is not a disagreement within the model as to how this cost is allocated, there is no impact on the identified base COS for any customer class.

In its brief, NXP argues that AE should charge the City of Austin for the cost of street lighting service rather than recovering this cost through other customer classes in the Community Benefit Charge (CBC).[135] City Council considered this issue in the 2012 Base Rate Review and determined that street lighting within the City provides numerous benefits to the community including increased public safety for drivers, riders, and pedestrians. Accordingly, City Council determined that it is appropriate to collect the cost of street lighting service from all customers through the CBC.

C. Present Revenues and Billing Determinants

Like almost all utilities, AE used a historical test year in preparing its COS in this matter. In contrast, TIEC witness Pollock makes the highly unusual suggestion that future billing determinants for FY 2023 be utilized to set base rates for AE.[136] Mr. Pollock's suggestion is reflective of a future test year concept, which is incongruent with the historical test year approach. Adoption of Mr. Pollock's recommendations would misalign AE's historical FY 2021 costs, adjusted for known and measurable events, with billing determinants from a future year—specifically FY 2023.

Curiously, Mr. Pollock suggests using the average energy consumption for customers over the four years from FY 2017 through FY 2020 as a basis for judging the billing determinants in the test year.[137] The historical energy sales Mr. Pollock used are not weather normalized. Further, this approach fails to recognize that average residential energy sales are on a multi-year downward trend, as outlined extensively in AE's RFP.[138] Thus, the suggestion to use this data should be rejected.

D. Miscellaneous

As noted above, after reviewing the position statements of the participants, AE modified its position on several issues in its rebuttal testimony. These modifications are discussed in the rebuttal testimonies of AE witnesses Dombroski, Rabon, and Gonzalez and at other points in this

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[135] NXP Brief at 14.
[136] *Id*. at 12-14.
[137] *Id.*
[138] AE Ex. 6 at 26-27.

brief. Three of the additional adjustments related to non-cash nuclear decommissioning, interest on nuclear decommissioning, and the BAB subsidy are discussed below.

As identified in the testimony of ICA witness Effron, AE agrees that a correction to the non-cash portion of the nuclear decommissioning contribution should be made. The original adjustment to this contribution was intended to remove the non-cash portion of this expense, given AE is using the cash flow approach to develop its revenue requirement. However, AE erroneously reversed the sign convention on the non-cash portion and increased the cash obligation, rather than decreasing the cash obligation. Specifically, AE increased the cash needs by $4,662,375 when it should have decreased the cash needs by $4,662,375.[139] Thus, the overall impact was $4,662,375 times two, or $9,324,751, as suggested in Mr. Effron's testimony.

AE also determined that a portion of the cash contribution was funded from interest on the nuclear decommissioning trust. Given that interest income on the trust was not included as a source of revenue to offset the cash needs of the utility, as it was assumed to accrue in the trust (see Work Paper C-3.4.1), AE should not have included this portion of the cash funding for nuclear decommissioning in the revenue requirement. Removing the portion of the cash contribution that came from interest income results in an additional $2,594,248 reduction to the revenue requirement as compared with what AE originally filed.[140]

Finally, AE determined that the interest expense on the Series 2010B BAB refunding was missing the subsidized portion in AE's original analysis. The subsidy was included as a source of funding in the analysis (see Work Paper C-3.4.1), but the interest expense the subsidy was offsetting was missing because the debt service used was net of the subsidy. Thus, AE has added the subsidy portion of the interest expense to the revised analysis. The subsidy portion was $1,849,557 in FY 2021 and $1,791,095 in FY 2022.[141]

III. COST ALLOCATION

A. Background

After determining the utility's total COS, AE allocates the COS to customer classes based on how each class uses electricity and the resulting demands placed upon the electric infrastructure. AE's goal in this process is to distribute costs as accurately as possible based on how much it costs

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[139] AE Ex. 3 at 7.
[140] *Id.*
[141] *Id.*

AE to serve each customer class.[142] AE's cost allocation methodologies are commonly used in the utility industry, are recognized by the American Public Power Association (APPA), the National Association of Regulatory Utility Commissioners (NARUC), the National Rural Electric Cooperative Association (NRECA), are consistent with the Public Utility Regulatory Act (PURA), and are in accordance with generally accepted practices.[143] AE's COS methodology includes three general steps: (1) Functionalization, (2) Classification, and (3) Class Allocation.[144] Several participants take issue with AE's cost allocation methodology, discussed more in the sections below.

B. Functionalization

The first step in AE's cost allocation methodology is functionalization, which separates expenses into major categories based on the utility's primary business functions, which for AE are production (i.e., generation), transmission, distribution, and customer service.[145] Cost assignment by function falls into two general categories: direct assignments and derived allocations.[146] Costs that are readily identifiable to a specific utility function are directly assigned to that function.[147] Derived allocators are allocation factors based on the sum, average, or weighted effect of amounts that have been directly assigned or allocated in prior steps in the analysis.[148]

1. Production Function

The energy generated by AE is sold to the ERCOT market and serves as a physical and financial hedge against ERCOT market price fluctuations for power.[149] AE must purchase from ERCOT all the power necessary to serve its own customers. The hedge works because, as prices for power in the ERCOT market increase, at times so do revenues paid to AE for sales to ERCOT, mitigating the impact on AE's customers. The generation hedge provides a direct benefit to AE's customers by shielding them from high price spikes in the ERCOT wholesale market.[150] While

142 AE Ex. 1 at 47.
143 *Id*.
144 *Id*. at 48.
145 *Id*.
146 *Id*. at 50.
147 *Id*.
148 *Id*.
149 *Id*. at 51.
150 *Id*.

no participant takes issue with AE's classification of production costs, several participants disagree with its proposed allocation methodology, which is addressed below in Section III.D.

2. Transmission Function

The Commission has exclusive jurisdiction over rates, terms, and conditions for the provision of wholesale transmission services.[151] The Commission sets the rate AE is paid by those who use AE's portion of the transmission system, and the rate AE pays as its share of statewide transmission costs to serve its load.[152] Transmission costs are recovered through the AE's Regulatory Charge.[153] Thus, no part of the transmission function has any impact or relevance to the base rates being set in this proceeding.

3. Distribution Function

AE connects the ERCOT transmission grid to more than 520,000 customer accounts through the local distribution power grid using over 12,000 miles of distribution lines.[154] The distribution function includes all costs associated with operating and maintaining the distribution system, including capital expenses. This function also encompasses all the distribution lines and substations, transformers, and poles, as well as primary and secondary conductors and meters and installations on customer premises.[155] While no participant takes issue with AE's classification of distribution costs, some participants disagree with its proposed allocation methodology, which is addressed below in Section III.D.1.b-c.

4. Customer Service Function

The customer service function includes all aspects of operations needed to meet customer support requirements.[156] There are many separate business functions within AE's customer service function, which include customer accounting (billing and collections), customer service, meter reading, and key accounts.[157] Certain participants disagree with AE's sub-functionalization of customer service costs, addressed below.

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151 *Id*. at 52.
152 *Id*.
153 *Id*. at 53.
154 *Id*.
155 *Id*.
156 *Id*. at 54.
157 *Id*.

a. 311 Call Center

The 311 Call Center is a communication system that connects users with various city departments, including Austin Energy. The cost of the Call Center is driven by call volume, which best correlates with the number of customers. As a result, the 311 Call Center should be functionalized to customers and allocated to each rate class based on the number of customers in the class. The 311 Call Center provides a benefit that should be distributed equally between customers.

b. Bad Debt

The ICA argues that uncollectibles should not be functionalized to customer service because an uncollectible expense is a "system cost of doing business."[158] As the ICA is aware, AE is a MOU, and as such, it must recover all "costs of doing business" from its customers. The logical rationale is that uncollectible expenses are more customer-driven as compared to production, transmission, or distribution. The customer function, which encompasses customer accounting, including billing and collections, is most consistent with cost causation because uncollectible expense is caused by customers who fail to pay.[159] ICA witness Johnson recommended that instead of using a direct assignment of this expense, AE should use revenue as the basis for the allocation of this expense.[160] AE will demonstrate why direct assignment of this expense is appropriate in Section III.D.6, below.

c. Services and Meters

The ICA recommended that fees for electric meter damage, broken seals, after-hours connections, and new service connections be functionalized to customer, rather than distribution function.[161] Although the meters and services are distribution assets, and the functionalization of revenues should align with the functionalization of costs, AE has classified meters as being customer-related.[162] Therefore, meters are correctly functionalized as distribution, but this category of costs and revenues is classified as customer-related and allocated to customer classes

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158 ICA Brief at 16.
159 AE Ex. 9 at 43.
160 ICA Ex. 3 at 39-42.
161 *Id*. at 37-38.
162 AE Ex. 6 at 7.

based on a weighted customer meter allocator.[163] The revenues for electric meter damage, broken seals, and after-hours connections are similarly classified as customer-related within the distribution function.[164] Thus, AE has already correctly addressed the customer-related nature of these revenues in its proposal and no adjustment is appropriate.

ICA witness Johnson also recommends that new service connection revenues be functionalized to customer, rather than demand.[165] AE agrees with the ICA's proposal. The new service connection fee is a flat fee per new connection—independent of the demands the customer will place on the electric system.[166] Making this change reduces the identified customer-related costs.

The ICA's proposed cost allocation of meter-related costs, including smart meters, is discussed below in Section III.D.3.

C. Classification

Classification, or subfunctionalization, further separates the functionalized costs simultaneously into (1) cost classifications based on the general type of activity that causes the costs, and (2) sub-functions which are sub-divisions within each business function.[167] Most cost classifications are demand-related, customer-related, and energy-related.[168] Some costs are revenue-related, measured by revenue requirement, while some can be directly assigned to a customer or customer class.[169]

1. Demand-Related Costs

Demand, or capacity, costs are those costs associated with designing, installing, and operating the system to meet maximum hourly electric load requirements.[170] Demand-related costs are considered fixed costs because they do not vary with consumption.[171] Demand-related costs are associated with the production, transmission, and distribution systems and represent the costs of meeting the overall electric demand on AE's system.[172] Thus, demand-related costs are

[163] *Id*.
[164] *Id*.
[165] ICA Ex. 3 at 37-38.
[166] AE Ex. 6 at 8.
[167] AE Ex. 1 at 48.
[168] *Id*. at 56-57.
[169] *Id*. at 58.
[170] AE Ex. 1 at 48.
[171] AE Ex. 1 at 56.
[172] *Id*.

assigned to each customer class based on the class contribution to system demand. For cost allocation purposes, class demands are measured at different points on the system and also at different times for different functions.

- For the production function, AE is concerned with making generation available during the ERCOT system peak throughout the year; therefore, to allocate demand costs to each customer class, AE calculates each customer class's contribution to ERCOT peak demand in each month of the year.[173] This is the most appropriate methodology for AE, as described in Section III.D.1.a, below.
- For the transmission function, the Commission has determined that the transmission grid is built to meet the peak demands during the summer months of June, July, August, and September; therefore, class demands coincident with ERCOT system peak summer demands, known as "4CP demands," are used to allocate transmission costs to each customer class.[174]
- The distribution function is concerned with meeting localized demands; therefore, class maximum demands are used to allocate distribution costs.[175] This is the most appropriate methodology for AE, as described in Section III.D.1.b, below.
- For individual customers, AE is concerned with the maximum demand that the specific customer places on the system. These demands are significant cost drivers for AE's capital expenses, including debt.[176]

2. **Energy-Related Costs**

Energy-related costs are expenses that vary with electricity consumption.[177] Costs related to supply are classified as energy-related to the extent they vary with the amount of electricity purchased or generated by the utility for its customers. The most significant energy-related costs incurred by AE are fuel and energy market costs.[178] The costs of coal, natural gas, renewable contracts, nuclear fuel expenses, and purchases from the ERCOT wholesale market are all considered energy-related costs.[179] AE does not recover any energy-related costs in base rates (although AE does recover some fixed costs through energy charges).[180]

The ICA takes issue with AE's classification of all production base rate O&M expense as demand-related and recommends that AE adopt the NARUC Cost Allocation Manual (CAM)

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173 *Id*.
174 *Id*. at 56-57.
175 *Id*. at 57.
176 *Id*.
177 *Id*.
178 *Id*.
179 *Id*.
180 *Id*. Energy-related costs are recovered through the PSA, which is not affected by any adjustment to base rates.

approach to classify production O&M costs, which would classify a significant portion of production non-fuel O&M expense as energy-related.[181] Given AE's current business environment, this approach is inappropriate.

The description of fixed and variable production costs in the CAM were developed when the electric utility industry was comprised of vertically integrated utilities operating in a monopoly business environment.[182] These guidelines were developed long before the deregulation of wholesale power markets. Today's business environment in the ERCOT market is very different from the monopoly environment of vertically integrated utilities that existed when NARUC's CAM Cost Accounting classification guidelines were published.[183] Significant changes in the ERCOT power market have impacted the industry's business operations.[184] Like other Texas utilities, AE is faced with a competitive wholesale power market, aggressive conservation and demand response goals, increased interest in distributed generation options by customers, and long-term, low-load growth projections.[185] All of these factors create load uncertainty, energy volatility, and greater revenue instability. Fixed cost recovery is no longer certain in the wholesale power market or through rates.[186] The CAM's consideration of long-run variable costs are not applicable to generation facilities in a nodal market and are more appropriately considered a demand-related cost. Therefore, the CAM classification guidelines pertaining to production infrastructure that the ICA has relied upon are not relevant and should not be considered by the IHE.

AE's classification of production variable costs aligns with the economics of generation dispatch in ERCOT and reflects costs AE will recover from the market.[187] Depending upon market prices, other costs above and beyond these short-run variable costs may be recovered, but this is not guaranteed. As a result, AE's customers are ultimately responsible for some or all of the generation costs above short-run variable costs.[188] Given that it is proper to recognize short-run variable costs as energy related, it is also proper to recognize O&M expenses as demand related. AE generation assets must be in a state of "readiness to serve," or operationally available, when

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[181] ICA Brief at 19-20.
[182] AE Ex. 8 at 18.
[183] *Id*.
[184] *Id*.
[185] *Id*. at 18-19.
[186] *Id*. at 19.
[187] AE Ex. 8 at 20.
[188] *Id*. at 19.

market conditions provide economic opportunities for dispatch.[189] O&M practices are critical in keeping units available to operate on short notice.[190] With high availability, AE generation resources can effectively act as a financial hedge and protect customers from costly market events.[191] Non-fuel related O&M expenses ensure high availability and capacity-on-demand for all AE generation resources.[192] Therefore, these O&M expenses are properly classified as demand related costs in the nodal market. For these reasons, the ICA's production function classification recommendations should be rejected.

Notably, during the 2016 Base Rate Review, the IHE found that AE dispatches its production units to meet market demand and is no longer based on the paradigm in the NARUC CAM.[193] The IHE agreed that AE's classification of production variable costs aligns with the economics of generation dispatch in ERCOT and reflects costs AE will recover from the market.[194] Therefore, AE's proposal should be adopted.

3. **Customer-Related Costs**

Customer-related costs are expenses that reflect the minimum amount of fixed costs that the utility needs to supply for customers to access the utility system.[195] These are the cost of meters, meter reading, meter maintenance, and billing.[196] These costs vary with the addition or subtraction of customers, not usage.[197] Therefore, they are properly considered customer-related costs rather than demand-related cost or energy-related costs.

The ICA recommended that fees for electric meter damage, broken seals, after-hours connections, and new service connections be functionalized to customer, rather than distribution function.[198] As discussed in Section III.B.4.c, above, AE has already correctly addressed the customer-related nature of these revenues in its proposal and no adjustment is appropriate.

