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

NXP SEMICONDUCTORS, INC'S POST HEARING BRIEF

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I. INTRODUCTION

A. The Goals of NXP Semiconductors

NXP Semiconductors ("NXP") has been a part of the Austin community for decades and has been a long-standing Austin Energy ("AE") customer. NXP's priority in this proceeding is affordable and reliable electricity. It is important to Austin businesses, and it is important to the employees and residents who live here. As presented in the opening statements at the final hearing ("Hearing"), AE is a public power utility that is owned by the community and serves a mission to provide clean, reliable, affordable energy.[1] As a member of the Austin community and as an AE customer, NXP has a primary goal of access to affordable electric rates that are determined based on equitable ratemaking principles focused on cost of service.

NXP believes that AE should establish rates for each of its customer classes that are affordable and equitable based on established cost-based methodologies. These methodologies should be developed in a manner that considers *all* customer classes, which AE's proposals fail to do. In fact, AE's proposals in this proceeding not only result in an inflated revenue requirement that harms every customer class, but would also establish a class-based revenue allocation that serves as a detriment to some classes (such as NXP's class) and a benefit to others, regardless of the fact that AE's overall need for a base rate increase is predominately driven by one specific rate class.[2] NXP also notes that certain of AE's ratemaking proposals even fail to comply with the financial policies established for AE by the City Council as described further herein.

To establish a revenue requirement and class cost allocation method that leads to an equitable revenue distribution and equitable rates for *every* customer class, proceedings such as this one must be transparent and allow for a full financial accounting of AE's costs and infrastructure planning. This requires a process that is at least as robust, impartial, and transparent as that utilized by the Public Utility Commission of Texas ("PUCT"), which has appellate jurisdiction over AE's base rate proceeding and is the primary electric regulatory body for most electric utilities in the State of Texas.[3] Unfortunately, despite the best efforts and eminent qualifications of the Independent Hearings Examiner ("IHE"), AE's rate review process has been far from transparent or impartial. The IHE has been extremely limited in how the case could be

[1] *See Austin Energy's 2022 Base Rate Review*, Tr. at 20:1-5 (Brocato Opening) (July 13, 2022).
[2] *Id*. at 18:7-9 and 18:35-19:12.
[3] *See* Tr. 69:32-70:3 (Dombroski Cross) (July 14, 2022); *see generally* NXP Ex. 1.

conducted since AE set the scope of the proceeding, AE created the procedural rules, and because AE needlessly condensed the timeline of the case as compared to a PUCT proceeding (even given AE's narrowly limited willingness to extend certain procedural deadlines by a nominal number of days).

B. The Austin Energy Rate Case Process

AE's procedural handling of this proceeding directly harmed Intervenors' ability to fully and fairly participate in the case and ultimately tainted the ability of the City Council to conduct a meaningful scrutiny of AE's proposals. AE's actions as described below inhibited those parties with divergent views from AE in their ability to participate in this process and to effectively learn of and present to the City Council additional information that AE might not want to have conveyed, which masks the community's views. Additionally, the restrictions AE imposed in the process suggest that the entire exercise is simply designed to placate public *desires* to be heard rather than provide an actual forum for different interests to be presented to the City Council and have those views truly considered. This can only undermine public confidence in any rate decision the City Council will make, particularly one that closely lines up with AE's recommendations.

From the outset, Intervenors were put at a disadvantage to AE by not being afforded an opportunity to provide commentary on the rate case procedures. AE's 2022 Base Rate Review website makes clear that participants' ability to contribute to the proceeding includes (1) providing input on AE's proposed base rates; (2) asking questions of AE Staff; and (3) presenting their perspective for the IHE to consider.[4] IHE Order No. 1 confirms that AE established the procedural guidelines for this proceeding and mandated that all participants should follow them.[5] The Order further indicates that the IHE will look to these guidelines to make rulings and conduct the rate case process, including the preliminary and final conferences.[6] During the Hearing, AE confirmed that the procedural guidelines set the scope of the proceeding, and that Intervenors were not provided an opportunity to adjust this scope.[7] A resulting consequence, among others, is that Intervenors were not able even to comment on the deadlines set forth in AE's procedural schedule from the outset. AE's initial procedural schedule, which was *marginally* extended by agreement

[4] https://austinenergy.com/ae/rates/2022-base-rate-review/ihe-process/how-to-participate-ihe-process
[5] Order No. 1 (Apr. 28, 2022) at 2.
[6] *Id.*
[7] Tr. 69:5-12 (Dombroski Cross) (July 13, 2022).

of the parties,[8] only allowed Intervenors 44 days to conduct discovery on AE's rate filing package from the start of the discovery period, assuming parties intervened immediately upon AE's filing of the rate package. From the intervention deadline, Intervenors had only two weeks to engage in discovery. Overall, AE took approximately two years to develop its rate study, while the remaining parties had a maximum of two months to analyze the study and prepare position statements.[9]

AE's procedural guidelines further restricted this proceeding by prohibiting the IHE from issuing Protective Orders which are common in PUCT proceedings and which are essential information-gathering tools to obtain ratemaking and accounting information that is critical to a transparent rate review.[10] The guidelines also generally prohibit any confidential information from being available in any filings, and leave the determination of whether information is "confidential" to the City of Austin Law Department – essentially delegating authority for this decision to AE itself through an affiliated entity.[11] In the event a party found it necessary to obtain "confidential" information to develop its Position Statement, the party would have to seek the information through a Public Information Act Request ("PIA"), which AE acknowledged could take weeks or even months to resolve.[12] Given the accelerated nature of the AE procedural schedule, it was effectively impossible in this proceeding for a party to receive a PIA response prior to the conclusion of this case.

AE also hampered Intervenors' ability to conduct sufficient discovery by placing severe limitations on the number of Requests for Information ("RFIs") that Intervenors could propound on AE's Rate Filing Package ("RFP") and rebuttal testimony, as well as prescribing an exceptionally narrow timeframe to submit discovery requests following AE's submission of rebuttal testimony.[13] A formal rate case process fundamentally requires that all affected customers have meaningful access to Austin Energy's cost of service study, rate proposals, and supporting documentation, as well as an opportunity to conduct a robust review, including a thorough review of *all* relevant information, confidential or otherwise. Unfortunately, this has not occurred in the present case because it simply was not possible given the limitations that AE set forth in its

[8] NXP Ex. 13 at 3-4.
[9] NXP Ex. 1 at 14.
[10] NXP Ex. 13 at 18; Tr. 68:26-28 (Dombroski Cross) (July 13, 2022).
[11] NXP Ex. 13 at 12; Tr. 68:13-28 (Dombroski Cross) (July 13, 2022).
[12] Tr. 68:39 – 69:3.
[13] NXP Ex. 1 at 13. Notably, Intervenors were limited to a total of 50 RFIs on AE's rate filing package, and had only 24 hours to review AE's rebuttal testimony and propound only seven discovery requests. *See also* NXP Ex. 13 at 4 and 11.

procedural guidelines. This issue was compounded by the fact that, unlike in base rate case proceedings before the PUCT, AE did not submit any supporting testimony with the RFP, despite the fact that certain AE employees did, in fact, sponsor certain portions of the filing.[14] The identity of the supporting employees, however, was not made publicly available until AE filed its cross-rebuttal testimony, only allowing the parties to make this determination after-the-fact.[15] The result is that discovery conducted on AE's RFP was more of a fishing expedition to uncover AE's rationales for its proposals than a meaningful opportunity for the parties to ask educated questions of the sponsoring witnesses regarding AE's analyses.[16] This was particularly prohibitive on the parties because AE proscribed too narrow a timeline for the Intervenors to prepare position statements in comparison to both its prior 2016 rate case and the PUCT's procedures.[17] From the close of the discovery period, Intervenors had only 14 days to prepare and submit their position statements.[18]

In addition, AE limited the IHE's ability to conduct a fair and transparent hearing by explicitly withholding authority from the IHE to swear-in participants.[19] This means that none of the position statements admitted as evidence in the Hearing were submitted under oath, and none of the testimony given at the Hearing was provided under oath. Furthermore, AE did not provide an official court reporter or official transcript of the hearing, but rather a text-to-talk "transcript-like" document based on videos of the proceeding that is very hard to decipher, as well as a link to the actual videos of the proceeding. However, the majority of the video from the last day of the hearing that featured the bulk of Intervenors' cross examination on Austin Energy's rebuttal filing was remarkably still unavailable as of Intervenors' deadline to submit post-hearing briefs.[20] Having an accurate hearing transcript that is timely accessible to the parties is a fundamental requirement for parties to brief a hearing of this type, and as the IHE acknowledged during the hearing, these post-hearing briefs are crucial to deciding the outcome of base rate proceedings. Rather than incur the very modest expense to retain a proper court reporter to facilitate the creation

[14] Tr. 69:13-22 (Dombroski Cross) (July 13, 2022).
[15] *See id* and NXP Ex. 1 at 13.
[16] NXP Ex. 1 at 13.
[17] NXP Ex. 13 at 14.
[18] *See* NXP Ex. 13 at 4.
[19] *Id.*
[20] Counsel for AE confirmed the morning of July 28th that because of unforeseen technical difficulties, the full video would not be available until after Intervenors' briefing deadline.

of a full and accurate record, AE inexplicably chose not to do so, further imposing an unnecessary burden on Intervenors' ability to advocate for their positions.

Despite the considerable shortcomings of this process, NXP has expended considerable time and resources to full participation in the review of AE's RFP and in presenting the case below. We hope that an equitable and reasonable result is ultimately possible. We are very grateful to the IHE and his staff for their efforts to make the process as objective and meaningful as possible in spite of the obvious limits placed on the IHE's authority by Austin Energy.

II. REVENUE REQUIREMENT

A. Approach

AE has used the "cash flow" approach to determine its proposed revenue requirement and return.[21] The PUCT has allowed non-investor-owned utilities ("IOUs") (such as AE) to utilize this methodology of determining the return component of a non-IOU's total revenue requirement. Unlike an IOU, AE does not develop its revenue requirement to earn a profit for equity investors.[22] The cash flow approach is intended to provide adequate revenue requirements for a municipally-owned utility ("MOU") to meet its financial needs for ongoing operations and construction of plant, and therefore examines AE's cash requirements in excess of its expenses and debt service.[23] Under the cash flow method, a MOU's revenue requirement is determined by the sum of operating and maintenance costs, debt service requirements, cash outlays from revenues for capital additions, working capital requirements, bond defeasance costs, and payments to the City for services provided and/or to secure the payment of bonds, less interest income and other income from miscellaneous services the utility provides.[24] These cash needs are generally met by three main funding sources, which include base rates collected from customers, contributions and payments to the utility from specific customers to fund plant, and the proceeds of debt issuances.[25] The specific methodology is set forth in the non-IOU transmission cost of service ("TCOS") rate filing package.[26]

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[21] NXP Ex. 1 at 51.
[22] *See id* and TIEC Ex. 3 at 9.
[23] *Id.*
[24] NXP Ex. 1 at 51.
[25] NXP Ex. 1 at 51-52.
[26] NXP Ex. 1 at 52.

