C. Depreciation and Amortization Expense [PO Issue 25]

TCUC recommends a $34.6 million reduction to the Company's proposed depreciation expense[727] based on what it claims are "errors" in CEHE witness Dane A. Watson's analysis. However, as explained in his direct testimony, Mr. Watson utilized the same depreciation methodology and practices that he has been using to recommend depreciation rates for Texas electric utilities over the last 30 years.[728] What TCUC calls "errors" are established practices long-recognized by Mr. Watson, by this Commission and by the learned treatises and authoritative texts regularly relied on by depreciation experts.[729]

1. Study Methodology

The suggestion that CEHE has failed to "meet its burden" to prove the reasonableness of its depreciation rates rings hollow. The Company filed hundreds of pages of testimony, studies, analyses, workpapers and schedules *specifically* explaining the basis for the changes in its depreciation rates, many of which resulted in reduction to the currently existing service lives or net salvage rates.[730] Mr. Watson thoroughly addresses in his rebuttal testimony his depreciation methodology and his concerns about TCUC witness Mr. Garrett's approach.[731] Commission Staff in fact was able to rely on the information produced in the Company's direct case to perform its own entirely separate analysis.[732]

The Company's initial brief further explains that Mr. Garrett's recommended life curves are derived from an arbitrary and unsound methodology that disregards Mr. Watson's simulated plant record ("SPR") and actuarial analysis and the Company-specific plant data, operations and asset experience upon which Mr. Watson's recommendations are based.[733] Moreover, Mr. Garrett's novel approach of relying on the service lives approved for *other* utilities (two of which

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[727] To be clear, the Company's total proposed depreciation and amortization expense based on test year plant balances is approximately $378 million, which represents an overall increase of approximately $2.5 million compared to the Company's depreciation and amortization expense included in existing rates. CEHE Ex. 2 at 313-316, Schedule II-E-1 & 1478-1479, WP/II-E-1 Adj 1 & 1480, WP/II-E-1 Adj 1a. Commission Staff's Initial Brief reference a depreciation expense amount of $366 million, which is the total accrual based on the plant balances used in the study periods relied on by Mr. Watson. TCUC references a depreciation expense in the amount of approximately $325 million, which is the total accrual based on the plant balances used in the study periods relied on by Mr. Watson, excluding the amortization expense associated with intangible plant.

[728] Direct Testimony of Dane A. Watson, CEHE Ex. 25 at 2449-2451 (Bates Pages); Rebuttal Testimony of Dane A. Watson, CEHE Ex. 41 at 8-26 (Bates Pages).

[729] CEHE Ex. 25 at 2449-2451 (Watson Direct); CEHE Ex. 41 at 8-26 (Watson Rebuttal).

[730] *See generally* Mr. Watson's direct testimony, exhibits and workpapers (CEHE Ex. 25) and his rebuttal testimony, exhibits and workpapers (CEHE Ex. 41).

[731] CEHE Ex. 41 at 8-22 (Watson Rebuttal).

[732] Direct Testimony of Reginald Tuvilla, Staff Ex. 9 at 6; Staff Initial Brief at 44.

[733] *See* CEHE Initial Brief at 100-102 and footnotes cited therein.

are from Oklahoma) should only be applied in extraordinary circumstances, such as when a utility lacks *any* plant data for its assets.[734] Furthermore, Mr. Garrett does not explain how these utilities assets or operations are comparable to CenterPoint Houston's or provide *any* of the evidence relied on by other commissions to approve the other utilities' service lives.[735] His approach also represents a significant departure from well-established depreciation practices and the depreciation methodologies relied on by this Commission in prior cases.[736]

With regard to the integrity of Mr. Watson's SPR analysis and supporting data, TCUC continues to question the use of SPR analysis to set depreciation rates. Contrary to TCUC's assertions, SPR data is reliable and, as recognized by both Mr. Watson[737] and Staff witness Reginald Tuvilla[738] at the hearing, is regularly utilized by depreciation experts and produces results that can be as accurate and reliable as those using actuarial analysis. In fact, CEHE has been using the SPR analyses and underlying data since at least 1985.[739] Moreover, the implication advanced at the hearing on the merits that somehow Company personnel could not be relied on to provide objective engineering information to inform Mr. Watson's SPR analysis was thoroughly debunked at the hearing. Mr. Watson specifically rebutted this assertion and explained that he was not aware of Company personnel ever fabricating information to manipulate service lives and that he validates the integrity of all information he includes in his study.[740]

Notably, Staff witness Mr. Tuvilla not only recognized that Mr. Watson's study methodology and reliance on Company-specific data is appropriate but also, after conducting his own SPR and actuarial analysis, confirmed that *no changes* were necessary to Mr. Watson's service lives, net salvage rates, or resulting depreciation rates.[741]

2. Specific Service Life Recommendations

With regard to the specific life recommendations, the Company summarizes its support for its proposed life curves below, though Mr. Watson's rebuttal testimony provides a more detailed discussion.

