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

NXP SEMICONDUCTORS, INC'S RESPONSE TO THE IMPARTIAL HEARING EXAMINER'S RECOMMENDATION

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I. INTRODUCTION

NXP Semiconductors ("NXP") appreciates the efforts of the Impartial Hearing Examiner ("IHE") in presiding over the Hearing and in preparing his Final Recommendations ("Report"). NXP also appreciates the opportunity for parties to present any exceptions they may have to the Report. NXP presents its exceptions herein to some of the IHE's Recommendations, many of which recommendations support Austin Energy's ("AE") proposals in this proceeding. Overall, NXP believes that AE has failed to provide sufficient evidence to substantiate its requested revenue requirement and that its cost allocation proposal fails to comport with widely-accepted ratemaking principles such as cost causation. The resulting ratemaking methodologies that AE proposes and that the IHE supports are not established in the record as resulting in just and reasonable rates. AE has failed to meet its burden of proof on several aspects of its case. Accordingly, NXP respectfully offers these exceptions to the IHE's Report.

II. REVENUE REQUIREMENT

A. Cash Flow Methodology

NXP disagrees with the IHE's recommendation to include depreciation and amortization ("D&A") in the Operations and Maintenance expense component of AE's revenue requirement.[1] As stated in NXP's post-hearing brief, the D&A expense is not reflected in AE's rates, is not a source of cash, and does not affect cash flow; therefore, it should not be included in the calculation of a cash flow return.[2] Including the D&A expense in AE's rate of return leads to a significant understatement of the true rate of return that AE is requesting, and which will be imbedded in AE's proposed rates.[3] It is this confused representation of implied return on rate base that concerns NXP because the City Council should see the true amount of cash that AE is requesting above that needed to fund ongoing non-capital operations.[4] This remains the case *even if* removing D&A from the cash flow method calculation does not change the overall revenue requirement.

At the Hearing, NXP referenced two non-investor-owned utility ("IOU") Transmission Cost of Service ("TCOS") Rate Filing Packages ("RFP") demonstrating a cash flow methodology

[1] Impartial Hearing Examiner's Final Recommendation at 10 (Sept. 9, 2022) ("IHE Report").
[2] NXP Semiconductors, Inc.'s Post Hearing Brief at 6 (July 28, 2022) ("NXP Brief").
[3] *Id.; see also* NXP Ex. 1 at 53.
[4] NXP Brief at 8 and NXP Ex. 1 at 54.

calculation similar to NXP's proposal wherein D&A is excluded.[5] These examples controverted AE's claims that AE's approach to the cash flow methodology calculation "is consistent with every non-investor owned utility transmission rate filing at the Commission that has utilized the cash flow approach."[6] Of the two examples, AE only argued against one – the Brownsville Public Utilities Board ("BPUB") TCOS RFP. AE claimed in its brief, with no citation to any record evidence, that the BPUB approach excluding D&A is "not a common way to file such a request and it makes the resulting fallout rate of return incomparable with other non-investor owned utilities."[7] The IHE Report recommends use of the cash flow methodology including D&A, stating that "AE's approach is consistent with non-investor owned utility TCOS rate filings at the Commission, including – as noted by AE – AE's last full TCOS case."[8] NXP disagrees with this recommendation for the reasons stated herein and in its direct case and Post-Hearing Brief. Contrary to AE's suggestion, NXP asserts that (1) AE's practice of including D&A in the cash flow methodology calculation is not consistent with *every* other non-IOU TCOS RFP; (2) this proceeding is not a non-IOU TCOS case and therefore the one-to-one comparison is not appropriate regardless; and (3) the imputed rate of return does matter and that AE's proposed cash flow methodology approach inappropriately skews this figure.

1. Internally-Generated Funds for Construction ("IGFC" or "IGFFC")

NXP disagrees with the IHE's recommendation to set AE's IGFC level to 50%, and additionally disagrees that AE is obligated to do so as a result of the City Council's directive to prospectively implement a "policy" of 50% funding for IGFC.[9] AE Financial Policy No. 14 states that capital projects should be financed through a combination of cash and debt with an equity contribution ratio between 35% and 60% being desirable.[10] NXP's recommendation to set AE's IGFC level at a 35% target is not only consistent with this policy, but is also more consistent with AE's actual, historical debt funding ratio when contributions in aid of construction ("CIACs") are properly included.[11]

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[5] NXP Brief at 6 and NXP Ex. 6 and 7; *see also* Tr. 68:6-22 (Rabon Cross) (July 15, 2022).
[6] Austin Energy's Closing Brief at 10 (Aug. 9, 2022) ("AE Brief").
[7] *Id.*
[8] IHE Report at 10.
[9] IHE Report at 28.
[10] IHE Report at 27; AE Ex. 1 at 21.
[11] NXP Brief at 9; NXP Ex. 1 at 55-56; TIEC Ex. 3 at 14.