B. Cash Flow Methodology

While NXP believes AE's overall revenue requirement return calculation is mathematically accurate, NXP disagrees with the presentation of the cash flow return as reflected in AE's actual rate request. AE's proposed cash flow methodology calculation consists of the following components as they appear on Schedule C-3 of AE's rate filing package: Debt Service, Non-Nuclear Decommissioning, General Fund Transfer ("GFT"), and Internally Generated Funds for Construction ("IGFC"). In AE's methodology, these items are incorrectly reduced by Depreciation and Amortization.[27]

1. Operation and Maintenance Expenses

AE improperly includes $146,765,700 in Depreciation and Amortization ("D&A") of Operations and Maintenance ("O&M") expense in the calculation of its revenue requirement (Line 7 of Schedule A) as this D&A expense is *not reflected* in AE's rates, is not a source of cash, and does not affect cash flow.[28] Therefore, this amount should not be included in the calculation of a revenue requirement utilizing a *cash flow* return. The IHE should therefore exclude the amount of the D&A expense from AE's O&M expense in calculating the rate of return to arrive at the correct revenue requirement.[29]

The result of AE's inclusion of D&A expenses in its calculated rate of return is that it leads to a significant understatement of the true return that AE is requesting and that would be embedded in the rates AE proposes in this proceeding.[30] As reflected in the below tables, the actual amount of cash flow that AE is requesting over actual O&M is $344,034,416 and not the $197,268,716 reflected on Line 29 of AE's Schedule A.[31]

Table 1

IOU Cash Flow Using AE Revenue Requirement

1	Requested Revenue Requirement (excludes D&A & before Pass-throughs applied)	$1,337,575,011
2	Total Expenses (Includes D&A & Pass through costs)	$1,140,306,295
3	Cash Flow Return Requested (Line 1 minus Line 2)	$197,268,716
4	Add Back Non-Cash D&A	$146,765,700
5	Cash Flow Method Reflected In AE Request	**$344,034,416**

[27] *Id.*
[28] *Id.*
[29] *Id.*
[30] NXP Ex. 1 at 53.
[31] *Id.*

Table 2

Alternative PUC Non-IOU Cash Flow Return Method

		AE Requst (a)	Adjust (b)	As Adjusted (c)
Overall Revenue Requiemrent				
1	Total Expenses	$1,140,306,295	($146,765,700)	$993,540,595
2	Requested Return (Calculated below)	$197,268,716	$146,765,700	$344,034,416
3	Total Rev Req (before Pass-throughs)	$1,337,575,011		$1,337,575,011
Cash Flow Return Calculation				
4	Debt Service	$143,115,070		$143,115,070
5	Non-Nuclear Decommissioning	$8,000,000		$8,000,000
6	General Fund Transfer	$121,000,000		$121,000,000
7	Internally Generated Funds for Construc	$119,817,642		$119,817,642
8	Depreciation & Amortization	($146,765,700)	$146,765,700	$0
9	Interest and Dividend Income	($4,270,316)		($4,270,316)
10	Contribution in Aid of Construction	($43,627,981)		($43,627,981)
11	Total Return	$197,268,716		$344,034,416
12	Rate Base	$2,488,130,769		$2,488,130,769
13	Rate of Return - Line 11/Line 12	**7.9%**		**13.8%**

AE is incorrect in its assertion that inclusion of D&A expense comports with the PUCT's TCOS rate filing instructions, as described in Schedule C-3 and Schedule E-1 of those instructions.[32] The instructions "are applicable to all schedules required in the Transmission Cost of Service Rate Filing Package (TCOS-RFP) for non-investor owned transmission service providers (TSP) in ERCOT, unless otherwise noted."[33] Schedule C-3 of the PUCT's TCOS instructions describes then cash flow method and does not include reference to inclusion of D&A expense.[34] Schedule E-1, which is not specific to the cash flow method, does include a section accounting for depreciation expense.[35] However, the proceeding at issue in this case is a MOU base rate proceeding and *not a non-IOU TCOS proceeding*. Accordingly, an appropriate application of the PUCT's cash flow method as described in the PUCT's instructions is limited to the factors included in Schedule C-3 which exclude reference to D&A expenses. This is further supported by the fact that, contrary to AE's rebuttal testimony on this point, other MOUs have removed D&A expense from the cash flow method calculation.[36]

[32] *See* AE Ex. 8 at 21.
[33] *See* NXP Ex. 1 at 144.
[34] NXP Ex. 8 at 16; *see also* Tr. 58:44 and 60:46-61:5 (Loy Cross) (July 14, 2022).
[35] AE Ex. 8 at 21.
[36] *See* NXP Ex. 6 and 7; *see also* Tr. 68:6-22 (Rabon Cross) (July 15, 2022).

Based on NXP's proposed adjusted rate of return as reflected in the above Table 2, the resulting imputed 13.8% is a cash flow return, and is not comparable to a return that would be granted to a regulated IOU as it excludes the effect of D&A. However, NXP believes this is a better indicator of the amount of cash that AE is actually requesting above that which is needed to fund ongoing non-capital operations.[37]

2. Depreciation Expenses and Amortization of Contributions in Aid of Construction ("CIAC")

CIACs represent cash provided by AE's customers to establish service and help to direct excess costs (i.e. those exceeding the normal amount incurred to provide tariffed service) to the customer causing those costs, which in turn lowers rates (or helps establish more equitable rates) for other customers on the system. Because CIACs are ultimately treated as equity on a utility's balance sheet, these amounts should be considered as a source of cash in determining the IGFC. NXP's opposition to AE's treatment of Contributions in Aid of Construction is encompassed in the below section on IGFC.

3. Internally Generated Funds for Construction

AE's 50% equity assumption used to determine the IGFC level should be rejected, as AE errs in failing to account for AE's CIACs in its IGFC. Instead, the IHE should recommend a percent level that falls within the City's financial policy and is closer to the City's actual average utilization of IGFC over the last three years of 22%.

IGFC is the amount of revenue collected from customers that is used, in conjunction with funds received from issuances of debt, for construction, improvements, and replacements.[38] The AE financial policy on IGFC characterizes it as an equity contribution, stating "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."[39]

AE developed the IGFC using two prior test years (2019 and 2020) plus the 2021 test year to establish the known and measurable amount of $119.8 million, representing the amount of cash

[37] NXP Ex. 1 at 54.
[38] *Id.*
[39] *See id.* citing Capital Policy No. 14 located in Appendix B of the Rate Filing Package.

used to fund AE's construction budget.[40] AE proposes use of a cash funding assumption of 50%, meaning AE would set rates that result in funding 50% of its construction needs with cash and 50% with debt.[41] AE's Schedule WP C-3.3.1 shows that in FY2019, FY2020, and FY2021, the average percentage of construction that was debt-funded was 85.1%, 53.2%, and 46.2%, respectively (or a three-year historical average debt funding ratio of 67.2%).[42] CIACs provided an average of 11% funding over the same time period; therefore, the actual proportion of capital costs that was funded through base rate revenues only averaged 22% during the last three years.[43]

AE's assumed 50% in equity funding improperly excludes CIACs. Referencing the total Cash to Fund Capital Spending shown on AE's workpaper, the total equity (i.e. non-debt) funding that would be provided by customers ranges between 54% and 59% for the FY2019 through FY2021 period, averaging 56%, or close to the top of the range provided in AE's financial policy guidance as cited above.[44] NXP recommends that the cash funding assumption within AE's model be set to 35%, which would reduce the IGFC included in AE's cash flow return from $119,817,642 to $96,960,744.[45] This would result in an overall equity contribution to fund construction of 43%, which is well within AE's financial policy range and more consistent with AE's actual, historical debt funding ratio.[46]

While AE acknowledges that its financial policies do set a range of 35% - 60% for IGFC, AE contends that this policy must also be balanced with AE's *other* financial "policies" which include Financial Policy No. 6, its objective to maintain its credit rating, and the instruction it was provided by the City Council at the conclusion of its 2012 base rate proceeding to prospectively implement a policy of 50% funding for IGFC.[47] However, none of these considerations amount to a mandate that AE set its IGFC funding at 50%; moreover, AE has consistently *not* abided by this principle in recent years, as discussed herein.

During the Hearing, AE witness Mr. Grant Rabon indicated that AE Financial Policy No. 6 suggests that AE shall "target" debt service coverage of a minimum of "two times."[48] He

[40] NXP Ex. 1 at 54; citing AE Ex. 1 at Schedule WP C-3.3.1, Line 69; TIEC Ex. 3 at 13.
[41] NXP Ex. 1 at 54; TIEC Ex. 3 at 13.
[42] NXP Ex. 1 at 55; TIEC Ex. 3 at 13..
[43] *Id.*
[44] *Id.*
[45] NXP Ex. 1 at 55-56.
[46] *Id.;* TIEC Ex. 3 at 14.
[47] AE Ex. 6 at 23.
[48] Tr. 69:22-26 (Rabon Cross) (July 15, 2022).

explained that the more debt the utility has, the more leveraged it is, and the more difficult it becomes to remain in compliance with this policy, implying that the utility would need more coverage due to necessarily having more debt service.[49] However, Mr. Rabon stated that AE did not perform a calculation to determine at which percentage levels of IFGC that AE would cross over and be out of compliance with Financial Policy No. 6, implying that setting a less than 50% IGCF does not necessarily mean that AE would fail to reach its "target" debt service coverage.[50]

Mr. Rabon also indicated that despite his belief that the City Council has established a policy that AE should target a 50/50 debt to equity ratio, AE has not met this objective over the past three years (2019, 2020, and 2021).[51] Accordingly it remains to be seen why an AE "policy" (which is really just a "target") that AE has consistently not followed must now be used to set the IFGC when AE's actual financial policies set a range for the IFGC. The IHE should therefore reject AE's arguments.

4. General Fund Transfer

The $121 million of General Fund Transfer ("GFT") AE has requested is unsupported, controverts AE's own financial policies, and its inclusion in rates does not comport with longstanding rate-making principles. This amount represents about 18% of AE's requested base rate revenues, of which NXP witness Mr. Chuck Loy estimates that NXP will pay approximately $7.3 million and the residential class (inside and outside the city limits) will ultimately pay approximately $62 million (under AE's model).[52] As an alternative to AE's proposal, NXP recommends a GFT based on the City's budgeted amount, which would result in a $7 million reduction to AE's GFT.

The PUCT's cash flow return computation as referenced in the non-IOU TCOS instructions contemplates that a general fund transfer ("GFT") is allowable from AE to the City of Austin, but within certain limitations.[53] The PUCT's instructions provide the following guidance on permissible GFT: "for municipal utilities, annual payments for transfers to the City's general fund at rates established by the municipal utility's governing authority, to the extent such amounts are

[49] Tr. 69:26-33 (Rabon Cross) (July 15, 2022).
[50] Tr. 69:33-35 (Rabon Cross) (July 15, 2022).
[51] Tr. 70:12-20 (Rabon Cross) (July 15, 2022).
[52] NXP Ex. 1 at 55-56; TIEC Ex. 3 at 14.
[53] NXP Ex. 1 at 56.

not recovered through other elements of the TCOS".[54] The instructions indicate that GFTs should be a reimbursement for the costs of services related to the provision of *providing utility services* or costs that could otherwise be recovered in the TCOS.[55] Many MOUs receive administrative services such as human resources, financial and accounting, office maintenance, etc. from their host Cities. These costs will be reimbursed to the City via transfer to the City's General Fund.[56]

The City of Austin does provide such administrative services to AE; in fact, AE has included over $62 million in charges from City Services in its rate filing package.[57] However, AE includes these expenses with other O&M expenses rather than through its Cash Flow Method return calculation. The rate filing package indicates that AE transfers funds to the City for its share of services such as the City Fleet Department, Law Department and Administrative Support and Communications and Technology Management.[58] Therefore these amounts, which would fall within the realm of GFT per the PUCT's non-IOU TCOS instructions are not accounted for in the $121 million AE has designated as attributable to GFT.

Moreover, AE has not demonstrated that the $121 million it proposes for GFT reflect City of Austin services to AE for the "provision of utility service." AE's explanation for its GFT calculation is as follows:

> "Consistent with standard practice amount MOUs and Texas Government Code subsection 1502.059, Austin Energy transfers a percentage of revenues to the City. Austin Energy makes transfers to the City's general fund *in lieu of paying franchise fees, taxes, dividends; and also in lieu of earning a return on investment*. The transfer payment from Austin Energy to the City is invested directly back into the local community, rather than flowing to outside investors, which is a benefit to residents in Austin and those in surrounding communities" (emphasis added).[59]

AE's description does not indicate how the $121 million figure was determined, with the GFT appearing to be for an unspecified non-utility purpose. Accordingly, its inclusion in rates does not follow rate-making standards common to the electric utility industry.[60] As an additional consideration, AE also fails to provide any information to substantiate how GFT is invested back

[54] NXP Ex. 1 at 56 and 155.
[55] NXP Ex. 1 at 56; *see also* NXP Ex. 1 at 155-56.
[56] NXP Ex. 1 at 56.
[57] NXP Ex. 1 at 56-57.
[58] NXP Ex. 1 at 57.
[59] NXP Ex. 1 at 57, citing AE Ex. 1 at 34.
[60] NXP Ex. 1 at 57.

into the local community.[61] AE also cites Texas Gov't Code Sec. 1502.59 (Transfer of Revenue to General Fund) to support its proposed GFT but does not provide any tangible support for reliance on this provision.[62] This ordinance indicates:

> "Notwithstanding Section 1502.058 (Limitation on Use of Revenue) (a) or a similar law or municipal charter provision, a municipality and its officers and utility trustees may transfer to the municipalities general fund and may use for general or special purposes revenue of any municipality owned system in the amount and *to the extent authorized in the indenture, deed of trust, or ordinance providing for and security payment of public securities issued under this chapter or similar law"* (emphasis added).[63]

Mr. Loy has indicated that, based on his knowledge as an expert in the field of municipal utility regulations, rates, and funding, this provision relates to payment of bonds and other expenses related to securities, bond defeasance, or a cash infusion to help the city meet its debt coverage covenants; however, there is no mention of these types of payments in AE's GFT description.[64] The Texas Water Commission ("TWC") (whose rate regulatory functions have since been reassigned to the PUCT) has held in another case that municipal utility transfers to a city's general fund are acceptable if they reimburse the city for *administrative expenses*.[65] However, the TWC indicated that *unspecified* transfers to the general fund would only be justifiable if they are needed to provide the city with adequate debt service coverage.[66] This logic is consistent with the standard ratemaking principle applicable to AE's proceeding that the cost of providing utility service should be the basis of rates.[67] AE's explanation of the $121 million proposed GFT amount does not reflect that these costs are related to utility services and fails to indicate how the funds will be used "for and securing payment of public securities" to assist the City as stated in Texas Gov't Code Sec. 1502.59.[68] As proposed, it appears the GFT is a $121 million backdoor tax on

[61] NXP Ex. 1 at 58.
[62] *Id.*
[63] *Id.*
[64] *Id.*
[65] *Id.*

[66] NXP Ex. 1 at 58-59, citing Pet. Ex. 5 at 25; JJJ-5 at 949-50; TWC Docket No. 7144-M, *In the Matter of Complaints of Springwoods Municipal Utility District, et al. against the City of Austin,* Findings of Fact Nos. 40 and 41.

