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

TEXAS INDUSTRIAL ENERGY CONSUMERS' RESPONSE TO THE IMPARTIAL HEARING EXAMINER'S FINAL RECOMMENDATION

September 26, 2022

Katherine L. Coleman
State Bar No. 24059596
Benjamin B. Hallmark
State Bar No. 24069865
John R. Hubbard
State Bar No. 24120909
O'MELVENY & MYERS, LLP
303 Colorado St., Suite 2750
Austin, TX 78701
(737) 261-8600

ATTORNEYS FOR TEXAS INDUSTRIAL ENERGY CONSUMERS

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

TABLE OF CONTENTS

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

TEXAS INDUSTRIAL ENERGY CONSUMERS' RESPONSE TO THE IMPARTIAL HEARING EXAMINER'S FINAL RECOMMENDATION

I. INTRODUCTION

Texas Industrial Energy Consumers (TIEC) submits this response to the Independent Hearing Examiner's (IHE) final recommendation in this base rate review. TIEC is a trade association that represents the interests of large energy users in rate proceedings. TIEC's participating member in this case is Samsung Austin Semiconductor (Samsung). Samsung has one of the most advanced semiconductor manufacturing facilities in the world here in Austin. It directly employs over 3,300 employees, supports well over 10,000 local jobs, and contributes billions of dollars to the local economy on an annual basis. Electricity is a major production cost for TIEC members, and Samsung is no exception. Electric rates that are fair, cost-based, and minimize subsidies across customer classes are critical to Samsung's ability to manage costs and compete in the global semiconductor marketplace. Accordingly, this is an important case for Samsung (as it is for all of Austin Energy's (AE) customers), and TIEC appreciates the City Council's careful attention to it.

AE's recent announcement that it will increase the Power Supply Adjustment (PSA) portion of its electric rates by 71%, and the regulatory charge by 23%, underscores the significance of setting fair rates in this proceeding.[1] For large, high-load-factor customers such as Samsung, the PSA (which includes fuel costs) represents a higher percentage of the total electric bill than for a typical customer. Thus, while AE estimates that the impact of these increases would be to raise the average residential customer's bill by 24%,[2] the impact to Samsung will be greater. Indeed, Samsung estimates that the new pass-through rates will increase its bills by tens of millions of dollars a year, which again highlights the importance of this case to Samsung.

---

[1] Austin Energy, *Austin Energy Submits Annual Adjustments to Utility's Pass-Through Charges as ERCOT Market Costs, Natural Gas Prices Drive Increase* (Sept. 21, 2022) (available at: https://austinenergy.com/ae/about/news/news-releases/2022/austin-energy-submits-annual-adjustments-to-utility-pass-through-charges).

[2] *Id.*

At the outset, TIEC commends the IHE and his team for their efforts in presiding over a multi-day hearing and presenting a thorough recommendation that covers a broad swath of complicated issues. **For the Council's convenience, TIEC has attached an executive summary of the issues it addresses in response to the IHE's recommendation as <u>Attachment A</u> to this pleading.**

One of AE's primary goals in its application is to move all customers closer to their actual cost of service, and to reduce inter-class subsidies. As noted, TIEC generally supports this overall objective. However, several of AE's proposals are at odds with that goal. The IHE's recommendation properly recognized this in some respects, but would approve AE proposed methodologies that are inconsistent with cost causation in others.

One of the most significant problems with AE's application is its failure to recognize that large business customers who take service directly from AE's substations through a single, dedicated distribution feeder do not use or cause investment in AE's broader integrated distribution network and should not have to pay those costs. AE's witnesses did not dispute that certain customers use only discrete, dedicated circuits past the AE substation, and are not similarly situated to other distribution-voltage customers in terms of their impact on overall distribution system costs.[3] However, AE opposed reflecting these differences in rates because these customers do not currently have the option to either directly pay for or own their dedicated distribution feeders.[4] The IHE properly rejected AE's complaints, finding that, with respect to distribution costs, these customers "should only bear the cost of the radial distribution feeders that are used to serve them."[5] Accordingly, the IHE recommends that a separate "Primary Substation" rate be established, under which these customers would be able to directly pay for their dedicated feeders and, in exchange, would not be required to pay for the costs of the broader distribution system that they do not use.[6] This recommendation is consistent with cost-causation and the existing practice

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

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

[5] IHE Final Recommendation at 86.

[6] *Id.* at 85-87.

for investor-owned utilities, including Oncor—the state's largest utility.[7] Moreover, the class-cost-of-service study (CCOSS) that CPS Energy, San Antonio's municipal utility submitted in its last base rate process, also recognizes primary-substation service.[8] TIEC urges the City Council to adopt the IHE's recommendation on this point and implement a Primary Substation rate in this proceeding.

While the IHE recommendation properly applied cost-causation principles on the Primary Substation issue, TIEC respectfully submits that it fails to do so with respect to other significant cost-allocation methodologies. Chief among these is the IHE's recommendation to approve AE's proposed methodology for allocating generation resources,[9] which is inconsistent with cost causation and the practices of utilities that peak in the summer, as AE does.[10] In fact, AE did not identify any utility anywhere that allocates its production costs in the manner it proposes here.[11]

TIEC addresses these and other points below. TIEC is not submitting exceptions on every issue on which the IHE disagreed with TIEC's proposal, but does request that the Council revisit several of the IHE's recommendations on important issues. Additionally, TIEC addresses several of the IHE's recommendations that should be adopted, including using the test-year amount of the General Funds Transfer (GFT) to set rates in this case rather than a higher amount that has no basis in the evidence or AE's financial policies.