AE claims, and the IHE acknowledges, that AE must also consider Financial Policy No. 6, which sets an objective to maintain AE's credit rating.[12] AE asserts that Fitch recently downgraded AE's credit rating to 'AA-,' citing elevated leverage and weaker operating cash flows primarily driven by lower base rate revenues that contributed to the utility's rising leverage.[13] Therefore AE concludes that NXP's recommended 35% IGFC would result in greater levels of debt, putting AE at risk of additional downgrades in contravention of Financial Policy No. 6.[14] The IHE Report re-states AE's claim that adoption of NXP's recommendation "would result in greater levels of debt and put AE at risk for additional downgrades."[15] While it is not clear whether the IHE explicitly agrees with AE's argument or was simply presenting AE's argument, NXP finds it prudent to point out that the IHE Report contains no independent analysis of this issue. Moreover, the IHE Report fails to acknowledge that during the Hearing, AE confirmed it *did not perform a calculation* to determine the IFGC percentage level at which AE would cross over and be out of compliance with Financial Policy No. 6.[16] Therefore AE has not demonstrated that adopting a 35% IGFC would result in the level of debt necessary to further decrease its credit rating.

AE also claims, and the IHE acknowledges, that the City Council "instructed" AE to target a 50/50 debt to equity ratio as part of its 2012 base rate case.[17] The IHE improperly concludes on this basis that "[i]f the City Council has instructed AE to implement 50% funding for IGFFC, then AE is obligated to do so."[18] It would seem AE is not so obligated given the fact that AE has failed to meet this objective over the past three years (2019, 2020, and 20201) as NXP highlighted in its post-hearing brief.[19] 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 IGFC when AE has an *actual* financial policy that sets a range for the IGFC *and* where AE's actual, historical debt funding ratio falls within this policy. Therefore, NXP asserts that the City Council should adopt NXP's proposed 35% IGFC.

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[12] IHE Report at 9.
[13] AE Brief at 19; AE Ex. 3 at 6.
[14] *See* AE Brief at 20.
[15] IHE Report at 27.
[16] NXP Brief at 10.
[17] IHE Report at 27-27; AE Brief at 19; *See also* City of Austin Ordinance No. 20120607-055, Part 7 (Jun. 7, 2012).
[18] IHE Report at 28.
[19] NXP Brief at 10; Tr. 70:12-20 (Rabon Cross) (July 15, 2022).

2. General Fund Transfer ("GFT")

NXP agrees with the IHE's recommendation to set GFT based on the test-year GFT of $114 million, or at most, the $115 million estimate that AE used for FY 2023.[20] Specifically, NXP agrees that setting a GFT at this amount is more consistent with AE's financial policies than AE's proposed GFT of $120 million with respect to being a known and measurable adjustment of the test-year GFT to align the GFT with the proposed base rates to be in effect for at least five years.[21]

3. Pass-Through Items

NXP disagrees with the IHE's recommendation that service area streetlighting costs attributable to the City of Austin should continue to be recovered through the Community Benefit Charge ("CBC") on the basis that the City Council has already addressed this issue as a matter of policy.[22] The IHE relies on AE's assertion that the City Council considered this issue in the 2012 Base Rate Review and "determined that street lighting within the City provides numerous benefits to the community, including increased public safety for drivers, riders, and pedestrians. Accordingly, City Council determined that it is appropriate to collect the costs of street lighting service from all customers through the CBC."[23] However, apart from the fact that street lighting is included in the 2012 CBC rate schedule, AE's claims about public policy are unsupported as AE has provided no reference to record evidence to support this assertion. The 2012 Ordinance setting AE's rates makes no reference to the street lighting component of the CBC, and the only narrative reference to street lighting in the CBC schedule itself is as follows: "Service Area Lighting (SAL) recovers the cost of street lighting (other than lighting maintained by TxDOT) and the operation of traffic signals throughout the entire Austin Energy Service Area."[24] AE's argument that the decision to include street lighting costs in the CBC as a forgone matter of policy is hardly apparently in this narrow language.