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[734] CEHE Ex. 41 at 10 & 16-17 (Watson Rebuttal); *see* Tr. at 841 (Tuvilla Cross) (Jun. 26, 2019) (explaining that using other utilities' approved service lives would be more appropriate "if a company has never had that type of plant before, like a wind facility or a battery, you have to start somewhere, ...").
[735] CEHE Initial Brief at 100-102; CEHE Ex. 41 at 15-20 (Watson Rebuttal).
[736] CEHE Ex. 41 at 15-20 (Watson Rebuttal).
[737] Tr. at 325, 329, 342-345 & 349-353 (Watson Cross) (Jun. 25, 2019).
[738] Tr. at 838-839 (Tuvilla Cross) (Jun. 26, 2019).
[739] CEHE Ex. 41 at 4 (Watson Rebuttal).
[740] Tr. at 342-345 & 349-353 (Watson Cross) (Jun. 25, 2019).
[741] Direct Testimony of Reginald Tuvilla, Staff Ex. 9 at 6; Staff Initial Brief at 44.

Account	CEHE	TCUC	
390 (Actuarial)	50 R4	58 R2	• This account includes building structures and improvements, both large and small; Mr. Garrett ignores life expectations for shorter-lived assets in this account like HVAC, chillers, roofs, fencing, water systems, lighting systems, elevators, fire protection systems, and other capitalized assets that will likely be replaced prior to the building shell.[742] • This is further demonstrated in Mr. Garrett's exclusion of a significant portion of the actuarial life curve, ignoring all assets that are older than 50 years old.[743] He also inappropriately limits his analysis to a single band.[744] • Mr. Garrett relies entirely on mathematical curve fitting despite recommendations by depreciation authorities to use both mathematical and visual curve fitting in actuarial analysis.[745]
353 (SPR)	53 R0.5	56 R0.5	• Mr. Garrett dismisses the Company-specific SPR analysis as unreliable despite the fact that 30-year and 40-year bands exhibit good and excellent Conformance Index ("CI") results.[746] Even if the account had consistently low CI results, it would indicate a need to rely *more*, not less, on information about the Company's specific plant assets, which Mr. Garrett also ignores.[747] • This account has recently been incorporating more electronics and newer style breakers that have a shorter expected life.[748] • Mr. Garrett did not explain why his life expectations, which exceed the demonstrations of the SPR analysis, are operationally justified, choosing instead to rely on service lives approved for SWEPCO and OG&E, without any evidence to support those comparisons.[749]
354 (SPR)	59 R2.5	66 R2	• Mr. Garrett ignores the high CI and Retirement Experience Index ("REI") results from Mr. Watson's recommendation and instead relies on the approved service life of a single Oklahoma utility to increase the average service life for this account, without any evidence to support the

742 CEHE Ex. 41 at 56 (Watson Rebuttal).
743 *Id.* at 51-52.
744 *Id.* at 53-55.
745 *Id.* at 53-54.
746 *Id.* at 27-28.
747 *Id.*
748 CEHE Ex. 25 at 2489-2490, Exh. DAW-1 (Watson Direct); CEHE Ex. 41 at 28 (Watson Rebuttal).
749 CEHE Ex. 41 at 28-29 (Watson Rebuttal).

