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

TEXAS INDUSTRIAL ENERGY CONSUMERS'
POST-HEARING BRIEF

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I. INTRODUCTION

Austin Energy (AE) serves a number of large businesses who are competing in global markets, including participating members of the Texas Industrial Energy Consumers (TIEC). For these business customers, fair and cost-based electricity rates that minimize subsidies across customer classes are critical to managing production costs and remaining competitive. TIEC appreciates that a primary motivation behind AE's requested rate change is an effort to move all customers closer to their actual cost of service, and to reduce inter-class subsidies. TIEC generally supports this overall objective.

However, many of AE's specific proposals are at odds with well-established ratemaking practices and policies in Texas, and do not achieve the ultimate goal of fair, cost-based rates. Some of AE's recommendations even conflict with AE's own past positions and prior recommendations of its own witnesses. The role of an independent hearing examiner (IHE) is to provide an objective review of these issues, and not to give undue preference to AE's recommendations as the utility. TIEC believes that this should include giving due weight to well-established, objective ratemaking precedent by the Public Utility Commission of Texas (PUCT) for utilities that are similarly situated to AE. While the City Council is not bound by decisions made by the PUCT, the PUCT is the state's expert in setting regulated rates for utilities in Texas, including vertically integrated electric utilities that operate very similarly to AE. The PUCT has encountered a broad range of varied fact patterns over the years, and the precedent it has established over the course of several decades should be persuasive in crafting recommendations for the City Council in this case. To that end, there are a number of proposals from AE that are out of line with PUCT precedent and will have significant adverse impacts on large business customers. TIEC's priority in this case is to ensure that these issues are addressed appropriately and fairly.

For TIEC, the most significant issue is AE's failure to recognize that large business customers who take service directly from AE's substations, through a single, dedicated distribution feeder, do not use or cause investment in AE's broader integrated distribution network and should not have to pay those costs. Under PUCT precedent, customers in this situation have been placed in a separate "Primary Substation" class where they are able to directly pay for their dedicated feeders and, in exchange, are not required to pay for the costs of the broader distribution system that they do not use.[1] This is a pervasive shortcoming in AE's proposed Class Cost of Service Study (CCOSS) and its revenue distribution, and it also has a number of secondary impacts on issues like line loss factors. AE's witnesses do not dispute that certain customers use only discrete, dedicated circuits past the AE substation, and are not similarly situated to other distribution-voltage customers in terms of their impact on overall distribution system costs.[2] However, AE opposes reflecting these differences in rates because these customers do not currently have the option to either directly pay for or own their dedicated distribution feeders.[3] This issue is easily resolved, as discussed below, by: (a) requiring AE to develop a facilities charge that will allow customers to either own or directly pay for their dedicated distribution feeders and, in exchange, (b) establishing a Primary Substation class that will be open to all customers who take service directly from an AE substation using a dedicated feeder. This proposal is consistent with cost-causation and mirrors the existing practice for investor-owned utilities, including Oncor—the state's largest utility.[4] This issue has a significant impact on large business customers, and TIEC urges the IHE to recommend some workable path forward for these business customers to obtain rates that reflect the differences in their service costs as compared to the broader population of distribution-voltage customers.

Similarly, AE has proposed novel allocation methodologies for certain costs that are inconsistent with well-established precedent in Texas, and these proposals have substantial cost impacts for TIEC's members. Perhaps the most significant issue with AE's proposed allocation is its proposal to allocate production-demand (generation) costs based on peak demand in each month of the year, known as a "12 Coincident Peak (12CP)" methodology, which fails to reflect that he

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[1] *E.g. Application of Oncor Electric Delivery Company, LLC for Authority to Change Rates*, PUCT Docket No. 35717, Order on Rehearing at 11 (Nov. 30, 2009) (ordering 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").

[2] TIEC Ex. 23 (AE's Response to NXP's RFI 1-5R) at 1, note 1 ("Each feeder [serving AE's Above 20 MW High Load Factor customers] does not serve other customers.").

[3] AE Ex. 8 (Burnham Reb.) at 26.

[4] *See Application of Oncor Electric Delivery Company, LLC for Authority to Change Rates*, PUCT Docket No. 35717, Order on Rehearing at 11 (Nov. 30, 2009).

primary driver in AE's generation investment is serving load during summer peak demand periods. TIEC's witness, Jeffry Pollock, recommends the Average & Excess Demand (AED)-4CP allocation method,[5] which has been consistently used for Texas utilities under PUCT jurisdiction for *decades*—including vertically integrated utilities that are part of a centrally dispatched wholesale markets like AE.[6] This methodology captures the role of average demand (i.e. energy usage) in causing generation investment under the "average" portion of the allocation, but gives appropriate weight to the ***primary*** driver for new generation capacity investments in Texas, which is the need to serve the maximum system demands during the summer peak periods.[7] AE has itself endorsed the AED-4CP methodology for allocating generating capacity in the past.[8] As discussed below, the arguments for deviating from this established allocation practice for production-demand costs are flawed and inappropriate for a summer peaking utility like AE.

Finally, TIEC asks that the IHE take an objective look at the capital structure and revenue requirement components that AE actually needs to provide service at reasonable rates. AE has made unsupported adjustments to test year values in certain scenarios to increase its revenue request—like artificially increasing the General Funds Transfer (GFT) in a manner that does not align with its own Financial Policies[9]—while failing to make appropriate adjustments to test year values in other scenarios where it would decrease the need for a rate increase—such as reflecting the impact of Winter Storm Uri in reducing customer usage and billing determinants during the test year.[10] To the extent possible, AE's rates should be based on test year values, adjusted for known and measurable changes, and normalized to exclude data that is an aberration like the impacts of Uri. AE's rate proposal falls short of this objective in several regards, and TIEC asks the IHE to appropriately recommend modifications to address these discrepancies. These and other important issues are addressed in further detail below.

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[5] TIEC Ex. 1 (Pollock Dir.) at 19-22.

[6] *See id.* at 24 (analyzing PUCT precedent on this point).

[7] *Id.* at 25.

[8] NXP Ex. 3 (COA Ordinance 20120607-055) at Bates 000003 ("The Council adopts as policy the use of the A&E 4CP methodology to allocate production demand costs among customer rate classes.").

[9] Tr. (July 13) 73:7-10 (Dombroski Cr.); AE Rate Filing Package, Appendix B (AE Financial Policies) at Bates 21.

[10] TIEC Ex. 1 (Pollock Dir.) at 7-11.

II. REVENUE REQUIREMENT

B. Cash Flow Methodology

4. Internally Generated Funds for Construction

AE should reduce its internal cash funding of new construction projects to 40% of project costs. AE's proposed revenue requirement assumes that AE will fund 50% of its construction costs with internally generated cash, thereby maintaining the equivalent of a 50% equity and 50% debt capital structure.[11] However, as TIEC witness Billie LaConte testified, AE's ratepayers would save money if AE used additional low-cost debt financing in place of cash.[12] Ms. LaConte's recommendation is consistent with AE's Financial Policies, which allow for a debt ratio between 40% and 65%.[13] Further, a 60% debt ratio would be more in line with AE's recent historical debt funding ratio of 67.2%.[14] Because debt financing is significantly cheaper than using equity,[15] adjusting AE's debt ratio to 60% would save ratepayers approximately ***$12 million per year***,[16] which is far more than the resulting increase in AE's annual debt payments.[17] These savings are particularly important at a time when AE's customers are experiencing significant inflationary pressure.[18]

Using additional debt financing will not compromise AE's financial position, contrary to AE's assertions.[19] Reducing the cash funding to 40% would increase AE's debt funding by only $15 million per year.[20] As a point of reference, AE's total outstanding debt is just over $2 billion,[21]

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[11] TIEC Ex. 3 (LaConte Dir.) at 13.

[12] *Id.* at 14.

[13] *Id.*; AE Rate Filing Package, Appendix B (AE Financial Policies) at Bates 21.

[14] *Id.* at 13.

[15] *Id.* at 14 ("[T]he cost of debt is still low; therefore, more debt funding would be more cost efficient for ratepayers. The interest rate for Corporate AA rated debt is currently 4.30%.").

[16] *Id.* at Exhibit BSL-3.

[17] TIEC witness Billie LaConte calculated the annual debt payment would increase by $914,000 when AE had an AA credit rating. There is only a small difference in debt costs between a AA and even an A credit rating, which is one run below AE's current rating of AA- (4.30% compared to 4.54%). *Id.* at 7-8, 14.

[18] *Id.* at 17-18.

[19] Tr. (July 13) at 95:22-32 (Dombroski Cr.); AE Ex. 3 (Dombroski Reb.) at 6.

[20] TIEC Ex. 3 (LaConte Dir.) at 15.

[21] *Id.* at 8.

so Ms. LaConte's proposal would not result in some massive upheaval to AE's finances.[22] In fact, if Ms. LaConte's proposal to increase debt financing to 60% were adopted, AE's debt service coverage ratio would be 2.36x, which is still well above the targeted minimum of 2.0x set forth in AE's Financial Policies.[23] And, even with its recent one-notch downgrade, AE's credit rating of AA- remains very strong.[24] Indeed, while AE claims it cannot accommodate any additional debt in its capital structure due to financial constraints, the evidence shows that AE's requested return would equate to a return on equity of 12% for an investor owned utility (IOU) as a matter of simple math.[25] The impact of TIEC's proposals on AE's finances are discussed in greater detail in Sections II.B.6.b. of this brief, below.

AE's preferred capital structure is also not dictated by prior actions by the City Council. AE has claimed that its capital structure must be 50% debt and 50% equity in order to comply with a 2012 City Council Ordinance.[26] However, AE admitted that the 2012 City Council Ordinance is not binding on the current City Council, which has the discretion to change AE's capital structure as appropriate.[27] The IHE should recommend that City Council take advantage of AE's strong credit rating to mitigate AE's proposed rate increase by modestly increasing debt funding of capital investments.

5. General Fund Transfer

The General Fund transfer (GFT) AE proposes to reflect in rates is also excessive. GFTs are yearly payments that AE makes out of its revenues to the City's general fund.[28] Under AE's Financial Policies, the GFT is "to not exceed 12% of Austin Energy three-year average revenues less power supply costs and on-site energy resource revenue, calculated using the current year estimate and the previous two years' actual revenues less power supply costs and on-site energy

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[22] *See* Tr. (July 14) 3:38-39 (LaConte Cr.) ("But the $15 million and I'm proposing is *de minimus* compared to Austin Energy's total."); TIEC Ex. 3 (LaConte Dir.) at 14-15 (explaining TIEC's proposal would increase the debt by $15 million); *Id.* at 8 (explaining that AE's current outstanding debt is $2.1 billion).

[23] TIEC Ex. 3 (LaConte Dir.) at 15.

[24] *See id.* at 7.

[25] *Id.* at 10. Ms. LaConte calculated this ROE for illustrative purposes and acknowledged that AE does not actually earn a return on its equity. *Id.*

[26] Tr. (July 13) at 77:4-6 (Dombroski Cr.); TIEC Ex. 5 (AE Response to TIEC 7-4) at 1.

[27] Tr. (July 13) at 77:8-12 (Dombroski Cr.).

[28] AE Rate Filing Package at 34.

resource revenue from the City's Comprehensive Annual Financial Report."[29] From a ratemaking perspective, the GFT is treated as an expense in calculating AE's revenue requirement.[30] AE's calculation of the GFT for ratemaking purposes is flawed and unsupported.

Despite basing its application on a historical test year,[31] AE did not use the test-year GFT amount, which was $114 million, in its proposed revenue requirement.[32] Instead, AE made what it called a "known and measurable" adjustment to arrive at a $121 million GFT by using (a) the maximum GFT percentage allowed (12%) times (b) operating revenues that include AE's ***requested*** revenue requirement in this case.[33] In its Rate Filing Package, AE states that a known and measurable is adjustment is appropriate when: "1) the adjustment is quantifiable and 2) the adjustment reflects an 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."[34] AE's adjustment to the GFT does not satisfy its own standards.