In sum, TIEC believes that the Council can set rates in this case that provide AE with a sufficient (but not excessive) revenue requirement and move customer classes closer to cost (i.e., paying their fair share of AE's costs) without inflicting rate shock on any class. TIEC therefore respectfully requests that the Council adopt the recommendations set forth below.

---

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

[8] CPS Energy, *Cost-of-Service Model* (Sept. 23, 2021) (available at: https://www.cpsenergy.com/content/dam/corporate/en/Documents/RAC/20180212%20ucos%20model%20FY17%20redacted%20for%20RAC.xlsx).

[9] IHE Final Recommendation at 76-79.

[10] *Id.* At 71; TIEC Ex. 1 (Pollock Dir.) at 20 and Exhibit JP-3 at 1; TIEC's Post-Hearing Br. at 17.

[11] AE's Closing Br. at 40-46.

II. REVENUE REQUIREMENT

B. Cash Flow Methodology

5. General Fund Transfer

The IHE correctly recommends that AE's revenue requirement be set based on the amount of the General Funds Transfer (GFT) that AE actually paid to the City during the test year ($114 million) or no more than the amount it calculated for Fiscal Year 2023 ($115 million).[12] AE's requests that its rates be set based on a $120 million[13] GFT is contrary to test-year ratemaking principles and would result in an excessive revenue requirement.

The GFT is a yearly payment that AE makes out of its revenues to the City's general fund.[14] Under AE's Financial Policies, the GFT is "to not exceed 12% of Austin Energy three-year average revenues less power supply costs and on-site energy resource revenue, calculated using the current year estimate and the previous two years' actual revenues. . ."[15] From a ratemaking perspective, the GFT is treated as an expense in calculating AE's revenue requirement, and the question presented here is how the GFT should be accounted for in AE's rates.[16]

AE filed this case under the historical test-year construct, using Fiscal Year 2021 as the test year. And, as AE acknowledged in its rate filing package, adjustments to the expenses it incurred during that test year should only be made if the adjustment is "known and measurable."[17] The GFT that AE actually paid to the City in the test year was $114 million.[18] As noted, AE's Financial Policies call for the GFT calculation to be based on two historical years and an estimate of the current year's revenues.[19] So AE should have used the test year GFT (which was calculated

---

[12] IHE Final Recommendation at 34.

[13] This is based on AE's rebuttal case. AE's Closing Br. at 22.

[14] AE Rate Filing Package at 34.

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

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

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

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

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

in this manner and actually paid to the City[20]) and ***not*** a GFT calculated based on adjusted 2021 revenues (including its requested revenue requirement in this case) alone. Further, even if one accepts the proposition that the actual test year GFT should be displaced by a calculation that includes the revenues approved in this case, that calculation should still include the average of the two historical years, which were lower than AE's requested revenue requirement in this case.[21]

AE's proposed adjustment to the test-year GFT is thus anything but "known and measurable." It was not calculated how AE will actually calculate its GFT during the years these rates will be in effect. Instead, it was calculated in a manner that systematically overstates what the GFT payment will be. Any doubt on this score was removed when it was revealed at the hearing that AE calculated its Fiscal Year 2023 GFT will be $115 million, and submitted that estimate to the City Manager for inclusion in the preliminary budget document.[22] Thus, to recap, AE's actual test-year GFT was only $114 million, and it calculated the GFT for Fiscal Year 2023 was $115 million. But AE is asking the Council to set its rates based on an assumption that it makes a $120 million GFT payment every year.[23] The IHE properly rejected that proposal, and the Council should set the GFT based on the test-year amount of $114 million or no more than the Fiscal Year 2023 amount of $115 million.

C. Present Revenues and Billing Determinants

AE failed to demonstrate that its test-year sales were normal and should be used to set rates without further adjustment. In particular, the test year used in this case, fiscal year 2021, included Winter Storm Uri, which resulted in widespread and long-lasting outages.[24] Failing to account for a non-recurring reduction in test-year sales due to a once-in-a-generation storm would have the effect of understating the amount of revenue that present rates would generate going forward. This, in turn, will cause the utility to overstate the extent it needs to increase its rates. The IHE

---

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

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

[22] Tr. (July 15) at 39:30-37 (Dombroski Cr.); TIEC Ex. 25 at Bates 5.

[23] Further, even AE's projections of the GFT amount for future years, which are based in part on estimated future revenues, appear to be lower than the $120 million amount it is requesting. See TIEC Ex. 25 at Bates 4 (showing projected GFTs for 2024 and 2025 that increase only slightly from the 2023 level, which is $115 million).

[24] ICA Ex. 2 at 14.

recognized the problem with AE's failure to demonstrate that it had accounted for Winter Storm Uri, and recommended that AE be required to provide additional evidence proving that it did so.[25] To date, AE has not done that. In any event, there is reason to be concerned that AE did not properly account for Winter Storm Uri's effects in calculating its proposed rate increase.