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[189] *Id*. at 19-20.
[190] *Id*. at 20.
[191] *Id*.
[192] *Id*.
[193] *Id*.; Austin Energy's 2016 Rate Review, Impartial Hearing Examiner's Report at 149 (Jul. 15, 2016) (2016 IHE Report); National Association of Regulatory Utility Commissioners' Electric Utility Cost Allocation Manual (Jan. 1992) (NARUC CAM).
[194] *Id*.
[195] AE Ex. 1 at 57.
[196] *Id*.
[197] *Id*.
[198] ICA Ex. 3 at 37-38; ICA Brief at 20.

Therefore, the ICA's recommendation to increase the amount of fees classified as customer-related by $2.8 million is unnecessary and should be rejected.

The ICA also recommended that new service connection revenues should be functionalized to customer, rather than demand.[199] As discussed in Section III.B.4.c, above, AE agrees with the ICA's proposal in this limited regard.

The ICA also recommended a change to the way services are classified and allocated to customer classes.[200] Mr. Johnson suggested services should be classified as customer-related, rather than demand-related, and that this cost should be allocated to customer classes based on a weighted allocator comprised of 50 percent 12 Non-Coincident Peak (NCP) and 50 percent customer count.[201] While Mr. Johnson is correct that it is not unusual for services to be allocated based on a weighted customer allocation, AE views services as demand-related because the COS varies with a customer's individual demand.[202] Thus, AE allocated services to customer classes based on sum of maximum demand (SMD) excluding primary and transmission voltage customers (not 12 NCP as claimed by Mr. Johnson).[203] While Mr. Johnson's suggestion of a weighted allocator may not be inappropriate, the use of SMD as the selected allocator for services is fair and reasonable because this allocator is derived through a combination of customer (meters) and demand. SMD is the sum of customer maximum demands at the meter which is, in fact, a weighted customer allocator that reflects both customer count and demand. Further, it is worth noting that Mr. Johnson's suggested weighted allocator of 50 percent 12 NCP and 50 percent customer count yields a virtually identical outcome for residential customers as the allocator selected by AE.[204]

4. Revenue-Related Costs

Revenue-related costs are costs that vary with the amount of revenue generated by the utility.[205] No participant took issue with AE's classification of revenue-related costs.

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[199] *Id*.
[200] *Id*. at 45-46.
[201] *Id*.
[202] AE Ex. 6 at 11.
[203] *Id*.
[204] *Id*.
[205] AE Ex. 1 at 58.

5. **Direct Assignments**

Costs that can be readily attributed to a particular customer or customer class are directly assigned to that customer or class.[206] Some participants took issue with AE's use of direct assignment to allocate Uncollectible Expense to customer classes, which is discussed below in Section III.D.6.

6. **A&G Expense and Indirect Costs**

The ICA disagrees with AE's classification of administrative and general (A&G) expenses, specifically related to FERC Account 920, A&G Salaries, and FERC Account 930, Miscellaneous General Expenses.[207] ICA witness Johnson recommended that the functionalization of FERC Account 920 expenses be altered so that more of these expenses would be assigned to the production function. AE's use of labor to functionalize the portion of FERC Account 920 expenses that were not directly assigned to the production function is consistent with the NARUC CAM's[208] treatment of this expense.[209] The production function direct assignment is associated with expenses related to operations at South Texas Project (STP) and FPP.[210] Given that AE is able to directly assign this proportion of the overall FERC Account 920 expenses to production, it is appropriate to do so. The remainder of FERC Account 920 expenses are correctly functionalized based on AE's labor costs, which exclude labor expenses at STP and FPP because AE employees do not operate or manage these generation units.[211]

The nature of the expenses in FERC Account 920 (such as executive management, accounting, finance, human resources, planning, budgeting, etc.) are most appropriately affiliated with AE's workforce.[212] Because AE's employees do not operate STP or FPP, it would be inappropriate to include an estimate of labor costs at STP and FPP in the labor allocator used for functionalization of this expense.[213] This would have the outcome of ignoring a direct assignment of a portion of this expense in favor of a more general allocation. When direct assignments are

[206] *Id*.
[207] ICA Brief at 21-22.
[208] NARUC CAM at 35.
[209] AE Ex. 6 at 5.
[210] *Id*.
[211] *Id*. at 5-6.
[212] *Id*. at 6.
[213] *Id*.

practical, as in this case, they should be favored.[214] Therefore, the ICA's recommendations related to FERC Account 920 should be rejected.

For FERC Account 930, ICA witness Johnson recommended replacing the payroll method with non-fuel O&M factors, and in support of this proposal, the ICA claims that Account 930 "includes virtually no payroll expense, further confirming that a payroll classification is inappropriate."[215] This statement is misleading. The ICA is correct that less than one percent of the FERC Account 930 expenses are composed of AE's employee labor, but many of the expenses in FERC Account 930 are related to supporting AE's employees, such as Human Resources, Information Technology, and Corporate Support Services.[216] Similar to FERC Account 920 expenses, it is appropriate to functionalize expenses that were not directly assigned to the production function based on labor, as AE has done. This is consistent with treatment in the NARUC CAM.[217] Therefore, the ICA's recommendations related to FERC Account 930 should be rejected.

7. Cost Classification Results

The numeric results of AE's cost classification are included in Table 5-E of AE's RFP, with more detailed results in Schedule G and associated workpapers.[218]

D. Class Allocation

Class Allocation attributes the functionalized and classified costs to individual customer classes based on cost causation.[219] Class allocation factors are developed for demand-related, energy-related, and customer-related costs.[220] AE then applies these factors to distribute classified costs to each customer class according to the class's contribution to that cost.[221] AE's proposed allocation factors were developed to be consistent with each cost classification methodology applied. AE's allocated COS Study is consistent with cost-causation principles and should be adopted.

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[214] *Id*.
[215] ICA Ex. 3 at 33-37; ICA Brief at 22.
[216] AE Ex. 6 at 6-7.
[217] *Id*. at 7.
[218] AE Ex. 1 at 58.
[219] AE Ex. 1 at 48.
[220] *Id*. at 59.
[221] *Id*.

1. **Demand-Related Costs**

Demand-related costs are expenses that are driven by demand on the system.[222] Within each function, the allocation of demand-related costs to each customer class was based on accepted industry practices that seek to assign costs to each class in alignment with the way costs are incurred by the utility.[223] The ICA, NXP, and TIEC all recommended changes to AE's proposed demand cost allocation methods, discussed below.

a. Production-Demand

AE's proposal utilizes the ERCOT 12 Coincident Peak (ERCOT 12CP) methodology to allocate the cost of generation.[224] The ERCOT 12CP methodology better aligns the relationship between the costs and the benefits that accrue from owning and operating AE's fleet of generation in the ERCOT market, where benefits and some of the costs flow back to AE's customers through the PSA.[225] This methodology allocates production expenditures to customer classes based on each class's contribution at the time of the ERCOT system peak demand during each of the twelve calendar months.[226] Applying this methodology recognizes that all of AE's customers benefit from AE's generation fleet year-round, and importantly, balances the interests of residential and commercial customers. In contrast, three participants advocate instead for adoption of allocation methodologies that shift costs to other customer classes whose interests they do not represent—the ICA, who recommends the Baseload-Intermediate-Peak (BIP) method; and NXP and TIEC, who recommend the Average & Excess (A&E) 4CP allocation methodology. Both the BIP method and A&E 4CP method are flawed in their failure to recognize fundamental market principles. AE's recommended 12CP allocation methodology more accurately reflects how the ERCOT nodal market impacts production costs and is a reasonable way to assign the recovery of those costs to AE's customer-owners.

The ICA recommended adopting the BIP allocation method, which classifies a significant portion of production-demand costs, specifically, 83.5 percent, as energy-related, and allocates these costs to the various rate classes on the basis of energy.[227] This recommendation,

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[222] *Id*. at 60.
[223] *Id*.
[224] *Id*.
[225] *Id*. at 60-61.
[226] *Id*. at 61.
[227] TIEC Ex. 2 at 8.

unsurprisingly, shifts fixed cost recovery from low load factor residential customers to high load factor commercial and industrial customers. The BIP allocation method is outdated and is not appropriate for AE.

The BIP method is a production stacking method where baseload, intermediate, and peaking units are dispatched to meet AE's load.[228] This allocation method is not relevant to the ERCOT nodal market, where generation units are economically dispatched into the market and not dispatched to serve AE's hourly load requirements.[229] Generation resource terms such as "baseload," "intermediate," and "peaking," which used to serve utilities' load, no longer have traditional meanings in ERCOT due to the structure of the ERCOT market.[230] As mentioned in Mr. Burham's rebuttal testimony, the bids from generation resources dictate the dispatch of generation units in ERCOT given market conditions.[231] Because of market conditions, with the exception of STP, AE cycles all generation units within the limits of the resource technology.[232] AE's generation portfolio is dispatched in the market for the financial benefit of all AE customers.[233] Dispatchable demand, as measured by availability of generation resources, is a valuable economic component provided by the AE generation portfolio. In this market, categorizing units as "baseload," "intermediate," and "peaking," is much less meaningful.[234] Therefore, similar BIP categories are not relevant.

The fundamental flaw with the BIP method is that it assumes that a resource, like a baseload unit, will be dispatched to serve load given the load profile and resource planning needs of the utility.[235] The BIP method classifies costs based on the demand and energy needs of the system regardless of cost. However, in ERCOT, generation assets are dispatched based on market needs and price competitiveness with price being the primary factor under uncongested circumstances.[236] In ERCOT, higher capacity factors of AE's coal (i.e. FPP) and nuclear (i.e. STP) units cited by ICA witness Johnson are not the result of baseload units serving load, but rather a recognition that these resources are low-cost market resources and are often called on to serve the market.[237] These

[228] AE Ex. 8 at 6.
[229] *Id*.
[230] *Id*.
[231] *Id*. at 10.
[232] *Id*.
[233] *Id*.
[234] *Id*. at 6.
[235] *Id*. at 7.
[236] *Id*. at 7-8.
[237] *Id*. at 8.

assets must perform when dispatched into the ERCOT market to provide value, therefore asset availability and associated capacity are critical. In the ERCOT nodal market, all generating units monetize their capacity value through the market clearing price. However, BIP ignores both by assigning zero capacity value to FPP and STP baseload units and assumes that these units will be dispatched into the market at any price. Therefore, BIP severely understates the capacity value of these low-cost generation resources which are often called upon to serve ERCOT load. Further, the effectiveness of the physical hedge provided by the generation fleet is a function of available capacity to offset AE's load requirements.[238] Therefore, fixed production costs are most appropriately associated with AE's peak load requirements, not energy.[239] As a result, energy allocation methods, like BIP, are not appropriate.

Fundamentally, the ICA's advocacy for the BIP production cost allocation methodology is rooted in an outdated view of the ERCOT market. Similarly, his analysis and calculations are constructed to attempt to match specific AE loads with specific AE generating resources. The ICA's proposed allocation methodology would shift costs of the most capital-intensive resources to larger commercial classes and away from the residential class. But, AE has shown that this is not an appropriate way to distribute production related costs because AE no longer serves its own load with its resources. Notably, the ICA recommended the BIP methodology in the 2016 Base Rate Review, and the IHE recommended against it because it "ignores the reality of the market in which Austin Energy operates" and places too much emphasis on the market paradigm of a fully integrated utility in the non-ERCOT services areas in Texas.[240] AE is not aware of any utilities in Texas using the BIP method, and the Commission has not approved the BIP method in over 20 years. Therefore, the ICA's recommendation should be rejected.

NXP and TIEC recommend use of the A&E 4CP allocation method, which, contrary to the ICA's proposal, shifts costs from large commercial and industrial customers to the residential class by approximately 5.2 percent.[241] The 12CP allocation approach is more equitable than the A&E 4CP method for allocating production demand costs. As discussed above, AE generation assets are dispatched to the ERCOT market, not to serve AE load. As demonstrated by ICA witness

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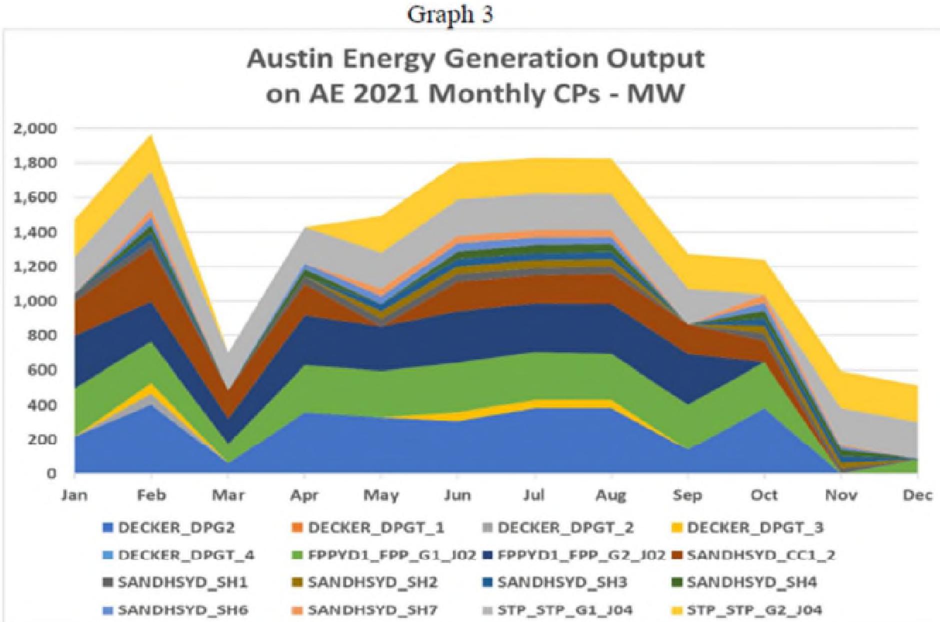
[238] *Id*.
[239] *Id*.
[240] AE Ex. 8 at 9; 2016 IHE Report at 36.
[241] AE Ex. 8 at 17.