As noted, AE's Financial Policies call for the GFT calculation to be based on two historical years and an estimate of the current year's revenues.[35] So AE should have used the test year GFT (which was calculated in this manner and actually paid to the City[36]) and ***not*** a GFT calculated based on adjusted 2021 revenues (including its requested revenue requirement in this case) alone. Further, even if one accepts the proposition that the actual test year GFT should be displaced by a calculation that includes the revenues approved in this case, that calculation should still include the average of the two historical years. But AE calculated its proposed GFT based solely on 12%

[29] AE Rate Filing Package, Appendix B (AE Financial Policies) at Bates 21.

[30] TIEC Ex. 3 (LaConte Dir.) at 5.

[31] AE Rate Filing Package at 26 ("To ensure that rates adequately recover costs, the utility examines historical expenditures, capital improvement requirements, and customer loads, which are adjusted for known and measurable changes that occur after the end of the Test Year and produce a revenue requirement under normalized conditions.").

[32] Tr. (July 13) 73:7-10 (Dombroski Cr.); AE Rate Filing Package, Appendix C at Bates 91 (WP C-3.2.1, General Fund Transfer K&M Adjustment).

[33] Tr. (July 13) 73:7-10 (Dombroski Cr.); AE Rate Filing Package, Appendix C at Bates 91 (WP C-3.2.1, General Fund Transfer K&M Adjustment).

[34] AE Rate Filing Package at 27, note 11.

[35] AE Rate Filing Package, Appendix B (AE Financial Policies) at Bates 21.

[36] TIEC Ex. 6 (City of Austin Approved 2021-22 Budget Excerpt) at Bates 002 ("In accordance with these average revenue calculations, the transfers for FY 2021-22 are calculated based on a rolling average of actual revenue from fiscal years 2018-19 and 2019-20 and estimated revenue in FY 2020-21.").

of its proposed test year revenues of $1,009,396,489,[37] which are higher than the revenues from the prior two years.[38]

Ultimately, there is nothing known and measurable about AE's adjusted GFT amount. The GFT that AE actually paid to the City of Austin in Fiscal Year 2021 (the test year) was $114 million and the amount that was approved in 2021 for payment in Fiscal Year 2022 was also $114 million.[39] Further, at the hearing AE conceded that that its actual proposed GFT for Fiscal Year 2023 (based on AE's calculation that it provided the City Manager under its Financial Policies[40]) is only $115 million.[41] Even AE's projections of the GFT amount for future years, which are based in part on estimated future revenues, appear to be lower than the $121 million amount it is requesting.[42]

In addition to the fact that AE's proposed GFT is not properly calculated, there is another reason to reject it: AE's proposal results in a disproportionally high GFT compared to the historical average, which raises equity concerns during a time when ratepayers are coping with inflationary pressures. As set out in Ms. LaConte's testimony, the three-year average for 2018-2020 (the three years before the test year) was only $110 million.[43] Notably, and in addition to the flaws with this calculation set forth above, AE's proposal in this case is based on the premise that the GFT must be calculated based on 12% of the applicable revenues, while the actual Financial Policy is that the amount ***should not exceed*** 12%.[44] These considerations further weigh against accepting AE's proposed adjusted GFT.

AE's proposed test-year adjustment should be rejected as not known and measurable, since it represents an amount that AE did not pay in the test year and will not pay in the rate year (2023)

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[37] AE Rate Filing Package, Appendix C at Bates 91 (WP C-3.2.1, General Fund Transfer K&M Adjustment).

[38] This is evidenced by the fact that the 2022 GFT was $114 million and the calculated GFT for 2023 is $115 million, whereas the revenues that AE used resulted in a $121 million GFT calculation.

[39] TIEC Ex. 25 (COA Proposed 22-23 Budget Excerpt) at Bates 005.

[40] Tr. (July 15) at 39:30-37 (Dombroski Cr.).

[41] *Id.*; TIEC Ex. 25 at Bates 5.

[42] *See* TIEC Ex. 25 at Bates 4 (showing projected GFTs for 2024 and 2025 that increase only slightly from the 2023 level, which is $115 million).

[43] TIEC Ex. 3 (LaConte Dir.) at 11.

[44] AE Rate Filing Package, Appendix B (AE Financial Policies) at Bates 21.

or any other year in evidence. Rates should be set based on the test year GFT of $114 million or, at the most, the $115 million estimate that AE used for FY 2023.

6. Debt

a. Debt Service Coverage Ratio

AE's Debt Service Coverage Ratio (DSCR) target can comfortably accommodate TIEC's revenue requirement proposals. The DSCR is calculated as revenues less operating expenses (excluding depreciation and amortization) divided by the annual debt service payments.[45] Under AE's Financial Policies, AE must target a DSCR above 2.0x on electric utility revenue bonds.[46] AE's requested DSCR is 2.32x, which is 16% higher than its minimum target of 2.0x.[47] However, AE also inappropriately included non-retail electric revenues in its calculation, as discussed below.[48] When non-retail electric revenues are removed, the requested DSCR is actually 2.50x.[49] TIEC recommends that AE's revenue requirement be adjusted to reflect a DSCR of 2.30x,[50] after excluding the non-electric retail revenues. This will provide a lower cost to ratepayers, but is still comfortably above AE's targeted minimum 2.0x ratio.[51]

In evaluating these issues (and AE's financial risk), it is important to limit any subsidy that AE's retail electric ratepayers are paying for AE's other utility customers.[52] The rates at issue here are for AE retail electric customers only, not customers for AE's other services, such as district cooling or wholesale transmission.[53] Accordingly, when evaluating the impact of the various revenue requirement proposals, DSCR should be calculated based on AE's retail-electric business

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[45] TIEC Ex. 3 (LaConte Dir.) at 8.

[46] AE Rate Filing Package at 33.

[47] TIEC Ex. 3 (LaConte Dir.) at 8-9.

[48] *Id.* at 15.

[49] *Id.* at 9.

[50] Notably, Ms. LaConte's DSCR calculations assume that AE's GFT is reduced to $110 million, based on AE's historical average. TIEC Ex. 3 (LaConte Dir.) at 12. If the GFT is reduced to $114 million based on rejecting AE's improper known and measurable adjustment (as set forth above), the calculated DSCRs would be even higher.

[51] *Id.* at 14-17 (showing the various calculations of the DSCR implementing TIEC's recommendations); AE Rate Filing Package, Appendix B (AE Financial Policies) at Bates 21 ("In addition to these requirements, electric rates shall be designed to generate sufficient revenue, after consideration of interest income and miscellaneous revenue, to ensure a minimum debt service coverage of 2.0x on electric utility revenue bonds.").

[52] *See* 2WR Ex. 3 at 2-3 (explaining that the non-utility business show a debt service coverage of approximately 0.67 for AE's non-retail electric operations).

[53] TIEC Ex. 3 (LaConte Dir.) at 9.

only, as Ms. LaConte recommends.[54] AE notes that credit-rating agencies consider all of AE's revenues and expenses in analyzing AE's risk,[55] but that does not mean that AE's retail electric ratepayers should pay more than their fair share of AE's overall DSCR. Notably, AE admits that its non-retail electric operations have a DSCR of approximately 0.67x,[56] meaning that ***AE's non-retail electric customers are not paying enough in rates to cover the debt that is used to provide their service, much less to provide any coverage margin whatsoever***.[57] The IHE should give little weight to AE's claims that TIEC's proposals on AE's capital structure would make AE riskier to investors or that the participants' adjustments would generally "accelerate the deterioration of Austin Energy's financial position"[58] when it is clear that AE's non-retail electric services are a burden on the company's DSCR.

AE should address any financial deficits from its other utility services directly, rather than requiring its retail electric customers to pick up the slack.[59] Accordingly, only the DSCR for AE's retail electric service should be considered in setting rates here. However, even if a combined DSCR including both retail and non-retail electric revenues is considered, TIEC witness Ms. LaConte's revenue requirement proposals would still result in a 2.16x DSCR, which is above AE's minimum targeted 2.0x DSCR.[60] Therefore, TIEC's revenue requirement proposals, including its recommendation for AE to reduce its dependence on internally generated cash financing to 40%, are reasonable and would appropriately maintain AE's financial health without requiring substantial subsidies between utility businesses.

b. Credit Rating

TIEC's recommended revenue-requirement adjustments will also allow AE to maintain an

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[54] Id.

[55] AE Ex. 3 (Dombroski Reb.) at 26.

[56] Tr. (July 15) at 13:40-14:4 (Dombroski Cr.); 2WR Ex. 3 at 2-3.

[57] *See* TIEC Ex. 3 (LaConte Dir.) at 8 ("The debt service coverage ratio measures a utility's ability to meet its debt service payments.).

[58] Tr. (July 13) at 95:22-37 (Dombroski Cr.); AE Ex. 3 (Dombroski Reb.) at 6 ("Acceptance of the majority of the Participants' adjustments to the revenue requirement would accelerate the deterioration of Austin Energy's financial position, further increase Austin Energy's leverage, decrease Austin Energy's operating cash flow, force Austin Energy to expend its cash and reserves, and increase its debt.").

[59] TIEC Ex.3 (LaConte Dir.) at 9.

[60] *Id.* at 16-17.

investment-grade credit rating and reliable access to debt-capital markets. Although Fitch recently downgraded AE by one notch,[61] AE maintains a very healthy credit rating of AA-.[62] For context, issuances rated below BBB- or Baa3 are considered junk bonds, so AE's credit rating is fully 6 rungs above the lowest rating that is necessary to maintain investment grade status, as referenced in Ms. LaConte's Table 3:[63]

Table 3
Credit Rating Scale

Moody's	S&P	Fitch
Aaa	AAA	AAA
Aa1	AA+	AA+
Aa2	AA	AA
Aa3	AA-	AA-
A1	A+	A+
A2	A	A
A3	A-	A-
Baa1	BBB+	BBB+
Baa2	BBB	BBB
Baa3	BBB-	BBB-

AE's AA- credit rating is strong, regardless of the recent downgrade, and significantly higher than the credit ratings of investor-owned vertically integrated regulated electric utilities (IOUs). Southwestern Electric Power Company (SWEPCO) has an A- Rating from S&P (3 rungs below AE) and Southwestern Public Service Company (SPS), El Paso Electric Company (EPE), and Entergy Texas (ETI) have Baaa2 ratings from Moody's (5 rungs below AE).[64] Even at their lower ratings, these IOUs have not had problems attracting debt capital at reasonable costs.[65]

Contrary to AE's claims,[66] they are similarly situated to IOUs. While IOUs have access to equity from stock issuances, AE sets its rates to provide a cash margin to fund capital

[61] AE Ex. 3 (Dombroski Reb.) at 6.

[62] Fitch calculated AE's DSCR to be 1.5x, which is within the range for public power utilities with AA rated debt (0.90x-3.96x DSCR). *See* TIEC Ex. 24; TIEC Ex. 3 (LaConte Dir.) at 10.

[63] *Id.* at 7.

[64] *Id.* at 6-7.

[65] TIEC Ex. 1 (Pollock Dir.) at 9.

[66] AE Ex. 3 (Dombroski Reb.) at 24-25 (arguing that AE does not have equity investors and that they must rely on long-term debt (bonds) to fund capital needs).

improvements,[67] which AE refers to as "equity" in its own Financial Policies.[68] In addition, while both municipally owned utilities (MOUs) and IOUs can issue debt, AE can issue municipal revenue bonds, which are seen as lower risk compared to the corporate bonds IOUs issue.[69] Indeed, while AE claims there is no basis for comparing the credit ratings of IOUs and MOUs, they are all rated on the same rating scale and using the same metrics by the ratings agencies.

AE's arguments regarding the credit ratings of other MOUs are similarly unavailing. MOUs are self-regulating, so it is unsurprising that they maintain rates that enable them to have very high credit ratings. This does not prove that MOUs ***require*** higher ratings than IOUs to access debt, much less far higher ratings. Indeed, one can only imagine how high most IOUs' credit ratings would be if they were allowed to set their own rates.