Additionally, as demonstrated in NXP's post-hearing brief, AE is proposing a meaningful increase in the cost of serving area street lighting as part of this proceeding.[25] Under the current

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[20] IHE Report at 28.
[21] IHE Report at 33-34.
[22] IHE Report at 46.
[23] *Id.*
[24] NXP Ex. 3 at 42.
[25] NXP Brief at 14; Tr. 65:14-21 (Rabon Cross) (July 15, 2022).

practice of charging these costs as part of the CBC, these increased costs will be recovered from AE's customers – many of whom will be experiencing a significant increase in customer class-specific rates as a result of this proceeding in the first place. NXP continues to recommend that AE 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.[26] 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. Despite the IHE's recommendation on this issue, removing street lighting service costs from the CBC is a change to AE's tariff that can and should be approved by the City Council.[27]

B. Present Revenues and Billing Determinants

NXP agrees with the IHE's recommendation that AE should better explain its assertion that Winter Storm Uri had no impact on test-year sales, revenues, and billing determinants before the revenue requirement is set; however, NXP disagrees with the IHE that in the absence of additional documentation, AE has provided sufficient evidence that sales were weather-normalized.[28] As discussed in the IHE's Report, AE was asked in discovery to produce a copy of its analysis of Winter Storm Uri's impacts on test-year sales and base rate revenues.[29] In response, AE indicated "No responsive document exists. There was no impact on Austin Energy's test year energy sales and base revenues from Winter Storm Uri. Energy sales are weather normalized and current rates are applied to the weather normalized sales to calculate test year revenues."[30] NXP therefore agrees with the IHE that it is unclear from this response how AE took Winter Storm Uri into account.[31]

Moreover, NXP witness James Daniel testified during the Hearing that as even as a high load factor customer (considered by AE to be in a nonweather-sensitive class) Winter Storm Uri *did have impacts* on NXP's demands during the weather event.[32] Unfortunately, it was not possible

[26] NXP Brief at 14; Tr. 53:28-40 (Daniel Cross) (July 14, 2022); AE Ex. 6 at 20.
[27] Tr. 53:40-44 and 54:4-10 (Daniel Cross) (July 14, 2022).
[28] IHE Report at 49.
[29] *Id.*
[30] *Id.*; AE Response to TIEC RFI 3-5 (June 6, 2022).
[31] IHE Report at 49.
[32] NXP Brief at 15; Tr. 54:4-15 (Daniel Cross) (July 14, 2022).

for Mr. Daniel to determine the full extent of the storm's impact on billable demands or demand revenues for the entire high-factor load class because AE did not provide the information.[33] NXP shares TIEC's concern that AE's use of billing determinants that have not been appropriately adjusted for Winter Storm Uri impacts could result in rates that over-recover AE's costs when those rates are applied to future billing determinants.[34] NXP recommends that AE be required to produce data that demonstrates its Winter Storm Uri adjustments to present revenues and billing determinants for the test year to demonstrate that the weather event had no impact.

III. COST ALLOCATION

A. Classification

1. A&G Expense and Indirect Costs

NXP agrees with the IHE's Report that AE's classification of expenses in FERC Accounts 920 and 930 is reasonable and should be adopted as previously explained in NXP's post-hearing brief.[35]

B. Class Allocation

1. Demand-Related Costs

a. Production-Demand

While NXP agrees with the IHE's recommendation to reject the Independent Consumer Advocate's ("ICA") Base-Intermediate-Peak ("BIP") production demand cost allocation methodology, NXP disagrees with adopting AE's proposed 12 coincident peak ("12CP") method.[36] Instead, NXP restates its prior recommendation for the City Council to adopt an Average and Excess 4CP methodology ("A&E 4CP") as also supported by TIEC in this proceeding.