Although AE claims the storm had no impact on its test year energy sales or base revenues,[26] Uri was an extreme in both its intensity and duration.[27] Over 220,000 customers in Austin experienced electric outages of 4 to 5 days.[28] Further, AE's test-year kWh sales were well below ***actual*** sales in 2018 through 2020,[29] and despite strong customer growth in recent years, total test-year sales were only 0.6% higher than the average for the four prior fiscal years.[30] Test-year sales were also significantly lower on a per-customer basis: residential customers used nearly 2% less energy per customer and commercial and industrial (C&I) customers used 5.2% less per customer as compared to the average usage in 2017 to 2020.[31] Winter Storm Uri appears to be the only plausible explanation for this blip.[32]

AE argues that the lower usage in the test year is a result of a multi-year downward trend, and that it normalized test-year sales and revenues.[33] However, as the IHE noted, AE has not demonstrated that it accounted for Uri's effects on test year usage.[34] Moreover, in addition to the lack of information on this point,[35] it is far from clear that a typical weather-normalization adjustment would address the Uri problem. Weather normalization is used to adjust the actual kWh sales in a test year to account for the effects of abnormal weather. But if there are no actual kWh sales for an extended period of time due to outages, there would be nothing to adjust during

[25] IHE Final Recommendation at 49-50.

[26] AE Response to TIEC RFI 3-5 (June 6, 2022).

[27] IHE Final Recommendation at 19.

[28] ICA Ex. 2 at 14.

[29] TIEC Ex. 1 (Pollock Dir.) at 7-8.

[30] *Id.* at 10, Table 1.

[31] *Id.*

[32] *Id.*

[33] *Id.* at 13.

[34] IHE Final Recommendation at 48-49.

[35] *Id.*

those times. For example, if there were 0 kWh of sales over those days due to outages, even a 10x normalization-multiplier would still result in 0 kWh of sales. AE has not demonstrated that any weather-normalization adjustment it made actually accounted for Winter Storm Uri. Additionally, as the IHE noted, the fact that there has been a multi-year downward trend does not explain how the 2021 residential, commercial, and industrial kWh sales were the lowest since 2017, despite fluctuations in those prior years in both categories.[36]

If Winter Storm Uri resulted in lower sales during the test year than should be expected under normal conditions, which appears to be the case, AE's requested rate increase is too high. Specifically, TIEC's expert witness Mr. Pollock estimates that AE's rate filing package would result in rates that over-collect approximately $24.3 million per year.[37] If AE cannot demonstrate that it properly accounted for Winter Storm Uri's effects on test year sales, its requested revenue requirement in this case should be reduced by that amount.

III. COST ALLOCATION

D. Class Allocation

1. Demand-Related Costs

a. Production-Demand

AE's proposed ERCOT twelve coincident peak (12-CP) methodology for allocating production-demand costs is contrary to cost-causation principles and well-established utility precedent for utilities that peak in the summer, like AE. The Council should therefore reject the IHE's recommendation[38] on this point and instead adopt the Average and Excess Demand – Four Coincident Peak (AED-4CP) allocation method, which has been consistently used for Texas utilities under the jurisdiction of the Public Utility Commission of Texas (PUCT)[39] for ***decades***.[40]

Production-demand related costs are the costs associated with building and maintaining

---

[36] *Id.* at 49; TIEC Ex. 1 (Pollock Dir.) at 10.

[37] TIEC Ex. 1 (Pollock Dir.) at 7-8, 12.

[38] IHE Final Recommendation at 78.

[39] TIEC recognizes that the City Council is not bound by the PUCT's precedent. However, the PUCT has extensive expertise in regulating public utilities, including vertically integrated electric utilities that operate very similarly to AE. The PUCT has encountered a broad range of varied fact patterns over the years, and TIEC submits that the precedent it has established over the course of several decades should be considered in this process.

[40] *See* TIEC Ex. 1 (Pollock Dir.). at 24 (analyzing PUCT precedent on this point).

AE's generation fleet or contracting for outside generation capacity.[41] For this category of costs, following cost causation requires analyzing the utility's load characteristics, which determine the amount of capacity required to meet expected demand.[42] The methodology used to allocate production-demand costs should reflect each customer class's contribution to AE's need for additional production capacity.

AE's proposed methodology fails this test. The 12-CP methodology implicitly assumes that each month of the year is equally responsible for driving AE's production demand costs. But that, of course, is not true for a utility operating in Texas. The primary driver of AE's generation investment is serving customers during summer peak demand periods when customers are consuming the most electricity due to the hot weather.[43] It is undisputed that AE is a summer-peaking utility, and AE expects its system to continue to peak in the summers "[t]hroughout its ten-year planning horizon."[44] The average of a summer-peaking utility's 12 monthly peaks will be lower than it actual peak demands in the summer. Accordingly, for such a utility, production demand costs should be allocated based on summer peaks, consistent with the AED-4CP methodology (which utilizes the utility's four summer peaks).[45] A 12-CP methodology would only be appropriate for a utility that expects its peaks to occur relatively uniformly throughout the year.[46]

The AED-4CP allocation is a widely accepted methodology for allocating production-demand costs for vertically integrated utilities that peak in the summer, although the IHE recommendation barely grapples with this fact.[47] Specifically, the PUCT has consistently used AED-4CP to allocate production demand costs for all four of the vertically integrated utilities it regulates.[48] Other nearby states, including New Mexico and Colorado, have similarly approved

---

[41] *Id.* at 22.