Account	CEHE	TCUC	
			comparisons.[750] He also fails to justify the low REI results from his recommendation.[751] • Mr. Garrett ignores plant characteristics and recent experience that suggest a shorter service life for this account, including electrical capacity upgrades, the impacts of chemical reactions and higher loading on foundations, and the fact that CEHE will replace all or a portion of the structure when having to replace the foundations.[752]
362 (SPR)	48 R1	55 R0.5	• Mr. Watson's proposed curve and life produce CI's that are in the good or excellent range with an REI close to 100 and in every band are higher than Mr. Garrett's.[753] • Company interviews indicate plans to replace switchboard panels and move to a higher level of electronics in substations, which may limit asset life today and in the future.[754] • Many of the same factors affecting transmission substations are affecting distribution substations, but distribution substations tend to have shorter lives, as reflected in Mr. Watson's recommendation (53 years vs. 48 years for Account 353).[755] Mr. Garrett recommends a *longer* service life for this account compared to Account 353 (56 vs. 55 years).[756]
364 (SPR)	35 R0.5	45 R0.5	• There is no operational reason the life should increase by 10 years (nearly 30 percent) as Mr. Garrett proposes. • CEHE uses wood poles in this account, which are being impacted by high water tables, high acidity levels in the soil, other coastal conditions and high humidity. Also, materials used for newer poles are shortening the lives, and more pole contacts and more frequent inspections result in more replacements, causing a decreasing service life.[757] • The low CI results in this account are indicative of these changing life characteristics,[758] not "unreliable" data. • Mr. Garrett's proposed curve produces a lower CI and REI than Mr. Watson's.[759]

[750] TCUC Ex. 2 at 24 (Garrett Direct).
[751] *Id.*
[752] CEHE Ex. 41 at 31 (Watson Rebuttal); CEHE Ex. 25 at 2491, Exh. DAW-1 (Watson Direct).
[753] CEHE Ex. 41 at 33 (Watson Rebuttal).
[754] *Id.* at 33-34; CEHE Ex. 25 at 2503, Exh. DAW-1 (Watson Direct).
[755] CEHE Ex. 41 at 33 (Watson Rebuttal); CEHE Ex. 25 at 2503, Exh. DAW-1 (Watson Direct). For example, distribution-level assets see more fault current than transmission and will, consequently, have a shorter life. CEHE Ex. 25 at 2503, Exh. DAW-1 (Watson Direct).
[756] CEHE Ex. 41 at 33 (Watson Rebuttal).
[757] *Id.* at 36.
[758] *Id.* at 35-36.
[759] *Id.* at 36.

Account	CEHE	TCUC	
365 (SPR)	38 R0.5	40 R0.5	• Mr. Watson's proposed curve produces the highest CI and REI results.[760] • Low CI results indicate changing life characteristics of the assets in the account, not that the data is "unreliable."[761] • For instance, Company engineers estimate that the insulated wire now being used will allow current conductors to last approximately 40 years; however, lightning strikes, wind, automobile strikes to poles and environmental conditions have a dampening effect on the life, which Mr. Watson accounted for in his study.[762] • Also, the increasing level of electronic equipment in the account (such as sensors, motors and sectionalizing equipment with a much shorter life) is providing downward pressure on the service life.[763]
366 (SPR)	62 R2.5	65 S1	• While Company input and the SPR analysis indicate extending the service life for these assets as Mr. Watson proposes, they do not support extending the lives as much as Mr. Garrett recommends.[764] • Mr. Watson's proposed life produces a much higher CI and REI result than Mr. Garrett's.[765] • Mr. Garrett's dispersion curve anticipates assets in this account surviving to nearly age 130, which is unreasonable.[766] Mr. Watson's dispersions curve anticipates more realistic expectations.
367 (SPR)	38 R0.5	42 L0	• Underground conductor life is increasing due to newer conduit technology that better protects the cable. However, the Company's more recent shift in practice to direct burying cable will also shorten the cable life. Mr. Watson's recommendation reconciles these retirement forces.[767] • Mr. Garrett does not provide any information demonstrating whether his "peer group" utilities are subject to the same retirement forces and company practices (e.g., placing cable in conduit or direct burying).[768] • Mr. Garrett's dispersion curve anticipates assets surviving to nearly age 160, which is unreasonable.[769] Mr. Watson's dispersions curve anticipates more realistic expectations.

[760] *Id.* at 37-38.
[761] *Id.* at 38.
[762] *Id.* at 39.
[763] *Id.*; CEHE Ex. 25 at 2506, Exh. DAW-1 (Watson Direct).
[764] CEHE Ex. 41 at 42 (Watson Rebuttal).
[765] *Id.* at 41.
[766] *Id.* at 41-42.
[767] *Id.* at 45-46.
[768] *Id.* at 46.
[769] *Id.* at 44-45.