[67] NXP Ex. 1 at 59.
[68] *Id.*

customers both inside and outside the City of Austin's city limits – a tax for which many communities in Texas would require a vote from informed citizens.[69]

Moreover, AE's calculation of the GFT controverts its own financial policies, which require that the transfer of GFT be based on the three-year average revenues (less PSA revenues) times 12%.[70] More specifically, the policy indicates that "the GFT shall not exceed 12% of AE's three-year average revenues less power supply costs and on-site energy resource revenue."[71] AE's $121 million requested GFT, however, is based on a percentage of the *cost of service* calculated in this case, ignoring previous years. Therefore, the rates necessary to support the amount of transfer included in AE's request will not be fully included in the calculation as detailed in AE's financial policy until three years from now, resulting in a windfall for the utility.[72] AE witness Dombroski confirmed during the Hearing that AE's GFT was not calculated in compliance with AE's financial policies because AE utilized test year data *only,*[73] despite the fact that AE does not have discretion to ignore the financial policies set forth by the City Council.[74] The appropriate method of calculation would have been for AE to consider the average revenues (less PSA) for 2020, 2021, and estimated revenues for 2022 which would be based on AE's budgeted revenues for 2022.[75] Based on the revenues for 2019, 2020 and 2021 and as described below, the calculation for "average three year revenues" to be used in 2022's GFT calculation should be $11 million less than AE's proposed amount, which demonstrates something significantly less than $121 million.[76] Moreover, AE's requested $121 million in GFT represents 12% of the projected operating revenues for the test year – the maximum ratio allowed under its financial policies.[77] The ratio of GFT to operating income is over 50% higher than AE's average over the past three years, with the average amount being $110 million.[78] AE's requested GFT is clearly too high and unnecessarily inflates its revenue requirement.[79]

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[69] NXP Ex. 1 at 60.
[70] *Id.*
[71] AE Ex. 1 at Appendix B-2 (Policy No. 13).
[72] *Id.*
[73] Tr. 73:22-27 (Dombroski Cross) (July 13, 2022).
[74] *See* Tr. 36:25-32 (Dombroski Cross) (July 15, 2022).
[75] Tr. 74:24-37. (Dombroski Cross) (July 13, 2022).
[76] *See* T.r. 74: 26-42.
[77] TIEC Ex. 3 at 11.
[78] *Id.*
[79] *See id.*

Mr. Loy proposes a reduction in the AE's GFT to $114 million, which is the GFT transfer amount reflected in the City's latest budget document.[80] This was also confirmed during the Hearing to be the amount of GFT budgeted by the City Council for FY 2022.[81] If only $114 million is transferred, this represents $7 million in cash that AE will collect in rates and not transfer to the general fund. Not only does a $7 million reduction in the GFT to match the City's own proposed budget benefit all rate classes, but it is also more consistent with AE's own financial policies.

5. Pass-Through Items

AE should charge the City of Austin for the cost of street lighting service rather than recovering this cost through other customer classes in the Community Benefit Rider. AE's method results in an unjustified cost being imposed on customer classes who do not contribute to that cost.[82] As in other Texas cities, the City should pay for street lighting service from AE and it should already be accounted for in the City's budget and paid for with tax dollars rather than transferred to Austin electric customers.[83] Otherwise, it amounts to an additional hidden general fund transfer.[84]

As shown on Schedule G-6 of AE's COSS, the total cost of serving area street lighting was $19,179,377 during the test year.[85] The portion of this amount that is recovered by AE in the Community Benefit Rider from AE's retail customers should instead be billed to the City of Austin. Under AE's current policy of not charging the City of Austin for street lighting service, the amount passed through to retail customers constitutes an additional transfer to the City's General Fund.[86] As acknowledged by AE witness Mr. Grant Rabon during the Hearing, the increase AE proposes to its service area streetlighting costs attributed to the City of Austin is a meaningful increase.[87] AE should be required to charge the City of Austin for streetlighting service using the Inside City Limits rate in its service area lighting tariff. By way of example, AE provides street lighting service to some cities other than the City of Austin, and AE recovers those costs by directly billing those cities for this service.[88] AE should also bill the City of Austin for its associated street lighting service, and not recover those costs from AE's other retail customers. This is a change to AE's tariff that can and should be

[80] NXP Ex. 1 at 61.
[81] Tr. 75:22-76:31 (Dombroski Cross (July 13, 2022).
[82] *See* NXP Ex. 1 at 34-35.
[83] NXP Ex. 1 at 11.
[84] NXP Ex. 1 at 35.
[85] AE Ex. 1 at Schedule G-6.
[86] *See* NXP Ex. 1 at 35.
[87] Tr. 65:14-21 (Rabon Cross) (July 15, 2022).
[88] Tr. 53:28-40 (Daniel Cross) (July 14, 2022); AE Ex. 6 at 20.

approved by the City Council.[89]

C. Present Revenues and Billing Determinants

AE's proposed revenue requirement, both as proposed in the RFP and as adjusted in AE's rebuttal testimony, fails to adjust test year revenues, energy sales, demand levels and billing determinants in February 2021 for the Winter Storm Uri outages for some customer classes.[90] This omission would result in AE over-recovering its revenue requirement if AE's proposal were adopted by the IHE.[91]

For the classes that AE considers to be weather-sensitive customer classes, AE adjusted its base rate study for impacts caused by Winter Storm Uri by conducting a weather normalization analysis.[92] This analysis should have adjusted these customer classes' revenue, energy, and demand levels for Winter Storm Uri impacts. For those classes that AE considers to be non-weather sensitive customer classes, AE has not made any adjustments to its 2021 Electric System Rate Study for Winter Storm Uri Impacts.[93] Failing to make these adjustments is an error, because the winter weather event had an impact on non-weather sensitive customer classes' February 2021 revenues, energy usage, and demands.[94] As NXP witness Mr. Jim Daniel explained during the Hearing, high load factor customers that AE classifies as "non weather-sensitive" can still have a portion of their usage that *is* weather-sensitive.[95] And as Mr. Daniel also explained, based on NXP's demands during the Winter Storm Uri event, it is not the case that the storm had *no impact,* or even a negligible impact on high load factor customers' billable demands or demand revenues during the February 2021 load shed event.[96] Unfortunately, Mr. Daniel is not able to opine on the full extent to which all high load factor customers were impacted during the weather event because AE did not produce this information.[97] Ignoring these impacts likely resulted in AE's rate study to be flawed, as these customer classes' test year revenue levels, energy usage, demands, and billing determinants likely need adjusting for February 2021.[98] The IHE should require AE to conduct this

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[89] Tr. 53:40-44 and 54:4-10 (Daniel Cross) (July 14, 2022).
[90] NXP Ex. 1 at 35-36.
[91] *See id.*
[92] NXP Ex. 1 at 35.
[93] *Id.*
[94] NXP Ex. 1 at 36.
[95] Tr. 54:18-30 (Daniel Cross) (July 14, 2022).
[96] Tr. 54:4-15 (Daniel Cross) (July 14, 2022).
[97] NXP Ex. 1 at 36 and Tr. 54:15-16 (July 14, 2022).
[98] *Id.*

analysis. Using billing determinants that have not been adjusted for Winter Storm Uri to design AE's approved rates could result in rates that will over-recover AE's costs when those rates are applied to future billing determinants.[99]

III. COST ALLOCATION

A. Background

A utility, including a municipally-owned utility like AE, develops a class cost of service study ("COSS") for use in a rate proceeding to determine the portion of the utility's total retail cost of service or revenue requirement that should be borne by each customer class, in consideration of other factors.[100] Each cost component of the utility's total cost of service is either directly assigned or allocated to the various customer classes, with the results then considered in determining the level of revenues needed to be recovered through rates from each customer class.[101] This determination is made so that the utility has an opportunity to earn its overall revenue requirement; the results of the class COSS will also provide important information for designing rates.[102] As AE acknowledged during the Hearing, generally the City of Austin has a policy that rates should assign revenue responsibility to each class equal to, or reasonably equal to, their allocated cost of service.[103]

Typically, a class COSS is developed using the following three steps: (1) the various components of the utility's overall revenue requirements are assigned to their functional use, *e.g.*, production, transmission, distribution, metering, and billing and customer service; (2) the functionalized costs are classified based on cost causation factors to the cost categories of fixed or demand-related, variable or energy-related, and customer-related; and (3) the classified costs are directly assigned to their respective classes, or allocated to customer classes using allocation factors developed for each classified cost category.[104] Various methodologies or approaches exist for conducting each step in the COSS process; however, AE's methodology does not appropriately abide by a "cost causation" principle.[105]

[99] *Id.*
[100] NXP Ex. 1 at 14.
[101] *Id.*
[102] *Id.*
[103] Tr. 59:20-26 (Murphy Cross) (July 15, 2022).
[104] NXP Ex. 1 at 15.
[105] NXP Ex. 1 at 16.

B. Functionalization

Production costs are classified as either demand-related or energy-related costs. Typically, energy-related costs include those costs that vary with the generation of energy, such as fuel costs, and the energy charges and fuel charges for purchased power.[106] Demand-related costs are mostly fixed costs that do not vary with the amount of energy generated. Examples of demand-related costs are *investment costs for power plants* and labor costs for operating power plants.[107]

1. Production Function

AE's demand-related costs are related to the planning, investment, and operation of its AE-owned fleet of generation in the ERCOT market. NXP does not object to AE's classification of this cost as a "production" demand cost but disagrees with it its proposed allocation methodology as described in subsection (D) below.

2. Customer Service Function

a. Services and Meters

NXP does not object to AE's classification of services and meters charges to the customer service function. NXP does object, however, to the Independent Consumer Advocate's ("ICA") proposed cost allocation of meter-related costs, as discussed in Section (D)(3).

C. Classification

1. A&G Expense and Indirect Costs

The ICA proposes adjustment to the functionalization of AE's administrative and general ("A&G") expenses.[108] The adjustment is to the functionalization of FERC Account No. 920, A&G salaries, and Account No. 930, Miscellaneous General Expenses. Regarding Account 920 expenses, the ICA disagrees with AE's functionalization factor which is based on labor expenses in each function, and with the amount AE directly assigns to the production function that are related to the South Texas Project ("STP") and the Fayette Power Plant ("FPP"). Instead, of the

[106] NXP Ex. 1 at 15.
[107] *Id.*
[108] ICA Ex. 3 at 33-37.

$3,334,160 that AE directly assigns to the production function for STP and FPP, the ICA proposes to directly assign $10,394,162.