[42] *Id.* at 19.

[43] *Id.* at 20.

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

[45] *Id.* at 20.

[46] *Id.*

[47] IHE Final Recommendation at 73.

[48] TIEC Ex. 1 (Pollock Dir.) at 23 and Appendix D; *see also* Tr. (July 13) at 110:27-111:16 (Murphy Cr.).

AED-4CP to allocate production-demand costs.[49] In contrast, AE has not cited any utility that uses its proposed ERCOT 12-CP method.

Notably, AE itself formerly supported the AED-4CP methodology. In its 2012 rate case, AE used this method,[50] and the City Council even adopted an ordinance endorsing the AED-4CP methodology.[51] AE also defended the AED-4CP allocation methodology when the 2012 case was appealed to the PUCT. AE's witness in that proceeding, Joseph Mancinelli, explained that AE's peak demands occur during the summer, and that its system peaks during that time are consistently within 90% of the overall peak.[52] Nevertheless, AE now proposes a methodology that minimizes the importance of the summer peak months, treating them the same as all other months.

AE's rationale for switching to the ERCOT 12-CP method is that it better reflects its operating conditions in the ERCOT nodal market, which was implemented in 2010.[53] In this connection, the IHE agreed that the ERCOT 12-CP methodology reasonably reflects AE's use of its generating resources as a physical hedge against high market prices in ERCOT.[54] This argument misses the mark. As an initial matter, vertically integrated utilities regulated by the PUCT participate in competitive wholesale markets like ERCOT, and they allocate their production costs based on AED-4CP.[55] So, AE's reliance on its participation in the ERCOT nodal market does nothing to distinguish the PUCT's precedent on this point.

Moreover, AE's use of its power plants as a hedge does not change the analysis. Like all load serving entities in ERCOT, AE purchases all of the energy used to serve its load from the ERCOT market.[56] Further, as a generation owner, AE also offers its physical generation capacity into the market, and if it is dispatched, the resulting revenues are used to offset the cost of serving

49 TIEC Ex. 1 (Pollock Dir.) at 24.

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

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

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

53 AE's Closing Br. at 40.

54 IHE Final Recommendation at 78.

55 TIEC Ex. 1 (Pollock Dir.) at 24. Specifically, SWEPCO and SPS participate in the Southwest Power Pool market, and ETI participates in the MISO market. *Id.*

56 *Id.* at 22.

AE's load.[57] Thus, to maximize the value of its generating resources as a hedge against market prices, AE must ensure that it has sufficient capacity to serve its own load at times of peak demand.[58] And it is undisputed that both AE and ERCOT peak in the summer.[59] That is also when market prices tend to be the highest in ERCOT, as the IHE acknowledged.[60] In fact, TIEC witness Mr. Pollock provided a compilation of locational marginal prices to serve AE's load from the years 2016 to 2021, and it shows that the highest average prices occurred during the summer months.[61] This evidence was not disputed. Against this backdrop, the IHE's observations that market prices are sometimes high outside the summer months provides no basis for departing from the AED-4CP methodology.

Indeed, it is worth noting that in the same 2012 AE rate case referenced above, AE's witness Mr. Mancinelli endorsed the used of AED-4CP in allocating demand costs, ***even in the ERCOT nodal market***, stating

> [I]n the case of production fixed costs, those costs have historically been incurred to serve AE's load with the primary concern of meeting AE's peak demand. ***Even under the current ERCOT Nodal Market, AE's generation fleet acts as a hedge against fluctuations in the market price. Austin Energy's exposure to market prices is directly related to purchasing power from the market to serve native load. Therefore, AE's system load is the primary driver of costs. To preserve the relationship between cost causation and cost allocation, the AE system peak expressed as the 4CP must be used***.[62]

This testimony directly contradicts AE's position in this case.

In sum, AE's proposed production-demand allocation methodology is inconsistent with cost causation, the practice of similarly situated utilities, and AEs own past practice. TIEC requests that the City Council adopt the AED-4CP methodology for allocating production-demand costs.

---

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

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

[59] NXP Ex. 1 at 20; TIEC Ex. 1 (Pollock Dir.) at 20; Ex. JP-3 at 1.

[60] IHE Final Recommendation at 77.

[61] TIEC Ex. 1 (Pollock Dir.) at 23, JP-4.

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

b. Distribution-Demand

The City Council should also reject the AE's proposal to use the twelve-month average non-coincident peak demand (12-NCP) method for allocating distribution-demand costs, which the IHE recommendation adopts.[63] Instead, AE should use each class's annual non-coincident peak demand (1-NCP) to allocate distribution demand costs, as proposed by TIEC.[64] For context, the 12-NCP method allocates costs based on the average of each class's highest demand in each of the twelve months. Conversely, the 1-NCP method allocates costs based on each class's actual peak over the course of the year. Unlike AE's proposal (and the IHE's recommendation), TIEC's suggested approach is generally accepted and tracks cost-causation on the distribution system.