Regardless, AE's downgrade by Fitch to AA- is not material to determining AE's appropriate capital structure, and it should not be used to justify AE's proposed rate increase. As Mr. Dombroski agreed at the hearing, AE should not pursue the highest credit rating possible without regard to the cost to ratepayers.[70] At some point the benefit to ratepayers in terms of lower debt costs from a higher credit rating is outweighed by the higher revenue requirement necessary to obtain that rating.[71] For example, the cost of debt for Corporate AA rated debt is only 24 basis points lower than Corporate A rated debt (4.30% compared to 4.54%).[72] If for some reason AE was further downgraded to an A rating, and hypothetically immediately refinanced the entirety of its outstanding debt, $2.1 billion, its annual debt service cost would only increase by $3.6 million per year.[73] For context, Ms. LaConte's recommendations alone would reduce AE's revenue requirement by approximately $20 million pe year.[74]

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[67] Tr. (July 14) at 11:20-34 (LaConte Cr.).

[68] AE Rate Filing Package, Appendix B (AE Financial Policies) at Bates 21 ("Capital projects should be financed through a combination of cash, referred to as pay-as-you-go financing (equity contributions from current revenues), and debt. An equity contribution ratio between 35% and 60% is desirable.").

[69] Tr. (July 14) at 6:5-8 (LaConte Cr.).

[70] Tr. (July 15) at 42:16-28 (Dombroski Cr.).

[71] TIEC Ex. 3 (LaConte Dir.) at 7.

[72] *Id.* at 7-8.

[73] *Id.* at 8.

[74] *Id.*

In sum, the impact of AE's proposed rate increase can be substantially mitigated by adopting TIEC's revenue requirement proposals, and without compromising AE's strong financial position.

10. Pass-Through Items

AE should remove pass-through costs (with the exception of Area Street Lighting costs) from its Class Cost of Service Study (CCOSS). AE admits that its pass-through costs are not at issue in this proceeding and are not subject to change.[75] Instead, pass-through costs change dynamically over time as the underlying costs change, such as AE's fuel and purchased power costs.[76] Including these dynamic pass-through costs in the CCOSS skews the outcomes for base rate allocations by reflecting items that (a) will frequently change over time, and (b) cannot be changed here.

More significantly, including non-base rate, pass-through costs in its CCOSS has the effect of improperly allocating certain costs to classes that should not receive them. For example, one category of pass-through costs improperly included in the CCOSS are Energy Efficiency Services (EES) costs.[77] According to AE's own tariffs (and rebuttal testimony[78]) Primary ≥ 20 MW HLF class customers are not charged for EES costs.[79] However, AE's CCOSS study allocates $2,319,031 to this class for EES,[80] which has the effect of raising the class's revenue based on costs those customers are not supposed to pay.[81]

To avoid these issues, all pass-through costs, with the exception of Area Street Lighting, should be removed from AE's CCOSS. The amount of Area Street Lighting pass-through costs should be derived in AE's CCOSS. If those pass-through costs are removed, AE's proposed base

[75] TIEC Ex. 1 (Pollock Dir.) at 18.

[76] *Id.* at 18.

[77] *See e.g.*, AE Rate Filing Package, Appendix C at Bates 251.

[78] AE Ex. 7 (Genece Dir.) at 5.

[79] AE Rate Filing Package, Appendix F at Bates 472 ("Charges for Service Area Lighting (SAL) and Energy Efficiency Services (EES) do not apply under this rate schedule.").

[80] *See e.g.*, AE Rate Filing Package, Appendix C at Bates 251 (showing that Primary Voltage ≥ 3<20 MW are assigned $1,518,350 relating to Energy Efficiency Programs, and Primary Voltage ≥ 20 MW are assigned $2,319,031 relating to Energy Efficiency Programs).

[81] Appendix C shows the Energy Efficiency Program cost is included in the amount for Total Production (line 9), which is then added into the Total Cost of Service (line 46) and the Adjusted Total Cost of Service (line 53). *Id.* at 251.

revenue requirement would be $705 million.[82]

C. Present Revenues and Billing Determinants

AE's test-year data should be adjusted to account for the anomalous, non-recurring impacts of Winter Storm Uri. AE's application overstated its test-year base revenue deficiency because it failed to adjust revenues for Winter Storm Uri, even though AE claimed to have normalized test-year sales and revenues.[83] The outages resulting from Winter Storm Uri depressed test-year kWh sales and base revenues, but AE did not adjust test-year sales to remove this aberration.[84] As a result, AE's test-year kWh sales were well below ***actual*** sales in 2018 through 2020.[85] Using artificially low sales numbers results in artificially rates on a per-unit basis, since the revenue requirement must be recovered through fewer billing determinants. If actual sales numbers are ultimately higher, then AE will over earn—perhaps significantly.

As demonstrated in Mr. Pollock's testimony, AE's "normalized" test-year sales are lower than the total energy sales in 2018 and 2019. Additionally, despite strong customer growth in recent years, total test-year sales were only 0.6% higher than the average for the four prior fiscal years.[86] Test-year sales were also significantly lower on a per-customer basis—residential customers used nearly 2% less energy per customer and commercial and industrial (C&I) customers used 5.2% less per customer as compared to the average usage in 2017 to 2020.[87] The only plausible explanation for this blip in sales is Winter Storm Uri.

Further confirming that the dip in test-year sales is an anomaly, AE projects increasing sales and revenues going forward. AE's 2020 Resource Plan forecasts both continued peak load growth and energy sales growth after 2021.[88] Mr. Pollock's Table 2 illustrates AE's projected growth in weather-normalized base revenues going forward:[89]

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[82] TIEC Ex. 1 (Pollock Dir.) at 19.

[83] *Id.* at 3.

[84] *Id.* at 7.

[85] *Id.* at 7-8.

[86] *Id.* at 10.

[87] *Id.*

[88] *Id.* at 11.

[89] *Id.*

Table 2 Normalized Base Rate Revenues ($ Millions)	
Fiscal Year	**Amount**
2021	$648
2023	$701
2024	$729
2025	$737
2026	$745
2027	$754
FY 2023-2027 Increase	1.8% per Year
Sources: RFP at WP G-10.2; RFP at 117 (Figure 7-35).	

As Mr. Pollock explains, if AE fails to appropriately adjust for Winter Storm Uri's impact on test-year sales and revenues, AE's projected revenue deficiency will be overstated and the resulting rates will over-collect approximately $24.3 million per year.[90] As such, test-year sales, revenues, and billing determinants must be restated to reflect expected sales and revenues. Unfortunately, AE refused to produce detailed projections of sales and revenues beyond FY 2021 or historical sales data by customer class, notwithstanding that AE has relied on such projections for its own purposes.[91] Without the information needed to make a precise adjustment based on AE's own projections,[92] TIEC recommends reducing AE's claimed revenue deficiency by $24.3 million based on Mr. Pollock's analysis.[93]

III. COST ALLOCATION

D. Class Allocation

A fundamental principle of utility ratemaking is that costs should be allocated based on

[90] *Id.* at 7-8, 12.

[91] *Id.* at 12 (citing AE Objection to TIEC 4-10 and the Rate Filing Package at 117).

[92] Tr. (July 14) at 15:4-6 (Pollock Cr.) (explaining that it's better to take the test year and do a forensic analysis but the information was not available).

[93] TIEC Ex. 1 (Pollock Dir.) at 14.

cost causation.[94] AE acknowledges this, explaining in its Rate Filing Package that "for costs that cannot be directly assigned, an appropriate allocation methodology must be developed consistent with cost causation principles."[95] Accordingly, the goal of class cost allocation is to ensure that each customer class bears the costs that AE incurs to serve it. As set forth below, however, AE's class-cost-of-service study ("CCOSS") departs from cost-causation principles and should be modified in several important ways.

1. Demand-Related Costs

a. Production-Demand

Production-demand related costs are the costs associated with building and maintaining AE's generation fleet or contracting for outside generation capacity.[96] For production-demand related costs, following cost causation requires analyzing the utility's load characteristics, which determine the amount of capacity required to meet expected demand.[97] The methodology used to allocate production-demand costs should reflect each customer class's contribution to AE's need for additional production capacity.

i. AE's production-demand related costs should be allocated using the AED-4CP method.

Consistent with cost causation, AE should allocate its production-demand costs using the Average and Excess Demand – Four Coincident Peak ("AED-4CP") methodology. As explained in greater detail below, the AED-4CP method recognizes that, for summer peaking utilities like AE, the primary driver of production demand costs is maintaining sufficient capacity to serve load during the summer peaks.[98] The AED-4CP methodology is represented by the following formula:[99]

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[94] *Id.* at 19.

[95] AE Rate Filing Package at 13-14; *see also id.* at 48-49 ("Class Allocation attributes the functionalized and classified costs [of utility service] to individual customer classes based on cost causation.").

[96] TIEC Ex. 1 (Pollock Dir.) at 22.

[97] *Id.* at 19.

[98] *Id.* at 20.

[99] *Id.* at 25.

$$AED = (AD\% \times ASLF\%) + [ED\% \times (1\text{-}ASLF\%)]$$

Where:

AD% = A class's share of Average Demand (or energy usage);

ED% = A class's share of Excess Demand, which is the difference between a class's Peak Demand and its Average Demand; and

ASLF% = Annual System Load Factor.[21]

AED-4CP accurately reflects cost causation because it recognizes that a utility's generation fleet must have sufficient load-following generation to meet peak demand, but must also include sufficient baseload capacity to meet average demand at the lowest overall cost.[100] The "average demand" portion of the calculation considers each class's average energy consumption, which reflects the class's contribution to the need for baseload generation investment.[101] This reflects the generation capacity costs the utility would incur if it served the same demand at a constant 100% load factor—*i.e.,* if there were no variability in usage.[102] The "excess demand" portion of the calculation measures the ***relative variability*** of each class's load—the difference between the class's average demand and its peak demand—which reflects each class's contribution to the need for incremental load-following generation to meet system peaks.[103] The "average demand" and "excess demand" portions of the allocation are weighted based on the annual system load factor—the ratio of system average demand to system peak demand[104]—which represents the relative contributions of average demand (energy usage) and peak demand in driving generation investment.[105] TIEC witness Mr. Pollock applied the AED-4CP allocation methodology and derived the appropriate class allocation factors for production-demand, as shown in his Exhibit JP-5.

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[100] TIEC Ex. 2 (Pollock Cross-Reb.) at 3.

[101] TIEC Ex. 1 (Pollock Dir.) at 25.