The ICA's explanation for a revised direct assignment of account 920 expenses is that this effectively includes on-site labor expenses at STP and FPP in the production function payroll expenses for the calculation of the payroll functionalization factors.[109] The ICA's only basis for this adjustment is a belief that AE's functionalization factor understates the amount that should be functionalized to the production function.[110] However, this belief is unsupported. The ICA has not shown that AE's Chief Executive Officer and other top administrators directly supervise non-AE employees onsite at SPP and FPP.[111] Since AE does not operate or maintain either of those two power plants, it is unlikely that AE executives supervise the non-AE on-site employees.[112] The majority owners of those two power plants do that and typically the minority owners of power plants pay the majority owners for their A&G expenses. The ICA's proposed adjustment will result in too much of the Account 920 expenses being functionalized as production-related and should be rejected.[113]

D. Class Allocation

1. Demand-Related Costs

a. Production-Demand

AE's proposal to use the ERCOT 12 Coincident Peak ("ERCOT 12 CP") methodology to allocate production demand-related costs is misguided because it is not based on cost causation principles which are driven by AE's peak demands occurring in the summer months.[114] The ICA's proposal to use the Base-Intermediate-Peak ("BIP") methodology is flawed for various reasons as discussed below and has never been adopted by any electric utility in Texas. Instead, the IHE should adopt the proposal set forth by NXP and TIEC to allocate production demand-related costs using the average and excess ("A&E") with 4CP demand allocation methodology,[115] which reflects that AE's generating capacity has been developed and operated with the primary goal of meeting

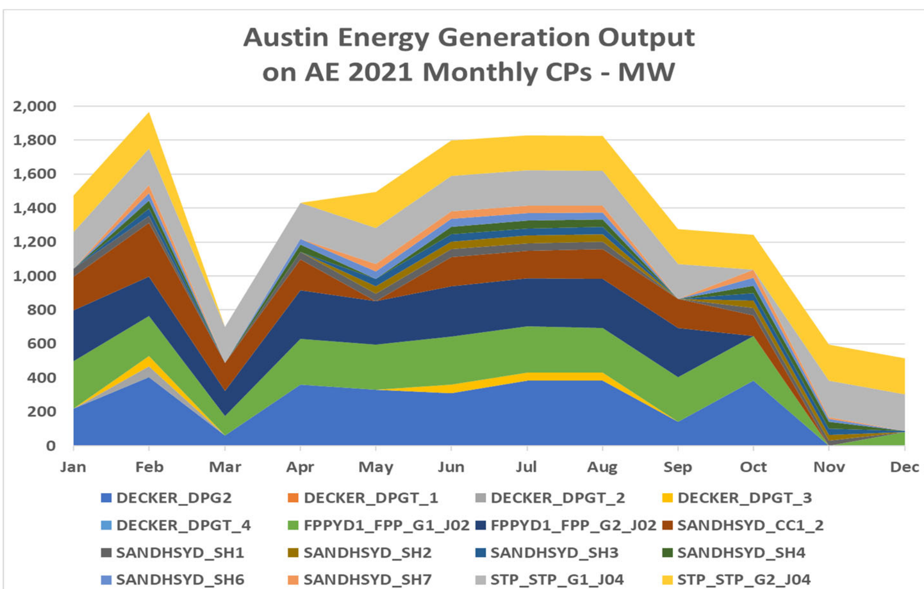
[109] NXP Ex. 2 at 21; ICA Ex. 3 at 34.
[110] NXP Ex. 2 at 21.
[111] NXP Ex. 2 at 22.
[112] *Id.*
[113] *Id.*
[114] NXP Ex. 1 at 16 and 25.
[115] NXP Ex. 1 at 17 – 28; TIEC Ex. 1 at 23-26.

the summer peak system demands; this methodology *does* reflect cost causation, is a widely accepted practice for utilities across the state, has been adopted by the Austin City Council in the past, and continues to be the City Council's official policy established in its 2012 rate review ordinance as there is no evidence that this ordinance has been repealed.[116]

AE's Proposal

AE claims that the ERCOT 12 CP allocation methodology for production demand-related costs "better aligns the relationship between the costs and benefits that accrue from owning and operating its fleet of generation in the ERCOT market" and that it "recognizes that all of AE's customers benefit from AE's generation fleet year-round."[117] AE also mistakenly claims that the 12 CP allocation method appropriately recognizes the benefit of the capacity hedge provided by its generation fleet over a greater number of peak hours during the year.[118] As support for this claim, AE proposes that the following graph demonstrates that AE resources were "significantly dispatched" to meet ERCOT load during non-summer (4CP) months including January, February, April, May, and October of 2021.[119]

Graph 3[120]



[116] *See* NXP Ex. 1 at 17; *see also* Tr. 73:8-13 (Burnham Cross) (July 15, 2022) wherein AE expert Scott Burnham, who provided testimony on AE's proposed production demand cost allocation methodology could not confirm whether directives in the 2012 rate ordinance have been repealed.

[117] AE Ex. 1 at 60-61.

[118] AE Ex. 8 at 12.

[119] *Id.*

[120] Originated in NXP Ex. 1 at 23 and reproduced in AE Ex. 8 at 12.

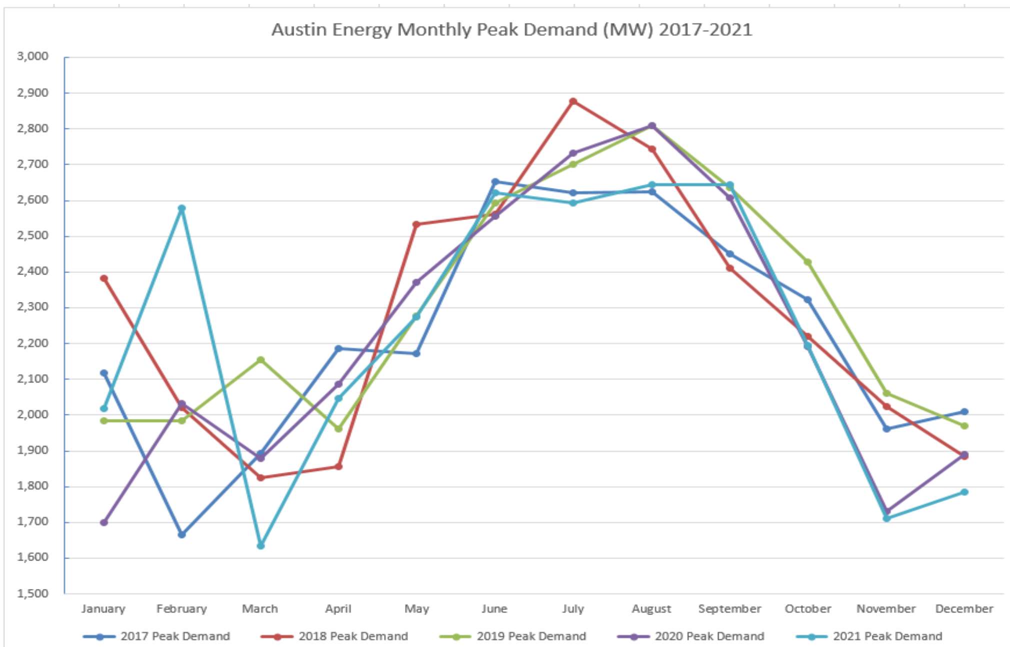
AE specifically points to its generation output during the outlier Winter Storm Uri event in February 2021 to support that ERCOT market prices experienced significant increases during periods outside of the four summer months (June through September 2021), and suggests that this demonstrates the way in which AE generation resources provide "value" to AE customers throughout the year.[121] AE asserts that because the financial hedge provided by its generation fleet benefits customers all year with stable and low rates, this financial benefit should be considered in determining the appropriate production demand-related allocation methodology.[122] AE claims that by comparison, the A&E 4CP methodology does not fully recognize the hedging value that AE's generation fleet provides to customers over a complete percentage of peak hours, particularly given the "unpredictability of market prices throughout the year."[123] However, this confuses the purpose in determining the allocation of production demand-related costs, which are related to capacity planning rather than to quantifying the hedge benefit provided by AE's generation fleet.

NXP's Proposal

As an initial consideration, NXP provides the following explanation of the A&E 4CP allocation methodology. The average and excess methodology considers both average demands and peak demands of AE's customer classes. The average demand is usually determined using customer class energy usage and the excess demand is typically determined using the customer class critical monthly CP demands.[124] For AE, the use of the four summer month CP demands reflects the importance of AE's *summer peaking* system.[125] The average demand is determined by dividing the class's annual energy usage by 8760 hours. The excess demand is determined by subtracting the average from the class's 4CP demand. The average demand component is weighted by the system load factor with the excess demand weighted by one minus the system load factor.[126] The benefit to using this methodology is that in allocating production demand-related costs to retail customer classes, it considers both the critical monthly system peak demands during the summer months and also ensures that costs are allocated to classes that may not be "on" during the times of system CP demands (such as outdoor lighting).[127]

[121] AE Ex. 8 at 13.
[122] AE Ex. 8 at 14.
[123] *Id.*
[124] NXP Ex. 1 at 18.
[125] *Id.*
[126] *Id.*
[127] *Id.*

AE acknowledges that the effectiveness of the financial hedge provided by its generation fleet is *its availability compared to AE's system peak demands*, and that having enough dispatchable capacity to cover peak demand requirements is one way that AE manages market price risk.[128] Moreover, AE states that "the financial hedge can only be effective if available capacity meets or exceeds the system peak. Demand-related costs associated with system capacity are incurred *to meet system peaks*" (emphasis added).[129] While AE claims that the proper reflection of this cost causation relationship is the 12CP method, such a claim fails to acknowledge that AE's own system is, in fact, summer peaking as demonstrated by the below graph (reflecting AE's monthly system peak demand for calendar years 2017 through 2021).[130]



Because AE's system is summer-peaking, it must plan to have adequate total demand-related generation capacity to meet its ultimate maximum peak demand occurring during those 4CP months (June through September), otherwise the hedge provided by its own capacity is inadequate and has no value. By measure of comparison, ERCOT also experiences its largest system peak demand in the 4CP summer months and plans its generation capacity accordingly.[131]

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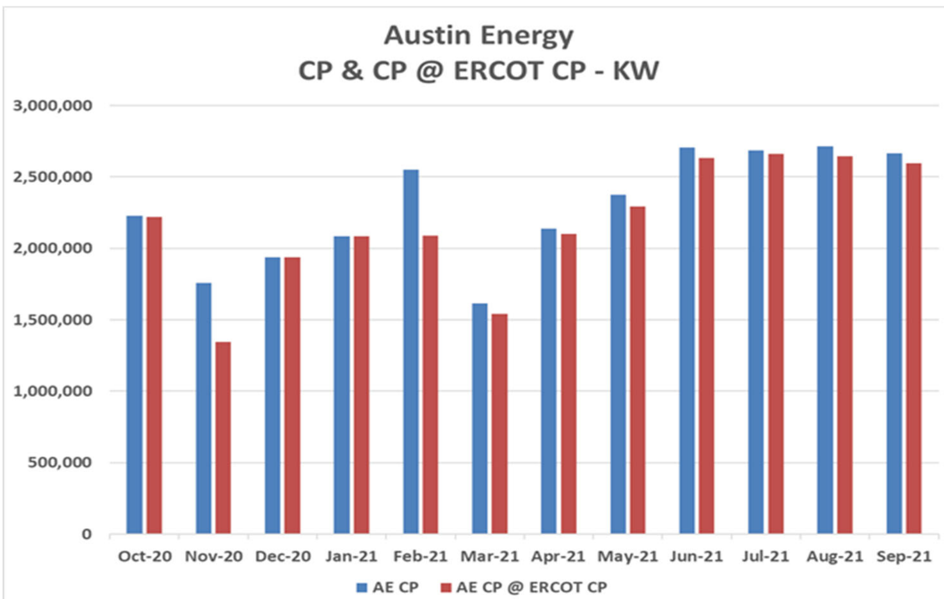
[128] AE Ex. 8 at 11.
[129] *Id.*
[130] NXP Ex. 1 at 27 and 78
[131] NXP Ex. 1 at 20.