The IHE acknowledges that production-demand related costs are those associated with building and maintaining AE's generation fleet or contracting for outside generation capacity, and that the methodology used to allocate production-demand costs should reflect each customer class's contributions to AE's need for additional production capacity.[37] The A&E 4CP

[33] *Id.*
[34] NXP Brief at 16; TIEC Ex. 1 at 7-8, 12; IHE Report at 47.
[35] NXP Brief at 17-18.
[36] IHE Report at 66.
[37] IHE Report at 65, citing TIEC Ex. 1 at 22.

methodology best serves this purpose. 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.[38] For AE, the use of the four summer month CP demands reflects the importance of AE's summer peaking system.[39] 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).[40]

AE has acknowledged 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.[41] 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).[42] 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.[43] 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.[44]

Additionally, AE buys power from the ERCOT market at the market price on a sub-hourly basis to serve load.[45] 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

[38] NXP Ex. 1 at 18.
[39] *Id.*
[40] *Id.*
[41] AE Ex. 8 at 11.
[42] *Id.*
[43] NXP Ex. 1 at 20.
[44] NXP Ex. 1 at 20.
[45] AE Ex. 8 at 10.

fleet).[46] 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 ("SCED").[47]

As demonstrated by Graph 3 of NXP's direct testimony,[48] with the exception of the outlier February Winter Storm Uri event, AE's peak output during 2021 occurred in the four 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.[49] AE has 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.[50] The IHE Report acknowledges that TIEC and NXP have demonstrated that AE is a summer-peaking utility in terms of demand.[51] NXP continues to maintain that 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.[52]

Moreover, NXP has demonstrated that AE's own planning documents reflect an emphasis on peak demand in "maintaining" its fleet – a clear production demand cost. As disused in NXP's post-hearing brief, on March 5, 2020, Austin's Electric Commission's 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.[53] 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" (emphasis added).[54]

The IHE incorrectly accepts AE's focus on peak wholesale prices throughout the year (rather than demand) and its assertion that even if demand normally peaks during the four summer

[46] *See id*.
[47] NXP Ex. 1 at 22.
[48] Originated in NXP Ex. 1 at 23 and reproduced in AE Ex. 8 at 12.
[49] NXP Ex. 1 at 22.
[50] Tr. 71:46-72:3 (Burnham Cross) (July 15, 2022).
[51] IHE Report at 77.
[52] NXP Ex. 1 at 22-23.
[53] NXP Brief at 24.
[54] *Id.*

months in a given year, non-summer wholesale prices in ERCOT may approach and could even exceed summer wholesale prices.[55] As stated in the IHE Report:

> "While TIEC and NXP offered evidence that market prices are consistently higher in the highest demand summer months, this is not always the case. It is possible that market prices during a high-demand winter storm could rival or even exceed prices during the summer. This could be due to circumstances such as less generation online, fuel scarcity, or other issues. As a result, the hedging value provided to customers by AE's generation portfolio over a greater percentage of peak hours is a reasonable and equitable approach to the allocation of production demand costs."[56]

Respectfully, NXP asserts that this argument is flawed and inconsistent with a standard ratemaking principle favoring cost-causation. The IHE concedes that record evidence demonstrates that costs and hedging benefits are driven in large part during the 4CP high demand summer months, with TIEC Witness Pollock providing an exhibit showing ERCOT's highest cost intervals *are aligned* with the highest demand periods in the summer.[57] Despite this routine and historical demonstration of high costs corresponding with peak demand months, the IHE inexplicably gives greater weight to AE's argument that in every year, *some* winter months *may* see demand rivalling summer months, pointing specifically to 2021 wherein January demand was "fairly high" relative to summer months, and pointing to the outlier Winter Storm Uri event.[58] The *possibility* that demand and/or pricing *might occasionally* spike outside of the high demand summer months should not be a basis on which to establish a production cost allocation methodology – particularly where a historical trend reflects that both demand (on AE's system and the ERCOT system) and wholesale prices routinely peak in the summer months and where AE's own planning documents put an emphasis on preparing for operation in those summer months.

NXP also highlights that the City Council previously directed AE to implement an A&E 4CP production-demand cost allocation methodology as part of the 2012 AE base rate review.[59] Part 6 of the 2012 Ordinance adopting AE's rates specifically states "the Council adopts as policy the use of the A&E 4CP methodology to allocate production demand costs among customer rate

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[55] IHE Report at 67.
[56] IHE Report at 77.
[57] *Id.*
[58] IHE Report at 77-78.
[59] NXP Brief at 26.

classes."[60] As mentioned in NXP's post-hearing brief, AE was not able to testify during the hearing that this Ordinance was ever repealed.[61] If this is true, it remains to be seen why AE asserts it is required to implement Part 7 of this same ordinance which sets a long-term policy of maintaining a 50/50 debt-to-equity ratio while at the same time proposing a production cost allocation methodology other than A&E 4CP as required in Part 6 of the same Ordinance. AE cannot be allowed to simply pick and choose the sections of a City Council Ordinance with which it must comply.