The allocation of distribution demand costs should reflect the fact that distribution facilities are constructed to have sufficient capacity to reliably serve each class's ***maximum demand***, not the average of 12 monthly demands, which will be a lower amount.[65] The IHE's final recommendation misconstrues TIEC's argument on this point when it states that the construction of the distribution system to meet peak is a reliability measure and not determinative on cost allocation.[66] However, TIEC's argument speaks directly to what causes distribution-demand costs, which is the need to size the distribution system to withstand the actual peak demand. As AE acknowledged, if the distribution system were only designed to meet the 12-NCP average, and not the actual peak demand, AE could experience outages and be forced to curtail customers at times of peak use.[67] As such, the 1-NCP methodology more closely tracks cost causation because it accurately recognizes the contribution of each rate class to AE's distribution-demand costs.[68]

The use of a 1-NCP allocator is consistent with the weight of utility precedent in this state. Both vertically integrated utilities[69] and ERCOT transmission and distribution utilities,[70]

---

[63] IHE Final Recommendation at 81.

[64] TIEC Ex. 1 (Pollock Dir.) at 16; TIEC's Post-Hearing Br. at 25.

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

[66] IHE Final Recommendation at 80.

[67] Tr. (July 13) at 119:38-46 (Burnham Cr.); TIEC Ex 1 (Pollock Dir.) at 27.

[68] TIEC Ex. 1 (Pollock Dir.) at 28; TIEC's Post-Hearing Br. at 26.

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

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

consistently use this allocator for distribution demand costs. This precedent underscores the reasonableness of the 1-NCP methodology, and outweighs the fact AE was able to identify two small municipally owned utilities that use its preferred 12-NCP method.

Load Dispatch Expense

The City Council should reject the IHE's recommendation to adopt the Independent Consumer Advocate's (ICA) proposed change to AE's allocation of load-dispatching expense from the 12-NCP methodology to average demand.[71] As AE witness Mr. Rabon testified, distribution load dispatching expense is caused by the need to manage changing system load conditions.[72] And the fact that load-dispatching expense occurs year round is adequately captured by AE's proposal to use a 12-NCP methodology (given that the "12" aspect of this methodology refers to the average of the 12 months in a year).[73] As Mr. Rabon correctly explained, "[l]oad dispatch is not a cost that varies with the amount of energy used, so the use of average demand, which is essentially energy, is not appropriate."[74]

Ultimately, load-dispatching expense is closely related to the underlying function with which it is associated. AE proposes to allocate distribution-demand costs on the basis of 12-NCP, which proposal the IHE recommends the Council accept.[75] While TIEC disagrees with that recommendation (as discussed above), AE's proposal to allocate distribution load-dispatching expense based on the same 12-NCP allocator is at least internally consistent. To adopt a 12-NCP allocator for distribution-demand costs (over the objections of TIEC and other industrial customers) but then also change the allocator for distribution load-dispatching expenses to average demand (which also shifts costs to industrial customers) would implicate precisely the type of "costly inconsistencies" that the IHE warned against.[76] The City Council should adopt AE's proposed 12-NCP methodology for load-dispatching expenses.

---

[71] IHE Final Recommendation at 82-83.

[72] AE Ex. 6 (Rabon Reb.) at 12.

[73] *Id.*

[74] *Id.*

[75] IHE Final Recommendation at 82.

[76] *Id.* at 83.

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

The IHE appropriately recommended that a primary substation rate be established for the three Primary Substation customers that are directly connected to AE distribution substations located adjacent to their sites through dedicated radial feeders.[77] The City Council should adopt this recommendation and direct AE to implement the new substation rate in conjunction with the rates that will be established in this case.

As the IHE noted, it is undisputed that certain of AE's primary customers are served through dedicated radial feeder lines that are directly connected to an AE substation and do not serve other customers.[78] As a result, these customers ("Primary Substation" customers) do not use AE's interconnected primary distribution network of lines, poles, and conductors.[79] This type of primary service is nearly identical to Transmission service, except that for Primary Substation customers, AE must first transform power down to a primary distribution voltage.[80] All three of AE's High Load Factor Primary Voltage (≥ 20 MW) customers qualify as Primary Substation customers.[81]

Primary Substation service stands in stark contrast to the service provided to the other primary distribution customers ("Primary Distribution" customers). To serve Primary Distribution customers, AE must not only own the transformation equipment to step power down from transmission to distribution level, but must also construct and maintain a network of interconnected primary poles, lines, conductors and related facilities to provide service.[82] In fact, a utility must invest in hundreds if not thousands of miles of distribution wires and related facilities to serve Primary Distribution customers, and providing that service also results in greater line losses.[83]

[77] *Id.* at 85-87.

[78] *Id.* at 32; TIEC Ex. 23 (AE's Response to NXP's RFI 1-5R) at 1, note 1 ("Each feeder [serving AE's Above 20 MW High Load Factor customers] does not serve other customers."); Tr. (July 15) at 76:6-20 (Burnham Cr.) (showing that the only factual dispute was over the term "directly" and it was based on the ownership of the feeder line).