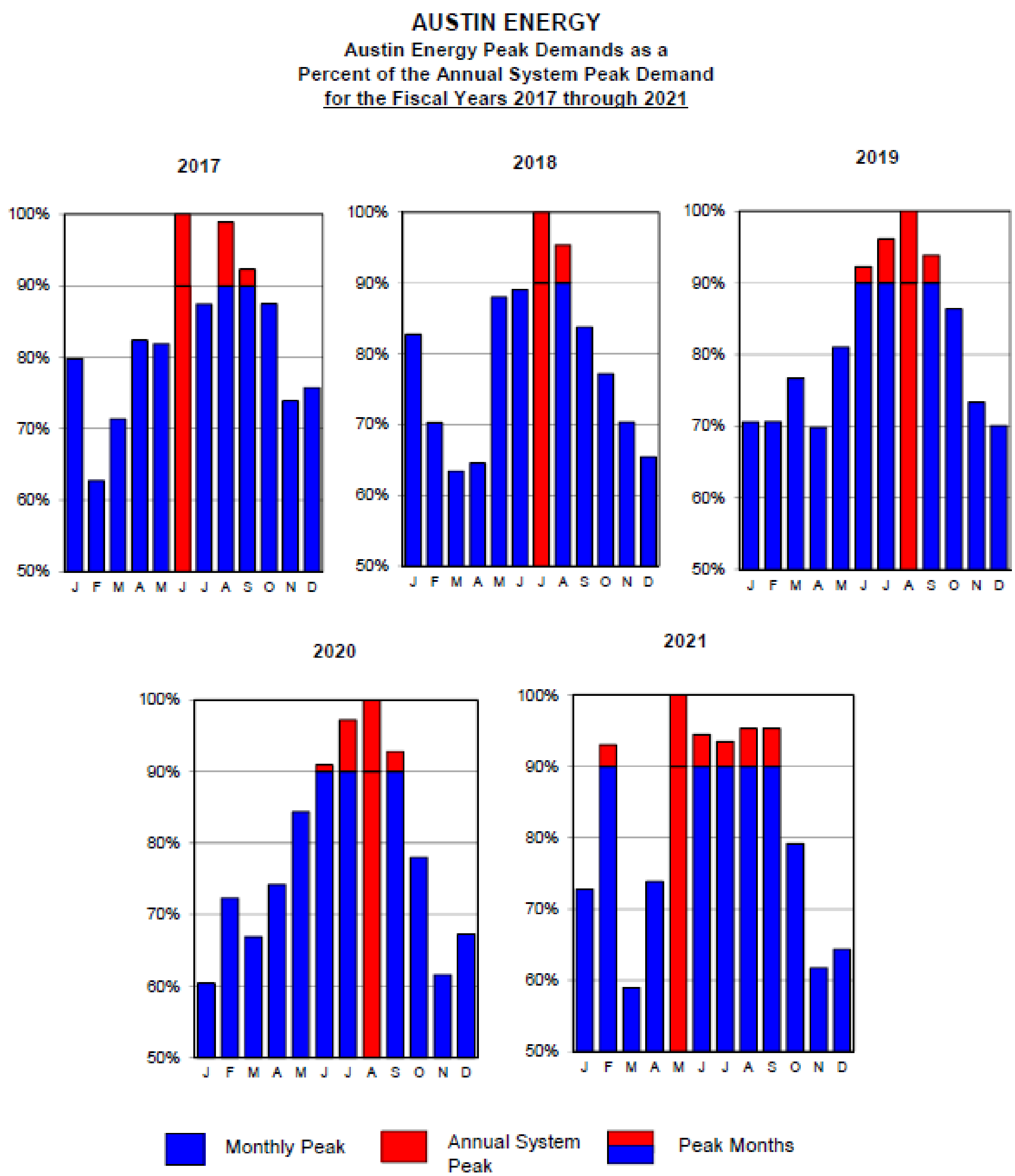
[102] *Id.*

[103] *Id.*

[104] As noted in Mr. Pollock's testimony, the PUCT has consistently determined that when using an AED-4CP allocation, the system load factor should be calculated by using the single annual coincident peak, rather than the average of four coincident peaks. *See Id.* at 26, note 24. AE's Rate Filing Package workbook incorrectly used the average of the four coincident peaks. *Id.* Mr. Pollock used a single CP system load factor in his AED-4CP calculation, and that should be adopted in this case.

[105] *Id.* at 26.

As noted, the AED-4CP methodology is appropriate for a summer peaking utility like AE. Like the ERCOT system generally, AE's load peaks in the summer months.[106] This is illustrated by Mr. Pollock's Exhibit JP-3, which plots AE's monthly system peak demands as a percentage of the annual system peak for the years 2017 through 2021:[107]



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[106] *See Id.* at 20 and Exhibit JP-3 at 1.

[107] *Id.* at Exhibit JP-3.

AE expects to remain a summer peaking utility in the future[108] and admitted that "[t]hroughout its ten-year planning horizon, Austin Energy projects that it will still peak in the summers, including within the next five years."[109] The same is expected in ERCOT more generally.[110] A summer peaking utility's production-demand costs are driven by the need for adequate capacity at the summer peaks.[111] Accordingly, AE's production demand costs are driven primarily by summertime peak demands, and not by lower demands at other times of the year. As such, cost causation principles dictate that production-demand costs should be allocated to each customer class based primarily on their demand during the four summer coincident peak intervals, as in the AED-4CP methodology. However, the AED-4CP methodology also reflects that a utility will invest in baseload generation if it is expected to have a high capacity factor, meaning it will run frequently—which is typically driven by average demand/energy. As a result, the AED-4CP method appropriately captures the role of both year-round energy usage and peak demand in driving new generation investment.

For these reasons, the PUCT has consistently used AED-4CP to allocate production demand costs for all four of the vertically integrated utilities it regulates.[112] Other nearby states with summer peaks, including New Mexico and Colorado, have also approved AED-4CP to allocate production demand costs.[113] In fact, even AE witness Mr. Murphy has previously testified at the PUCT in support of using this methodology.[114] Mr. Murphy is AE's Energy Analyst Supervisor for Rates and has twelve years of experience as a testifying rate expert at the PUCT and elsewhere.[115] However, AE chose to retain third-party witness Mr. Burnham to present its recommendation on this issue instead of utilizing Mr. Murphy (even though, as discussed below, Mr. Burnham was unaware that generation owned by vertically integrated utilities is centrally

[108] *Id.* at 20.

[109] *Id.* at Appendix F (AE Response to TIEC 5-6).

[110] *Id.* at 20.

[111] Id.

[112] *See Id.* at 23 and Appendix D; *see also* Tr. (July 13) at 110:27-111:16 (Murphy Cr.).

[113] TIEC Ex. 1 (Pollock Dir.) at 24.

[114] *See* TIEC Ex. 9 (D. 44941 Direct Testimony of Brian Murphy Excerpt) at 21.

[115] AE Ex. 9 (Murphy Reb.) at Exhibit BTM-1; Tr. (July 13) at 109:44-110:1.

dispatched in the MISO and SPP markets).[116] When asked about AE's proposal to use a method other than AED-4CP at the hearing, Mr. Murphy provided no particular support, referring the question to Mr. Burnham and simply stating "I do not support that part of Austin Energy's case"[117] because "we have a division of labor and . . . luck of the draw."[118] Given his experience, Mr. Murphy's response is telling. AED-4CP is the proper methodology for allocating AE's production-demand costs, and the IHE should recommend its adoption.

ii. The IHE should reject AE's proposal to allocate production-demand costs based on the ERCOT-12CP.

AE's proposal to allocate production-demand costs to customers using the ERCOT-12CP method does not track cost causation. The ERCOT-12CP method allocates production-demand costs based on each customer class's demand during the ERCOT coincident peak ***for each month*** of the test year.[119] This allocation method would make sense for a utility that expects similar peak demands in all parts of the year. As noted, however, it is undisputed that both AE and ERCOT peak in the summer months. As AE witness Mr. Burnham admitted, if a utility has sufficient capacity to meet its single peak demand for the year, the utility's system will necessarily be able to meet demands in the remaining months.[120] Accordingly, cost causation principles require that production-demand costs be allocated to each customer class based on their demand during the four summer coincident peak intervals, as in the AED-4CP methodology discussed above. The ERCOT-12CP method is inconsistent with cost causation because it allocates costs based on customers' demand during periods that ***do not*** drive AE's generation investment, such as the relatively moderate peak demands experienced in non-summer months.

Notably, AE itself supported an AED-4CP allocation for production-demand costs as recently as its 2012 rate review,[121] and even adopted an ordinance endorsing the AED-4CP

[116] AE Ex. 8 (Burnham Reb.) at 18-20.

[117] Tr. (July 13) at 111:32 (Murphy Cr.).

[118] *Id.* at 111:15-16 (Murphy Cr.).

[119] TIEC Ex. 1 (Pollock Dir.) at 19.

[120] Tr. (July 13) at 114:22-28 (Burham Cr.).

[121] TIEC Ex. 1 (Pollock Dir.) at 22; Tr. (July 13) at 115:39-42 (Burnham Cr.).

methodology.[122] AE also defended the AED-4CP allocation methodology when the 2012 case was appealed to the PUCT. AE's witness in that proceeding, Joseph Mancinelli, explained that AE's peak demands occur during the summer, and that its system peaks during that time are consistently within 90% of the overall peak.[123] Further, Mr. Mancinelli explained that "throughout ERCOT, the system experiences a significant summer peak"[124] and "***[i]n recognition of the cost causation associated with utilities meeting load during these [summer] peak months, the PUC has adopted 4CP allocation methodologies.***"[125]

AE proposed the ERCOT 12CP allocation for its production-demand costs in its 2016 base rate review,[126] but that case was resolved through a black-box settlement that did not specify any particular allocation methodology.[127] Further, the basis for AE's proposed change in allocation policy was incorrect. Specifically, AE claimed that it was appropriate to switch to an ERCOT-12CP methodology once ERCOT transitioned to a nodal market.[128] This was also the primary reason that the IHE in AE's 2016 base rate review recommended the ERCOT-12CP methodology, stating that "unlike vertically-integrated utilities, AE's generation resources are not exclusively maintained to meet system peak; rather, they are maintained to be dispatched based on system wholesale price."[129] This analysis is flawed because high wholesale prices occur when demand approaches available supply—i.e., during peak demand periods—so the incentive to capture high nodal pricing ***still supports a peak-based allocation***.

Like all load serving entities in ERCOT, AE purchases all of the energy used to serve its load from the ERCOT market.[130] But as a generation owner, AE also sells its physical generation

[122] NXP Ex. 3 (COA Ordinance 20120607-055) at Bates 000003 ("The Council adopts as policy the use of the A&E 4CP methodology to allocate production demand costs among customer rate classes.").

[123] TIEC Ex. 13 (D. 40627 Direct Testimony of Joseph Mancinelli Excerpt) at Bates 73.

[124] *Id.*

[125] *Id.*.

[126] TIEC Ex. 1 (Pollock Dir.) at 22; Tr. (July 13) at 118-119 (Burnham Cr.); TIEC Ex. 12 (D. 40627 Direct Testimony of Joseph Mancinelli Excerpt) at Bates 39; TIEC Ex. 13 (D. 40627 Direct Testimony of Joseph Mancinelli Excerpt) at Bates 24-25.

[127] Tr. (July 14) at 58:8-10 (Daniel Cr.).

[128] TIEC Ex. 1 (Pollock Dir.) at 22.

[129] TIEC Ex. 11 (2016 Impartial Hearing Examiner's Report Excerpt) at 150.

[130] TIEC Ex. 1 (Pollock Dir.) at 22.

capacity into the ERCOT market, and if it is dispatched, the resulting revenues are used to offset the cost of serving AE's load.[131] While these hedging benefits can occur to some extent throughout the year, AE's need for generating capacity to serve its own load is still driven by summertime peak demands,[132] and the value of AE's generation in the wholesale market is also greatest during these peak demand periods. AE contends that a 12CP allocation is appropriate because it can use its generation capacity as a hedge to protect its customers against high prices throughout the year,[133] but ERCOT's highest cost intervals are aligned with the highest demand periods in the summer, as shown in Mr. Pollock's Exhibit JP-4.[134] So the hedging benefits of AE's generation are also driven by demands during the summertime peaks.[135] In fact, AE witness Mr. Burnham explained that AE sizes its generation portfolio to provide sufficient capacity to serve its expected summer peaks.[136]

Indeed, AE previously admitted (in the PUCT appeal of AE's 2012 rate proceeding), that AED-4CP properly tracks cost-causation even after the transition to the nodal market:

> [I]n the case of production fixed costs, those costs have historically been incurred to serve AE's load with the primary concern of meeting AE's peak demand. Even under the current ERCOT Nodal Market, AE's generation fleet acts as a hedge against fluctuations in the market price. ***Austin Energy's exposure to market prices is directly related to purchasing power from the market to serve native load. Therefore, AE's system load is the primary driver of costs. To preserve the relationship between cost causation and cost allocation, the AE system peak expressed as the 4CP must be used.*** Further, since the A&E-4CP allocation method is primarily concerned with system and customer class load factors, these characteristics can only properly be determined using the AE system 4CP.[137]

[131] *Id.* at 22-23.

[132] *Id.* at 23.

[133] TIEC Ex. 1 (Pollock Dir.) at 21; *see also* Tr. (July 13) at 113:39-45 (Burnham Cr.).