Johnson, the A&E 4CP method is similar to a 4CP demand allocator.[242] However, a 12CP allocation approach is superior to a 4CP allocation approach because the 12CP recognizes the hedging value provided to customers by AE's generation portfolio over a greater percentage of peak hours.[243] Given the unpredictability of market prices throughout the year, the benefit to AE ratepayers is more appropriately recognized over a larger number of hours. The 12CP allocator appropriately recognizes the benefit of the physical hedge over the year. As shown below, AE resources were significantly dispatched to meet ERCOT load during non-summer months, including January, February, April, May, and October of 2021.[244]

Figure 1 – Austin Energy Generation Output

Graph 3

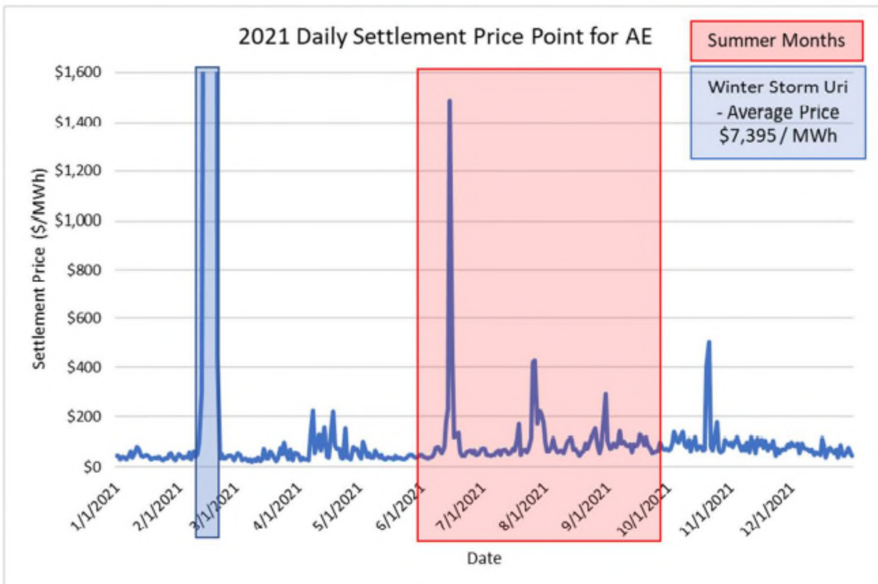


The capacity value of AE's generation resources is realized throughout the year and is not limited to the four summer months in ERCOT. As experienced during Winter Storm Uri in February 2021, AE was able to provide generation when a large portion of the ERCOT market was not able to do so.[245] Additionally, in 2021, ERCOT market prices experience significant increases during periods outside of the four summer months (June, July, August, September), as indicated

[242] ICA Ex. 4 at 6-7.
[243] AE Ex. 8 at 14.
[244] AE Ex. 8 at 12, *citing* NXP Ex. 1 at 23.
[245] AE Ex. 8 at 13.

in the figure below, which shows the peak daily market price in dollars per megawatt hour ($/MWh) for 2021 for the AE node.[246]

Figure 2 – 2021 Daily Settlement Point Price for Austin Energy



As indicated, there were several days during the non-summer months, exclusive of Winter Storm Uri, which experienced an hourly price greater than $100/MWh.[247] This proves that AE generation resources provide value to AE customers throughout the year.

AE's approach to production demand cost allocation methods has been modified consistent with changes in the market. In the 2012 COS Study, the Base Rate Review test year was based on FY 2009 operating results, which was a pre-nodal market test year.[248] When the 2012 COS Study was completed, it included the A&E 4CP method.[249] In the 2016 COS Study, based on several years of actual data operating in the ERCOT nodal market, AE recognized that an effective capacity hedge was a key benefit to its customers in the ERCOT nodal market, which justified utilizing an ERCOT CP basis.[250] At that time, AE recognized that the benefit of the hedge was

246 *Id.*
247 *Id.*
248 *Id.* at 15.
249 *Id.*
250 *Id.*

year-round and not just during the summer peak demand months. Accordingly, the previous demand allocator of A&E 4CP was modified to a 12CP allocator.[251]

The 12CP allocator was recommended by the IHE in the 2016 Base Rate Review.[252] Maintaining the 12CP allocation methodology established in 2016 would provide consistency in AE's ratemaking process, which is beneficial to AE ratepayers. Consistency in cost allocation is an important element in rate design, assuming there have been no significant changes in the underlying power market operations. A consistent cost allocation method sends a consistent price signal to customers to influence their electricity usage.

Since deregulation occurred in 1999, the Commission has conducted little retail rate review of utilities operating in the ERCOT market. Nearly all of the Commission's retail rate examination has focused on the fully regulated, vertically integrated utilities operating outside the ERCOT region.[253] To look to vertically integrated utilities for appropriate cost causation methodologies, as TIEC and NXP advocate in their briefs,[254] is to ignore the significant differences between the ERCOT wholesale market and the fully regulated environment in which these vertically integrated utilities operate. Unlike AE, vertically integrated utilities operating outside of ERCOT are not subject to wholesale market forces in which generation companies must compete based on economic efficiency in order to have their units run. And, unlike vertically integrated utilities, AE's generation resources are not exclusively maintained to meet AE system peak; rather, they are maintained to be dispatched based on system wholesale price. AE's proposal avoids an overreliance on a traditional approach that is outdated.

NXP and TIEC's argument in favor of the A&E 4CP methodology ignores how ERCOT nodal market prices impact the production costs of resources needed to meet demand, and fail to recognize that wholesale market price increases do not exclusively occur during peak demand periods of the year. Moreover, TIEC and NXP broadly and erroneously over-emphasizes the importance peak demand plays in AE's production cost analysis, whereas they should be most concerned with peak price intervals. The 12CP method simply acknowledges that price spikes caused by demand for energy can occur throughout the year in the ERCOT market. When market

[251] *Id.*

[252] *Id.*, *citing* 2016 IHE Report at 166.

[253] The sole case was the appeal of Austin Energy's retail rates for outside-city customers by HURF in 2012-2013. While the Commission approved an A&E 4CP allocation methodology at that time, one case does not substantively establish "historical precedence."

[254] TIEC Brief at 18; NXP Brief at 26.

price spikes can occur as often in February as they do in August, critique of the historical precedence of a summer peaking methodology is reasonable. ICA witness Johnson even acknowledged that if his proposal of the BIP method was not adopted, that 12CP is favorable over A&E 4CP.[255]

While it is true that average wholesale prices tend to be higher during the summer months when demand typically reaches its peak, AE has shown that high market prices are not exclusive to the four summer months. They can and do occur throughout the year, and spikes can be significantly higher than average prices, even higher than the average summer month prices. These price spikes represent undesirable risks against which the MOU must hedge its exposure. In order to ensure that its resources are available to provide energy when market prices are high, AE must maintain its fleet throughout the year. Mr. Burnham stated that O&M expenses ensure high availability and capacity-on-demand for all AE generation resources and are properly classified as demand-related costs in the nodal market.[256] It is therefore reasonable for AE to allocate its production costs based on a methodology that considers the impact of peak market prices throughout the year.

Throughout the base rate review process, participants have disagreed over which production cost allocation methodology most appropriately reflects ERCOT market fundamentals and cost causation principles. For example, AE agrees with the ICA that AED 4CP "do[es] not effectively recognize annual energy use."[257] But, AE agrees with TIEC that BIP "is contrary to cost-causation and is unsupported by precedent,"[258] and NXP that BIP "simply does not reflect cost causation and would result in a disparate impact on the majority of AE's customer classes."[259] Both sets of alternative proposals are results-oriented and shift the majority of the costs from one class of customers to another—notably, between residential and commercial customers. Accounting for these concerns, AE's recommended ERCOT 12CP production cost allocation methodology comes closest to mirroring ERCOT wholesale market fundamentals and reasonably balances cost assignment among the various rate classes based on documented cost causation principles.

[255] Tr. (July 14) at 86:21-44 (Johnson Cr.).
[256] AE Ex. 8 at 20.
[257] ICA Brief at 25.
[258] TIEC Brief at 23.
[259] NXP Brief at 31.

b. Distribution-Demand

Distribution substations, poles, and conductors should be allocated using the 12 NCP allocator, as proposed by AE and supported by the ICA.[260] In contrast, NXP and TIEC recommended using the 1NCP method for allocating distribution substations, poles, and conductors. As noted in Mr. Burnham's rebuttal testimony, the use of 12NCP is more equitable than 1NCP.[261] This is because the 12NCP method recognizes that distribution capacity provides value to customers throughout the year, not just during the peak hour or the summer peak months. Because the NCP calculation is done at the class level, off peak or seasonal customers may not be fully accounted for in a 1NCP calculation.[262] A 12NCP calculation solves this problem. This is important as customers are becoming increasingly interested in distributed generation options and are able to shift load and demand. From a cost allocation perspective, certain rate classes may be able to avoid a portion of distribution demand related costs by shifting demand during NCP periods. If the demand measure is a single hour (i.e., the 1NCP), the ability to shift and avoid cost responsibility is easier compared to a 12NCP method.[263] Additionally, the distribution system is spread across the geographic footprint of the system. The system is sized in consideration of localized demand that varies from area to area based on variations in the customer mix. These variations are better represented by a 12NCP allocator which takes into consideration the value of load diversity across the distribution system.[264]

Other factors also weigh in favor of adopting the 12NCP allocator. First, other MOUs in Texas utilize a 12NCP method to allocate distribution costs. Specifically, Bryan Texas Utilities and Greenville Electric Utilities utilize the 12NCP method used to allocate distribution costs.[265] Second, like TIEC and NXP's production-demand proposal, their distribution-demand proposal of a 1NCP cost allocator is results-oriented, and serves to shift cost responsibility for distribution costs from the non-residential customers to the residential and small commercial customers.[266] Further, the ICA supports AE's proposal of a 12CP allocator "because it recognizes the load

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[260] ICA Ex. 4 at 8-9; ICA Brief at 26-29.
[261] AE Ex. 8 at 21.
[262] *Id*.
[263] *Id*.
[264] *Id*. at 23.
[265] *Id*. at 22.
[266] *Id.* at 22-23.

diversity and localized nature of distribution planning."[267] Therefore, the 12NCP allocator proposed by AE should be adopted.

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

NXP and TIEC recommended removing the allocation of primary distribution poles and lines for the primary voltage above 20,000 kW class to create a separate rate class.[268] Their proposal to create a new rate class should not be adopted in this proceeding.

AE serves three primary >= 20,000 kW customers.[269] Despite TIEC's and NXP's contentions, none of these customers are served directly from any substation on AE's system.[270] AE's policy does not allow this to occur. The point of interconnection (POI) for all customers is outside of the AE substation.[271] AE must install and maintain the primary distribution poles and lines to serve customers up to the POI, regardless of the geographic location of the interconnection point.[272] Distribution feeders can be direct or shared and are comprised of some combination of AE owned and maintained overhead and/or underground conductors. Further, distribution feeder lengths vary between a few hundred feet up to several miles and there is no direct correlation between the location of the substation and a customer's property. In addition, it is common ratemaking practice to recover system costs on a class average basis regardless of the physical location of the interconnection. Therefore, primary voltage customers should be allocated costs for the primary distribution poles and lines that are part of these feeders.

Despite AE revising prior responses and participating in meetings with the participants directly to clarify, NXP and TIEC continue to state that high load factor voltage (=> 20,000 kW) customers are directly connected to an AE distribution substation through dedicated feeders.[273] As AE has stated multiple times throughout the course of this proceeding, there are no primary >=20,000 kW customers that are served directly from the substation. AE does not allow customer-owned equipment in its substations for safety concerns. Therefore, no customers are allowed to directly connect to AE substations.

[267] ICA Ex. 4 at 8-9; ICA Brief at 27.
[268] TIEC Ex. 1 at 31-34; NXP Ex. 1 at 32-34; NXP Brief at 35-36; TIEC Brief at 28-33.
[269] AE Ex. 8 at 25.
[270] *Id*.
[271] *Id*.
[272] *Id*.
[273] TIEC Brief at 28; NXP Brief at 35.

Both NXP and TIEC continue to rely on an Oncor case in which the Commission ordered Oncor to create a new tariff for Primary Substation customers who "receiv[e] voltage from, or near, a substation" and who "construct and maintain the distribution facilities themselves."[274] However, the Oncor rate case should not apply to AE's situation for primary voltage distribution customers.[275] As noted in the Order on Rehearing, the Commission approved the creation of a new primary substation rate class for Oncor.[276] However, this approval was conditioned upon customers "construct[ing] and maintain[ing] the distribution facilities themselves."[277] In contrast, AE owns and maintains the distribution facilities necessary to serve its primary voltage customers load up to the POI. TIEC and NXP downplay the distinguishing facts as if ownership of the facilities is not the dispositive issue. However, AE's ownership and maintenance of the distribution facilities necessary to serve its primary voltage customers' load up to the POI means that these customers use a portion of the distribution system, and therefore, should be allocated costs for the primary distribution poles and lines that are part of the feeders that serve them.

Further, the ICA supports AE's approach to allocate primary distribution costs to customers near or adjacent to substations as it is consistent with average cost ratemaking principles.[278] Contrary to TIEC and NXP's arguments, it is inappropriate to set rates based upon the geographical location of the customer. Therefore, NXP and TIEC's proposal to remove the allocation of primary distribution poles and lines for the primary voltage above 20,000 kW class and to create a separate rate class should be rejected.

2. **Energy-Related Costs**

Energy allocation methods are used to allocate energy-related costs.[279] Energy allocation factors are only applied to the production function costs that are recovered outside base rates under the PSA pass-through charge.[280] When electricity is transmitted and distributed, a certain percentage of energy is lost due to resistance. In general, losses are estimated by calculating the discrepancy between energy produced and energy sold to customers. Line loss factors are

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[274] TIEC Brief at 30; NXP Brief at 36; *Application of Oncor Electric Delivery Company LLP for Authority to Change Rates,* Docket No. 35717, Order on Rehearing at 11 (Nov. 30, 2009).

[275] AE Ex. 8 at 27.

[276] *Id*.

[277] *Id*.; *Application of Oncor Electric Delivery Company LLP for Authority to Change Rates,* Docket No. 35717, Order on Rehearing at 11 (Nov. 30, 2009).

[278] ICA Ex. 4 at 9-10; ICA Brief at 29.

[279] AE Ex. 1 at 64.

[280] *Id*.

discussed more in Section III.D.7. The ICA disagrees with AE's classification of Production Non-Fuel O&M Accounts, which is addressed in Section III.C.2.

3. Customer-Related Costs

The distribution and customer service functions each include customer-related costs.[281] The distribution function contains customer-related costs related to metering.[282] In the customer service function, all costs are classified as customer-related.[283]

Meter expense should be allocated using a weighted customer allocator. Meter reading costs should be allocated based upon the number of customers. As NXP notes, "[t]his approach is consistent with that of all major utilities in Texas, which allocate 100 percent of meter costs using a weighted meter cost allocation."[284] ICA witness Johnson proposes that, rather than having all of the meter expense allocated to customer classes based on AE's meter cost weighted customer allocation, 51 percent of the meter cost should instead be allocated based on revenue requirement.[285] His reasoning is that this portion of the cost of the meter is related to the newer features that "smart meters" allow beyond what traditional meters would facilitate. Mr. Johnson's recommendations should be rejected.

The additional features allowed by smart meters, such as customer reporting communicating with customers, and remote start/stop of service, are appropriately allocated to customer classes based on AE's selected allocator.[286] These benefits apply to all customers relatively equally and are not influenced by customer size or revenue.[287] Allocating this expense based on revenue requirement would assign a significant amount of this cost to customer classes based on energy.[288] This makes Mr. Johnson's suggestion a poor fit with the nature of the fixed cost of meters, which do not vary with energy use, and his suggestion should be rejected.

Outside of the issue of metering, AE proposes to allocate certain customer service expenses (FERC Accounts 911 through 917) on the basis of the number of customers in each customer class.[289] The ICA instead recommended an alternative allocation of customer expenses. ICA

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281 AE Ex. 1 at 65.
282 *Id*.
283 *Id*.
284 NXP Brief at 36.
285 ICA Ex. 3 at 42-45.
286 AE Ex. 6 at 10.
287 *Id*.
288 *Id*.
289 *Id*. at 13.

witness Johnson suggested a weighted allocation comprised of 61 percent revenue requirement and 39 percent number of customers.[290] The 61 percent represents the proportion of costs identified as Customer Service on Schedule G-5 of the RFP that are associated with FERC Accounts 911, 912, 913, and 916 as compared with the total costs identified as Customer Service on Schedule G-5 associated with FERC Accounts 907 through 916.[291] The ICA's recommendation should not be adopted. The programs reflected in this expense are targeted to smaller, less sophisticated customers—not large commercial or industrial customers.[292] Thus, the use of a revenue requirement allocator will inappropriately allocate disproportionate amounts of this cost to the large commercial or industrial customers. Mr. Johnson's suggestion is not equitable and should be rejected. These costs are appropriately allocated based on number of customers, as AE has done.