This is reflected in ERCOT's Summer Seasonal Assessment of Resource Adequacy report, which assesses whether there is adequate generation production capacity to meet the *ultimate* ERCOT peak hour of demand for the *year*.[132] Therefore, insofar as AE's system peak demands relate to ERCOT's system peak demands, AE's concern for total system capacity should lie within the four summer months as this is what ERCOT evaluates for its own system planning. It follows that peak demands occurring during the summer months are the drivers of demand-related production costs, and *not* those demands occurring during non-summer months.[133] The close relationship between AE's monthly CP demands and ERCOT's peak demands during the test year are demonstrated below.[134]



Additionally, AE buys power from the ERCOT market at the market price on a sub-hourly basis to serve load.[135] Concurrently, ERCOT dispatches AE's generation units into the ERCOT market based on those resources' marginal operating costs given ERCOT market conditions for the financial benefit of AE's customers (hence the financial hedge provided by the generation fleet).[136] AE must consider that its own fleet operates at greater capacity levels during peak demand periods in the summer months as directed by ERCOT's security constrained economic dispatch

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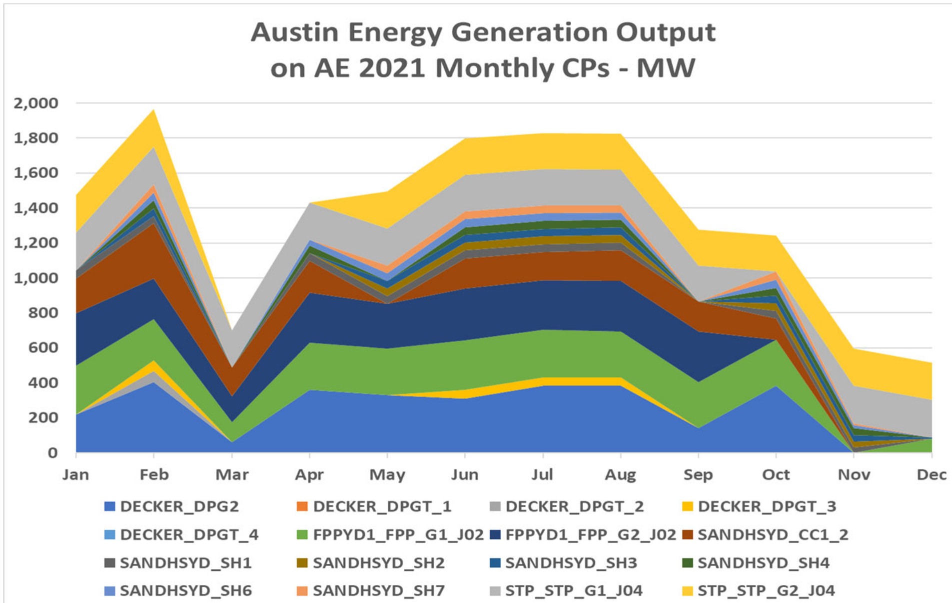
[132] *Id.*
[133] *Id.*
[134] NXP Ex. 1 at 22 as "Graph 2".
[135] AE Ex. 8 at 10.
[136] *See* id.

("SCED").[137] Contrary to AE's assertion, this is demonstrated by the above-referenced table on p. 19, reproduced below for ease of reference.

Graph 3[138]



As reflected in the above graph, with the exception of the outlier February Winter Storm Uri event, AE's peak output during 2021 occurred in the 4 summer months. In fact, with the exception of February, the sum of AE's individual generation resource MW output is higher during the 4CP summer months than in the other months.[139] During the Hearing, AE witness Mr. Scott H. Burnham conceded that generally speaking, both ERCOT and AE's systems are summer-peaking and that over the past five years, the AE system has experienced summer peaks.[140] This demonstrates that AE's production demand capacity was planned, and continues to be substantially economically dispatched by ERCOT, consistent with AE's customer peak load requirements occurring in the summer months.[141] Although AE's fleet did generate some amount of power in every month of 2021, so too does every utility operating in ERCOT. No utility simply mothballs its generation capacity during months of lower peak demand.[142] Although AE's generation fleet

[137] NXP Ex. 1 at 22.
[138] Originated in NXP Ex. 1 at 23 and reproduced in AE Ex. 8 at 12.
[139] NXP Ex. 1 at 22.
[140] Tr. 71:46-72:3 (Burnham Cross) (July 15, 2022)
[141] NXP Ex. 1 at 22-23.
[142] *See* Tr. 72:11-20 (Burnham Cross) (July 15, 2022).

operated at some level throughout the 2021 test year, this does not mean that AE builds its system to ensure it is only capable of operating in the non-system peak months;[143] rather, AE *must* build its system to operate effectively to meet peak demand in the summer months. This means the A&E 4CP allocation methodology more accurately and equitably reflects class cost causation of AE's production demand-related costs than the 12CP methodology.

As additional support for use of the A&E 4CP allocation methodology, AE's own system planning and demand-side management programs reflect the importance of AE's demands during the summer months. On August 12, 2019, Austin's Electric Commission created the Resource Plan Working Group ("Working Group") to provide recommendations and strategic goals to Austin Energy and the Austin City Council addressing technical and market issues to meet the City Council's environmental efficiency and affordability goals.[144] On March 5, 2020, the Working Group finalized the "Austin Energy Resource, Generation and Climate Protection Plan to 2030" ("Vision Plan") based on an analysis of the risks, costs, and opportunities associated with AE meeting *future demand* for electricity.[145]

The AE Vision Plan states that "Austin Energy will maintain an energy supply portfolio sufficient to offset customer demand while eliminating carbon and other pollutant emissions from its generation facilities as rapidly as feasible within the limitations set by the Austin City Council."[146] The Vision Plan also highlights, notably, that the retirement of its Decker Prairie Steam gas-fired units was delayed *until after the summer peaks* of 2020 and 2021.[147] This corroborates that the largest AE coincident peaks and AE peaks coincident with the ERCOT peaks occurred during the four summer months of the test year (June through September) with the test year being from October 2020 to September 2021.[148] This is also reflected in Appendix C-178, WP F-6.1 of the rate filing package.[149]

<u>Impact of Financial Hedge</u>

AE's driving argument in favor of the 12CP allocation methodology is that its generation capacity has value throughout the year as a physical and financial hedge, which the 12CP

[143] Tr. 72:19-32 (Burnham Cross) (July 15, 2022).
[144] NXP Ex. 1 at 26.
[145] *Id.*
[146] *Id.*
[147] *Id.*
[148] *Id.*
[149] NXP Ex. 1 at 26 and 77.

methodology captures better than the A&E 4CP methodology.[150] However, this is not the proper basis on which to determine a production demand-related cost allocation. AE, operating as an integrated municipal electric utility and a non-opt-in entity in ERCOT, schedules its load for purchase from the ERCOT nodal market.[151] AE also offers its generation into the ERCOT market through a combination of energy and ancillary service schedules.

As referenced previously, ERCOT dispatches AE's generators based on SCED at their marginal cost, adjusted for congestion constraints for the applicable time period.[152] AE and all other generators are paid the locational marginal price ("LMP") in ERCOT as adjusted for congestion during the time periods in which they are dispatched as part of the economic generation stack for the whole system.[153] Essentially, AE buys at the market price when the LMP is below its generation cost (meaning AE will not run its own generation to serve its loads), and net pay at its generation cost when the LMP is above that cost (meaning AE offers its generation resource to ERCOT for dispatch).[154] When AE's generation units are dispatched, AE pays the higher LMP for its load, expends its variable cost to run the units, and is paid the higher LMP for its generation output. When AE's generation units are dispatched by ERCOT, all three parts flow through and are matched together in the power cost adjustment factor, hedging AE's cost for that time period approximately at its variable generation cost.[155]

NXP recognizes that AE's operations in the ERCOT market produce a proper alignment of AE's *energy-related* production costs. The physical and financial hedge benefit derived from AE's energy-related production costs net generation revenue from ERCOT are separately paired with AE's associated purchase of all the power necessary from ERCOT to serve AE's own customers flowing through the Power Supply Adjustment ("PSA").[156] NXP acknowledges that AE has appropriately aligned the hedge benefits of AE's generation with AE's associated purchases from ERCOT for its customers in the AE PSA.[157] However, AE has clarified that its PSA is "not a part of this base review."[158] Further, the procedural guidelines (established by AE) state that

[150] AE Ex. 8 at 11; Tr. 72:3-12 (Burnham Cross) (July 15, 2022).
[151] NXP Ex. 1 at 24; Tr. 71:1-10 (Burnham Cross) (July 15, 2022)
[152] NXP Ex. 1 at 24.
[153] *Id.*
[154] *Id.*
[155] *Id.*
[156] NXP Ex. 1 at 24-25, referencing the Rate Filing Package at 51.
[157] NXP Ex. 1 at 24.
[158] NXP Ex. 1 at 24-25, referencing the Rate Filing Package at 51. *See also* Tr. 33:43 – 34:2, 42:21-22, 69:5-9 (Dombroski Cross) (July 13, 2022).

"[i]tems in the Power Supply Adjustment that are approved in the annual budget process, including fuel costs, generation investment, purchase power contracts, and regulatory charges are also beyond the scope of the 2022 Austin Energy Base Rate Review."[159]

Based on AE's own statements in its rate filing package and procedural guidelines, alignment of AE's generation production hedge benefits and costs appropriately flow through its PSA, which is neither a part of nor a driver for this base rate review.[160] Accordingly, allocation of *demand-related* production costs to customer classes in this proceeding should be based on cost causation principles that are driven by AE's peak demands, which occur in the summer 4CP months.[161]

<u>Prevalence and History of A&E 4CP</u>

All of the investor-owned utilities ("IOUs") in Texas that are integrated use the A&E 4CP methodology to allocate production demand-related costs, and the PUCT has approved this methodology for those utilities and for unbundled IOUs when they were still vertically-integrated.[162] Moreover, there are MOUs like AE that also utilize the A&E 4CP methodology for allocating demand-related production costs, such as CPS Energy which is a substantially similar system to AE.[163] CPS Energy is also a bundled MOU in ERCOT that owns significant generation resources and serves a comparable load to AE (having both extensive residential customers and high load factor customers over a large geographic area).[164] As demonstrated by a September 23, 2021 CPS Energy presentation to its Rate Advisory Committee on "Allocating Revenue Requirements to Customer Groups", CPS Energy allocates its production non-fuel costs (meaning production demand-related costs) using an A&E 4CP methodology.[165]

Additionally, the Austin City Council has previously adopted the use of an A&E 4CP production demand-related cost allocation. Austin City Council Ordinance No. 20120607-055 addresses AE's 2012 base rate review, with Part 6 of the Ordinance explicitly stating "the Council adopts as policy the use of the A&E 4CP methodology to allocate production demand costs among

[159] NXP Ex. 13 at 6.
[160] NXP Ex. 1 at 25.
[161] *Id.*
[162] NXP Ex. 1 at 28.
[163] NXP Ex.1 at 28; NXP Ex. 2 at 9.
[164] NXP Ex. 2 at 9.
[165] NXP Ex. 2 at 9 and 53 (slide 13).

customer rate classes."[166] As far as AE was able to testify during the hearing, this Ordinance has not been repealed.[167] However, AE erroneously relies on the outcome of its 2016 base rate proceeding to advocate for use of the 12CP production demand-related cost allocation methodology.[168]

AE attempts to explain away its prior use of the A&E 4CP method by asserting that during its 2012 rate review, the COSS was based on 2009 fiscal year operating results, which was a pre-nodal market test year.[169] However, rebuttal testimony from AE witness Joseph Mancinelli (in the 2012 AE rate case) refutes this claim. Mr. Mancinelli's testimony clearly indicates that even in a nodal market, use of the A&E 4CP production demand allocation methodology is appropriate and aligned with cost causation principles for AE:

> " [I]n the case of production fixed costs, these costs have been historically 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 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 be determined using the AE system 4CP."[170]

AE also promotes use of the 12CP allocation method by asserting that the IHE recommended this method in his 2016 base rate review report.[171] What AE fails to acknowledge, however, is that the 2016 base rate review was resolved via a black box settlement agreement, which on its face "adopted" no particular methodology for production demand-related cost allocation, regardless of the IHE report.[172] The City Council's Ordinance adopting rates for the 2016 case states:

> "Part I (B):
>
> Of the 25 stakeholder participants in the hearing process, 18, including the independent consumer advocate, initially signed a negotiated joint recommendation to the Council regarding retail electric base rate and charges, and related financial

[166] NXP Ex. 1 at 28; NXP Ex. 3.
[167] *See* Tr. 73:8-13 (Burnham Cross) (July 15, 2022).
[168] *See* AE Ex. 8 at 15.
[169] *Id.*
[170] NXP Ex. 2 at 39-40.
[171] AE Ex. 8 at 15.
[172] *See* Ex. NXP-15 (Ordinance No. 20160829-004); *see also* Tr. 58:8-10 (Daniel Cross) (July 14, 2022).

> and budget policies. On August 15, 2016, the general terms of the joint recommendation were approved by the Electric Utility Commission by a vote of 9-1-1."
>
> "Part 2. Council approves the terms of the joint recommendation."[173]

As shown by a plain reading of the Ordinance, the City Council adopted no particular production-demand cost allocation policy that is precedential in this proceeding and also did not explicitly repeal its 2012 policy which gives clear direction for AE to use an A&E 4CP allocation methodology. Therefore, it is most consistent with existing City Council black letter law to implement an A&E 4CP allocation methodology. Additionally, AE's logic is flawed regarding the basis for transitioning from A&E 4CP to 12 CP allocation in the 2016 case. The change to a nodal market in ERCOT did not then, and does not now, justify utilizing a 12 CP allocation for the reasons already discussed herein – cost causation principles associated with AE's actual production demand-related costs support use of A&E 4CP.