Finally, NXP notes that the IHE failed to acknowledge that apart from AE's own history of approving an A&E 4CP production cost allocation methodology, there is also history of other municipally-owned utilities ("MOU") that are similarly situated to AE utilizing this methodology. NXP previously provided the example of CPS Energy – a substantially similar system to AE, which is 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).[62] 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.[63] It is unknown whether the IHE failed to consider this example as in his analysis or if he considered it and rejected it as being unpersuasive.

b. Distribution Demand

NXP disagrees with the IHE's recommendation that AE's 12 NCP allocator be adopted for distribution demand costs rather than NXP's and TIEC's recommended 1NCP methodology.[64] Interestingly, the IHE states that he "does not deny that a 1NCP methodology has been found reasonable for allocating distribution demand costs. However, the IHE finds more compelling the fact that other MOUs in Texas, such as Bryan Texas Utilities and Greenville Electric Utilities, use a 12NCP method to allocate distribution costs."[65] This fails to consider that NXP provided an

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[60] NXP Ex. 1 at 28; NXP Ex. 3.
[61] See Tr. 73:8-13 (Burnham Cross) (July 15, 2022).
[62] NXP Brief at 26.
[63] *Id.* citing NXP Ex. 2 at 9 and 53 (slide 13).
[64] IHE Report at 81.
[65] *Id.*

example of an MOU in Texas that utilizes the 1NCP method – CPS Energy.[66] The IHE is also mistaken in basing his recommendation on AE's claim that a 1NCP allocation methodology might allow certain rate classes to avoid a portion of distribution demand related costs by shifting demand during NCP periods.[67] As NXP stated in its post-hearing brief, AE's concern is ill-founded and fails to consider that the 1NCP methodology actually solves a "free rider" dilemma.[68] 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.[69] Therefore, AE's concern is unfounded.

The IHE is correct in that NXP's position is that 1NCP better tracks cost because AE builds its distribution system to have sufficient capacity to reliably serve its customers at the time of maximum demand.[70] However, the IHE ignores the cost component of this argument in stating that building a distribution system to meet peak demand is a reliability measure that is not determinative of cost allocation methods.[71] In reality, 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. Accordingly, the IHE's conclusion on this issue is inconsistent with AE's own RFP, which states:

> "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).[72]

Additionally, the IHE fails to consider that AE has acknowledged its use of peak demands (and not average 12 NCP demands) in its planning process for new distribution facilities.[73] In discovery, AE provided a document titled "Distribution Planning Criteria," which states that "distribution capacity studies assume summer peak conditions to determine substation peak

[66] NXP Brief at 35.
[67] IHE Report at 82.
[68] NXP Brief at 34.
[69] *Id.*
[70] IHE Report at 80.
[71] *Id.*
[72] NXP Brief at 33, citing AE Ex. 1 at 57.
[73] NXP Brief at 33, citing NXP Ex. 1 at 30.

loading.[74] This further supports the use of a 1NCP allocation methodology for distribution demand costs.

c. Primary Distribution Demand-Related Costs

NXP agrees with the IHE's recommendation that a separate substation rate be developed for Primary Substation customers, as the existing three Primary Substation customers (including NXP) are directly connected to AE distribution substations through dedicated radial feeders that serve no other customers.[75] NXP further agrees with the IHE that cost-causation principles dictate that Primary Substation customers should only bear the cost of the radial distribution feeders used to serve them, and should not bear cost responsibility for the full distribution network which they do not use.[76] While NXP agrees that AE should work with industrial customers to develop this rate class, NXP urges the City Council to require AE to develop the class and to transition customers within 12 months of a final order being issued in this proceeding. Impacted customers, potential customers, and AE will all benefit from the certainty afforded by this deadline for implementation.

2. Customer-Related Costs

a. Meter Cost Allocation

NXP agrees with the IHE's recommendation to adopt AE's customer-weighted cost allocation for meter expenses. NXP reiterates its position that this method is reasonable and consistent with that of all major utilities in Texas, which allocate 100 percent of meter costs using a weighted meter cost allocation.[77]

b. FERC Accounts 911 Through 917

NXP agrees with the IHE's recommendation to adopt AE's proposal to allocate customer service expenses in FERC Accounts 911 through 917 on the basis of the number of customers in each customer class.[78] This recommendation is consistent with NXP's proposal outlined in its post-hearing brief.[79]