4. **Revenue-Related Costs**

To allocate Service Area Lighting and Energy Efficiency programs, AE used revenue-related allocation factors that distribute the cost to customer classes. However, ultimately, these expenses are removed from the base revenue requirement and collected through the CBC.[293] No participant took issue with this proposal.

5. **Service Area Street Lighting**

AE incorporates by reference its discussion of NXP's proposal related to service area streetlighting costs in Section II.B.5.

6. **Direct Assignments**

AE uses a direct assignment to allocate Uncollectible Expense to customer classes.[294] The ICA recommended that instead of using a direct assignment, AE should use revenue as the basis for the allocation of this expense.[295] The ICA also claims that the NARUC CAM specifically excludes bad debt from the customer classification.[296] However, the NARUC CAM, cited by Mr. Johnson, says the following:

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[290] ICA Ex. 3 at 48-50.
[291] AE Ex. 6 at 12.
[292] *Id.* at 13.
[293] AE Ex. 1 at 69.
[294] AE Ex. 6 at 8.
[295] ICA Ex. 3 at 39-42; ICA Brief at 31-32.
[296] AE Ex. 6 at 9.

> Customer-related costs (Accounts 901-917) include the cost of billing and collection, providing service information, and advertising and promotion of utility services. By their nature, it is difficult to determine the "cause" of these costs by any particular function of the utility's operation or by particular classes of their customers. An exception would be Account 904, Uncollectible Accounts. Many utilities monitor the uncollectible account levels by tariff schedule. Therefore, ***it may be appropriate to directly assign uncollectable accounts expense to specific customer classes***.[297]

The ICA's reliance on its claim that the NARUC CAM specifically excludes bad debt from the customer classification is inappropriate. Similarly, the ICA cites Commission precedent supporting his recommendation.[298] This reliance is misplaced, as the Commission case cited by the ICA is from 1998, which was more than 20 years ago and is therefore outdated. The direct assignment method is appropriate and recognizes that there is a different likelihood (or risk) of uncollectible expense depending on the customer class.[299] Thus, direct assignment based on historical experience better aligns the test year cost with the customer classes that have contributed to this cost.[300] Therefore, the ICA's recommendation that Uncollectible Expense should be allocated on the basis of revenues should be rejected.

7. **Energy and Demand Line Loss Factors**

AE relied upon the System Loss Study for FY 2018 (Line Loss Study), as filed on June 6, 2022 as an Amendment to the RFP, to adjust normalized energy sales and demands at the meter for each customer class to the generation level to adjust for the percent energy losses at each applicable voltage level.[301] NXP and TIEC claim that AE's Line Loss Study was conducted in error.[302] First, NXP witness Daniel and TIEC witness Pollock recommend the use of demand losses for CP cost allocation.[303] AE does not disagree with their recommendation. Ideally, demand losses should be utilized to adjust load. However, AE only has a demand loss measured for the

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[297] AE Ex. 6 at 9; NARUC CAM at 102 (emphasis added).

[298] ICA Brief at 31; *Application of Entergy Gulf States, Inc. for Approval of its Transition to Competition Plan and the 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).

[299] AE Ex. 6 at 9.

[300] *Id*.

[301] AE Ex. 1 at App. 361-386.

[302] NXP Brief at 38; TIEC Brief at 33-36.

[303] *Id.*; TIEC Ex. 1 at 36; NXP Ex. 1 at 37-38.

peak hour of the year (1CP).[304] AE does not have a demand loss measured for each peak hour of the month applicable to the 12CP cost allocation.[305] Losses would be expected to be different at different loads and different ambient temperatures throughout the year.[306] Therefore, the use of the average energy loss as a proxy for the 12CP demand loss is reasonable and acceptable.

NXP witness Daniel and TIEC witness Pollock then recommend the use of demand losses for NCP cost allocation.[307] AE disagrees with this recommendation. The NCP of a customer class may occur at any time during the month and the losses associated with the peak for the class would prove difficult to measure on a consistent and regular basis.[308] Therefore, the use of the average energy losses as a proxy for the 12NCP demand loss is reasonable.

TIEC purports to have created the "correct methodology for directly deriving energy and peak demand loss factors from AE's loss study."[309] AE does not agree with the proposed loss calculations provided by TIEC witness Pollock and has several concerns with the analysis provided. For example, the same demand loss factor appears to have been applied to the CP hour and similarly the same demand loss factor for the NCP hour for each month, which does not take into account variations in demand or ambient conditions by season.[310] NXP and TIEC's recommendations should be rejected, and AE's Line Loss Study should be adopted without revision.

8. Cost Allocation Summary

For the reasons discussed above, the IHE should adopt AE's class allocation proposals, including the following: adoption of the ERCOT 12CP methodology to allocate the cost of generation; adoption of the 12NCP allocator for distribution substations, poles, and conductors; rejection of the new Primary Substation rate class as proposed by NXP and TIEC; allocating meter expense using a weighted customer allocator; allocating meter reading costs and certain customer service expenses (FERC Accounts 911 through 917) based upon the number of customers in each customer class; use of direct assignment to allocate Uncollectible Expense; and adoption of AE's

[304] AE Ex. 8 at 24.
[305] *Id*.
[306] *Id*.
[307] TIEC Ex. 1 at 36; NXP Ex. 1 at 37-38.
[308] AE Ex. 8 at 24.
[309] TIEC Brief at 34; TIEC Ex. 1 at Exhibit JP-8.
[310] AE Ex. 8 at 25.

Line Loss Study. AE's allocated COS Study and recommendations above are consistent with cost-causation principles and should be adopted.

E. Cost of Service Results

AE's total COS results are presented in its RFP in Table 5-O,[311] without any adjustments made based on accepted proposals by various participants. The results highlight that the residential customer class is under-recovering relative to its COS, while the non-residential customer classes, as a group, are over-recovering, some by a substantial margin.[312] These COS findings prompt AE's proposed rate design, discussed more in Section V.

F. Cost Allocation Conclusions

AE's cost allocation proposals should be adopted. The COS Study indicates adjustments are needed to align all classes with their total COS. AE's proposed class revenue distribution is designed to move classes toward their COS without producing unacceptably large customer impacts.[313] AE also recognizes that the current economic and affordability conditions in AE's service area could not support a complete shift to full COS or the accompanying rate shock such an immediate change would cause.[314] Therefore, AE applies a moderate approach to address COS imbalances to mitigate rate shock.[315] AE uses the COS Study results as the foundation for developing the class revenue distribution and proposed base rates, discussed next.

IV. CLASS REVENUE DISTRIBUTION

AE's COS Study indicates that under AE's current base rates, significant inter-class cross-subsidization exists.[316] As such, AE has proposed a gradual approach to revenue distribution. Under AE's proposal, target revenues are set below COS for certain classes to avoid excessive rate impacts for those classes.[317] Setting target revenues below cost for some classes necessarily requires that the revenue contributions from certain other classes will be set somewhat above COS. AE's proposal avoids setting class revenues directly and immediately to class COS, because that approach would result in a dramatic increase in base rates for the residential classes that are

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[311] AE Ex. 1 at 73.
[312] *Id*.
[313] *Id*.
[314] *Id*.
[315] *Id*.
[316] *Id*. at 75.
[317] *Id*.

currently well below COS.[318] AE's ultimate goal is for each class's revenue target to be set directly to COS. However, if base rates were set directly to cost in this proceeding, it would promote an unacceptable degree of excessive rate impacts, so AE proposes implementing a standardized gradualist approach to class revenue distribution.

AE's class revenue distribution approach can be put simply as "halfway to cost."[319] Under AE's proposal, all classes receive the system average increase or decrease in step one.[320] Then, from each class's position after step one, each class moves halfway toward COS.[321] AE's methodology balances several desirable policy objectives, including fairness, recognition of COS, and gradualism. Several participants propose alternative class revenue distribution methodologies, which should be rejected, as discussed below.

ICA witness Johnson testified that revenue distribution should involve considerations other than cost, such as efficient behavior.[322] Cost-based rates are the best way to achieve efficient behavior, in addition to enhancing revenue stability and encouraging conservation.[323] AE's proposal effectuates those goals, while applying a gradualist approach which does not apply one hundred percent weight to the results of the COS, in order to lessen the impact on the residential class.

ICA witness Johnson also raises concerns about the COVID pandemic related to class revenue distribution.[324] However, AE's gradualist approach to revenue distribution adequately addresses this uncertainty by avoiding assigning 100 percent weight to the COS.[325] The ICA also promotes the principle of rate mitigation, and claims the Commission has historically supported rate mitigation.[326] Notwithstanding the fact that AE's retail rates are not subject to the original jurisdiction of the Commission, recent Commission precedent supports rate classes being set at COS, unless gradualism would be appropriate to avoid rate shock.[327]

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318 *Id.*
319 *Id.*
320 *Id.*
321 *Id.*
322 ICA Ex. 3 at 53; ICA Brief at 34.
323 AE Ex. 9 at 11; TIEC Brief at 36.
324 ICA Ex. 3 at 53.
325 AE Ex. 9 at 11.
326 ICA Brief at 34; ICA Ex. 3 at 54.
327 AE Ex. 9 at 11.

The ICA takes issue that under AE's proposal, some classes receive a decrease when the system receives an increase.[328] However, the principle of fairness leans in favor of AE's approach. Classes that are above COS have been paying above-cost charges for many years, and bringing all classes toward COS, even if some classes receive a decrease, is fair and consistent with ratemaking principles.[329] The fact that some classes are getting increases is not a valid reason to delay other classes' movement toward COS.[330]

NXP witness Daniel proposes a two-step approach to revenue distribution methodology.[331] In step one, Mr. Daniel moves all the below-cost classes one-third of the way toward COS. Classes currently above COS are left alone. In step two, Mr. Daniel identifies the overall revenue surplus that exists after step one, and allocates the surplus among above-cost classes in proportion to revenue surplus. Mr. Daniel's approach is flawed in that it does not allow for adequate movement toward COS for the residential class.[332] As explained in AE's RFP, residential customer growth is adding costs to the system that are not avoided when customers conserve energy, and average consumption per customer is declining.[333] These factors are causing the residential class to drift away from cost between base rate updates, as costs to serve residential customers are increasing at a faster rate than revenues collected from them. Therefore, the residential class needs to be assigned enough revenues in this proceeding so that the gap is being gradually closed despite usage trends that will be expanding the gap between base rate reviews.[334] Mr. Daniel's proposal should be rejected.

NXP criticizes AE's revenue distribution methodology because it results in class subsidies and in some customer classes moving further from their COS.[335] While AE's proposal will result in some inter-class subsidization, AE retains subsidies among classes based on the principle of gradualism and in the interests of mitigating the customer bill impacts that would result from moving all classes directly to cost.[336] The residential class would require a 25.7 percent increase to get to cost as originally filed, which would result in rate shock.[337] However, the increase AE

[328] ICA Ex. 3 at 54.
[329] AE Ex. 9 at 13.
[330] *Id*.
[331] NXP Ex. 1 at 42-43.
[332] AE Ex. 9 at 17.
[333] *Id*.
[334] *Id*.
[335] NXP Ex. 1at 5; NXP Brief at 40-42.
[336] AE Ex. 9 at 13.
[337] *Id*.

assigns to the residential class ($52.3 million as originally filed) exceeds the total increase for the system as a whole ($48.2 million as originally filed), and represents meaningful movement toward cost.[338] NXP is incorrect in its assertion that AE's methodology results in some customer classes moving further from their COS. As displayed in AE witness Murphy's rebuttal testimony, all classes move closer to COS under AE's proposal.[339] As shown in the table below, all classes currently below cost would move closer to cost without going above cost, and all classes currently above cost would move closer to cost without going below cost.[340] NXP points out that AE's step one moves some classes further from cost,[341] which is true, but step one is an intermediate step and is not intended to represent a class's final allocation of revenues.

Table 1: Distance from Cost

	CURRENT	PROPOSED	CLOSER?
Residential	-20.4%	-6.5%	YES
Secondary Voltage < 10 kW	-7.1%	0.2%	YES
Secondary Voltage ≥ 10 < 300 kW	23.7%	15.9%	YES
Secondary Voltage ≥ 300 kW	12.5%	8.4%	YES
Primary Voltage < 3 MW	-13.3%	-6.0%	YES
Primary Voltage ≥ 3 < 20 MW	-5.6%	-0.9%	YES
Primary Voltage ≥ 20 MW @ 85% aLF	-12.7%	-2.3%	YES
Transmission	-12.3%	-6.7%	YES
Transmission Voltage ≥ 20 MW @ 85% aLF	20.4%	15.5%	YES
City-Owned Private Outdoor Lighting	-43.0%	-19.3%	YES
Customer-Owned Non-Metered Lighting	-18.5%	-6.2%	YES

TIEC witness Pollock also takes issue with AE's revenue distribution, and his testimony states that AE's revenue distribution does not follow the COS.[342] He also states that AE's method moves two classes—Primary ≥ 3 MW < 20 MW and the High Load Factor Primary ≥ 20 MW—further from cost.[343] Mr. Pollock's proposal is flawed. TIEC proposed a different COS than AE, based on disagreements over cost allocation treatments in the COS study, such as production and distribution capacity costs.[344] Different cost allocation treatments result in a different class COS.

338 *Id.*
339 *Id.* at 14.
340 *Id.*
341 NXP Brief at 41-42; NXP Ex. 1 at 42.
342 TIEC Ex. 1 at 41.
343 TIEC Ex. 1 at 42; TIEC Brief at 37.
344 AE Ex. 9 at 18-19.

Because TIEC's and AE's COS targets are different, it is not appropriate to compare the results of AE's revenue distribution to TIEC's COS study. Regardless of Mr. Pollock's flawed analysis, AE's methodology uses the COS Study to move all classes toward COS, subject to gradualism constraints imposed by the rate shock that would be experienced if the residential class's revenues were set directly to cost.[345] As displayed in AE witness Brian Murphy's rebuttal testimony, under a corrected version of Mr. Pollock's comparison, both primary classes referenced by Mr. Pollock receive revenue decreases and move toward COS.[346]

Table 2: Comparison of Proposed Revenue Distribution Methodology

	Current Distance from cost TIEC CCOSS	Distance from cost TIEC CCOSS and AE Rev Dist	Movement Towards Cost?
Residential	-22.8%	-8.5%	YES
Secondary Voltage < 10 kW	-7.6%	-0.3%	YES
Secondary Voltage ? 10 < 300 kW	22.6%	15.9%	YES
Secondary Voltage ? 300 kW	27.0%	18.3%	YES
Primary Voltage < 3 MW	-11.1%	-2.2%	YES
Primary Voltage ? 3 < 20 MW	**10.0%**	**9.2%**	**YES**
High Load Factor Primary > 20 MW	**37.7%**	**24.1%**	**YES**
Transmission	-26.4%	-10.4%	YES
Transmission Voltage ? 20 MW @ 85% aLF	44.3%	27.6%	YES
City-Owned Private Outdoor Lighting	-38.0%	-16.7%	YES
Customer-Owned Non-Metered Lighting	-36.9%	-16.1%	YES
Customer-Owned Metered Lighting	-24.6%	-9.5%	YES

While each participant advocates for a methodology that would benefit the customers they represent, AE avoids assigning more weight to a class's current position or to its COS by moving all classes halfway to cost, with equal weight assigned to present revenues and COS. AE's proposal is fair, non-arbitrary, and repeatable. AE's proposed revenue distribution methodology should be adopted, and those proposed by the ICA, NXP, and TIEC should be rejected.