Independent Consumer Advocate's Proposal

The ICA has proposed use of a Base, Intermediate, and Peak (BIP) allocation methodology for production demand-related costs.[174] As discussed in this section, the ICA's proposal is misguided on several grounds and should be rejected in favor of A&E 4CP.

At a high level, the BIP methodology separates production costs into generation serving base, intermediate, and peak time periods and develops different class allocation factors for each component.[175] The ICA claims this alternative method is superior to AE's proposed 12CP method because AE's proposal fails to recognize the existence of different types of generation facilities with varying cost characteristics that are critical to the planning and dispatch of generation capacity.[176] In the BIP method, plants with the lowest operating costs are assigned to the base period, while plants with the highest operating costs are assigned to the peak period.[177] Plants with the more average operating costs are assigned to the intermediate, or shoulder peak periods.[178] The ICA proposes the following production demand costs assignment:[179]

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173 NXP Ex. 15 at 1-2.
174 ICA Ex. 3 at 20.
175 *Id.*
176 ICA Ex. 3 at 21.
177 NXP Ex. 2 at 6.
178 NXP Ex. 2 at 6-7.
179 NXP Ex. 2 at 7, Table R1 (citing ICA Ex. 3 at 27).

BIP Cost Assignment

Period	Percent
Base	79.8%
Intermediate	9.4%
Peak	10.8%
Total	100.0%

The ICA then proposes to allocate: (1) all of the base period costs on average demands, or energy, (2) 39% of the intermediate period cost on energy and 61% using 12CP demands, and (3) the peak period costs on the ERCOT 4CP demands.[180] Under ICA's proposal, this results in 83.5% (79.8% plus 39% times 9.4%) of AE's fixed production demand-related costs being allocated using an energy allocation factor.[181] In other words, as described by TIEC, the BIP proposal suggests that 83.5% of AE's production plant-related costs were incurred solely to reduce fuel costs rather than to serve the maximum expected load on the system.[182] This is premised on the theory of "Capital Substitution," which presumes that any new capital investments that are more costly than a peaking unit are designed to reduce year-round fuel costs.[183] As TIEC notes, this theory has been routinely and consistently rejected in Texas.[184]

As prefaced above, the ICA proposes use of the BIP methodology as an alternative to AE's proposed 12CP methodology because 12CP is a "pure peak" demand method which does not recognize the "average demand dimension of causation."[185] The ICA proposes that the BIP method will appropriately recognize the impact of energy use on cost causation unlike either the 12CP or the A&E 4CP allocation methods.[186]

The BIP methodology should not be used to allocate AE's production demand-related costs, as agreed upon by NXP, TIEC, and AE.[187] The BIP methodology erroneously allocates 83.5% of AE's fixed production demand-related costs using an energy-only allocation factor.[188] As

[180] NXP Ex. 2 at 7 (citing ICA Ex. 3 at 26). Note also that the ERCOT 4CP demand methodology is how AE, the Public Utility Commission ("PUC"), and ERCOT allocate transmission costs.
[181] NXP Ex. 2 at 7.
[182] TIEC Ex. 2 at 8.
[183] *Id.*
[184] *Id.*
[185] ICA Ex. 3 at 21-22.
[186] ICA Ex. 3 at 24.
[187] NXP Ex. 2 at 8; TIEC Ex. 2 at 7; AE Ex. 8 at 6.
[188] NXP Ex. 2 at 8.

noted by AE, BIP also falsely assumes that a generation resource, such as a "baseload unit," will be dispatched to serve load given the load profile and resource planning needs of the utility.[189] The BIP method classifies costs based on the demand and energy needs of the system regardless of cost; however, in ERCOT, generation resources are dispatched based on market needs and price competitiveness, with price being the primary factor under uncongested circumstances.[190] In the ERCOT nodal market, all generating units monetize their capacity value through the market clearing prices. The effectiveness of AE's physical hedge provided by its generation fleet is a function of available capacity to offset AE's load requirements.[191] Accordingly, *fixed* production costs are most appropriately associated with AE's peak load requirements rather than energy.[192]

Moreover, the BIP methodology results in a tremendous shift in cost responsibility from less efficient low load factor ("LLF") customers to more efficient high load factor ("HLF") customers as compared to more conventional recognized allocation methodologies. This cost shift is shown on the table below.[193]

Rate Class	12CP-ERCOT Peak	BIP (Note 1)	Impact - $	Impact - %
Residential	$ 374,653,342	$ 360,952,336	$ (13,701,006)	-3.7%
Secondary Voltage < 10 kW	23,740,654	23,755,916	15,262	0.1%
Secondary Voltage ≥ 10 < 300 kW	118,368,061	117,536,272	(831,789)	-0.7%
Secondary Voltage ≥ 300 kW	86,588,435	89,994,357	3,405,921	3.9%
Primary Voltage < 3 MW	9,889,409	10,729,776	840,367	8.5%
Primary Voltage ≥ 3 < 20 MW	26,040,268	29,846,788	3,806,520	14.6%
Primary Voltage ≥ 20 MW @ 85% aLF	38,838,726	43,797,883	4,959,157	12.8%
Transmission	913,278	938,455	25,177	2.8%
Transmission Voltage ≥ 20 MW @ 85% aLF	3,519,886	4,269,366	749,480	21.3%
Service Area Street Lighting	-	-	-	0.0%
City-Owned Private Outdoor Lighting	3,758,677	3,903,674	144,998	3.9%
Customer-Owned Non-Metered Lighting	56,297	79,652	23,355	41.5%
Customer-Owned Metered Lighting	476,458	497,062	20,604	4.3%
Total	**$ 686,843,493**	**$ 686,301,537**	**$ (541,956)**	**-0.1%**

Note 1: The difference in base revenues is due to additional costs being assigned to the SL class under the BIP methodology. These revenues are collected through the Community Service rider and are not included in Base Rates.

As shown above, the impact of the BIP methodology is dramatic and would cause severe impacts on some customer classes as compared to either the 12CP or A&E 4CP methodologies.[194]

189 AE Ex. 8 at 7.
190 AE Ex. 8 at 7-8.
191 AE Ex. 8 at 8.
192 *Id.*
193 NXP Ex. 2 at 9, Table R-2.
194 *Id.*

All considered, the BIP method simply does not reflect cost causation[195] and would result in a disparate impact on the majority of AE's customer classes.

These myriad issues with BIP are also demonstrated by the fact that no other utilities in Texas utilize the BIP method, despite the fact that it was proposed but not adopted in AE's 2011/2012 rate case.[196] Even the ICA has acknowledged it is unaware of the BIP methodology ever having been approved for an electric utility in Texas.[197] As mentioned previously, in AE's 2012 proceeding, AE witness Joseph Mancinelli filed testimony in support of the A&E 4CP production demand cost allocation methodology, expressing concerns with a BIP alternative as follows: [198]

> "**Q**: **Didn't AE seriously consider using the BIP method allocation of generation costs?**
>
> **A**: Yes, the BIP method has already been thoroughly vetted and rejected in a lengthy public process…Because the BIP method allocates baseload units on energy, the capacity value associated with these units is spread over all hours in the year. This approach undervalues capacity associated with these units during peak pricing and peak demand periods. The BIP method focuses on generation supply rather than customer demand. The BIP method ignores system and class load factors which drive capacity costs. This approach does not align with AE's objectives of sending pricing signals to customers that promote conservation and energy efficiency. Finally, if the BIP method is used and baseload units are classified as energy-related…this improper misclassification will distort the pricing signal by lowering demand charges and raising energy charges. This distorted pricing signal will further weaken AE's ability to recover fixed costs. For all these reasons, the BIP method should be rejected by the Commission."

Mr. Mancinelli later filed testimony in AE's 2016 rate proceeding, also criticizing the BIP proposal.[199] There is no new basis on which the IHE should seriously consider implementing the BIP methodology as it continues to be, and it has always been, an inappropriate proposal for allocation of production demand-related costs.

<u>Consistency as a Consideration</u>

AE claims that consistently in cost allocation "is an important element in rate design" and that a "consistent cost allocation method sends a consistent price signal to customers to influence

[195] TIEC Ex. 2 at 7.
[196] NXP Ex. 2 at 8-9; AE Ex. 8 at 10; TIEC Ex. 2 at 14.
[197] NXP Ex. 2 at 8.
[198] NXP Ex. 2 at 10 and 38.
[199] NXP Ex. 2 at 12.

their electricity usage."[200] AE further asserts that if it were to change its production demand-related cost allocation methodology from 12 CP to another method, such a change would send a confusing price signal to customers, which limits the ability of customers to make optimal investments and electricity usage decisions.[201] However, AE does not provide any data or actual analysis to suggest that changing its methodology from 12CP to A&E 4CP would produce any real impediment to customers' ability to make decisions about their electric usage. AE certainly does not claim that a switch to the A&E 4CP allocation methodology would affirmatively incentivize customers to make inefficient usage decisions.

Moreover, AE conveniently excludes from its "consistency" argument any consideration of the fact that its 12CP methodology used in 2016 was a change from that used in AE's 2012 rate case. AE also fails to provide any examples of how a change in production demand cost allocation methodology from its 2012 to 2016 rate cases resulted in any adverse price signals to customers. Further, AE testified during the Hearing that customers *do not* make "optimal investments" in their usage based on the production demand allocator used; rather, AE testified that customers make investment decisions in their usage based on what their bills are.[202] AE's claim that the IHE should adopt the 12CP allocation method in this case based on "consistency" is without merit and should be rejected. As aforementioned, the only real direction that the City Council has given AE in recent history on which production demand allocation method it should use is the A&E 4CP method.

b. Distribution-Demand

Primary distribution facilities include substations, poles, overhead ("OH") and underground ("UG") conductors or lines, and UG conduit.[203] NXP proposes that these costs be allocated using an annual (or highest monthly) non-coincident peak ("1NCP") methodology. Conversely, AE proposes to allocate the costs of these facilities using a 12-month average of the customer classes' monthly non-coincident peak ("NCP") demands for the test year.[204] AE refers to this cost allocation methodology as the 12NCP method. However, the "support" that AE provides

[200] AE Ex. 8 at 16.
[201] *Id.*
[202] Tr. 73:46-74:1 (Burnham Cross) (July 15, 2022).
[203] NXP Ex. 1 at 29.
[204] AE Ex. 1 at 62.

in its rate filing package for the 12NCP allocation methodology does not, in fact, support such a methodology.[205] AE's rate filing package states that

> "[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 the magnitude and timing of the class peak demand, which often occurs at times different from the system peak demand."[206]

These class peak demands are referred to as class NCP demands. As recognized in the AE language above, distribution facilities are sized and built to meet the *localized peak demands*; therefore, it does not logically follow that AE should use a 12-month *average* NCP demand to allocate primary distribution plant costs.[207] To appropriately reflect cost causation, a 1NCP or annual NCP should be used for allocating primary distribution plant costs.[208] This alternative is also supported elsewhere in AE's rate filing package. For example: "The distribution function is concerned with meeting localized demand; therefore, *class maximum demands* are used to allocate distribution costs. Finally, for individual customers, AE is concerned with the maximum demand that the customer places on the system. These demands are *significant cost drivers* for AE's capital expenses, including debt" (emphasis added).[209] Therefore, AE's use of the 12NCP demand allocation methodology is at odds with the actual class peak demands that cause AE to incur most of its distribution system costs.[210]

AE has acknowledged that it uses peak demands (and not average 12 NCP demands) in its planning process for new distribution facilities.[211] In discovery, AE provided a document titled "Distribution Planning Criteria," which states that "distribution capacity studies assume summer peak conditions to determine substation peak loading."[212] This further supports the use of a 1NCP allocation methodology for distribution demand costs. It is also worth acknowledging that AE's substations are functionalized to both the transmission and distribution functions.[213] The transmission-related portion of substation costs is recovered in AE's wholesale TCOS, with TCOS

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[205] NXP Ex. 1 at 29.
[206] AE Ex. 1 at 62.
[207] NXP Ex. 1 at 29.
[208] NXP Ex. 1 at 29-30.
[209] AE Ex. 1 at 57.
[210] *Id.*
[211] NXP Ex. 1 at 30.
[212] NXP Ex. 1 at 89.
[213] NXP Ex. 1 at 31.