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[74] NXP Brief at 33, citing NXP Ex. 1 at 89.
[75] IHE Report at 85-86.
[76] *See* IHE Report at 86.
[77] NXP Brief at 36.
[78] IHE Report at 89.
[79] NXP Brief at 37.

c. Energy and Demand Line Loss Factors

NXP appreciates the IHE's recommendation that AE, NXP, and TIEC revisit this issue to determine whether demand losses for CP cost allocation can be appropriately developed.[80] The IHE recognizes that all three parties agree that demand losses should be utilized to adjust load, but that AE claims it does not have a demand loss measured for each peak hour of the month applicable to the 12CP cost allocation.[81] To prevent this issue from occurring again the future, NXP respectfully reiterates its request that AE be ordered to develop and use demand loss factors in future base rate reviews.[82]

3. Cost Allocation Summary

NXP disagrees with the IHE's decision to largely adopt AE's class allocation proposals as discussed herein. NXP further disagrees that AE's allocated cost of service ("COS") Study and recommendations above are consistent with cost-causation principles.[83] The following AE recommendations supported by the IHE's report should be rejected as follows: 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. 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.

C. Cost of Service Results

NXP restates its position herein that 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 in its post-hearing brief.[84]

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[80] IHE Report at 93.
[81] *Id.*
[82] NXP Brief at 39.
[83] IHE Report at 93.
[84] NXP Brief at 39.

D. Cost Allocation Conclusions

NXP disagrees with the IHE's recommendation that AE's cost allocation proposals should be adopted. AE's current base rate revenues are significantly under-recovering the cost to serve the residential class, the transmission class, and the lighting classes (apart from service area street lighting). 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. Moreover, NXP does not support AE's requested revenue requirement as described above.

IV. CLASS REVENUE DISTRIBUTION

NXP appreciates the IHE's recognition that revenues should, subject to the rate design adopted and gradualism concerns, be set as close to cost as possible.[85] NXP also appreciates (and agrees with) the IHE's conclusion that NXP's revenue distribution would likely result in the common goal of all classes moving closer to cost.[86] NXP disagrees, however, that NXP has not adequately demonstrated that AE's "halfway to cost" distribution methodology is unreasonable, unjust, or discriminatory.[87] NXP takes exception to the IHE's recommendation that AE's methodology be adopted.

As stated in NXP's post-hearing brief, 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.[88] As NXP Witness Mr. Daniel has explained, step one of AE's proposal (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."[89] For example, the Secondary Voltage Greater Than 300 kw customer class's current revenues are already above the class's cost of service.[90] By increasing the class's current revenues by the overall percent revenue increase needed of 7.6%,

[85] IHE Report at 98.
[86] *Id.*
[87] *Id.*
[88] NXP Brief at 40.
[89] NXP Ex. 1 at 42.
[90] NXP Brief at 41.

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%. The IHE wrongly dismisses this issue by saying that the first step is an intermediate step and not the ultimate outcome – which undoubtedly moves all classes closer to cost of service.[91] AE has not provided any legitimate basis for this "first step," and in fact, Mr. Daniel's testimony is that he has never seen this step used by any other utility.[92] AE's only explanation is that such a "standard" for this and future rate decisions, it will eliminate "disputes."[93] It is telling that imparting such a standard is not a recognized ratemaking principle which any other party in this case has supported, or even acknowledged. Notably, not even the IHE advanced this argument in recommending adoption of AE's methodology.

Mr. Daniel proposes a more effective and straightforward allocation methodology as described in the IHE Report and in NXP's post-hearing brief. This methodology represents a more equitable treatment of all the class revenue distribution issues than that proposed by AE and should therefore be adopted.

V. RATE DESIGN

A. Primary Substation Rate

NXP reiterates its support for the IHE's recommendation that AE develop a primary substation rate and its recommendation that AE have an implementation deadline of 12 months from completion of this case.

VI. CONCLUSION

NXP appreciates the significant time and effort that the IHE and the parties have invested in this proceeding. NXP respectfully requests that its recommendations contained herein are given fair consideration and are ultimately adopted in the interest of a fair resolution of this case. NXP offers that its recommendations are consistent with standard well-established ratemaking principles including cost causation and gradualism, as appropriate.

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[91] IHE Report at 98.
[92] NXP Ex. 1 at 42.
[93] NXP Brief at 42, citing AE Ex. 9 at 15.

Respectfully submitted,

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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 26th day of September, 2022

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J. Christopher Hughes