[345] *Id*. at 18.
[346] AE Ex. 9 at 20.

V. RATE DESIGN

A. Residential Rate Design

AE is proposing meaningful changes to the residential base rate design. The changes AE is proposing are in response to changes in customers' use of the system that have occurred since the current residential base rate design was adopted. These changes include the increasing share of multi-family as compared to single-family homes, the housing mix becoming smaller and more efficient, and an increase in energy efficiency.[347] Declining average consumption keeps energy sales flat despite customer growth.[348] Revenue growth is hampered by an outdated residential base rate design that relies too heavily on energy sales.[349] The current steep five tier structure results in residential customers being subsidized by other residential customers that reside in the higher tiers, and in the residential class being subsidized by the other rate classes.[350]

To bring base rate financials back into balance, AE is proposing to update an outdated residential base rate structure; better recover fixed costs by relying less on energy sales; and bring customers closer to what it costs to serve them, establishing more equitable charges as the community continues to grow.[351] With respect to its base rate structure, AE is proposing to (1) reduce the number of residential rate tiers for inside City of Austin customers from five to three, which better aligns with the three tiers currently assessed to outside-city customers; (2) flatten the tiers; (3) increase the customer charge to better recover fixed costs; and (4) eliminate the base rate differential between inside- and outside-city customers. These proposals are discussed in more detail below.

Throughout the proceeding, some participants have classified AE's rate design proposal as one that disincentivizes energy efficiency and conservation.[352] AE's proposed base rate design still predominantly focuses on conservation.[353] One hundred percent of the demand costs are designed to be recovered in energy rates.[354] The energy rates are proposed in three tiers of inclining blocks of consumption, which amplifies the conservation price signals.[355] The proposed base rate

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[347] AE Ex. 1 at 78-79.
[348] *Id*. at 9.
[349] *Id*.
[350] *Id*.
[351] AE Ex. 1 at 10.
[352] ICA Ex. 3 at 8; SCPC Ex. 3 at 7.
[353] AE Ex. 9 at 27.
[354] *Id*.
[355] *Id*.

design introduces a greater emphasis on revenue stability and fairness. However, it is important to note that despite this, AE has analyzed the relationship between its base rate structure and conservation and was unable to detect quantitatively any relationship between changes to the rate structure and changes in conservation.[356] While ICA witness Johnson and SCPC/SUN witness Hausman criticize AE's proposal and claim it will weaken conservation price signals,[357] neither has provided any evidence that AE's customers are responding to conservation price signals. These same participants similarly argue that AE's proposed residential base rate design will increase future electricity consumption.[358] These claims are made without basis and with the sole purpose of making AE's proposal seem contrary to the public interest. There is no data to show that consumption will increase.[359]

Other participants claim that AE's proposed base rates should have alternative objectives altogether, such as supporting distributed generation.[360] These recommendations should be rejected, as they appear to suggest that it is sound ratemaking policy to distort base rates to incentivize the adoption of distributed generation technology.[361] Incentivizing the adoption of technologies is not a traditional objective of rate design and should not be emphasized over the primary objectives of fairness, economic efficiency, and revenue stability. AE promotes the adoption of distributed generation and renewable generation through various practices outside of base rates.[362] There is no need to distort base rates to make distributed-generation investments appear more economic.

While several participants categorize AE's residential base rate design proposal as radical, unfair, harmful, and abrupt, AE demonstrated that its proposal is necessary due to customer growth and changes in consumption patterns and corrects for years of subsidizations in an effort to move all classes toward their COS. AE's current residential base rate structure is an industry outlier, and AE's proposal moves residential customers closer to cost, which is a typical measure of fairness. Although AE's proposed base rate design results in an increase for some classes, it is

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[356] AE Ex. 1 at 87-130; AE Ex. 9 at 28.
[357] ICA Ex. 3 at 8; SCPC/SUN Brief at 11.
[358] ICA Ex. 3 at 68.
[359] AE Exhibit 9 at 31.
[360] SCPC Ex. 3 at 25.
[361] AE Ex. 9 at 34.
[362] *Id*. at 35.

cost-based, fair, and avoids rate shock, while still maintaining its emphasis on conservation and energy efficiency.

1. **Customer Charge**

AE's proposal increases the Customer Charge from $10 to $25 to reflect fixed customer costs that do not vary with consumption.[363] Matching the Customer Charge to the customer unit costs will result in customer charge revenues directly tracking the underlying cost driver—the number of customers.[364] While the level of the customer charge should be decided in the COS Study, the proposed Customer Charge is still less than the total combined customer and delivery costs suggested by the COS.[365] Nonetheless, the proposed Customer Charge assists AE in fixed cost recovery.

Historically, the two major policy considerations that have been cited to support the push to limit customer charges for residential customers include: (1) to protect vulnerable customers who are less able to afford a fixed charge on the bill, and (2) to promote energy conservation.[366] As described below, these policy considerations are offset by AE's base rate design and programs. First, and as discussed more fully in Section V.B.1, below, AE has an excellent Customer Assistance Program (CAP) where the Customer Charge is waived for vulnerable customers.[367] This eliminates the concern about vulnerable customers not being able to bear a higher fixed component of the bill, and not being able to otherwise avoid it, such as via changes in usage. Second, as discussed above, AE has proven that its base rate structure has little to no effect on energy conservation. Further, AE has a robust VoS program, discussed in Section VI, and has a separate resource generation and climate-protection planning function outside of the base rate review process.[368]

Several participants attempt to use benchmarking to show that AE's proposed Customer Charge is unreasonably high. For example, ICA witness Johnson compares AE's Customer Charge to MOUs in San Antonio and Lubbock.[369] However, this comparison fails to take into account other factors, such as demographic trends in Austin, including explosive customer growth

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[363] AE Ex. 1 at 109.
[364] *Id*. at 111.
[365] *Id*.
[366] AE Exhibit 9 at 35.
[367] *Id*. at 36.
[368] *Id*. at 35.
[369] ICA Ex. 3 at 13.

and shifts to smaller housing units.[370] Because of these factors, AE's revenue stability has taken on heightened importance and urgency, and it is appropriate for Austin's rates to be different from other MOUs in Texas. With declining average sales per customer, AE must turn to the customer charge to provide financial stability.

Another flaw in the participants' benchmarking analyses is that they fail to account for how AE's well-designed CAP program compares to assistance programs at other utilities. While AE waives the customer charge and CAP CBC, CPS Energy does not.[371] AE also gives a 10 percent discount on remaining charges.[372] CPS Energy requires the customer to apply for enrollment, whereas AE automatically enrolls customers who are already on certain federal, state, and local assistance programs.[373] CPS Energy qualifies customers who are at or below 125 percent of Federal Poverty Guidelines, while AE reaches up to 200 percent.[374] What's more, Lubbock Power and Light (LP&L) does not appear to offer any assistance to vulnerable customers.[375] AE's programs are far more considerate to its CAP customers' needs and AE is in a different position relative to CPS Energy and LP&L with respect to the potential impact of a customer charge on vulnerable customers.

Similarly, participants' benchmarking analyses fail to consider the utilities' mix of power production that is accomplished by fossil plants. For example, in 2021, 28 percent of the power produced by AE came from carbon-based resources.[376] At CPS Energy and LP&L, it was 56 percent fossil, or twice as much.[377] Further, AE has an aggressive plan to eliminate carbon-based generation. Under AE's current Climate Protection Plan, 86 percent of AE's electricity generation will be carbon-free by year-end 2025, 93 percent will be carbon-free by year-end 2030, and all generation resources will be carbon-free by 2035.[378]

Comparing AE's proposed customer charge to other MOUs' customer charges is also flawed in that other MOUs could have a declining block rate structure, while AE's base rate structure is an inclining structure. Other MOUs could also have the lowest usage tier set at a higher

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370 AE Ex. 9 at 39.
371 *Id*. at 36.
372 *Id*.
373 *Id*. at 36-37.
374 *Id*. at 37.
375 *Id*.
376 *Id*.
377 *Id*.
378 *Id*. at 38.

rate, while AE's is the reverse.[379] There are a myriad of factors that make a blanket comparison inappropriate and unreliable, and therefore these arguments put forth by various participants should be ignored. The ICA also compares AE's proposed customer charge to those of IOUs in Texas.[380] However, ICA witness Johnson is comparing wires and poles utilities like Oncor and CenterPoint to AE, a vertically integrated utility. The difference is that in areas open to competition, many of the customer-related services are provided by the retail electric provider (REP), and the costs of those services would not be included in the IOU's COS.[381] As a vertically integrated utility, AE serves the role of the REP, and incurs all the associated customer-related costs.

Additionally, there is Commission precedent to support the customer charge being set to cost, as AE proposes here. In Docket No. 22344, the Commission adopted a uniform rate design for IOU-TDUs where the customer charge and metering charge are set directly to cost.[382] AE's proposal to set the customer charge directly to cost is an accurate application of the uniform rate design.

The ICA appears to arbitrarily recommend that the share of revenues under the customer charge should stay the same, and that in any case, the customer charge should not be set above $13.00.[383] The ICA's recommendation proposes no change to the proportion of revenues collected under the fixed versus the variable charges, which ignores the driving factor in AE's declining financial stability altogether. Maintenance of the existing rate design is not reasonable because it has contributed to the undermining of AE's financial health and resulted in inadequate cost recovery from low-usage customers. The ICA's proposal does not address AE's need to strengthen its financial health and arbitrarily limits the customer charge at $13.00 without any reasoned basis.

The ICA makes several other incorrect assertions. First, the ICA erroneously states that the function of the customer charge is to ration access to the system.[384] The concept of rationing access to AE's system has no value because the City of Austin requires that citizens have electric

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[379] As an example, Denton Municipal Electric's residential rates adhere to a declining block rate structure with the lowest usage tiers experiencing the highest rates. Denton Municipal Utilities, Customer Information, https://www.cityofdenton.com/DocumentCenter/View/648/2020-to-2021-Denton-Municipal-Utilities-Rates-Brochure-PDF.

[380] ICA Ex. 3 at 8; ICA Brief at 37-38.

[381] AE Ex. 9 at 39.

[382] *Id*.

[383] ICA Ex. 3 at 8; ICA Brief at 41.

[384] ICA Brief at 40; ICA Ex. 3 at 61.

service.[385] The customer cannot respond to a price signal "rationing access" and forego electric service. Moreover, the waiver of the customer charge under the CAP eliminates the concern that vulnerable customers might forego electric service to avoid the customer charge.[386] Then, the ICA states that increasing the customer charge will make energy savings measures less attractive, and that a cost-based customer charge will disincentivize the adoption of energy-efficiency measures.[387] However, the ICA's recommendation to keep the customer charge below-cost will make energy-efficiency investments seem more attractive to customers who are calculating bill savings.[388] AE's proposal to set the customer charge to cost is superior from the standpoint of economic efficiency, because it mitigates the financial harm from inflated energy charges.

SCPC/SUN witness Hausman states that AE's proposal would harm energy efficiency and low-income customers.[389] However, in setting the customer charge to the unit cost, AE's proposal has no effect on the energy-related costs and the demand-related costs that are targeted for avoidance via energy efficiency programs.[390] In a continued effort to characterize AE's proposed customer charge as punitive and excessive, Dr. Hausman states that higher fixed charges penalize customers who have already invested in reducing their energy usage,[391] and that a higher fixed charge disincentivizes efficient use of resources.[392] These assertions again mischaracterize AE's proposal. Under AE's proposal, most residential costs would continue to be recovered under energy rates, and a customer who invests in energy efficiency would continue to see significant bill savings from lowered consumption.[393]

2WR suggested that the proposed customer charge was inflated by the inclusion of the GFT, which 2WR described as a profit. 2WR also recommended that the GFT be allocated based on revenues.[394] As discussed in Section II.B.5, the GFT is an expense that must be paid to the City of Austin, and is functionalized based on revenue requirement and then, for the portion that is functionalized to customer, sub-functionalized based on revenue requirement. Thus, the portion of the GFT that ends-up in the customer charge has been allocated based on revenue requirement.

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[385] AE Ex. 9 at 43.
[386] *Id*.
[387] ICA Brief at 40; ICA Ex. 3 at 62.
[388] AE Ex. 9 at 44.
[389] SCPC Ex. 3 at 4.
[390] AE Ex. 9 at 48.
[391] SCPC Ex. 3 at 12.
[392] *Id*.
[393] AE Ex. 9 at 52.
[394] 2WR Ex. 1 at 9-10.

2. **Tiers**

Currently, the vast majority of residential customers that reside inside the City of Austin are billed on a steep five tier structure with each tier priced progressively higher. The first and second tiers are priced below cost and are subsidized by the fourth and fifth tiers that are above cost. More than 40 percent of residential customers are being subsidized by other residential customers that reside in the higher tiers, and the residential class is subsidized by the other rate classes.[395] There are simply not enough customers with consumption in the higher tiers to make up the revenue deficit from the lower tiers' under recovery. Despite these imbalances, AE is mindful of rate impacts and the need for gradualism.

A change to the residential base rate structure is necessary to capture the new composition of the residential customer class. "High-use" customers are gradually disappearing from the system.[396] All the growth in sales is occurring in the lower tiers. The culmination of the shifting of consumption to lower tiers is that 76 percent of residential energy sales in FY 2021 occurred in Tiers 1 and 2, in the consumption blocks below 1,000 kWh.[397] The disappearance of energy sales from higher-priced tiers and the concentration of sales in the tiers priced below COS are two of the factors that have caused the residential class to drift further away from COS since the last rate review.[398] AE's residential base rate design must be adjusted to rely more heavily on cost recovery in the initial tiers, at lower levels of consumption. AE proposes to modify the residential base rate structure by reducing the number of tiers from five to three and flattening the steepness of the rate increases between each tier.

Under AE's proposal, the number of tiers is reduced from five to three, and the tier breakpoints are adjusted downward to match the shift in the bill frequency distribution towards lower levels of consumption.[399] New Tier 1 from 0 to 300 kWh reflects low customer consumption and is set slightly below COS (calculated as demand-related costs divided by kWh).[400] New Tier 2 from 301 to 1,200 kWh reflects the typical residential customer.[401] New Tier 3 is for usage

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[395] AE Ex. 3 at 12, *citing* AE Ex. 1 at 289.
[396] AE Ex. 1 at 103.
[397] *Id*.
[398] *Id*. at 105.
[399] *Id*. at 110-111.
[400] *Id*.
[401] *Id*.

above 1,200 kWh, which represents higher usage customers, and this rate is set above COS.[402] Under the proposal, approximately 34 percent of consumption would occur in the first tier; 50 percent of consumption would be in the second tier; and, the remaining 16 percent of consumption would occur in the third tier.[403]

Several participants take issue with AE's proposed redesign of the current five-tier base rate structure. The specific issues are discussed below, but generally, the participants' positions are to either (1) leave the rate design unchanged, (2) direct AE to develop a new proposal, or (3) to make only a minor change to the current base rate design.[404] These proposals are insufficient. AE's current residential base rate design is based on a 2009 test year, and as discussed above, residential consumption has changed greatly over the past 13 years.[405] In this period, the number of customers with kWh consumption in lower tiers, priced below COS, has increased. This change in consumption renders AE's current residential base rate design ineffective.

AE proposes moving all residential customers to three tiers to simplify its rate structure, create a more equitable rate structure, and address the inability of tier subsidization to accomplish revenue stability.[406] AE also adjusted the consumption levels of the three tiers to better reflect current customer usage patterns.[407] AE incurs significant costs that do not vary with the sale of energy. Those costs are recovered in base rates. However, the current base rate design overly relies on energy sales to generate the appropriate level of revenue. AE addresses this by proposing to increase the customer charge and reducing the rates charged in the residential tiers.