[134] *Id.* at Exhibit JP-4 (demonstrating that the highest LMPs cluster around peak hours in the summer).

[135] *Id.* at 23 and Exhibit JP-4.

[136] Tr. (July 13) at 114:13-28 (Burnham Cr.).

[137] TIEC Ex. 13 (D. 40627 Direct Testimony of Joseph Mancinelli Excerpt) at Bates 24-25 (emphasis added).

Accordingly, even based on AE's hedging argument, peak summer demands are still the primary driver in both: (A) the need for additional generation to serve AE's customers and (B) the financial benefits of that generation as a hedge for AE's customers.

AE incorrectly claims that a 12CP allocation is appropriate because its generation fleet provides value to customers throughout the year. This argument ignores that peak demand is still the primary ***cause*** for AE to incur additional production-demand costs, and it also ignores that AED-4CP ***does*** take average demand into account when allocating costs, as explained above. As AE witness Mr. Murphy explained in his previous testimony to the PUCT:

> I would like to clarify that all 8,760 hours in the Test Year are reflected in the average demand component of the [AED-4CP] calculation. In addition, each of the 4CP months are counted again in the excess demand component. So, the calculation reflects the assignment of some weight to all the hours in the year, and additional weight to the hours of the peaks in the summer months.[138]

As such, the AED-4CP allocation already takes into account that AE's generation operates and provides value throughout the year, and a 12CP allocation gives undue weight to non-peak demand periods in terms of driving additional investment.

AE's situation is exactly the same as vertically integrated utilities in other centrally dispatched grids. As noted in Mr. Pollock's testimony, three PUCT-regulated vertically integrated utilities—ETI, SPS, and SWEPCO—operate in competitive, nodal wholesale markets outside of ERCOT (MISO or SPP), and ***all three*** of those utilities use an AED-4CP methodology to allocate production-demand costs.[139] Like AE, all three of these utilities bid all of their plants into their respective wholesale markets, and purchase all of their power from the market.[140] The incentive to build generation to capture high wholesale prices is aligned with the incentive to provide a physical hedge during peak demand periods when prices are likely to be highest. Notably, when asked about nodal markets at the hearing, Mr. Burnham could not even confirm how dispatch works in the MISO and SPP nodal markets,[141] so it is does not appear that he understands the

[138] TIEC Ex. 9 (D. 44941 Direct Testimony of Brian Murphy Excerpt) at 23-24.

[139] TIEC Ex. 1 (Pollock Dir.) at 24.

[140] *Id.*

[141] *See* Tr. (July 13) at 117:15-45 (Burnham Cr.).

parallels between AE and the other Texas vertically integrated utilities. Overall, AE has provided no credible basis for distinguishing the facts here from the facts that have supported the PUCT's consistent precedent of allocating production-demand costs based on AED-4CP for vertically integrated utilities in centrally dispatched markets. The IHE should reject AE's request to use a 12CP allocation for production-demand costs and recommend the AED-4CP methodology instead.

iii. There is no basis to apply Mr. Johnson's proposed base, intermediate, peak ("BIP") allocation methodology.

The IHE should also reject Independent Consumer Advocate ("ICA") witness Mr. Johnson's proposed BIP allocation methodology because it is contrary to cost-causation and is unsupported by precedent. As Mr. Johnson acknowledges, a BIP allocation has never been adopted for any regulated electric utility in Texas.[142] Mr. Johnson allocates production-demand based heavily on year-round average demand (or, energy usage) rather than peak demand. Incredibly, his analysis results in 83% of AE's ***production plant costs*** being allocated on an ***energy basis.***[143] Unsurprisingly, Mr. Johnson was unable to identify any contested case in the last 10 years where a regulator approved allocating 80% or more of a utility's total production plant costs on an energy basis.[144] The BIP method would result in such dramatic and unprecedented cost shifting because it erroneously assumes that AE builds baseload generation for the sole purpose of reducing fuel costs, and that baseload plants have ***zero value*** for serving peak load.[145] This is factually incorrect and inconsistent with how utilities make generation investment decisions.

As Mr. Pollock explained in detail in his cross-rebuttal, utilities' decisions about whether to add capacity are driven, first and foremost, by the need to meet expected peak demand, and second, to minimize ***total*** costs.[146] So the decision of whether to build a baseload unit is not exclusively determined by a desire to save on fuel, but on whether the utility expects that a baseload resource would run for enough hours (at a lower hourly cost) to offset a higher initial investment compared to a peaking unit.[147] After that break-even point, energy usage is no longer a factor in

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[142] *See* TIEC Ex. 17 (ICA Response to TIEC 1-1); Tr. (July 14) 81:22-24 (Johnson Cr.).

[143] *Id.* at 9.

[144] *See* TIEC Ex. 18 (ICA Response to TIEC 2-2).

[145] TIEC Ex. 2 (Pollock Cross-Reb.) at 3-4.

[146] *Id.* at 8.

[147] *Id.* at 6.

a utility's decision to build a baseload plant, so it is inappropriate to allocate baseload generation entirely on an energy basis.[148] Additionally, as Mr. Johnson agreed, the BIP methodology only looks at the original undepreciated plant balance of the original investment, even though over the life of the plant it may be used to primarily serve load, but later used to serve peak demand as newer plants become more efficient.[149]

The BIP allocation also has other fatal flaws. For one, it double-counts (or perhaps even triple-counts) average demand by allocating all baseload plant costs based on classes' energy consumption, as well as part of the costs of intermediate (load-following) and peaking plants.[150] This is one reason the PUCT has rejected similar methodologies in the past. [151] In contrast the AED-4CP methodology allocates a portion of production-demand costs on average demand, but then removes that average demand component when calculating the "excess" (peak-driven) allocator to avoid double-counting. Mr. Johnson acknowledged at the hearing that the BIP methodology does not use an "excess" allocator, and it therefore suffers from the same double-counting issue by failing to remove "average" demand from the intermediate and peak allocators.[152] Further, the BIP method allocates a substantial portion of the high capital costs of baseload plants to customers based on their contribution to average demand, but does not accordingly allocate higher fuel costs associated with peaking plants based on customers' contribution to peak demands. This is, again, an asymmetry that has caused the PUCT to reject proposals similar to BIP in the past. As explained in one such rejection, "the low load factor classes [would be] relieved of an undue share of the high capacity costs associated with base load units, but the high load customers [would not be] granted the same relief with respect to the high fuel costs of peaker plants, thus resulting in high load customers paying for both high capacity costs and high fuel costs."[153] Mr. Johnson's methodology exhibits exactly this flaw, and even he

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[148] *Id.* at 7.

[149] Tr. (July 14) 81:22-24 (Johnson Cr.); *id.* at 82:17-45 (Johnson Cr.).

[150] Tr. (July 14) 80:35-41 (Johnson Cr.).

[151] TIEC Ex. 20 (Docket No. 7460, Examiner's Report at 197) ("As to double counting energy, the flaw in Dr. Johnson's proposal is the fact that the allocator being used to allocate peak demand, and 50 percent of the intermediate demand, includes within it an energy component. Dr. Johnson has elected to use a 4 CP demand allocator, but such an allocator, because it looks at peak usage, necessary includes within that peak usage average usage, or energy.").

[152] Tr. (July 14) 84:8-20 (Johnson Cr.).

[153] TIEC Ex. 20 (Docket No. 7460, Examiner's Report at 193).

acknowledged that changes to AE's fuel costs would be appropriate under the BIP methodology.[154] However, those fuel costs are not subject to modification in this case as they are separately recovered through the Power Supply Adjustment (PSA), which is not a base rate feature. Given the clear flaws in the BIP allocation, the IHE should reject Mr. Johnson's recommendations and instead apply the widely accepted AED-4CP method discussed above.

iv. Conclusion regarding production-demand allocation.

AED-4CP is consistent with cost causation for a summer peaking utility like AE, and AE's proposed ERCOT-12CP allocation is not. Further, while ICA witness Mr. Johnson proposed a third, even more unreasonable allocation methodology for production-demand costs, that does not mean AE's own unjustified proposal is a reasonable middle ground. As demonstrated above, AE's proposed ERCOT-12CP proposal is inconsistent with cost causation for a summer peaking utility and completely contrary to established precedent for allocating production-demand costs at the PUCT and other state regulators. AE can cite no precedent for using the ERCOT-12CP methodology for any similarly situated utility, and there is no reason to establish such a precedent here.

b. Distribution-Demand

Consistent with cost causation and industry practice, AE's distribution demand costs should be allocated on a 1-NCP basis, and AE's proposed 12-NCP allocation should be rejected.[155] Distribution-demand related costs include AE's distribution substations, poles, wires, conductors, and transformers.[156] These facilities are designed to serve the distribution-level load of each customer class without interruption,[157] which means these facilities must be sized to meet each class's ***maximum demand*** on the distribution system, whenever that occurs, and not some lower amount of demand.[158] If the distribution system were built to serve demand that is less than the maximum expected peak demand for each class, then available distribution capacity may be

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[154] Tr. (July 14) 83:13-27 (Johnson Cr.).; TIEC Exhibit 19 (ICA Response to TIEC 1-4).

[155] TIEC Ex. 1 (Pollock Dir.) at 16.

[156] AE Rate Filing Package at 62.

[157] TIEC Ex. 1 (Pollock Dir.) at 27.

[158] *Id*.

insufficient and outages could occur.[159]

AE does not propose to allocate distribution costs based on each class's individual maximum peak demand (1-NCP),[160] which tracks cost-causation. Instead, AE proposes to allocate these costs based on the ***average*** of the twelve monthly class (non-coincident) peaks during the year, which will necessarily be lower than the actual absolute peak demand.[161] As Mr. Pollock testified, the 1-NCP method should be adopted instead.[162] The 1-NCP methodology allocates distribution-demand costs using the annual peak demand of each rate class during the test year.[163] By using each class's highest annual demand, the 1-NCP methodology reflects that the distribution facilities needed to serve each class are sized to reliably serve the class's maximum demand, not some lower amount.[164] As such, this approach tracks cost causation because it more accurately recognizes the contribution of each rate class to AE's distribution-demand costs.[165]

AE's arguments in support of its 12-NCP method are unavailing. Mr. Burnham argues that the 12-NCP method recognizes that distribution facilities provide value throughout the year, and better captures the contributions of off-peak or seasonal customers whose demand may not be fully reflected in their class's peak.[166] However, if the utility constructs its distribution system to have sufficient capacity to reliably serve its customers at the time of maximum demand, it will have a system that is also capable of providing service in times of lower demand (whenever they may occur). Stated differently, off-peak or seasonal customer demand is not what drives investment in the distribution system. Indeed, Mr. Burnham agreed at the hearing that AE must build its

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[159] *Id.* at 27; Tr. (July 13) at 119:38-46.(Burnham Cr.).

[160] TIEC and AE agree that these costs should be allocated on an NCP basis rather than a CP basis. As AE explains in the Rate Filing Package: "[d]istribution facilities such as substations that directly interconnect with the transmission system are designed to meet the aggregated customer loads in specific geographic areas. As the systems are designed to meet localized demands, the costs are most appropriately allocated by analyzing the magnitude and timing of the class peak demand, which often occurs at times different from the system peak demand. . . . The peak demand of the class, without regard to the timing of the system peak demand, is referred to as the 'non-coincident peak' demand, or NCP demand." AE Rate Filing Package at 62.

[161] TIEC Ex. 1 (Pollock Dir.) at 27.

[162] *Id.* at 30.

[163] *Id.* at 28.

[164] *Id.* at 30.

[165] *Id.* at 28.

[166] AE Ex. 8 (Burnham Reb.) at 21.

distribution system to withstand peak usage.[167] And he also agreed that the average of 12-NCPs will tend to be lower than the actual NCP peak.[168] Again, if the distribution system were only designed to meet the 12-NCP average and not the 1-NCP demand, AE could have outages and be forced to curtail customers at the time of peak usage.[169] Thus, AE's contentions ignore what actually causes distribution-demand costs: the need for sufficient capacity to serve peak usage.