Account	CEHE	TCUC	
368 (SPR)	28 R1	32 L0	• The CI results for Mr. Watson's recommendations are significantly higher than Mr. Garrett's, [770] and Mr. Watson's dispersion curve reflects a more reasonable result for life expectation for this account.[771]

3. Reserve Re-allocation

Finally, Mr. Garrett's study contains a critical error because he failed to properly reallocate the depreciation reserve based on the changed service lives he recommends.[772] Accordingly, in addition to the errors in his methodology, his resulting depreciation rates are simply incorrect and cannot be relied on for purposes of making adjustments to the Company's rates.

D. Affiliate Expenses [PO Issue 35, 36]

As noted in the Company's Initial brief, no party challenged the evidence presented by the Company demonstrating that, with respect to affiliate expenses: (1) each class of items was reasonable and necessary; and (2) that the price charged to CEHE was not higher than the prices charged by Service Company and CERC to the Company's other affiliates or divisions or to a nonaffiliated person within the same market area or having the same market conditions.[773] Similarly, no party challenges the fact that a centralized corporate support services structure allows CNP to leverage resources across multiple business units, thereby giving the business units access to specialized skills and resources in an efficient and cost-effective manner.[774] Accordingly, the vast majority of the affiliate corporate support services charged to CEHE during the test-year and included in the Company's revenue requirement, which totaled $293.4 million, are unchallenged and CEHE has met its burden under PURA § 36.058 to recover its reasonable and necessary affiliate costs.[775] With respect to the limited Intervenor and Staff challenges addressed below, the evidence likewise demonstrates that CEHE has met its burden on all affiliate-related issues.

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[770] *Id.* at 47.
[771] *Id.* at 48-49.
[772] *Id.* at 55-56.
[773] PURA § 36.058(c).
[774] Direct Testimony of Michelle M. Townsend, CEHE Ex. 15 at 1074 (Bates Pages).
[775] CEHE Ex. 15 at 1067-1552 (Townsend Direct); CEHE Ex. 12 at 920-926 (Colvin Direct); CEHE Ex. 27 at 2862-2875 (McRae Direct); Direct Testimony of M. Shane Kimzey, CEHE Ex. 19 at 1668-1678 (Bates Pages); Direct Testimony of Kelly C. Gauger, CEHE Ex. 20 at 1695-1703 (Bates Pages); CEHE Ex. 13 at 993-996 (Pringle Direct); Direct Testimony of John E. Slanina, CEHE Ex. 16 at 1559-1571 (Bates Pages); CEHE Ex. 17 at 1582-1586 (James Direct); Direct Testimony of Rebecca Demarr, CEHE Ex. 18 at 1654 (Bates Pages); CEHE Ex. 22 at 1835-1839 (Harkel-Rumford Direct); and Direct Testimony of Diane M. Englet, CEHE Ex. 21 at 1711-1738 (Bates Pages).

1. Vectren Issues

OPUC continues to challenge the Company's proposed adjustment to normalize integration planning billings to reflect Service Company employee labor that would have been billed to CEHE if the integration planning for the Vectren transaction had not occurred.[776] Notably, OPUC does not challenge the reasonableness or necessity of Service Company costs during the test-year or dispute the fact that Service Company costs to CEHE were less than normal as a result of the Vectren integration planning.[777] Rather, OPUC simply continues to argue that the adjustment is not known and measurable.[778] The evidence, however, demonstrates otherwise. It is undisputed that the Company's adjustment was calculated based on CEHE's portion of total test year billings from the Service Company after removing the abnormal integration planning billings.[779] It is likewise undisputed that the amount of Service Company costs billed to Vectren integration activities was tracked in SAP by each employee's cost center and thus, is known and measurable.[780] In short, the adjustment reflects a reasonable and necessary increase of $1.6 million in affiliate billings to CEHE that should be adopted.

The Company addresses GCCC's continued request for a "Merger Savings Rider" related to the Vectren acquisition in Section IX.B. below.