rates being based on the CP demands in the four summer months.[214] This recognizes the importance of peaks during the summer; yet for the distribution-related portion of each substation, AE's proposed 12NCP allocation methodology improperly de-emphasizes the importance and cost causation of peak demands on its substations.[215] As AE witness Mr. Burnham clearly stated in the Hearing, the design of AE's system and the cost of its system are "obviously" driven by its peak demand.[216] AE's system "needs to be designed" to meet the 1CP.[217]

Despite the fact that AE's distribution costs are clearly driven by class and customer peak demand, AE claims that 12 NCP is "more equitable" than 1NCP because use of a 12NCP "recognizes that distribution capacity provides value to customers throughout the year – not just during the peak hour during the summer."[218] AE claims that because the NCP calculation is done at the class level, off-peak or seasonal customers may not be fully accounted for in a 1NCP calculation, while a 12NCP calculation solves this problem.[219] AE claims that there is sufficient variability in the monthly system NCP over the FY 2021 test year, and that the 1NCP methodology does not capture this variability in load, and may result in certain classes not being assigned sufficient costs, resulting in a "free rider" dilemma.[220] AE's concern is ill-founded and fails to consider that the 1NCP methodology actually solves a "free rider" dilemma. If a class's annual 1NCP is based on its peak monthly hour of demand, all members of the class will pay for distribution costs accordingly regardless of whether certain customers in the class were off-peak during that hour. Therefore, AE's concern is unfounded. AE's actual basis for proposing a 12NCP demand appears to be focused on the cost implications for certain customer classes in particular. AE asserts that the use of a 1NCP cost allocator in place of a 12NCP cost allocator for poles, conductors, and substations would result in a shift in cost responsibility for distribution costs from the non-residential customers to the residential and small commercial customers.[221] This rationale appears to be aimed at a particular outcome relative to certain rate classes rather than adhering to generally accepted rate-making principles. The IHE should adopt a distribution cost allocation

[214] *Id.*
[215] *Id.*
[216] Tr. 74:29-31 (Burnham Cross) (July 15, 2022).
[217] Tr. 74: 33-40 (Burnham Cross) (July 15, 2022).
[218]AE Ex. 8 at 21.
[219] *Id.*
[220] *Id.*
[221] AE Ex. 8 at 22-23.

methodology that is consistent with cost causation principles and standard utility practice – meaning the 1NCP method.

For comparison, it is NXP's experience that the PUCT usually supports a 1NCP demand allocation methodology for both integrated and unbundled IOUs.[222] NXP is unaware of *any instance* in which the PUCT has accepted a 12NCP allocation methodology for distribution costs.[223] Examples of utilities in Texas that allocate distribution costs using a version of a 1NCP demand allocation methodology include Oncor and Southwestern Public Service Company.[224] Moreover, there are MOUs in ERCOT, such as CPS Energy, that use the 1NCP methodology for allocating distribution demand-related costs.[225]

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

AE allocates primary distribution system costs to all customer classes except the two transmission voltage customer classes which do not use the primary distribution system.[226] As discussed in this section, NXP proposes that primary voltage customers also be exempt from paying a load ratio share-based rate for use of the distribution system in certain instances.

All distribution facilities that operate at primary voltage are included as part of AE's primary distribution system. These facilities include the distribution-related portion of substations, primary poles and towers, primary OH and UG lines, and primary UG conduit.[227] As a prevailing principle, customer classes should not be required to pay for facilities they do not use.[228] Although AE has provided conflicting information on this point throughout the course of the proceeding, AE ultimately stated during the Hearing that it does not serve any Primary Voltage over 20 MW customers directly from AE-owned substations, meaning AE does not serve any such customers that are connected in an AE-owned substation or by a feeder owned by the customer rather than by AE.[229] Regardless, NXP proposes that if the delivery point of any customer in the class is on a short feeder coming out of an AE substation, then the cost of that feeder is more appropriately

[222] NXP Ex. 1 at 31.
[223] *Id.*
[224] *Id.*
[225] NXP Ex. 1 at 32 and NXP Ex. 2 at 53.
[226] NXP Ex. 1 at 32.
[227] *Id.*
[228] *Id.*
[229] *See* Tr.76:6-20 (Burnham Cross) (July 15, 2022).

recovered through a facilities charge to the customer than through requiring that customer to pay for a load ratio share of AE's entire primary distribution system's poles and lines costs.[230] This rate option should be available to the Primary Voltage Above 20 MVA customers. And per Mr. Burnham's testimony in the Hearing, this option could be workable.[231]

This practice is also consistent with that of other IOUs in ERCOT, such as Oncor which has a PUCT-approved substation service rate class.[232] AE argues that the Oncor example is irrelevant in this instance because the PUCT's approval of this rate class was conditioned upon customers "construct[ing] and maintain[ing] the distribution facilities themselves", while in contrast, "Austin Energy owns and maintains the distribution facilities necessary to serve its primary voltage customers load up to the point of interconnection."[233] AE is incorrect that the Oncor example is inconsistent with NXP's recommendation that a substation service rate class be available where the costs associated with the distribution line between the AE substation and the customer's point of interconnection are recovered through a facilities charge – the point is that the customer (rather than AE) ultimately bears that cost directly[234]

2. Energy-Related Cost

NXP incorporates by reference its discussion of AE's PSA as previously discussed in Section III(D)(1)(a).

3. Customer-Related Costs

AE appropriately proposes to use a traditional weighted metering cost allocation methodology to allocate its smart meter costs. This approach is consistent with that of all major utilities in Texas, which allocate 100% of meter costs using a weighted meter cost allocation.[235] The ICA erroneously opposes this methodology on the grounds that "AE has been aggressive in the sophistication of the meters it deploys."[236] And because these smart meters can allow for additional functions to be performed, the ICA recommends allocating 51% of the meter costs based on the customer class revenue requirement.[237] However, deployment of smart meters for residential

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230 NXP Ex. 1 at 34.
231 Tr. 75:36-43 (Burnham Cross) (July 15, 2022).
232 NXP Ex. 1 at 35.
233 AE Ex. 8 at 27.
234 Tr. 56:20-29 (Daniel Cross) (July 14, 2022).
235 NXP Ex. 2 at 17-18.
236 ICA Ex. 3 at 42.
237 ICA Ex. 3 at 43.

customers is not unique to AE and the ICA has not provided any quantification of any claimed *system* benefits.

Moreover, the ICA's proposal would allocate the cost of AE's new smart meters to customers that already have sophisticated meters, such as large customers who have invested in meters that have functions similar to AE's smart meters. This would mean that larger customers would be required to pay for their sophisticated meters plus an allocated share of the costs of the newly deployed smart meters that they do not utilize. Such practice is inconsistent with PUCT Substantive Rule §25.130(k), which requires the costs of smart meters deployed to a customer class to be surcharged only to the customers in that customer class – meaning the PUCT prohibits subsidization of the cost of smart meters. In sum, AE's proposal is consistent with standard utility practice in this state for allocation of smart meter costs and is consistent with the PUCT's Substantive Rule on this issue. The ICA's proposal is inappropriate, inequitable, and should be rejected.

AE appropriately proposes to allocate certain customer service expenses (FERC Accounts 911 through 917 on the basis of the number of customers in each customer class.[238] The ICA erroneously recommends an alternative allocation of customer expenses "broadly across functions."[239] To accomplish this, the ICA proposes to allocate 61% of all customer service expenses using an allocation factor based on each customer class's revenue requirement.[240] The ICA fails to support its claim that expenses in Accounts 911-017 are related to "system objectives" that affect all utility functions. However, this proposal fails to recognize that a significant portion of AE's customer service expenses are identified as Key Accounts expenses. In AE's COSS, the Key Accounts expenses, which are primarily for larger commercial and industrial customers, are assigned to the customer classes based on a study that determined the amount of time Key Account customer service representatives spent with customers in each customer class.[241] The ICA's allocation of 61% of customer service expenses on the basis of class revenue requirement will over-allocate expenses from these accounts. For example, Key Accounts expenses included in Account 912 were separately assigned to specific customer classes that included key accounts customers. AE's allocation of its customer service expenses provides for a more reasonable

[238] *See* NXP Ex. 2 at 18.
[239] *Id.*
[240] *Id.*
[241] *Id.*

allocation and assignment of these expenses to the customer classes, therefore the ICA's proposal should be rejected.[242]

4. Service Area Street Lighting

NXP incorporates by reference its discussion of AE's service area streetlighting costs as previously discussed in Section II(B)(5).

5. Energy and Demand Line Loss Factors

Treatment of losses in class cost of service study is important because customers take service at different voltage levels on AE's system, and AE incurs system energy and demand losses at each voltage level.[243] Accordingly, customers receiving service at lower voltages cause more losses than customers receiving service at higher voltages. When allocating costs, it is important to adjust customer energy and demand at their sales or delivery level to the generation voltage level so that allocation factors are calculated on a comparable voltage level – this ensures that customers and customer classes pay for the losses they cause.[244] AE's system loss study performed for use in preparing the class cost of service study is based on load flow results at the 2018 system peak that occurred in July.[245] Using this information, AE adjusted normalized energy sales and demands at the meter for each customer class to the generation level to adjust for the percent energy losses at each applicable voltage level; however, in adjusting CP and NCP demands used for allocation factors for losses, AE's demand loss adjustment was done incorrectly.[246] Instead of adjusting the customer class CP and NCP demands using demand loss factors, AE used energy loss factors. AE confirmed this error in response to discovery.[247]

The result of AE's error is that AE has under-adjusted the CP and NCP demands of customer classes receiving service at secondary distribution voltages. This results in under-allocating distribution costs to the secondary voltage customer classes and over-allocating costs to the primary voltage classes.[248] Unfortunately, NXP was unable to adjust for AE's error because AE's system loss study provided with its rate filing package only develops energy loss factors; AE also confirmed in discovery and its rebuttal testimony that it did not conduct the analysis necessary

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[242] *Id.*
[243] NXP Ex. 1 at 37.
[244] *Id.*
[245] NXP Ex. 1 at 37.
[246] NXP Ex. 1 at 37-38.
[247] NXP Ex. 1 at 38.
[248] *Id.*

to develop demand loss factors.[249] To prevent this issue in future rate proceedings, NXP proposes that the IHE order AE to develop and use demand loss factors in future base rate reviews.[250]

6. Cost Allocation Summary

AE has incorrectly allocated its production demand-related costs using an average ERCOT 12CP demand allocation methodology. To appropriately track cost causation, AE's production demand-related costs should be allocated using an A&E 4CP allocation methodology. AE has incorrectly allocated its primary distribution demand-related costs using an average 12NCP demand allocation methodology. Instead, AE's primary distribution demand-related costs should be allocated using the 1NCP demand allocation methodology. AE has incorrectly allocated primary distribution costs for poles, conductors, and underground UG conduit to the Primary Voltage Above 20 MW at 85% Load Factor customer class, which should be permitted to take service at a substation rate. The cost of street lighting service to the City of Austin should be charged to the City rather than be charged to the other customer classes through the Community Benefit Rider. In its class cost of service studies, AE improperly adjusts customer class demands for losses by applying the energy loss factors from the 2018 System Loss Study.

E. Cost of Service Results

AE's cost of service study does not accurately reflect cost causation principles, as discussed above. Accordingly, NXP has conducted an adjusted class cost of service study at NXP's reduced revenue requirement for the GFT, the results of which are reflected below:[251]

	Current Base Rate Revenues	NXP Base Rate Cost of Service	Under/(Over) Recovery - $	Under/(Over) Recovery - %
Residential	$ 298,139,951	$ 381,153,142	$ 83,013,191	27.8%
Secondary Voltage < 10 kW	22,062,516	23,667,983	1,605,467	7.3%
Secondary Voltage ≥ 10 < 300 kW	146,379,682	112,137,947	(34,241,735)	-23.4%
Secondary Voltage ≥ 300 kW	97,431,981	78,383,098	(19,048,883)	-19.6%
Primary Voltage < 3 MW	8,571,888	9,529,850	957,962	11.2%
Primary Voltage ≥ 3 < 20 MW	24,590,380	22,471,254	(2,119,126)	-8.6%
Primary Voltage ≥ 20 MW @ 85% aLF	33,906,126	29,417,951	(4,488,175)	-13.2%
Transmission	801,058	1,184,535	383,478	47.9%
Transmission Voltage ≥ 20 MW @ 85% aLF	4,236,381	2,980,278	(1,256,103)	-29.7%
Service Area Street Lighting	-	-	-	n/a
City-Owned Private Outdoor Lighting	2,141,558	3,776,789	1,635,231	76.4%
Customer-Owned Non-Metered Lighting	45,878	73,005	27,127	59.1%
Customer-Owned Metered Lighting	316,344	439,417	123,072	38.9%
Total	**$ 638,623,744**	**$ 665,215,248**	**$ 26,591,505**	**4.2%**

[249] *Id. See also* AE Ex. 8 at 24
[250] NXP Ex. 1 at 39.
[251] NXP Ex. 1 at 30, Table 2.