Using a 1-NCP allocation for distribution-demand costs is also consistent with PUCT precedent for both ERCOT and non-ERCOT utilities. Southwestern Electric Power Company (SWEPCO), Southwestern Public Service Company (SPS), and Entergy Texas, Inc. (ETI) all have had PUCT approved 1-NCP allocations for distribution-demand related costs.[170] Similarly, Oncor Electric Delivery Company (Oncor) and Texas-New Mexico Power Company (TNMP) have both consistently applied the 1-NCP method to allocate distribution plant and related expenses.[171] In recent rate cases, TNMP and Oncor's witnesses explained that the 1-NCP method best recognizes the cost causation associated with the load of each rate class on the utility's distribution system.[172] Additionally, AE's own witness Mr. Murphy supported the use of 1-NCP allocation for distribution-demand costs in at least one prior PUCT case.[173] The PUCT's consistent precedent on this issue further underscores the reasonableness of allocating distribution demand costs using a 1-NCP methodology.

The IHE should adopt a 1-NCP methodology for allocating distribution-demand costs and incorporate all necessary changes to AE's CCOSS, as set forth in TIEC witness Mr. Pollock's direct testimony.[174]

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[167] Tr. (July 13) at 119:38-39 (Burnham Cr.) ("… the distribution system has to be built to withstand its peak usage, right? That is correct.").

[168] *Id.* at 119:35-38 (Burnham Cr.).

[169] *Id.* at 119:38-46 (Burnham Cr.); Pollock Dir. at 27.

[170] TIEC Ex. 9 at 15-16 (showing a comparison of PUCT adopted class allocation treatments in Dockets 43695, 40443, and 39896).

[171] TIEC Ex. 1 (Pollock Dir.) at 28.

[172] *Id.* at 28-29.

[173] Tr. (July 13) at 111:34-112:5 (Murphy Cr.); *see also* TIEC Ex. 9 (D. 44941 Direct Testimony of Brian Murphy Excerpt) at 16.

[174] *See* TIEC Ex. 1 (Pollock Dir.) at 31; *id.* at Exhibit JP-6 (1-NCP class allocation factors applicable to secondary distribution costs); *id.* at Exhibit JP-7 (1-NCP allocation factors applicable to distribution substations and other primary distribution costs).

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

AE's proposed allocation of primary distribution demand-related costs contains another major flaw—it fails to distinguish between customers that use AE's interconnected distribution network and those that do not. Consistent with cost causation, primary customers who do not use the shared distribution network should not be required to pay those costs, just as transmission customers are not allocated any costs for the distribution network.

It is undisputed that certain of AE's primary customers are served through dedicated radial feeder lines that are directly connected to an AE substation and do not serve other customers.[175] As a result, these customers ("Primary Substation" customers) do not use AE's interconnected primary distribution network of lines, poles, and conductors.[176] This type of primary service is nearly identical to Transmission service, except that for Primary Substation customers, AE must first transform power down to a primary distribution voltage.[177] All three of AE's High Load Factor Primary Voltage (≥ 20 MW) customers are directly connected to AE distribution substations located adjacent to their sites through dedicated radial feeders, and thus qualify as Primary Substation customers.[178]

Primary Substation service stands in stark contrast to the service provided to the other primary distribution customers ("Primary Distribution" customers). To serve Primary Distribution customers, AE must not only own the transformation equipment to step power down from transmission to distribution level, but must also construct and maintain a network of interconnected primary poles, lines, conductors and related facilities to provide service.[179] In fact, a utility must invest in hundreds if not thousands of miles of distribution wires and related facilities to serve

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[175] *Id.* at 32; TIEC Ex. 23 (AE's Response to NXP's RFI 1-5R) at 1, note 1 ("Each feeder [serving AE's Above 20 MW High Load Factor customers] does not serve other customers."); AE Ex. 8 (Burnham Reb.) at 25 (explaining that no customers are "directly" served from any substation because the POI is outside of the substation and requires a feeder); Tr. (July 15) at 76:6-20 (Burnham Cr.) (showing that the only factual dispute was over the term "directly" and it was based on the ownership of the feeder line).

[176] TIEC Ex. 1 (Pollock Dir.) at 31, 79.

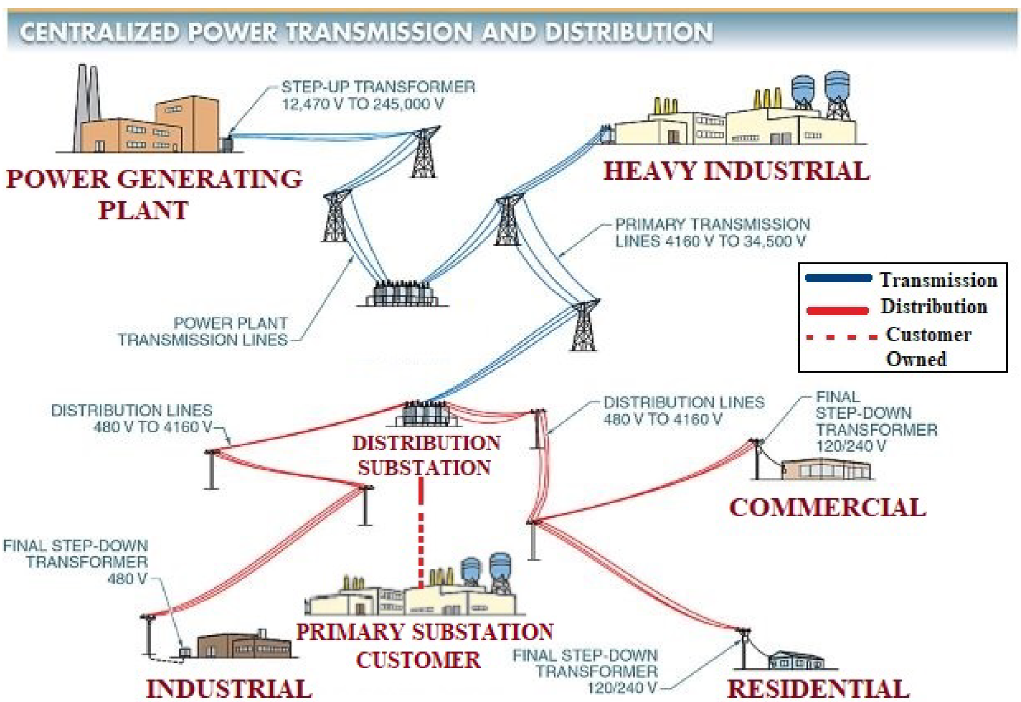
[177] Id.

[178] *Id.* This is also true of some of AE's customers in its Primary ≥ 3MW < 20 MW class. TIEC Ex. 1 (Pollock Dir.) at 32.

[179] *Id.* at 79.

Primary Distribution customers, and providing that service also results in greater line losses.[180] Primary Distribution service is thus more costly to provide than Primary Substation service in terms of both infrastructure costs and line losses.[181] The difference between Primary Distribution customers who are served from the interconnected distribution system and Primary Substation customers who are served directly from an AE substation using a dedicated, radial feed is an easy bright-line demarcation with significant cost consequences for the utility. This should be reflected in AE's CCOSS.

Mr. Pollock included the following graphic in his testimony illustrating the difference between Primary Substation service and Primary Distribution service:



As the graphic illustrates, Primary Substation customers do not use the distribution network; their use of the utility's distribution system is limited to substations and radial feeder lines that serve only that customer. A Primary Substation customer maintains its own distribution network for its industrial site.[182]

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[180] *Id.* at 80.

[181] Id.

[182] *Id.* at 81; Tr. (July 14) (Pollock Cr.) at 27:8-15.

Despite these fundamental differences, AE lumps Primary Substation customers together with Primary Distribution customers for cost-allocation purposes.[183] As a result, Primary Substation customers are allocated a share of AE's total distribution network infrastructure.[184] However, Primary Substation customers do not impose distribution network costs on the system because they take service from a distribution substation through a radial feeder.[185] Accordingly, AE's CCOSS should be modified to ensure that Primary Substation customers are not charged for the cost of distribution network assets that they do not use.[186] Cost-causation principles dictate that Primary Substation customers should instead only bear the cost of the radial distribution feeders that are used to serve them, which should be directly assigned.[187]

PUCT precedent supports distinguishing between Primary Substation and Primary Distribution service in this manner. In a litigated rate case in 2009, the PUCT 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."[188] Similarly, in a litigated 2014 rate case, the PUCT ordered that primary substation demands be removed from the distribution line cost-of-service study.[189] In both instances, the PUCT recognized that Primary Substation customers simply do not use the distribution network.[190] The allocation of distribution demand costs for AE should similarly reflect that the customers in the Primary ≥ 20 MW HLF

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[183] TIEC Ex. 1(Pollock Dir.) at 31.

[184] *Id.* at 31-32 ("In addition to distribution substation costs, AE allocates all Primary customers plant and related costs associated with the FERC accounts for Poles, Towers and Fixtures; Overhead Conductors and Devices; Underground Conduit; Underground Conduit and Devices; and Line Transformers.").

[185] *Id.*

[186] *Id.*

[187] *Id.* at 33-34. TIEC also proposes that Primary Substation customers should be allocated their portion of the costs associated with the substation. *Id.* at 33.

[188] *See id.* at 33 (quoting *Application of Oncor Electric Delivery Company, LLC for Authority to Change Rates*, PUCT Docket No. 35717, Order on Rehearing at 11 (Nov. 30, 2009)).

[189] *Application of Southwestern Electric Power Company for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 40443,Order on Rehearing at FoF 280-281, 304 (Mar. 6, 2014) (available at: https://interchange.puc.texas.gov/Documents/40443_1155_782838.PDF).

[190] *Application of Oncor Electric Delivery Company LLP for Authority to Change Rates*, PUCT Docket No. 35717, Order on Rehearing at FoF 159A ("Distribution customers should be permitted to avoid some distribution costs they do not impose on the system because these customers' hook up to the distribution system is at the substation.") (Nov. 30, 2009) (available at: https://interchange.puc.texas.gov/Documents/35717_999_633343.PDF); Docket No. 40443,Order on Rehearing at FoF 304.

class do not use AE's distribution network.

AE's arguments against a Primary Substation class are not based on cost-causation and are not supported by the facts. In his rebuttal testimony, AE witness Mr. Burnham disputed that Primary≥20 MW HLF customers are "directly connected to an Austin Energy distribution substation through dedicated feeders."[191] However, at the hearing, he clarified that his dispute is simply that he does not believe that these customers should be considered "directly" connected since they do not own the radial feeder.[192] He does not claim that these customers use the broader, interconnected distribution network that they are being required to fund under AE's proposal. Indeed, AE has provided a discovery response in this case that shows that the three Primary ≥ 20 MW customers are connected to dedicated feeders that each serve *no other customers*.[193]

In a similar vein, Mr. Burnham argued that the Oncor precedent establishing a Primary Substation class is distinguishable because the customers in the Oncor case owned and maintained the distribution facilities at issue.[194] However, this argument just supports direct assignment of the dedicated radial feeders for AE's Primary Substation customers—it does not support allocating all distribution network costs to Primary Substation customers who do not use that network, as proposed in AE's CCOSS. Rather, if the concern is that these dedicated feeders are included in AE's overall distribution costs, then the answer is to directly assign the costs of these dedicated feeders to the Primary Substation customers, or allow them to purchase the feeders. It is an accepted practice to directly assign costs to a customer or class of customers that can be identified as serving only those customers or classes, as Mr. Burnham agreed at the hearing.[195] In fact, AE's own Rate Filing Package states "[c]osts that can be readily attributed to a particular customer or customer class are directly assigned to that customer or class."[196] However, even though AE has specifically identified the feeders that serve Primary ≥ 20 MW HLF customers, it has not directly

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[191] AE Ex. 8 (Burnham Reb.) at 26.