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

[80] *Id.*

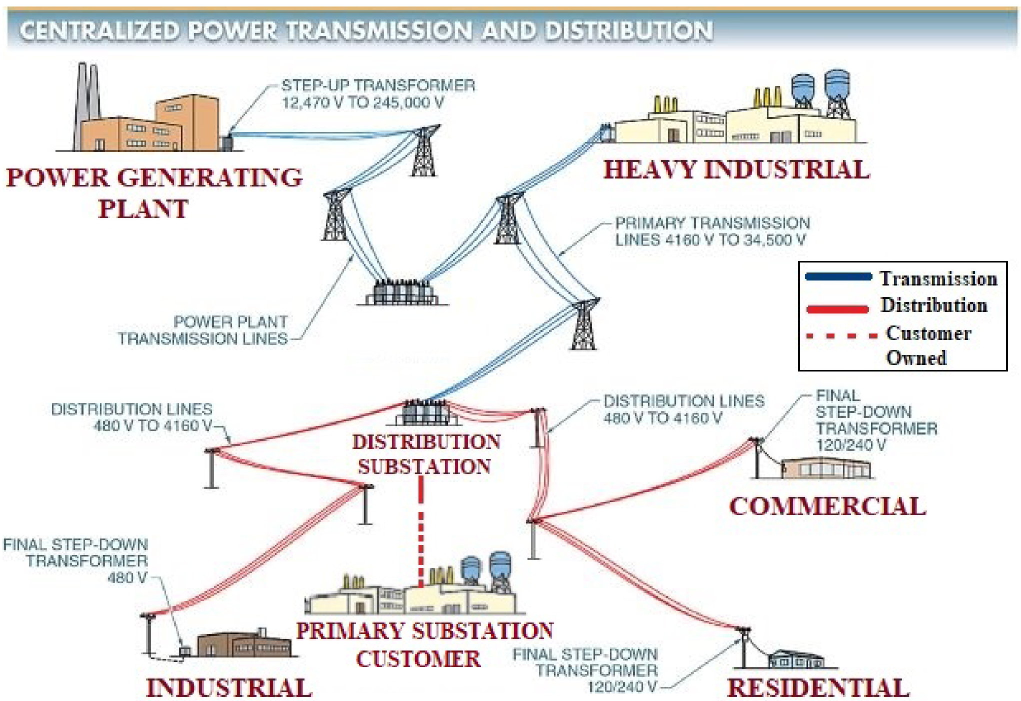
[81] *Id.* at 32.

[82] *Id.* at 79.

[83] *Id.* at 80.

Primary Distribution service is thus more costly to provide than Primary Substation service in terms of both infrastructure costs and line losses.[84]

The following graphic illustrates the difference between Primary Substation service and Primary Distribution service:



As can be seen, Primary Substation customers do not use the distribution network; their use of the utility's distribution system is limited to substations and radial feeder lines that serve only that customer. A Primary Substation customer maintains its own distribution network for its industrial site.[85] The difference between Primary Distribution customers who are served from the interconnected distribution system and Primary Substation customers who are served directly from an AE substation using a dedicated, radial feed is an easy bright-line demarcation with significant cost consequences for the utility.

Despite these fundamental differences in service characteristics, AE lumps Primary Substation customers together with Primary Distribution customers for cost-allocation purposes.[86]

---

[84] *Id.*

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

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

As a result, Primary Substation customers are allocated a share of AE's total distribution network infrastructure despite the fact that they do not use this infrastructure.[87] However, under bedrock cost-causation principles, these customers should pay for the costs of the radial feeder lines that serve them, but should not be allocated any costs for the distribution network that they do not use.[88] As noted above, both investor-owned[89] and at least one municipally owned utility recognize Primary Substation in their cost-allocation process.[90] AE should do the same, as the IHE concluded.

AE's objection to implementing a Primary Substation rate centers on the fact that the dedicated radial lines that serve Primary Substation customers are owned by AE, and not the customers themselves.[91] But as the IHE recognized, this can be addressed in a manner that is consistent with cost causation.[92] Specifically, Primary Substation customers should be allowed to lease or purchase these lines.[93] Alternatively, the cost of these lines should be directly assigned to these customers, which would be consistent with AE's stated policy on direct assignment.[94] As the IHE put it, in either event, "the primary goal of a new tariff is to ensure that all of the distribution costs associated with serving each Primary ≥ 20 MW HLF customer are being paid for by that customer, and there would be no allocation of additional distribution costs (for facilities they don't use) to that class."[95]

---

[87] *Id.* at 31-32.

[88] *Id.* at 86.

[89] *Id*.

[90] CPS Energy, *Cost-of-Service Model* (Sept. 23, 2021) (available at: https://www.cpsenergy.com/content/dam/corporate/en/Documents/RAC/20180212%20ucos%20model%20FY17%20redacted%20for%20RAC.xlsx).

[91] AE Ex. 8 (Burnham Reb.) at 26; Tr. (July 15) at 76:6-20 (Burnham Cr.) (showing that the only factual dispute was the term "directly" and it was based on the ownership of the feeder line); AE Ex. 8 (Burnham Reb.) at 25 (explaining that no customers are "directly" served from any substation because the POI is outside of the substation and requires a feeder).

[92] IHE Final Recommendation at 86.

[93] TIEC Ex. 1 (Pollock Dir.) at 45-46; IHE Final Recommendation at 86.

[94] IHE Final Recommendation at 87.