Several participants argue that the current residential base rate design, which includes steep tier pricing, is necessary to encourage energy efficiency.[408] These assertions are not true. Under AE's proposed residential base rate design, high use customers who use more energy will continue to have higher bills, sending price signals to customers.[409] The current inside-city five-tier residential base rate structure creates price distortion by sending incorrect pricing signals, resulting in poor economic decisions for both high and low use customers.[410] In addition, and as already

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[402] *Id.*
[403] *Id.*
[404] AE Ex. 3 at 9.
[405] *Id.*
[406] *Id.* at 10-11.
[407] *Id.* at 11.
[408] ICA Ex. 3 at 70-73; SCPC Ex. 3 at 7.
[409] AE Ex. 3 at 11.
[410] *Id.*

discussed, AE's analysis shows that customers do not respond to tiered pricing signals. The number of tiers and also the incline of the tiers has little effect on conservation among AE's residential customers.[411] AE has not been able to find any evidence in its load data that supports the idea that the number of tiers and the breakpoints of the tiers have any noticeable effect on energy conservation.[412]

AE's proposed residential base rate design, contrary to various assertions made by several participants, does not unfairly impact low usage customers. Currently, the majority of inside city residential customers not in CAP in the first residential tier range from 90 percent to 183 percent below COS.[413] This correlates to more than 40 percent of residential customers being subsidized.[414] The proposals put forth by the ICA and SCPC/SUN are not consistent with current customer usage, continue subsidies within tiers and thus are not based on cost, and do not provide fair and equitable rates. These proposals are not fair—they just reduce costs to low-usage customers and shift their cost responsibility to high usage customers, who are already (1) paying well above cost and subsidizing their low usage neighbors, and (2) charged more for their higher energy usage, resulting in higher bills. Continuing to subsidize low usage customers to the degree they are currently subsidized is not consistent with ratemaking principles, principles of fairness, and will not advance financial health for the utility or the community as a whole.

Participant Paul Robbins characterizes AE's proposal as an abandonment of its progressive rates.[415] However, since AE's tiered base rate structure was implemented, and it is now understood that to achieve conservation, the incline of the blocks does not need to be steep.[416] The State of California has outlawed steeply inclined block rates like AE's due to the resulting downturn of utilities' financial health there.[417]

Several participants contend that the current rate structure is responsible for the declining consumption.[418] As discussed above, AE has not been able to discover any empirical evidence that supports this position. In fact, AE demonstrated in Figure 7.12 in the RFP that outside-city

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[411] AE Ex. 1 at 87-90.
[412] *Id*. at 89-95.
[413] AE Ex. 3 at 12.
[414] *Id*.
[415] P. Robbins Ex. 1, Section 2.1.
[416] AE Ex. 9 at 32.
[417] *Id*., *citing* California Public Utility Commission, Rulemaking No. R.12-06-013, Residential Rate Reform Order Instituting Rulemaking.
[418] P. Robbins Ex. 1, Section 2.1.

customers with three-tiers had the same level of average reduction in consumption as customers inside the City of Austin who had five-tiers.[419] AE's proposal to modify the residential base rate structure by reducing the number of tiers from five to three and flattening the steepness of the rate increases between each tier should be adopted.

3. Rate Differentials

AE proposes to reduce or eliminate rate differentials in two ways—to reduce the steep rate differential between tiers, or consumption blocks, as discussed above, and to eliminate the base rate differential between all inside and outside City of Austin customers, discussed below.

4. Outside-City Customers

AE is proposing to eliminate the base rate distinction between inside- and outside-city customers such that there will be one single residential class that does not distinguish by geographic location.[420] Proposals by HURF and the ICA to maintain separate base rates for outside-city residential customers are not cost-based, fair, or equitable, and should therefore be rejected.

HURF argues for a reduction to the revenue requirement charged to AE' outside-city customers based on the settlement of PUC Docket No. 40627, in which HURF claims the GFT was removed from their COS.[421] HURF's reliance on the settlement in that case is misguided, and as discussed in Section II.B.5, HURF's proposed reductions to rates for outside-city customers should be rejected.

The ICA argues that AE's proposal shifts revenue responsibility from the outside-city customers to the inside-city customers and is therefore unfair.[422] However, no evidence supports the ICA's theory that AE's proposed single residential base rate structure is unfair to inside-city residential customers, other than an apparent preference for subsidization of inside-city residential customers by outside-city residential customers.[423] In addition, leaving outside-city residential customers unchanged would violate cost causation principles used in ratemaking.[424] Therefore, proposals to maintain separate base rates for outside-city residential customers should be rejected.

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[419] AE Ex. 3 at 36.
[420] AE Ex. 1 at 110.
[421] HURF Ex. 1 at 1; HURF Brief at 1, 3.
[422] ICA Brief at 42-44; ICA Ex. 3 at 69.
[423] AE Ex. 3 at 32.
[424] *Id*.

5. **Revenue Sufficiency**

As explained throughout this proceeding, AE is seeking a base rate increase because its financial position is deteriorating. AE's last base rate increase occurred one decade ago in 2012.[425] AE's last base rate change was in 2017, when it reduced rates by 6.7 percent.[426] As a result, AE had a combined net loss of $90 million in FYs 2020 and 2021.[427] Since AE's last ratemaking test year, FY 2014, prices have increased 16.5 percent while rates have remained unchanged.[428] In the last twelve months alone, prices have increased 15 percent.[429] Based on the COS Study using test year FY 2021, AE proposed a $48.2 million base rate increase, which has since been adjusted to $35.7 million.[430]

As discussed in Section II.B.6.b, Fitch Credit Ratings downgraded AE from 'AA' to 'AA-.' Acceptance of the majority of the participants' recommendations would accelerate the deterioration of AE's financial position, further increase AE's leverage, decrease AE's operating cash flow, force AE to expend its cash and reserves, and increase its debt. Participants consistently characterize AE as if it were an IOU seeking to earn a profit for the benefit of its shareholders. The reality is that AE is an MOU seeking to earn sufficient revenue in order to effectively deliver electric service to its customers. AE sets rates to recover only its costs and not to maximize shareholder value.[431] As an MOU, all risks and rewards are borne by the customers, and AE is tasked with managing risks on behalf of its customers. In its proposal, AE is moving residential base rates closer to COS to send the appropriate price signals to customers for good energy decision-making.

Many of the participants' proposals prioritize energy efficiency over stability and financial health, which is not the goal of residential rate design. Focusing exclusively on energy efficiency ignores other important rate design tenets such as effectively yielding the total revenue requirements and providing stable revenues.[432] AE must set rates to comply with its Financial Policies and bond covenants. In setting these rates, AE follows standard ratemaking principles as

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425 AE Ex. 3 at 5.
426 *Id*.
427 *Id*.
428 *Id*.
429 *Id*.
430 *Id*., *citing* AE Ex. 1 at 46.
431 AE Ex. 3 at 29.
432 *Id*. at 30.

stated in the RFP. One of these principles is to ensure the long-run financial strength of the utility.[433] Revenue stability refers to maintaining adequate revenues and cash flow to meet costs on a year-to-year basis. Ongoing revenue stability is a key principle in ratemaking throughout the electric utility industry, as addressed by James C. Bonbright in his Principles of Public Utility Rates.[434]

While AE's current base rates and tariff structures do not support the long-run financial strength and stability of the utility, AE's proposed rates and tariff structures provide a more definitive solution toward the long-run financial strength and stability of the utility as well as promoting energy efficiency.[435] Changes, specifically to the residential base rate design, are required that will support the continued viability of AE to meet current and future obligations. This is what AE is proposing here, and its proposal should be adopted.

6. **Customer Growth**

The AE service territory has experienced unprecedented customer growth. The number of residential customers on AE's system has grown by 16 percent since the last rate review's test year, and the number of non-residential customers has grown by 11 percent.[436] To support customer growth, AE has made significant utility infrastructure investments in power production, transmission lines, substations, distribution poles and conductor, customer support systems, and support services, totaling $2.1 billion from FY 2014 to FY 2021.[437]

AE has an obligation to serve customers in its territory. When a new customer joins the system, AE must ensure that system capacity is available to be dedicated for the customer's use. New customers also require customer support services such as customer care, billing systems, meters, customer records systems, and a slew of other services that cause AE to incur incremental costs, regardless of the customer's usage.[438] When customers join the system, AE's total costs increase. Because AE relies heavily on energy sales to recover its costs, increased costs must be met with a corresponding increase in sales revenues if AE is going to remain financially healthy. Unfortunately, sales growth is not keeping up with customer growth.[439] From a financial

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433 *Id*.
434 *Id*.; James C. Bonbright, et al, *Principles of Public Utility Rates* at 383 (2d. ed. 1988).
435 AE Ex. 3 at 31.
436 AE Ex. 1 at 97.
437 *Id*. at 98.
438 *Id*. at 99.
439 *Id*.

standpoint, the current residential rate design is unsustainable. A dramatic shift in emphasis to a rate design that promotes revenue stability and financial health is necessary.

7. Change in Tiers

A change to the residential rate structure is necessary to capture the new composition of the residential customer class. AE's proposal to modify the residential base rate structure by reducing the number of tiers from five to three and flattening the steepness of the base rate increases between each tier is discussed above in Section V.A.2.

8. Impacts on Vulnerable Customers

The current five-tiered rate structure negatively impacts CAP customers, who on average, consume more power. AE's proposed rate structure benefits CAP customers in at least two ways: (1) it increases the value of rate relief given to vulnerable customers by increasing the value of the CAP's waiver of the customer charge, and (2) it lowers the volumetric rates for high-usage customers, which includes CAP customers.

Several participants contend that low income customers are negatively impacted by AE's proposed residential base rate design. However, CAP customers do not pay the customer charge, and under AE's CAP, raising the customer charge to cost has the added benefit of increasing the rate relief provided to vulnerable customers by increasing the value of the CAP's waiver of the customer charge. Further, AE's research into usage patterns of customers enrolled in the CAP indicates that these customers, on average, use more energy than non-CAP customers.[440] Therefore, the higher customer charge (which CAP customers would not pay) and lower volumetric rates would be a benefit to CAP customers as compared to the current rate structure. AE provided $8.3 million in CAP discounts in FY 2021 and expects to give $14.4 million under the proposed rates.[441]

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[440] AE Ex. 3 at 12, *citing* AE Ex. 1 at 105-109.
[441] AE Ex. 9 at 36.

B. Proposed Residential Rates

As discussed above, AE proposes to modify the residential base rate structure by reducing the number of tiers from five to three and flattening the steepness of the rate increases between each tier, and increasing the proposed customer charge from the current $10 per month to $25 per month. This proposal will stabilize monthly residential bills, reduce the proportion of energy priced below cost, improve cost recovery, stabilize revenues, and result in a fairer rate design in order to effectively support a fast-growing, energy-efficient service territory.[442] While many residential customers may see bill increases under AE's proposal, this is because AE wants the customer's bill to be closer to what it costs AE to serve them, and to send them correct price signals. For the residential class, that means (1) lessening subsidies the class has been receiving from other classes, and (2) lessening subsidies within the class.[443]

The results of AE's COS analysis show that under AE's proposed base rates, all customer classes that participants have expressed concern about would experience charges that are closer to AE's costs incurred to serve the customers.[444] Classes that are experiencing increases are experiencing increases because under current base rates, they are being under-charged by AE relative to what it costs AE to serve them.[445] Classes that are experiencing decreases are experiencing decreases because under current base rates, they are being over-charged by AE relative to what it costs AE to serve them.[446] Customers with different usage levels will see different bill impacts because they are not equidistant from cost. This explains why customers see different impacts from the proposal.

Participants proposed alternative residential rate designs, namely the ICA. While AE's proposal treats customers the same with respect to where they would be relative to cost, ICA witness Johnson's proposal seeks to preserve subsidies for certain groups.[447] The analysis supporting these conclusions can be seen in Exhibit BTM-2.[448] AE's goal is fairness, which is achieved when the bill is at cost.

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[442] AE Ex. 1 at 109.
[443] AE Ex. 9 at 57.
[444] *Id*. at 58.
[445] *Id*.
[446] *Id*.
[447] *Id*. at 58.
[448] *Id*. at 69-76.

1. CAP Program Benefits

The proposed base rate design will significantly increase benefits under the CAP program to achieve greater levels of social equity among AE's residential customers. The value of the CAP program's waiver of the customer charge increases by 150 percent, from $10 per month to $25 per month. Using load information from the COS Study, AE expects the total value of CAP benefits to increase from $8.3 million to $14.4 million.[449] The increases in this value do not affect the base rates of any customer, but rather are funded exclusively through the CBC.

Participant Paul Robbins erroneously states that AE is increasing the CAP subsidy to compensate for radical rate restructuring.[450] Mr. Robbins misunderstands the way the CAP benefits are incurred. AE is not proposing any changes to the structure of the CAP. The expected increase in benefits under the CAP is a byproduct of the changes to the residential base rate design.[451] AE's proposed base rate restructuring is therefore responsible for the increase in the total value of CAP benefits.

Several participants, including Paul Robbins and the Solar and Storage Coalition (SSC), propose programmatic changes to the CAP, including changes to the enrollment process. Programmatic changes to the CAP, including the enrollment process, are outside the scope of this Base Rate Review. Therefore, AE is not seeking a ruling on these recommendations.

C. PRI-2 High Load Factor Tariff

AE proposes a new High Load Factor Primary Voltage tariff that will be available to customers who take service at primary voltage at a load level greater than or equal to 3 megawatts (MWs) but less than 20 MW, and whose monthly average load factor during the course of the year meets or exceeds 85 percent.[452] This new system of charges creates a new rate class of AE customers, the PRI-2 High Load Factor (PRI-2 HLF) class.[453] The creation of the new rate class is revenue neutral with regard to base rates.[454] Currently, AE offers a high-load factor rate option to primary customers at a load size above 20 MW.[455] The new charges for PRI-2 HLF customers

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[449] *Id*. at 36.
[450] P. Robbins Ex. 1, Section 1.4.
[451] AE Ex. 9 at 47.
[452] AE Ex. 1b.
[453] *Id*. at 2.
[454] *Id*.
[455] *Id*. at 3.

make the same rate option available to primary customers at lower load levels but with similar load profiles. This rate option is being extended to customers who exhibit steady loads and therefore utilize system resources more efficiently. The PRI-2 High Load Factor Tariff advances the important ratemaking objectives of fairness, economic efficiency, and revenue stability.[456] While the PRI-2 HLF class would be exempted from energy efficiency programs and energy efficiency charges, this is consistent with the treatment of AE's PRI-4 HLF rate class by recognizing that larger customers generally have sophisticated energy management programs, often have corporate mandates to manage energy use, and are capable of implementing their own energy efficiency measures.[457]

Rate design for the PRI-2 HLF rate class is two-part, with a customer charge and a demand charge.[458] The customer charge is set to the PRI-2 class's customer unit cost from the COS Study. The PRI-2 customer unit cost represents the costs per customer per month that AE incurred to provide customer-related services to customers in the PRI-2 class during FY 2021.[459] The second component of the PRI-2 HLF class's rate design is the demand rate, which is set to collect the remaining revenues assigned to the PRI-2 HLF class.[460] The level of revenues used to design the rates is a subset of the PRI-2 rate class's target revenues, determined by calculating the amount of revenues that would have been collected from all high-load factor customers in the class under the PRI-2 HLF class's proposed rates.[461]

Customers in the PRI-2 HLF class will see no energy base rates, which is appropriate. There are no energy costs to be recovered under an energy base rate, and the use of an energy rate to recover demand and customer costs creates fairness and efficiency problems.[462] PRI-2 HLF customers would be charged the energy rate under the PSA.[463] The PSA represents the cost of energy, and will be assessed to PRI-2 HLF customers on a per-kWh basis, same as all other customers.[464] PRI-2 HLF customers will not be assessed the energy efficiency rate because they

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[456] *Id*. at 2.
[457] *Id*. at 3-4.
[458] *Id*. at 4.
[459] *Id*.
[460] *Id*.
[461] *Id*.
[462] AE Ex. 9 at 60.
[463] *Id*.
[464] *Id*.

are not eligible for the programs and do not participate in the programs, as discussed more in Section VII.b, below.