F. Cost Allocation Conclusions

As demonstrated by the above table, AE's current base rate revenues are under-recovering the cost to serve the residential class by nearly 28%, the transmission class by nearly 48%, and the lighting classes (apart from service area street lighting) by anywhere from 39% to 76%. Meanwhile, AE's current base rate revenues are over-recovering the cost to serve several of its remaining customer classes, including the Primary Voltage Over 20 MW class by 13.2%. It should be noted that the table above does not reflect any adjustment to AE's revenue requirement and that NXP does not support the revenue requirement reflected in the above.

IV. CLASS REVENUE DISTRIBUTION

Once a utility determines its revenue requirement and allocates those costs to the various customer classes, it then must determine how to collect the necessary revenues from each class.[252] To do so it must utilize a revenue allocation methodology. Ideally each class would contribute as much revenue towards the utility's overall revenue requirement that it matches its allocated cost of service. But because past rate decisions and customer class growth or contraction have left the customer class's rates far from their allocated cost of service in several instances, rate setting should also ensure that a class's rates are not increased so dramatically.[253] Austin Energy utilized a methodology and proposes to recover revenues from each class in a manner that purports to match each class's revenues more closely to their allocated cost of service, without creating "rate shock." AE proposes to allocate revenue responsibility to the various classes and move classes towards their allocated cost of service by use of a novel, and ultimately unprincipled, three step methodology that fails to balance appropriately this objective with avoiding rate shock.

As a threshold matter, no record evidence at all supports AE's requested revenue distribution. AE's rebuttal case changed several revenue requirement items, each of which is allocated differently from the other. This means that the 25% reduction in overall revenue increase requested does not flow through to classes the same way that the original request did. The tables and workpapers Mr. Murphy offered to illustrate and support AE's requested revenue distribution do not match or even illustrate AE's actual proposed rate case. AE does not plan to update its cost of service model until after briefing, so the IHE (and other parties) have no means at their disposal

[252] NXP Ex. 1 at 40.
[253] NXP Ex. 1 at 40-41.

to see how AE's proposed revenue distribution methodology would actually flow through to AE's proposed customer classes. This would represent a fatal flaw in the utility's rate application in a normal case, warranting either dismissal for failure to offer a prima facie case, or an abatement during which the utility developed the necessary revised cost of service and revenue distribution, answer discovery questions about it, then put evidence about it into the record subject to cross-examination. AE will not agree to do anything like that here, however. Its refusal to do so at a minimum means that AE's cost of service, and its proposed revenue distribution, is simply an unknown as of the time of briefing.

Leaving that extremely important issue aside, the issue NXP has identified is that AE proposes a novel "three step" revenue distribution approach,[254] the first step of which would impose a revenue increase of the proposed system average percent base rate revenue increase (7.5%) on ALL classes, before then reducing or increasing their revenue obligation by ½ (from the increased revenue point that step one creates) based on whether the first step produces a revenue overcollection or shortfall. Finally, AE's methodology reallocates among classes the 20% discount given to military and university customers. [255]

The primary problem with this methodology, as Mr. Daniel explains is that step one (which is not an industry accepted approach) moves each "over-collected" class even further away from its allocated cost of service before then reducing its revenue obligation:

> "for some customer classes, this step moves them further from cost of service in opposition to AE's stated goal of moving class revenues towards cost of service."[256]

For example, the Secondary Voltage Greater Than 300 kw customer class's current revenues are already above the class's cost of service. By increasing the class's current revenues by the overall percent revenue increase needed of 7.6%, this class is moved further above its cost of service. The purported 50% movement toward cost of service actually reduces their rates less than if this class's rates were not already artificially increased by 7.5%. Mr. Daniel proposes a more effective and straightforward allocation methodology.

AE witness Murphy blithely asserts that the uniform system increase is necessary to "align the classes with their cost of service," without explaining what this actually means. What this step actually does is move the starting point from which the ½ reduction takes place to a point that is

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[254] NXP Ex. 1 at 42.
[255] NXP Ex. 1 at 41.
[256] NXP Ex. 1 at 42.

even higher than existing under current rates. In effect it provides less movement towards cost of service than would occur without it. And Mr. Murphy does not explain why this step is even necessary. Again, this rationale appears to be aimed at a particular outcome relative to certain rate classes rather than adhering to generally accepted rate-making principles.

Mr. Murphy simply asserts that the city should use this methodology because, as a "standard" for this and future rate decisions, it will eliminate "disputes."[257] While ignoring that a "dispute" is simply another way of describing other parties articulating their interests, he fails to explain why that justifies THIS methodology. Taken to its logical conclusion, AE could eliminate all disputes by simply not having a case and imposing its proposed rates without any dissent. Eliminating these kinds of "disputes" likewise would deprive the City Council of alternative perspectives and evidence that might be useful to its resolution of this and future rate cases. AE's methodology cannot even pass its own test of eliminating revenue allocation disputes. It did not eliminate disputes over revenue allocation here, and likewise provides no more guarantee of eliminating future disputes than past decisions on production cost allocation methodologies have done.

Mr. Daniel explains how the better method is just to allocate revenues in a way that leads to a more effective move toward cost of service without imposing overly significant rate increases. Mr. Daniel proposes simply moving classes that are currently significantly below or above their allocated costs 1/3 closer to their cost of service.[258] Then allocating the remaining customer class subsidies after the 1/3 move to cost of service to the other customer classes by proportionately spreading the "net" over-recovery (their cost of service over-recovery less the subsidies) to the other classes based on their cost of service so that some of the subsidy they currently pay is reduced.[259] This has the advantage of moving the residential class closer to cost of service, but without a significant rate increase. It would largely control the rate increases (or reductions) on other classes, while working towards cost of service. And most importantly would not cause other classes to fund (subsidize) one another to the same extent. Mr. Daniel summarizes the alternative distributions in his Exhibit JWD-7.

[257] AE Ex. 9 at 15.
[258] NXP Ex. 1 at 43.
[259] *Id*.

Mr. Murphy's one substantive criticism of this approach is that it fails to increase residential rates sufficiently.[260] NXP views that as a virtue, however, at a time where the ICA has already identified a number of hardships that AE's proposed rate increases will implement. The NXP methodology represents a more equitable treatment of all the class revenue distribution issues identified by Mr. Daniel.

V. RATE DESIGN

A. Proposed Primary Substation Rate

Several of the points of delivery in the Primary Voltage ≥ 20 MW @ 85% HLF class interconnect to an AE substation a short distance from the substation property itself. Unlike most Primary Distribution Service customers, who rely on AE's extensive distribution system, these customers utilize on average one or two spans of distribution line and one pole structure.[261] They do not require extensive transformation equipment to receive service, unlike the average distribution level customer, and do not require AE to invest in a network of poles, lines, conductors, and related facilities to serve them.[262]

Under these circumstances, allocating them a full share of AE's systemwide distribution costs is unreasonable and not supported under cost causation principles. These customers do not contribute to the overall AE distribution system cost in any meaningful way, and allocating them a full share of these costs essentially amounts to these customers subsidizing a substantial number of other AE customers taking service further from substations or at lower voltages. As Mr. Daniel testified, "Customer classes should not be required to pay for facilities they do not use."[263]

AE has acknowledged that a customer class should take account of the following customer factors:

1. Have similar demand and energy requirements (load patterns);
2. Have similar electric facilities requirements;
3. Are served at the same voltage levels (or within a predefined range of voltage levels); and

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[260] AE Ex. 9 at 17.
[261] TIEC Ex. 23 at 1.
[262] NXP Ex. 1 at 32-33; TIEC Ex. 1 at 31.
[263] NXP Ex. 1 at 33. TIEC likewise proposed a substation service class. TIEC Ex. 1 at 33-34.

4. Have similar uses of electricity.[264]

All of those characteristics apply to the current High Load Factor Primary >20MW class. As a consequence, both NXP and TIEC proposed the creation of a Primary Substation Service class, meeting these characteristics. Mr. Daniel proposed that AE simply direct bill these customers for the small distribution facility costs incurred to serve them.[265] At hearing, AE witness Burnham agreed AE is able to do this.[266] Mr. Pollock similarly recommended such a direct charge, rather than billing these customers as if though they were Primary Distribution Service customers.[267] This is in line with PUC precedent, in which the Commission directed Oncor to create a Primary Substation Class.[268] The only difference, which is not really a substantive one, is that the Oncor rate requires customers to pay for and own their own minimal distribution equipment, while AE proposes to own that equipment. But the tariff here could easily be adjusted to insert that requirement, and AE could collect its capital costs on its owned equipment through the proposed facilities charge as these customers transition to owning or leasing the small quantity of distribution equipment needed to take service at the substation.[269]

AE's only real response to this is that these are distribution customers and they should therefore bear the class allocated share of distribution facility costs.[270] But this simply describes AE's proposal; it does not explain or justify it in any way. These three customers are distribution customers being allocated distribution costs only because AE prohibits them from interconnecting directly in its substations, and because it designed the rate and class in that manner. The Oncor example disproves that just because three high load factor customers utilize a de minimis amount of distribution equipment, at AE's insistence, in no way requires allocating them full shares of AE's extensive distribution system cost.

[264] TIEC Ex. 22 at 2.

[265] NXP Ex. 1 at 34.

[266] Tr. 75:27-43 (Burnham Cross) (July 15, 2022).

[267] TIEC Ex. 1 at 45-46.

[268] PUC Docket No. 35771, *Application Of Oncor Electric Delivery Company LLC For Authority To Change Rates*, Order on Rehearing (Nov. 30, 2009) at 11 ("This new service affects about 50 primary substation customers, mostly industrial customers, receiving voltage from, **or near**, a substation.")(emphasis supplied); TIEC Ex. 1 at 55-56 (citing Entergy Texas as an integrated utility offering customers the opportunity to purchase distribution facilities outside the substation and be charged a substation class rate).

[269] TIEC Ex. 1 at 55.

[270] AE Ex. 8 at25, 27.

B. Proposed Facilities Charge Tariff

NXP incorporates by reference its discussion of its proposed facilities charge for primary voltage customers as previously discussed in Section III(D)(1)(c).

VI. CONCLUSION

NXP appreciates the opportunity to participate in this proceeding, and thanks the IHE for his time and attention to this very important matter, which impacts *all* of AE's customer classes. In summary, NXP respectfully requests that the IHE recommend approval of the following recommendations:

- Allocate AE's production demand-related costs using an A&E 4CP allocation methodology;

- Allocate AE's primary distribution demand-related costs using the highest monthly (1 NCP) demand allocation methodology;

- Exempt Primary Voltage Above 20 MW at 85% Load Factor customers from being allocated primary distribution costs for poles, conductors, and UG conduit. This should be implemented by allowing such customers to take service from a dedicated feeder and pay AE a facilities charge rather than be subject to a load ratio share portion of the aforementioned primary distribution costs;

- Remove the cost of streetlighting service attributable to the City of Austin from the Community Benefit Rider, and require those costs to be billed directly to the City;

- Require AE to adjust test year revenues, energy sales, demand levels and billing determinants in February 2021 for those customer classes it designates as "non-weather sensitive";

- Require AE to correct its improper adjustment of customer class demands for losses;

- Require AE to distribute its base rate increase among customer classes as proposed by NXP, which is more consistent with moving the classes closer to cost while also addressing the issue of subsidization among classes;

- Adjust AE's cash flow methodology to reflect a more accurate imputed rate of return, an IGFC level that is supported and within the range set by AE's financial policies as described by NXP, and reduce the GFT consistent with NXP's recommendations herein;

- Require a reduction in AE's revenue requirement consistent with the recalibrations described above.

Respectfully submitted,

By: */s/ J. Christopher Hughes*

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CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of this document was served on all parties of record in this proceeding, in accordance with Austin Energy Instructions, on the 28th day of July, 2022.

/s/ J. Christopher Hughes
J. Christopher Hughes