[192] Tr. (July 15) at 76:6-20 (Burnham Cr.) (showing that the only factual dispute was the term "directly" and it was based on the ownership of the feeder line); AE Ex. 8 (Burnham Reb.) at 25 (explaining that no customers are "directly" served from any substation because the POI is outside of the substation and requires a feeder).

[193] TIEC Ex. 23 (AE Response to NXP 1-5R).

[194] AE Ex. 8 (Burnham Reb.) at 27.

[195] Tr. (July 13) at 120:3-6 (Burnham Cr.).

[196] AE Rate Filing Package at 58.

assigned the feeder costs to those customers in exchange for excluding them from a broader allocation of distribution network costs. As Mr. Pollock testified, the costs of the relatively short feeders that serve each of these customers should be directly assigned to that customer.[197] This would mean that all of the distribution costs associated with serving each Primary ≥ 20 MW HLF customer are being paid for by that customer, and there would be no basis for allocating additional distribution costs to that class. Indeed, Mr. Burnham concurred at the hearing that Primary Substation customers who have the costs associated with their dedicated feeders directly assigned to them should be treated differently.[198] AE should allow this as an option.

AE should also allow Primary Substation customers to purchase the distribution assets used to serve them.[199] This would allow the customer to purchase the dedicated radial feeders or, if the customer wishes, to also purchase the transformation equipment and thus take service at the transmission level.[200] As, Mr. Pollock testified, there is ample precedent to establish a facilities charge tariff to provide this opportunity for qualifying customers.[201] Notably, Mr. Burnham also agreed at the hearing that if a Primary Substation customer purchased the radial feeder, that would be a cost differentiation from other distribution customers.[202]

AE's other argument against recognizing Primary Substation service in its CCOSS is that "it is a common ratemaking practice to recover system costs on a class average basis regardless of the physical location of the interconnection."[203] And in a related vein, ICA witness Clarence Johnson argues that TIEC's proposal on this issue is tantamount to "geographic ratemaking."[204] These arguments are, again, not factual. While it is true that Primary ≥ 20 MW HLF customers have substations located adjacent to their industrial sites,[205] a Primary Substation allocation is not

[197] TIEC Ex. 1 (Pollock Dir.) at 33-34.

[198] Tr. (July 13) at 121:24-33 (Burnham Cr.).

[199] TIEC Ex. 1 (Pollock Dir.) at 6.

[200] *Id.* at 46

[201] *Id.*

[202] Tr. (July 13) at 121:34-37 (Burnham Cr.).

[203] AE Ex. 8 (Burnham Reb.) at 25.

[204] ICA Ex. 4 (Johnson Cross-Reb.) at 10 ("Moreover, TIEC's proposal is a form of geographic rate making, since it is based on customers' location relative to specific substations.").

[205] Tr. (July 14) at 26:2-8 (Pollock Cr.).

based on the geographic proximity of the substation but the reduced electrical facilities that are needed to serve that customer because of the dedicated feeder. As discussed throughout this section, the basis for recognizing Primary Substation service is that these customers do not use the shared primary distribution network; they are directly connected to an AE substation through dedicated feeder lines that serve no other customers. This is unlike other primary customers, who are part of a looped distribution network. Indeed, at the hearing, Mr. Burnham agreed that it is likely that a downtown office building that takes primary service would not be served by a dedicated radial like Primary Substation customers.[206] Instead, an office building is typically served on a looped distribution network.[207] Correspondingly, TIEC's proposal is supported by cost causation and does not allocate costs based on geography, but based on the customer's use of AE's distribution system.

For all of the foregoing reasons, AE's rates should recognize Primary Substation service as distinct from Primary Distribution service, and remove the allocation of distribution network costs (FERC accounts 364-368) to the Primary ≥ 20 MW HLF class.[208] Mr. Pollock's revised class allocation factors[209] reflecting this change should be adopted.[210] If this necessitates a tariff change to directly assign dedicated feeder costs to Primary Substation customers, then that change should be made rather than continuing to charge these customers for the broader interconnected distribution network.

6. Direct Assignments

See Section III. D.1.c, above regarding the dedicated feeder lines that serve Primary Substation customers.

7. Energy and Demand Line Loss Factors

Customers take service at different delivery voltages, and line losses increase each time

[206] Tr. (July 15) at 77:11-19 (Burnham Cr.).

[207] *Id.*

[208] TIEC Ex. 1 (Pollock Dir.) at 32, 34.

[209] *Id.* at 24, TIEC Ex. 1A (Pollock WP) at Exhibit JP-7.

[210] Mr., Pollock's revised allocation factors also utilize 1-NCP allocation methodology for distribution demand costs, consistent with TIEC's recommendation on that issue as set forth above. Regardless of whether the 1-NCP or 12-NCP method is used for distribution demand costs, the CCOSS should not allocate primary distribution network costs to the Primary ≥ 20 MW HLF class.

voltage is transformed down to a lower level.[211] To equitably allocate costs to the various classes of service on an electric power system, utilities must use loss factors to adjust all customer sales volumes (demand and energy measured at the meter) to one common voltage level, which is typically the generation level.[212] Utilities generally rely on a loss study to determine the peak demand and energy losses that occur when an electric utility generates and delivers electricity to each of its retail customer classes.[213] That way, customers who take power at different voltage levels are appropriately allocated the corresponding demand and energy losses incurred in serving them.[214]

AE conducted a loss study in 2018, but did not use that loss study correctly when adjusting its customer classes' demands and energy from the meter to the generation level. The first problem with AE's approach is that it did not use the actual energy losses derived from its 2018 Loss Study.[215] Instead, AE quantified the energy losses by voltage level and spread those losses over the energy sales by voltage level to derive an implicit energy loss factor for each customer class.[216] Additionally, AE failed to use peak demand losses to adjust the CP and NCP demands.[217] Instead, AE used its flawed ***energy*** loss factors to adjust the CP and NCP demands. TIEC witness Mr. Pollock's Exhibit JP-8 demonstrates the correct methodology for directly deriving energy and peak demand loss factors from AE's loss study.[218] Peak demand losses are actually higher than energy losses because losses are directly related to power flow, and more power is flowing during peak demand periods.[219] As a result, AE under-adjusted the CP and NCP demands, which under-allocated distribution costs to the secondary voltage customer classes and over-allocated costs to the primary voltage customer class.[220] AE witness Mr. Burnham admits that "ideally demand

[211] TIEC Ex. 1 (Pollock Dir.) at 34.

[212] *Id.*

[213] *Id.* at 35.

[214] *Id.* at 34.

[215] *Id.* at 35.

[216] *Id.* at 34.

[217] *Id.* at 36.

[218] *Id.* at JP-8.

[219] *Id.*

[220] NXP Ex. 1 (Daniel Dir.) at 38.

losses should be utilized to adjust load."[221] Nevertheless, he argues that AE's flawed energy loss factor was necessary to accomplish its 12CP cost allocation because AE's loss study only determined demand losses at the peak hour of the year, and using a single peak does not take into account the variations in demand or ambient conditions throughout the year.[222] However, most of the class NCPs occur during the summer months. Further, if AE's existing loss study was not sufficient to conduct the analysis how it wanted, AE could have conducted a new loss study for this rate case, as traditionally done by utilities.[223] AE's failure to conduct a new study is not a valid reason to use derived loss factors that misrepresent conditions on its distribution system and therefore misallocate costs.

Finally, AE's loss adjustments failed to distinguish between Primary Substation and Primary Distribution services, even though the AE's Loss Study recognizes that there are lower demand and energy losses for Primary Substation service compared to Primary Distribution service.[224] AE incurs higher losses to deliver power and energy to Primary Distribution customers because they take service through additional distribution facilities and not directly from the substation like Primary Substation customers.[225] Therefore, the CP and NCP demands for energy at the generation level will be lower for Primary Substation service than for Primary Distribution service, and that differential should be reflected through different loss factors.[226]

The loss factors proposed in Mr. Pollock's Exhibit JP-9 are derived directly from AE's 2018 loss study and correct for the flaws in AE's loss analysis.[227] They also appropriately reflect the difference in losses incurred to serve Primary Substation and Primary Distribution customers.[228] Accordingly, TIEC's proposed loss factors better reflect cost causation and should be adopted by the IHE.

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[221] AE Ex. 8 (Burnham Reb.) at 24.

[222] AE Ex. 8 (Burnham Reb.) at 24.

[223] Tr. (July 14) (Daniel Cr.) at 55:44-46.

[224] TIEC Ex. 1 (Pollock Dir.) at 36.

[225] *Id.*

[226] *Id.*

[227] *Id.* at 37 and Exhibit JP-9.

[228] *Id.*

8. Cost Allocation Summary

As discussed above, the CCOSS should be revised to (1) remove pass-through costs, other than Service Area Streat Lighting; (2) allocate production demand-related costs using the A&E-4CP method, rather than the ERCOT-12CP method; (3) allocate distribution demand-related costs based on the class peak (1-NCP) method, rather than the 12-NCP method; (4) recognize Primary Substation service and remove primary poles, lines and conductors that were allocated to the High Load Factor Primary Voltage class with demand greater than 20 MW, which may include a process for directly assigning or allowing customers to purchase dedicated radial feeders from an AE substation; and (5) restate the CP and NCP demands from meter to the generation level based on the voltage/service level demand loss factors and restate the energy from the meter to the generation levels using the revised energy loss factors.[229] These changes are all incorporated into Mr. Pollock's modified CCOSS.

E. Cost of Service Results

The results of Mr. Pollock's CCOSS results are set forth in his exhibit JP-11, and indicate that there are significant disparities between AE's proposed base revenues and the base revenues required to move each customer class to cost.[230] The implications on the class revenue distribution will be discussed further in Section IV.

F. Cost Allocation Conclusions

As discussed above, TIEC's cost allocation proposals reflect cost causation and are supported by precedent governing similarly situated utilities. Neither is true of AE's proposed allocation methodologies addressed above. As such, TIEC's recommendations should be adopted on those issues.

IV. CLASS REVENUE DISTRIBUTION

Class revenue distribution is the process of determining how any base revenue change is apportioned to a utility's customer classes.[231] Base revenues should reflect the actual cost of providing service to each customer class as closely as practicable, but regulators may limit the immediate movement to cost based on gradualism, which is the principle that rates should move

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[229] *Id.* at 39.

[230] *Id.*

[231] *Id.* at 40.

gradually to cost if moving immediately to cost would result in rate shock.[232] A primary driver for AE's rate case filing is to move the residential class closer to its actual cost of service, and eliminate longstanding subsidies that were perpetuated by the 2016 settlement.

A. Class revenue distribution should be driven by the results of a proper CCOSS.

AE should implement a class revenue distribution that is based on the results of a proper CCOSS, which is designed to evaluate whether each class is appropriately contributing to its actual cost of service. Cost-based rates are fair, efficient, enhance revenue stability, and encourage conservation.[233] As illustrated by Mr. Pollock's Table 4, AE's proposed class revenue allocation is not cost-based because it actually moves two customer classes—Primary ≥ 3 MW < 20 MW and the High Load Factor Primary ≥ 20 MW classes—***further*** from cost. These classes would receive rate increases when an appropriate CCOSS, as developed by Mr. Pollock demonstrates that they should receive reductions.[234] Mr. Pollock's Table 4, which compares the results of TIEC's CCOSS to AE's proposed revenue distribution, is reproduced below:[235]

[232] *Id.*.

[233] *Id.* at 40-41.

[234] *Id.* at 41.

[235] *Id.*

Table 4 Required Vs. AE Proposed Base Rate Increase By Customer Class			
Customer Class	Required Increase per TIEC's CCOSS	AE Proposed Increase	Proposed Vs. Required Increase
Residential	32.9%	17.6%	53%
Secondary < 10 kW	11.1%	7.9%	71%
Secondary ≥ 10 kW < 300 kW	-16.3%	-6.3%	39%
Secondary ≥ 300 kW	-19.2%	-3.6%	19%
Primary < 3 MW	15.5%	8.4%	54%
Primary ≥ 3 MW < 20 MW	-6.7%	5.0%	-75%
HLF Primary ≥ 20 MW	-25.5%	11.9%	-47%
Transmission	39.4%	6.3%	16%
HLF Transmission > 20 MW	-28.9%	-4.0%	14%
Service Area Street Ltg.	69.9%	83.8%	120%
City-Owned Pvt. Out. Ltg.	65.5%	41.6%	64%
Customer-Owned Non-Met. Ltg.	62.7%	15.1%	24%
Customer-Owned Met. Ltg.	36.2%	29.1%	80%
Total	8.7%	8.7%	100%
Source: Exhibit JP-11 and WP G-10.2.			