Customers who take service under the PRI-2 HLF rate option will be required to sign a full requirements contract with a three-year term during which rates remain unchanged, similar to AE's current PRI-4 HLF class.[465] The PRI-2 HLF rate class's CAP and Service Area Lighting charges under the CBC will apply.[466] CAP charges will be limited to a maximum of $200,000 per account per year.[467] This proposal aligns with AE's longstanding ratemaking principles and will help to improve the long-term financial strength of the utility.

No participants oppose the creation of the PRI-2 HLF rate class, although SCPC/SUN and Paul Robbins take issue with the exemption of the class from energy efficiency charges, discussed further in Section VII.b.

D. Proposed Primary Substation Rate

NXP and TIEC argue for the creation of a new Primary Substation Rate.[468] AE incorporates by reference all of its arguments in Section III.D.1.c, and recommends that this proposal not be adopted in this proceeding. None of the primary >= 20,000 kW customers are served directly from any substation on AE's system, and TIEC and NXP do not own or maintain the distribution facilities necessary to serve the primary voltage customers load up to the POI.[469] TIEC argues that AE should allow Primary Substation customers to purchase the distribution assets used to serve them,[470] but AE is unaware of any such pending proposal from TIEC or another customer. Therefore, NXP and TIEC's proposal to create a new Primary Substation Rate should be rejected.

E. Proposed Facilities Charge Tariff

AE incorporates by reference its discussion of the proposed Primary Substation issue as previously discussed in Section III.D.1.c and Section V.E.

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465 AE Ex. 1b at 5.
466 *Id*.
467 *Id*.
468 TIEC Ex. 1 at 33-34; NXP Ex. 1 at 33-34.
469 AE Ex. 8 at 25.
470 TIEC Brief at 39.

F. Ratemaking Principles

During the 2012 Base Rate Review, the City Council adopted a set of ratemaking principles. AE's proposed rate design complies with each principle.[471]

1. Weather-Based Volatility in Revenues

AE's proposal reduces weather-based volatility in revenues. Under the current residential base rate design, fixed customer costs are included in the energy rates, which results in volatile revenues under energy rates because they are subject to weather fluctuations.[472] Under the existing rate structure, AE will under-recover its costs if it experiences a mild summer and energy sales are lower than average.[473] Under the current residential rate structure with the $10 customer charge, actual revenues can fall within an envelope that covers a range of almost $70 million above and below expected revenues.[474] The proposed base rate design reduces this variation by increasing the customer charge and flattening the tiers, both of which lessen the susceptibility of base revenues to weather fluctuations.[475]

2. Seasonal Swing in the Bill

AE's proposed base rate design will mitigate seasonal rate shock by decreasing volatility in electric charges from non-summer to summer.[476] Air conditioning systems run hard during Austin's summers, consuming a lot of power to cool homes. Cooling load adds consumption to the customer's monthly bill. On average, a residential customer's consumption increases by 342 kWh per month during the summer months (June to September), which is a 49 percent increase (from 704 to 1,046 kWh).[477] At the same time, higher levels of consumption during the summer occur in tiers 4 and 5, where rates are higher.[478] Increased consumption coupled with higher pricing creates a situation where summer base charges are typically significantly higher for AE's residential customers as compared to non-summer base charges. In FY 2021, average residential base charges were $35.90 in the non-summer season, but $56.76 during the summer season, an

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[471] AE Ex. 1 at 114-116.
[472] *Id*. at 116.
[473] *Id*. at 116-117.
[474] *Id*. at 117.
[475] *Id*.
[476] *Id.* at 118.
[477] *Id*.
[478] *Id*. at 119.

increase of 58 percent.[479] By flattening the tiers and increasing the customer charge, the proposed rate design mitigates this problem. Under the proposed base rates, the average swing from non-summer to summer would fall to 27 percent, from $53.46 to $68.02.[480]

G. Load Factor

AE's proposal mitigates fairness issues with respect to customers' load factors. AE incurs many costs in serving residential customers that are primarily driven by peak demand, rather than by total energy.[481] Some examples include the costs of the number and capacity of wires and the number and capacity of transformers.[482] Such costs may be referred to as "capacity costs," since installing and maintaining the capacity to serve creates the cost. For residential customers, AE recovers such capacity costs, which arise from peak demand, through charges on total energy.[483] Customers with flatter load profiles will subsidize the capacity costs incurred by AE to serve customers with more peaked load profiles.[484] Customers with flatter load profiles are said to have higher load factors, and, if capacity costs are recovered through total energy charges, customers with higher load factors will subsidize capacity costs caused by customers with lower load factors.[485]

The proposed base rate design mitigates this issue by increasing the customer charge and flattening the tiers.[486] The fairness and efficiency problem was expressly recognized by the Commission in Docket No. 43695, the last fully litigated base rate proceeding for Southwestern Public Service Company. The Commission found that "[i]ncreasing the [customer] charge to the Residential Service class will reduce the amount of capacity costs caused by that class being paid by customers with higher load factors that use capacity more efficiently."[487] AE's proposed increase to the customer charge is consistent with the Commission's decision in Docket No. 43695. Fully addressing the fairness and efficiency issues that arise from setting energy rates to recover demand costs is a significant challenge in residential rate design. The flattening of the tiers prepares AE for a more equitable treatment to address this challenge in the future.

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479 *Id*.
480 *Id*.
481 AE Ex. 1 at 120.
482 *Id*.
483 *Id*. at 121.
484 *Id*.
485 *Id*.
486 *Id*.
487 *Id*.

H. Load Size

Under steeply inclined residential tiered energy rates, such as in AE's current residential base rate structure, as customers consume more, they pay more per kWh.[488] This is true no matter how much it costs AE to serve the customers or how efficiently they use the system, which represents a fairness issue with the current base rate structure. The proposed base rates address this issue by lowering the rate differentials between tiers.

I. Increased Transparency

AE's proposed residential base rate structure will support low-income customers and be more transparent.[489] Reducing the energy burden on vulnerable customers is best addressed through targeted programs rather than rate structures, which can have unintended negative consequences for both the customer and AE.[490] In its base rates for residential customers, AE has the CAP, a targeted program to assist vulnerable customers. For those who qualify, AE waives the Customer Charge and the CAP component of the CBC and offers a 10 percent discount on all energy-based charges.[491] This is a direct and transparent way to provide bill assistance. Base rates are designed to recover costs; the CAP program is designed to assist vulnerable customers.[492] AE proposes that all the bill assistance for vulnerable customers be transparently provided under the CBC. The proposed base rate design mitigates the provision of nontransparent bill assistance to low usage customers by flattening the tier structure.[493] At the same time, the proposed increase to the Customer Charge will increase the value of the discount to the CAP customer that results from the waiver of the Customer Charge, which also increases the transparent portion of the bill assistance.[494]

1. Commercial and Industrial Base Rate Design

For non-residential customers, AE proposes several general adjustments to the base rate design: (1) increasing fixed charges for revenue stability; (2) eliminating the billing-unit adjustment that currently benefits low-load factor commercial customers; (3) calculating the

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[488] *Id*. at 122.
[489] *Id*. at 123.
[490] *Id*.
[491] *Id*.
[492] *Id*.
[493] *Id*.
[494] *Id*. at 123-124.

billing demand for Houses of Worship customers the same as all other commercial customers; (4) establishing consistency in recovery of discounts for State accounts and independent school districts accounts by assigning this cost responsibility to all non-lighting classes in proportion to COS; and (5) combining the current electric delivery charges with the demand charges.[495]

Similar to residential customers, the proposed base rates for non-residential customers generally reflect increased fixed charges (i.e., customer charge and demand charge) plus the elimination of the delivery charge.[496] To accommodate the elimination of the delivery charge, the demand charge was correspondingly increased. The proposed base rates also eliminate two rate accommodations under the existing rates. First, AE proposes to eliminate the low-load factor floor for commercial customers in the Secondary Voltage ≥ 10 < 300 kW and Secondary Voltage ≥ 300 kW customer classes.[497] Second, AE proposes to treat Houses of Worship customers just like other commercial customers, who are billed for demands regardless of what day of the week their maximum demand might occur.[498] No participant raised issues with AE's proposed commercial and industrial base rate design.

2. Proposed Non-Residential Rates

The proposed base rates for all non-residential and non-lighting customer classes are summarized in Table 7-D through Table 7-K of the RFP.[499] No participant raised issues with AE's proposed base rates for non-residential and non-lighting customer classes.

3. Gradualism

Although AE would support a class revenue distribution that sets each rate class at its COS, AE recognizes that in the current proceeding, a purely cost based approach would result in rate shock to the residential customer class. Therefore, as discussed above in Section IV, AE has imposed a gradualist approach in its proposal in this proceeding. AE's goal is to eventually bring all classes to cost such that gradualism is not necessary in future ratemaking proceedings.

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[495] *Id*. at 124.
[496] *Id*.
[497] *Id*.
[498] *Id*. at 125.
[499] AE Ex. 1 at 125-127.

J. Proposed Tariff

AE has included a copy of its proposed Tariff in Appendix F of in the RFP.[500]

VI. VALUE OF SOLAR

AE is proposing a new approach to VoS that provides greater transparency and flexibility in order to achieve a rate design that fairly compensates customers for their onsite renewable energy production and adequately stimulates customer-sited solar adoption to help meet the City's Resource Generation and Climate Protection goals.[501] In particular, AE identified some components historically used to calculate the VoS rate that were based on assumptions that no longer align with AE's underlying costs. As such, AE is proposing three changes to the VoS program. First, AE proposes separating the imputed VoS rate into three pillars: avoided costs, societal benefits, and policy driven incentives.[502] Second, AE is recommending changing the funding source for VoS from being funded solely from the PSA to being funded through the PSA and the Energy Efficiency Services (EES) charges.[503] The portion being recovered through the PSA is the avoided costs of purchased power, which is appropriate. The societal benefits and policy driven incentives which are not avoided purchased power costs, should be recovered through the EES where other similar program costs are being recovered, such as rebates and other solar incentives. Finally, AE is proposing to change the current methodology for determining the VoS rate from a future-looking method to a backward-looking method.

AE is proposing these changes to (1) create transparency by making clear delineation between the values used to impute VoS; (2) align recovery with the most appropriate rate mechanism; and (3) move from a marginal cost basis to an embedded cost basis for the avoided cost component of the VoS.[504] Specifically, VoS is an aggregated value that includes marginal costs, avoided costs, and environmental costs. Disaggregating the value into the three pillars noted above will increase transparency. Additionally, collecting the avoided costs through the PSA and the societal benefits and other subsidies through the EES component of the CBC would clearly

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[500] AE Ex. 1 at 459-506.

[501] Several participants expressed objection or confusion over AE proposing to change the VoS tariff within the context of this Base Rate Review. This was done because it is required by the VoS tariff. Specifically, the tariff states that the VoS rates, methodology, and inputs are required to be re-assessed and updated during AE's rate review using the calculations outlined in the tariff. It is for this reason that AE is addressing the VoS at this time.

[502] AE Ex. 1 at 140.

[503] *Id*. at 143-145.

[504] *Id*. at 16.

differentiate the imputed avoided cost of rooftop solar power from its societal costs and other subsidies.[505] Finally, it is preferable to calculate the avoided cost component on an embedded historical cost basis as opposed to a marginal cost basis that relies on estimated future costs. The embedded cost basis relies on actual documented expense. This would be consistent with AE's other rates including its power supply costs that are collected through the PSA. Consequently, the avoided cost of VoS would be calculated consistent with other power supply costs. With these changes AE will continue to be a national leader in the development of solar, demand-side management, and renewable energy initiatives.

The VoS is the rate at which AE credits residential and commercial customers with behind-the-meter solar generation system for the energy produced.[506] Historically, the methodology used to determine the VoS rate has been forward-looking, calculated based on marginal cost avoidance, and included an environmental adder in addition to avoided costs to the utility.[507] These costs were collected through the PSA. The goal of the new methodology is to promote transparency by making clear delineations within the VoS rate and to align the justifications with the most appropriate rate mechanisms.[508] Separating the VoS into three "pillars" will help to accomplish this. AE will conduct an annual assessment of each pillar to ensure the prevailing rates are consistent with market conditions, environmental reports, and policy objectives.[509] AE will hold a public meeting with each reassessment, present the findings to the EUC and Resource Management Commission (RMC), and seek City Council approval prior to implementation.[510]

With respect to the avoided cost component, AE proposes an approach that is inherently focused on the embedded costs that can be avoided by behind-the-meter solar generation systems.[511] This methodology bases the value components on the past FY as opposed to the historical methodology that looked to the future. The proposed methodology more accurately reflects the actual, realized value of distributed generation.[512] The avoided costs would be reevaluated annually.[513] This analysis is objective based on avoided costs that accurately reflect

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[505] *Id*. at 143-145.
[506] *Id*. at 138.
[507] *Id*.
[508] *Id*. at 140.
[509] *Id*.
[510] *Id*.
[511] *Id*. at 140-141.
[512] *Id*. at 143.
[513] *Id*.

the true benefits of solar customers to the system and is not outcome driven.[514] SCPC/SUN witness Rábago complained that AE's avoided cost calculation ignores avoided costs associated with system capacity, reserve generation and distribution capacity.[515] However, solar customers still require distribution infrastructure to serve them at times when their generation is not producing, and these customers use the distribution system to send their excess production onto the grid. In addition, AE is proposing to increase the VoS credit over the current value as well as over the calculated value using the current methodology for test year 2021, and the utility does not seek to suppress the credit as claimed by SCPS/SUN witness Rábago.[516] Since AE is crediting solar generation customers for their renewable energy contribution, the avoided cost component will be recovered through the PSA.

The second pillar is the societal benefit component. To calculate this component AE proposed to reference the social cost of carbon at a three percent discount rate. Mr. Rábago expressed concern that the societal benefit value does not include the societal benefits of avoiding a wide range of air-borne pollutants.[517] However, the societal benefit portion of the VoS is based on the societal cost of carbon and the avoided metric tons of CO2/MWh based on the Texas energy mix.[518] The AE proposal bases that value on carbon, in alignment with the objectives of the AE Resource, Generation and Climate Protection Plan to 2030 and is also in alignment with the City of Austin's overall climate goals. Additional details setting out how this component will be calculated are found at pages 144-145 of the RFP.[519] While the entire VoS including environmental benefits was historically recovered through the PSA, the societal benefit value does not represent an avoided cost to AE, so this cost should be recovered through the EES portion of the CBC going forward.

The third pillar relates to policy driven incentives. This proposed adder will be administered in the format commonly known as a performance-based incentive (PBI). Once in place, solar customers will be locked into the prevailing PBI based on their customer class. In contrast to the other two pillars, the PBI will not fluctuate in order to provide stability to customers

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[514] AE Ex. 7 at 8.