[95] *Id.*

Based on his findings, the IHE recommended that AE work with these industrial customers to implement the creation of a Primary Substation rate class.[96] TIEC has contacted AE's counsel and is ready to work with AE to expeditiously implement the new class. TIEC notes that its witness calculated a Primary Substation rate in his testimony (based on AE's filed case), and that AE has already identified the dedicated feeder lines that serve Primary Substation customers in a discovery response.[97] Accordingly, there should be no obstacle to implementing a new Primary Substation class with the new rates that will go into effect in January 2023. To do otherwise would ignore cost-causation and saddle these Primary Substation customers with a portion of the costs of a distribution system they do not use.

7. Energy and Demand Line Loss Factors

Line losses reflect the fact that as electricity travels over AE's system, some of it is lost. AE's customers take service at different delivery voltages, and line losses increase each time voltage is transformed down to a lower level.[98] Utilities generally rely on a loss study to determine the peak demand and energy losses that occur when an electric utility generates and delivers electricity to each of its retail customer classes.[99] AE conducted a line-loss study in 2018, but it has several flaws.

One problem with AE's line-loss analysis is that it failed to use peak-demand losses to adjust the peak demands.[100] Instead, AE used its ***energy*** loss factors to adjust the peak demands. Peak demand losses are actually higher than energy losses because losses are directly related to power flow, and more power is flowing during peak demand periods.[101] As a result, AE under-adjusted the peak demands, which resulted in under-allocating distribution costs to the secondary voltage customer classes and over-allocating costs to the primary voltage customer class.[102] The IHE recognized this problem and directed AE and TIEC to confer on potential adjustments to the

---

[96] *Id.*

[97] TIEC Ex. 23.

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

[99] *Id.* at 35.

[100] *Id.* at 36.

[101] *Id.*

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

demand line loss factors.[103] TIEC has contacted counsel for AE on this point, and stands ready to do just that. If an agreement cannot be reached, however, TIEC recommends that Mr. Pollock's proposed demand line-loss factors be adopted.[104]

Another problem with AE's line-loss factors is that they do not recognize Primary Substation service. As discussed elsewhere, the IHE properly recommends the adoption of a new Primary Substation rate,[105] which recommendation should be adopted. In concert with that new rate, new line-loss factors for Primary Substation should be implemented, as discussed in Mr. Pollock's testimony.[106] AE's line-loss study already recognizes that there are lower demand and energy losses associated with serving Primary Substation customers, so this can easily be accomplished.[107]

IV. CLASS REVENUE DISTRIBUTION

Class revenue distribution is the process of determining how any base-revenue change should be apportioned to a utility's customer classes.[108] The starting point for revenue distribution is a proper CCOSS, which is designed to evaluate whether each class is appropriately contributing to its actual cost of service. From there, classes should be moved to cost to the extent practicable.[109] Cost-based rates are fair, efficient, and enhance revenue stability while encouraging conservation.[110] Indeed, both TIEC and AE agree that cost-based rates are optimal.[111] However, as TIEC has acknowledged throughout this proceeding, it may be necessary to limit the immediate movement of a class to cost based on gradualism, which is a principle that is applied to avoid rate shock.[112]

---

[103] IHE Final Recommendation at 93.

[104] TIEC Ex. 1 (Pollock Dir.) at Exhibit JP-9.

[105] IHE Final Recommendation at 87.

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

[107] *Id.*

[108] *Id.* at 40.

[109] *Id.*

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

[111] *Id.*; AE Base Rate Filing Package at 76 ("Austin Energy's process is to first recognize the need to put all customer classes on an equal basis in comparison to cost of service.").

[112] TIEC Ex. 1 (Pollock Dir.) at 40.

Without knowing what the Council's final decisions on revenue requirement and cost-allocation and rate-design issues will be, it is difficult to say whether gradualism will be necessary in this case or how it should be applied. To the extent that Council decides that the movement of classes to cost should be tempered by gradualism, TIEC does not object in theory to AE's move-classes-halfway-to-cost approach, which was endorsed by the IHE.[113] This should include the High Load Factor Primary ≥ 20 MW class receiving at least 50% of the rate decrease that it would be due under a true cost-based approach.

V. RATE DESIGN

I. Proposed Tariff

Facilities Charge Tariff

TIEC requests that Council direct AE to develop a facilities charge tariff that would allow customers to lease or purchase the equipment necessary to take service at the Primary Substation or transmission level. As TIEC witness Mr. Pollock testified, customers should have the opportunity to transition to a higher level of service that allows the customer to better manage electricity costs, and there is ample precedent for such charges in the tariffs of other vertically integrated utilities.[114] A facilities charge tariff could be implemented in conjunction with the Primary Substation rate, but should also allow customers to transition to transmission service if the customer so chooses.

VIII. OTHER ISSUES

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

City Council should adopt the IHE's recommendation to revise the Power Supply Adjustment (PSA) to reflect the addition of the new Primary Substation rate.[115] AE has differentiated the PSA charges by voltage to reflect the differences in energy losses, but the PSA only differentiates the service provided at transmission, primary, and secondary voltages.[116] Providing energy to Primary Substation customers will have a lower line loss compared to other

[113] IHE Final Recommendation at 98-99.

[114] TIEC Ex. 1 (Pollock Dir.) at 46.

[115] IHE Final Recommendation at 141.

[116] TIEC Ex. 1 (Pollock Dir.) at 37-38.

primary customers,[117] so it is important the PSA is revised to reflect the new Primary Substation class.