TIEC recommends moving all customer classes to cost, unless it would cause excessive rate impacts to any particular class considering the revenue requirement and allocation methodologies that are ultimately adopted.[236] If the IHE determines that movement to cost should be balanced with the principle of gradualism, the two Primary Voltage classes should still at least move in the direction of cost, and should have their base rates reduced by at least 30% of the cost-based reductions reflected in Mr. Pollock's corrected CCOSS. Assuming TIEC's other recommendations are adopted, this would reduce base rates by 2% for the Primary ≥ 3 MW < 20 MW class and 7.7% for the High Load Factor Primary ≥ 20 MW class.[237] Adopting 30% of the cost-based reductions under a gradualism approach would be consistent with AE's proposal for the classes that are currently above cost under AE's CCOSS, which AE suggests should receive between 24-33% of their cost-based rate decreases.[238]

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[236] *Id.* at 42.

[237] *Id.*

[238] *Id.*

V. RATE DESIGN

D. Proposed Primary Substation Rate

As explained above, AE should recognize that the Primary ≥ 20 MW HLF class takes Primary Substation service and change the rates for this class accordingly (as reflected in TIEC's CCOSS). Mr. Pollock's Table 5, reproduced below, provides an illustrative Primary Substation rate design assuming a 7.7% base revenue decrease for High Load Factor Primary ≥ 20 MW customers, which would move those customers 30% toward cost:

Table 5
Recommended Primary Substation Rate Design
Assuming a 7.7% Base Revenue Decrease

Description	Billing Units	Current Rates		Proposed Rates	
		Rate	Revenues ($000)	Rate	Revenues ($000)
Base Revenues			$33,906.1		$31,295.3
Basic Charge	36	$11,000	$396.0	$11,000	$396.0
Delivery Charge	2,279,600	$4.50	$10,258.2	N/A	N/A
Demand Charge	2,279,600	$10.20	$23,251.9	$13.56	$30,899.3

This Primary Substation rate should be open to all customers who take Primary Substation service, which would include all three customers in AE's Primary Voltage ≥ 20 MW HLF rate class. Additionally any other Primary customers that can show they meet the characteristics for Primary Substation service should also be allowed to migrate to this rate in the future.[239]

E. Proposed Facilities Charge Tariff

AE should be required develop a facilities charge tariff that would allow current or prospective Primary Substation customers to lease or purchase the dedicated distribution feeders and/or transformation equipment used to serve them. Currently AE does not have a facilities charge tariff, so once a customer is interconnected, there is no opportunity for that customer to lease or buy facilities as needed to transition to a higher delivery voltage.[240] A facilities charge tariff that allows Primary Substation customers to purchase or lease dedicated distribution feeders and therefore be excluded from bearing the costs of the broader distribution system, as described

[239] *Id.* at 45.

[240] *Id.* at 45.

above.

There is ample precedent for similar facilities charges in the tariffs of other vertically integrated utilities in Texas,[241] and as AE's witness stated, it would be a policy decision whether or not a customer should have the right to purchase or lease those facilities.[242] Given AE's goals of directly assigning costs when possible, AE should create a facilities charge that would allow Primary Substation customers to lease or purchase the distribution facilities from which they take service. Similarly, a facilities charge should be implemented that would allow a Primary customer to transition to Transmission service by purchasing or leasing the necessary equipment from AE to meet the class service requirements.

G. Load Factor

High load factor customers use energy more predictably throughout the day and year, and this predictability makes them easier for AE to serve.[243] As discussed throughout this brief, TIEC's recommendations more closely recognize the cost efficiencies that AE realizes when serving high load factor customers compared to more unpredictable, low load factor customers who require AE to invest more resources toward meeting peak demand.

I. Increased Transparency

1. Commercial and Industrial Base Rate Design

TIEC's allocation and rate design proposals are discussed throughout this brief.

3. Gradualism

See Section IV, above.

J. Proposed Tariff

As discussed in Sections V.D. and V.E., TIEC recommends establishing a facilities charge tariff and a tariff to govern Primary Substation service.

VII. OTHER ISSUES

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

The proposed Power Supply Adjustment (PSA) should be revised to include a separate

[241] *Id.* at 46.

[242] Tr. (July 13) at 121:20-21 (Burnham Cr.).

[243] Amendment to AE's Rate Filing Package at 2; AE's Rate Filing Package at 121.

Primary Substation Adjustment Factor. The Power Supply Adjustment (PSA) is a separate rider that recovers fuel and purchased power expenses and expenses and debt service associated with AE's ownership of the Nacogdoches plant.[244] AE has differentiated the PSA charges by voltage to recognize the differences in energy losses.[245] However, the PSA only differentiates the service provided at transmission, primary, and secondary voltages.[246] It does not reflect that lower line losses are incurred to provide to supply energy to Primary Substation customers compared to other primary customers.[247] For the reasons discussed above, the PSA should be revised to include a separate Primary Substation Adjustment Factor. Mr. Pollock prepared a revised PSA adjustment factor based on the as-filed Rate Filing Package, which is reproduced below:[248]

Line	Delivery Voltage	Energy at Meter (kWh)	Energy at Generation (kWh)	Loss Multiplier	Loss Factor
		(1)	(2)	(3)	(4)
1	**Secondary**	10,216,365,913	10,766,102,700	1.05381	1.00760
2	**Primary**	1,333,707,288	1,367,887,663	1.02563	0.98065
3	**Substation**	1,547,738,660	1,573,108,657	1.01639	0.97182
4	**Transmission**	254,902,115	257,995,601	1.01214	0.96775
5	**Total**	13,352,713,976	13,965,094,622	1.04586	1.00000

2. Energy Efficiency Service

Industrial Customers should not be subject to the Energy Efficiency Services (EES) Fee. AE properly exempts certain industrial customers, specifically PRI-2 HLF (primary customers with a load size between 3MW and 20 MW) and PRI-4 HLF, primary customers with a load size

[244] TIEC Ex. 1 (Pollock Dir.) at 37.

[245] *Id.*

[246] *Id.* at 37-38.

[247] *Id.* at 38.

[248] *Id.* at Ex. JP-10.

above 20 MW) from Energy Efficiency Services (EES) charges.[249] In its amended Rate Filing Package, AE excluded primary customers above 3 MW (the PRI-2 HLF customer class) from EES charges, recognizing that industrial customers have market incentives to pursue cost-effective energy investments because minimizing energy costs is necessary to remain competitive.[250] Electricity is typically in the top three production costs for large industrial facilities, so minimizing electricity costs is essential to remaining competitive. Large businesses also have corporate mandates and sophisticated energy management programs that drive energy efficiency measures.[251] The PUCT[252] and the Texas Legislature[253] similarly exempt industrial customers from paying into or participating in a utility's energy efficiency programs, recognizing that industrial customers have inherent incentives to implement cost-effective energy efficiency measures on their own.[254]

The Sierra Club nevertheless argues that an EES fee should be assessed to each customer class evenly on a per-kilowatt-hour basis, including Transmission and primary customers over 3 MW.[255] This position is contrary to cost-causation principles, would put these industrial customers at an economic disadvantage, and would treat large customers unfairly as compared to other customer classes. Industrial customers have already invested in their own energy efficiency measures and programs on their own dime, and are not eligible to receive EES rebates from AE.[256] Because these customers cannot charge back their energy efficiency investments to AE, they should not be required to participate in the EES fee. This would require large business customers to pay for energy efficiency programs provided to AE's other customers in addition to funding their own measures outside of AE's rates.

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[249] Amendment to AE Rate Filing Package at 3-4. However, it appears that AE may be improperly allocating these costs to these classes as explained in Section II.B.10.

[250] TIEC Ex. 2 (Pollock Reb.) at 2; Tr. (July 14) 34:31-41 (Reed Cr.).

[251] *Id.*

[252] TIEC Ex. 15 at 003-04 (quoting the PUCT's order that declined to remove the energy efficiency opt-out for transmission customers).

[253] TIEC Ex 16 (citing PURA § 39.905(a), which specifically limits a utility's energy efficacy programs to residential and commercial customers).

[254] TIEC Ex. 2 (Pollock Reb.) at 13.

[255] SCPC Ex. 1 (Reed Dir.) at Bates 011.

[256] AE Ex. 7 (Genece Reb.) at 5; SCPC Ex. 1 (Reed Dir.) at Bates 009.

The Sierra Club claims that industrial customers should be included in the EES charges because all customers benefit from EES investments and the resulting reduction in system costs,[257] but this misses the point. Large industrial customers make their own energy-efficiency investments at their own expense.[258] These investments ***also*** benefit the system as a whole in that they similarly avoid system costs.[259] Nevertheless, no other customers pay for industrial energy-efficiency efforts (nor should they).[260] It would be unreasonable to require these same industrial customers to pay the EES fee, which is designed to recover costs associated with an energy-efficiency program that is not used by or suitable for industrial customers.[261]

Indeed, the Sierra Club has even admitted that large industrial customers (in particular, PRI-4 HLF customers) do not incur any EES program costs, and that its proposal would require those customers to pay twice for energy efficiency—both for the costs of their own self-directed energy efficiency measures and the EES charges incurred by AE.[262] Furthermore, Dr. Reed, Sierra Club's witness, agreed that the EES charges would put large industrial customers at a competitive disadvantage compared to industrial facilities outside of AE's service area.[263] Because large industrial customers are excluded from the direct benefits of the EES program and provide a system-wide benefit in the form of avoided system costs from their energy efficiency measures, large industrial customers should be excluded from EES charges.[264]

Alternatively, Sierra Club contends that exempt industrial customers should provide a report detailing their energy efficiency measures.[265] However, the details of industrial customers' energy efficiency efforts has no bearing on AE's provision of service to those customers. These customers pay for their own energy efficiency efforts, and the Sierra Club has not explained why AE or the public has any right to force these entities to publicly disclose those efforts or how such

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[257] SCPC Ex. 1 (Reed Dir.) at Bates 010.

[258] TIEC Ex. 2 (Pollock Reb.) at 14-15.

[259] See id.

[260] *Id.* at 12.

[261] AE Ex. 7 (Genece Reb.) at 5-6.

[262] Tr. (July 14) 46:12-16 (Reed Cr.); TIEC Ex. 2 (Pollock Reb.) at 2.

[263] Tr. (July 14) 41:2-9 (Reed Cr.).

[264] AE Ex. 7 (Genece Reb.) at 6.

[265] Tr. (July 14) 42:11-23 (Reed Cr.).

forced disclosures would serve the public interest. Further, the efforts of sophisticated large businesses to reduce their electricity consumption are often proprietary and confidential.[266] For example, energy efficiency measures can include investments in state of the art manufacturing technology,[267] and a report about those investments would give a competitor greater insight into the customer's confidential practices. Accordingly, the IHE should reject Sierra Club's ad hoc proposal to create an energy efficiency reporting requirement for industrial customers.

VIII. CONCLUSION

TIEC respectfully requests that the IHE adopt the recommendations set forth above and grant TIEC all other relief to which it is justly entitled.

Respectfully submitted,

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[266] Tr. (July 14) 23:15-17 (Pollock Cr.).

[267] TIEC Ex. 2 (Pollock Reb.) at 13.

CERTIFICATE OF SERVICE

I, Benjamin B. Hallmark, Attorney for TIEC, hereby certify that a copy of this document was served on all parties of record in this proceeding on this 28th day of July, 2022 by electronic mail, facsimile, and/or First Class, U.S. Mail, Postage Prepaid.

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