[515] SCPC Ex. 2 at 21.

[516] SCPC/SUN makes this same incorrect assertion in its brief: "Austin Energy seeks to alter the fundamental structure of the Value of Solar tariff by suppressing the production credit for customer-sited solar generation." SCPC/SUN Brief at 27.

[517] SCPC Ex. 2 at 8-9.

[518] AE Ex. 7 at 9.

[519] AE Ex. 1 at 144-145.

who invest in solar generation systems. Like the societal benefits and current incentives, the policy driven incentives will be recovered through the CBC.

SCPC/SUN witnesses Reed and Rábago expressed numerous concerns about the proposed changes to the VoS program. These concerns were detailed in SCPC/SUN's brief. Unfortunately, many of SCSPC/SUN statements are exaggerated or simply untrue. For example, SCPC/SUN asserts that AE is crediting solar customers with only the avoided cost of energy.[520] This is incorrect. AE proposed VoS includes credits associated with avoided costs, societal benefits, and policy driven incentives. Similarly, SCPS/SUN's asserts that under AE's proposal the avoided cost component would be calculated based on the previous year's average day-ahead price for ERCOT system energy and a fixed, nominal credit for transmission and ancillary services.[521] This is incorrect. Transmission and ancillary service values in AE's proposal are neither fixed nor nominal. SCPS/SUN claims that AE is proposing to "to slash its Value of Solar."[522] This is also incorrect. In truth, AE is proposing increases to the VoS rates over the current value as well as over the calculated value using the current methodology for test year 2021. The proposed increases are shown in Table 9-E, page 148 of the RFP.[523] SCPC/SUN incorrectly states that "Austin Energy proposed changes also disregard the utility's obligations under the 2030 Climate Plan."[524] In fact, this is specifically what the policy driven incentives are intended to address.[525] Finally, SCPC/SUN argues that "numerous jurisdictions have used true Value of Solar analyses to inform and support net metering and related customer generation rate decisions."[526] One of the reasons AE rejected net metering is because net metering credits would be considerably less per kWh. The only "true VoS analysis" that supports a VoS rate are those currently and historically conducted by AE. In sum, SCPC/SUN's statements about best practices are unsubstantiated for VoS rates.

SCPC/SUN witnesses Reed and Rábago also expressed concerns to the societal benefits and policy-based incentives of AE's VoS proposal. Specifically, Mr. Reed states that the recovery of VoS societal benefits through the EES charge will reduce the amount of monies available for other EES programs.[527] As discussed in the rebuttal testimony of AE witness Génecé, these

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[520] SCPC/SUN Brief at 1.
[521] *Id*.
[522] *Id*.
[523] AE Ex. 1 at 148.
[524] SCPC/SUN Brief at 23.
[525] AE Ex. 1 at 146.
[526] SCPC/SUN Brief at 28.
[527] SCPC Ex. 1 at 6.

concerns are unfounded. AE proposes a budget each year that is approved by the Austin City Council that provides the cost basis for determining the EES factors being charged to customers. This budget process is open to public participation and is the starting point for determining the amount of funds that will be available for funding EES programs. Additionally, there are multiple other settings where the public may weigh in on budgets and programs, such as the monthly EUC and RMC meetings. The EES budget is not determined by the EES charges; the EES charges are determined by the EES budget. Also, there is no proposed reduction of EES budget in the FY 2023 proposed EES budget portion of the Consumer Energy Solutions (CES) budget. In fact, the proposed CES budget for FY 2023 is larger than the current CES budget for FY 2022.[528] Contrary to Mr. Reed's claims, a more accurate and transparent method of paying for societal benefit portion of the VoS will not result in necessary programs being cut. Because a portion of the VoS credit is attributable to the societal benefits, funding this portion of the VoS through the EES fee rather than the PSA is a more transparent means of calculating the true goal being accomplished, rather than funding it entirely through the PSA despite only a portion being based on avoided costs. In addition, any increase in the EES charge due to VoS may be offset by a decrease in the PSA.

SSC made several suggestions for programmatic changes to VoS.[529] AE witness Maenius' responded in his rebuttal testimony by pointing out that SSC's proposals are outside of the scope of this Base Rate Review proceeding.[530] As noted in the Procedural Guidelines, only the VoS rates, methodology, and inputs—not programmatic changes—will be re-assessed and updated during this Base Rate Review.[531] Additionally, billing system updates will be considered by AE at the appropriate time, which again, is not during this Base Rate Review. Further, the proposed 24x7 carbon free rate is also beyond the scope of this proceeding.[532] Regarding the proposal to consider automatic enrollment for CAP in certain geographic areas, that is further addressed in the testimony of AE witness Galvan.[533]

In summary, AE seeks to promote full transparency of the costs and values associated with the VoS rate in order to promote informed discussions and solid policy making. Changes to the

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528 Upon approval of the VoS rate proposals, AE will request a budget amendment to increase the EES budget by the amount needed to recover the societal benefits portion of the VoS.

529 SSC Brief at 1-7.

530 AE Ex. 2 at 12. At the appropriate time, AE commits to including SSC as stakeholders in the development of programs raised in its brief.

531 AE Ex. 1 at App. 4.

532 *Id.*

533 AE Ex. 5 at 7-8.

calculation methodology and recovery method of the three pillars will achieve these goals. Significantly, the proposed methodology changes result in increase to the VoS for all customer classes relative to the current VoS rate. Therefore, proceeding with the proposed VoS tariff, rather than suspending any changes, will not make customers less likely to invest in solar generation as claimed by some participants. AE's proposed VoS tariff provides fair compensation for measurable benefits that solar customers create for AE and the community. As discussed above, the criticisms levied by the participants towards the VoS program should be rejected.

VII. OTHER ISSUES

A. Proposed Power Supply Adjustment Factor Adjustment for Primary Substation Customers

TIEC recommends that the proposed PSA should be revised to include a separate Primary Substation Adjustment Factor.[534] AE has differentiated the PSA charges by voltage—specifically, the service provided at transmission, primary, and secondary voltages—to recognize the differences in energy losses. AE does not have any primary substation customers. Primary distribution customers are within the primary distribution class and should be allocated a proportional share of the costs for the primary distribution system as developed by AE and included in the proposed base rate charge. Therefore, TIEC's recommendation should be rejected. AE's positions regarding the Primary Substation Issue are reflected above in Section III.D.c and Section V.D. Moreover, the PSA is not under review in this proceeding.

B. Energy Efficiency Service

As discussed above in Section V.C, AE proposes a new PRI-2 HLF rate class available to qualifying customers. AE currently offers a high-load factor rate option to primary customers at a load size above 20 MW, and AE's proposal makes the same rate option available to primary customers at lower load levels but with similar load profiles.[535] This rate option is being extended to customers who exhibit steady loads and therefore utilize system resources more efficiently.[536] The PRI-2 HLF class would be exempted from energy efficiency programs and energy efficiency charges, which participants SCPC/SUN and Paul Robbins object to.

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[534] TIEC Brief at 40.
[535] AE Ex. 1b at 3.
[536] *Id*. at 2.

The exemption of the PRI-2 HLF class from energy efficiency charges is consistent with the treatment of AE's PRI-4 HLF rate class by recognizing that larger customers generally have sophisticated energy management programs, often have corporate mandates to manage energy use, and are capable of implementing their own energy efficiency measures.[537] Further, these customers are not eligible to participate in AE's energy efficiency programs, so it is logical that they would not be subject to charges associated with programs they have no opportunity to benefit from.

SCPC/SUN opposes the exemption of the PRI-2 HLF class from energy efficiency charges and argues that all customers should be required to pay an EES charge. SCPC/SUN also argues that any and all customers can make private efficiency investments.[538] SCPC/SUN fails to consider that these high load factor customers have unique incentives, very different from residential and small commercial customers, to make private energy efficiency investment because electricity is one of the largest cost drivers for their business. These customers have their own sophisticated energy efficiency programs and make significant energy efficiency investments, and, as explained in the briefs of TIEC and Data Foundry, therefore do not benefit from AE's energy efficiency programs.[539] TIEC and Data Foundry also raise important precedential factors that AE supports. As stated in their briefs, the Texas Legislature codified the exemption of industrial customers from utility-administered energy efficiency programs in areas with retail competition in 2007.[540] The Commission then conducted rulemakings instructing that industrial customers cannot be required to participate in a Commission-jurisdictional energy efficiency program.[541] The policy behind these precedents holds true for AE and its customers, and therefore should be applied here.

SCPC/SUN also takes issue with the lack of quantifiable energy efficiency benefits that high load factor customers provide to the system, and recommend that all customers under the PRI-2 HLF rate class, and other transmission-level and primary-level customers, be subject to an "EES opt-out provision" in exchange for "an annual public report on their efforts to reduce energy use, lower peak demand and take actions to generate power locally."[542] AE has not proposed any

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[537] *Id*. at 3-4.
[538] SCPC/SUN Brief at 29-30.
[539] TIEC Brief at 42; Data Foundry Brief at 6.
[540] Data Foundry Brief at 8, *citing* Data Foundry Ex. 1 and TIEC Ex. 2 at 13-14.
[541] Data Foundry Brief at 8, *citing Rulemaking Proceeding to Amend Energy Efficiency Rules*, Project No. 39674.
[542] SCPC/SUN Brief at 34-35.

such mandatory reporting requirement, and generally agrees with TIEC and Data Foundry that requiring these customers to publicly disclose their energy efficiency efforts and investments imposes on the proprietary and confidential nature of such information, and would provide no benefit to AE's energy efficiency programs.[543]

Participant Paul Robbins also disputes AE's proposal to exempt the PRI-2 HLF class from energy efficiency charges and states that it will lead to subsidization.[544] This is not true. Subsidization occurs when costs caused by one group of customers are shifted onto rates by other customers who did not cause the costs. AE's proposal avoids the problem which would arise if PRI-2 HLF customers were assessed the energy efficiency component of the CBC, which would cause costs to be shifted from the customers who participate in the programs onto PRI-2 HLF customers.

Mr. Robbins raises several other misconceptions about the PRI-2 HLF class. First, he claims that PRI-2 HLF customers would not see energy rates.[545] It is appropriate that PRI-2 HLF customers will see no energy base rates. There are no energy costs to be recovered under an energy base rate, and the use of an energy rate to recover demand and customer costs creates fairness and efficiency problems.[546] PRI-2 HLF customers would be charged the energy rate under the PSA.[547] The PSA represents the cost of energy, and will be assessed to PRI-2 HLF customers on a per-kWh basis, same as all other customers. Mr. Robbins then states that the lack of an energy charge for PRI-2 HLF customer would induce waste.[548] The flaw in Mr. Robbins' reasoning is in thinking of energy consumption by commercial customers as the same as consumption by residential customers.[549] The conservation considerations are different for commercial customers as compared to residential. For a commercial or industrial customer, energy consumption fuels the production of goods and services and the creation of economic value.[550] Because much of AE's energy supply comes from renewable resources, all customers who pay the PSA, including PRI-2 HLF customers, contribute to clean energy.[551] Mr. Robbins also contends that the creation of a

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[543] TIEC Brief at 43-44; Data Foundry Brief at 9-14.
[544] P. Robbins Ex. 1 at Section 2.2.
[545] *Id*.
[546] AE Ex. 9 at 60.
[547] *Id*.
[548] *Id.*
[549] *Id*.
[550] AE Ex. 9 at 60.
[551] *Id*. at 60-61.

PRI-2 HLF class will reinforce an undesirable pattern.[552] Providing the high-load factor option to customers with load above 20MW, but not for customers with load between 3MW and 20MW, is inconsistent, and could be perceived as discriminatory. The proposal avoids this issue by extending the same option to primary customers at lower load levels, mitigating discrimination in the rate structure.

AE's proposal to create a new PRI-2 HLF rate class extends a high-load factor rate option available to AE's largest commercial customers to primary customers at lower load levels but with similar load profiles. The customers exhibit steady loads and therefore utilize system resources more efficiently, and AE's proposal should be adopted.

C. Additional Issues

The ICA claims that AE's current base rate design is "inappropriately blamed for utility financial performance."[553] This is untrue, has been disproven, and is discussed at length in Section V. The ICA also raises concern with the test year used and appears to argue that COVID and Winter Storm Uri have some impact on the COS, which the ICA acknowledged relied upon normalized billing units.[554] Despite this acknowledgment, the ICA still argues, without any evidence, that these events impacted actual revenues and costs "that AE uses to tie its claim of financial stress to the residential rate design."[555] As discussed in Section II.B.1.e., while COVID and Winter Storm Uri were severe events, their impact on AE's finances was relatively modest.

The ICA then mirrors the argument of SCPC/SUN that AE's current five-tier structure is solely responsible for promoting reduced power usage and energy efficiency, and that AE has therefore been "too effective" at promoting energy conservation and as a result, seeks to raise rates for residential customers.[556] As explained in Section V.A.2, the majority of AE's sales occur in tiers that are priced below COS. Regardless of the number of tiers or the differential in rates between the tiers, customers in the lowest usage tiers have not been paying their full COS and cannot continue to be subsidized. The ICA relies on a thirteen-year-old rate design that fails to account for changes in residential consumption and continues significant subsidies. Notwithstanding any of those considerations, the ICA continues to promote that AE's proposed

[552] *Id.*
[553] ICA Brief at 44-45.
[554] *Id.*
[555] *Id.* at 45.
[556] *Id.*

residential base rate design will "increase further electricity consumption,"[557] even though AE has proven that the number of tiers and the incline of the tiers has *little to no effect on conservation.*[558] The ICA's furtherance of the idea that AE seeks to undermine its own energy efficiency success distracts from the bottom line—that AE has been dramatically under-collecting from its residential ratepayers who have been subsidized to an unsustainable degree.

VIII. CONCLUSION

In this proceeding, AE seeks to increase revenues by $35.7 million. In support of its request, AE presented an RFP, supporting narrative, and rebuttal testimony in order to demonstrate the reasonableness of its request. As noted in the introduction to this brief, six of the fourteen participants in this case proposed adjustments to AE's proposed revenue requirement. Those adjustments ranged from $11 million to $41.7 million. These participants propose significantly different revenue requirement and cost allocation recommendations. Only AE presented a case that attempted to balance the interests of customers, the utility, and the community as a whole.

Furthermore, AE entered into a deliberative process in order to receive public input into the setting of its base rates. The City of Austin engaged an ICA to represent customers that may not be able to afford representation and hired an IHE to hear the evidence and make recommendations. From a procedural perspective, AE established a formal proceeding that facilitated input and transparency to give more access and receive feedback from its customers. Despite criticisms to the contrary, no other similarly situated utility in the state has undergone such a comprehensive or transparent process. Moreover, that transparency exists only because AE remains committed to such goals.

Finally, AE extends it appreciation to the IHE for his thoughtful consideration of the evidence and patience with this process. AE anticipates a well-reasoned report that will provide guidance to AE and the City Council on providing better service and reaching the proper outcome in this case. In conclusion, AE requests the IHE grant the relief contained in the evidence submitted by AE and summarized in this brief. AE further requests such other relief in law or equity to which it is entitled.

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[557] *Id.*
[558] AE Ex. 1 at 87-95.

Respectfully submitted,

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ATTORNEYS FOR THE CITY OF AUSTIN D/B/A AUSTIN ENERGY

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of this pleading has been served on all parties and the Impartial Hearing Examiner on August 9, 2022, in accordance with the 2022 Austin Energy Base Rate Review Procedural Guidelines.

THOMAS L. BROCATO

749-36/8454329