B. Energy Efficiency Service

TIEC recommends that City Council adopt the IHE's decisions related to Energy Efficiency Service (EES) as they relate to industrial customers.[118] Large industrial customers should not be subject to EES fees because these customers have sophisticated energy management programs, often times have corporate mandates to manage energy use, and are capable of implementing their own energy-efficiency measures.[119] The PUCT[120] and the Texas Legislature[121] similarly exempt industrial customers from paying into or participating in a utility's energy efficiency programs, recognizing that industrial customers have inherent incentives to implement cost-effective energy-efficiency measures to reduce their costs on their own.[122] Industrial customers have already invested in their own energy-efficiency programs on their own dime, and as the IHE notes, they are not eligible to receive EES rebates from AE.[123] Accordingly, allocating EES costs to the customers would be tantamount to making them pay twice for energy efficiency—both for the costs of their own self-directed energy efficiency measures and the EES charges assessed by AE.[124]

The IHE was also correct to conclude that these exempt customers should not be required to publicly report on their self-funded energy-efficiency measures, which was an ad hoc proposal raised by SCPC/SUN at the hearing.[125] Energy efficiency measures implemented by large industrial customers can include investments in state of the art manufacturing technology,[126] and

---

[117] *Id.* at 38.

[118] IHE Final Recommendation at 142-143.

[119] *Id.* at 142.

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

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

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

[123] IHE Final Recommendation at 142.

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

[125] IHE Final Recommendation at 143.

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

a report about those investments would give a competitor greater insight into the customer's confidential practices. As the IHE noted, requiring customers to publicly disclose such proprietary and confidential energy efficiency information would provide no benefit to AE's energy efficiency programs.[127]

IX. CONCLUSION

TIEC appreciates the opportunity to participate in this proceeding and thanks the City Council and IHE for their attention to these important rate-setting issues. TIEC respectfully requests that Council adopt the recommendations set forth above and grant TIEC all other relief to which it is entitled.

Respectfully submitted,

O'MELVENY & MYERS LLP

/s/ Benjamin B. Hallmark
Katherine L. Coleman
State Bar No. 24059596
Benjamin B. Hallmark
State Bar No. 24069865
John R. Hubbard
State Bar No. 24120909
kcoleman@omm.com
bhallmark@omm.com
jhubbard@omm.com
OMMeservice@omm.com

ATTORNEYS FOR TEXAS INDUSTRIAL ENERGY CONSUMERS

CERTIFICATE OF SERVICE

I, John R. Hubbard, Attorney for TIEC, hereby certify that a copy of this document was served on all parties of record in this proceeding on this 26th day of September, 2022 by electronic mail, facsimile, and/or First Class, U.S. Mail, Postage Prepaid.

/s/ John R. Hubbard
John R. Hubbard

[127] IHE Final Recommendation at 143.

Attachment A–Executive Summary of TIEC's Response to the IHE's Final Recommendation

Issue	TIEC's Recommendation
General Fund Transfer	Adopt the IHE's recommendation and set the GFT based on the test-year amount of $114 million or no more than the Fiscal Year 2023 amount of $115 million.
Present Revenues and Billing Determinants	Adopt the IHE's recommendation and require AE to demonstrate that it properly accounted for Winter Storm Uri's effects on test-year sales. If AE cannot do so, reduce its revenue requirement by $24.3 million.
Class Allocation: Production-Demand Costs	Reject the IHE's recommendation to allocate these costs using the ERCOT 12-CP methodology, which ignores that AE is a summer peaking utility and is inconsistent with cost causation. Instead adopt the AED-4CP methodology, which is widely accepted for summer-peaking, vertically integrated utilities.
Class Allocation: Distribution-Demand Costs	Reject the IHE's recommendation to use the 12-NCP method for allocating these costs, and adopt the 1-NCP method instead.
Load Dispatch Expense	Reject the IHE's recommendation to adopt the ICA's proposed change to AE's allocation of load-dispatching expense from the 12-NCP methodology to average demand, which is inconsistent with how the related distribution-demand costs would be allocated under the IHE's recommended approach.
Primary Distribution Demand-Related Costs (Primary Substation Issue)	Adopt the IHE's recommendation to establish a Primary Substation rate for the three Primary ≥ 20 MW HLF customers that are directly connected to AE distribution substations through feeders that do not serve other customers. Under cost-causation principles, these customers should pay for the costs of the feeder lines that serve them, but should not pay for the distribution network that they do not use. The Primary Substation class should be implemented with the new rates in January 2023, and AE should adjust the PSA to recognize the new class.
Energy Demand and Line Loss Factors	Consistent with the IHE's recommendation, AE and TIEC should confer to agree on proper demand loss factors. AE should also adopt separate line-loss factors for the new Primary Substation rate.
Class Revenue Distribution	Adopt the IHE's recommendation of using gradualism if necessary, which should include the Primary ≥ 20 MW HLF class receiving at least 50% of the rate decrease that it would be due under a cost-based approach.
Proposed Tariff: Facilities Charge Tariff	Direct AE to develop a facilities charge tariff that would allow customers to lease or purchase the equipment necessary to take service at the Primary Substation or transmission level.
Energy Efficiency Service (EES)	Adopt the IHE's recommendations that industrial customers (1) should not be subject to EES fees because these customers pay for their own EE measures; and (2) should not be required to publicly report on their EE measures, because such measures are self-funded and confidential and proprietary.