2. Compensation for Use of Capital

OPUC and Staff also continue to propose an adjustment related to compensation for use of affiliate capital.[781] Specifically, OPUC proposes to exclude $7,786,463 from the Company's cost of service, while Staff asks the Commission to disallow $4,942,320 instead.[782] Again, neither OPUC nor Staff challenge the legitimacy of the payments—which are for carrying charges associated with affiliate or shared assets. OPUC and Staff also do not dispute that the Service Company assets at issue are: (1) used and useful and held for the benefit of the business units, including CEHE;[783] (2) the costs for these assets are no different than utility-owned assets for which an equity return is earned; (3) and the costs of these assets were prudently incurred.[784] Instead OPUC argues that the Company did not meet its affiliate burden under the statute and Staff

[776] OPUC Initial Brief at 53-54; CEHE Ex. 37 at 16 (Townsend Rebuttal).
[777] CEHE Ex. 37 at 16 (Townsend Rebuttal).
[778] OPUC Initial Brief at 53.
[779] CEHE Ex. 37 at 16-17 & Exh. R-MMT-2 (Townsend Rebuttal).
[780] CEHE Ex. 15 at 1112 (Townsend Direct).
[781] OPUC Initial Brief at 55-58; Staff Initial Brief at 47-48.
[782] OPUC Initial Brief at 55; Staff Initial Brief at 47.
[783] CEHE Ex. 37 at 13-14 (Townsend Rebuttal).
[784] *Id.* at 13.

argues that the equity portion of carrying charges on Service Company's assets should be disallowed.[785] Both arguments lack merit.

With respect to OPUC's argument, it is undisputed that the Company followed the Commission's Schedule V-K-7 RFP Instructions - which require CEHE to list services by class and service category.[786] It is likewise undisputed that Compensation for use of Capital is a return on investment applied to the Service Company assets.[787] It is not a class or service category. Rather, it is a cost associated with several of the classes and service categories.[788] Therefore, it is not separately identified on the V-K-7 schedule, but rather was included as part of the cost allocation amounts assigned to the Finance, Technology Operations, and Business Operations Services service class totals on that schedule.[789] In short, the evidence demonstrates that CEHE was not required to separately identify Compensation for use of Capital as an affiliate class or service, as OPUC alleges. The Shared Services amounts identified on V-K-7 are fully eligible for recovery in CEHE's rates and satisfy the applicable affiliate standard.

Staff's position, on the other hand, relies on Commission decisions in cases not involving CEHE, with different facts and different evidence.[790] In this proceeding, CEHE has shown that Service Company assets are used and useful and held for the benefit of the business units, including CEHE.[791] These assets include hardware assets such as Network Equipment, Telephone Infrastructure, and Enterprise Servers, as well as software assets for SAP upgrades, Microsoft enhancements and Filenet.[792] CEHE has also shown that costs Service Company incurs for these assets are no different than utility-owned assets for which an equity return is earned, and that the costs of these assets were prudently incurred.[793] Therefore, just as a return is earned on the assets held by CEHE, the assets held by Service Company for the benefit of CEHE should earn a return.[794] This is consistent with PURA § 36.051, which provides that:

> In establishing an electric utility's rates, the regulatory authority shall establish the utility's overall revenues at an amount that will permit the utility a reasonable opportunity to earn a reasonable return on the utility's invested capital used and

785 OPUC Initial Brief at 55 and Staff Initial Brief at 47.
786 CEHE Ex. 37 at 15 (Townsend Rebuttal).
787 *Id.*
788 *Id.*
789 *Id.*
790 Staff Initial Brief at 48.
791 CEHE Ex. 37 at 13-14 (Townsend Rebuttal).
792 *Id.* at 14.
793 *Id.* at 13.
794 *Id.*

useful in providing service to the public in excess of the utility's reasonable and necessary operating expenses.

In sum, it is undisputed that the use of shared resources for corporate support services is efficient and therefore provides a benefit to customers. The Company has met its burden with respect to demonstrating the reasonableness, necessity and recoverability of its Service Company Compensation for use of Capital. OPUC's and Staff's proposed adjustments should be denied.

3. Service Company Pension and Benefit Costs

Service Company pension and benefit costs are addressed in CEHE's reply brief at Section IV.B.4.

4. Affiliate Carrying Charges

This issue is addressed above in CEHE's reply brief at Section IV.D.2 (compensation for use of capital).

5. Affiliate Labor Expenses

The post-test year affiliate payroll adjustment is discussed in CEHE's reply brief at Section IV.B.3. Issues relating to payment and recovery of incentive compensation are addressed in CEHE's reply brief at Section IV.B.1.

E. Injuries and Damages

The Company's requested amount of injuries and damages expense of $20.528 million is based on actuarial reports that determine the level of expense that is likely to occur in 2019.[795] Only Staff challenges CEHE's request on this issue, and CEHE responded to arguments Staff raises in its initial brief about the proper level of injuries and damages expense.[796] It bears repeating, however, that Staff's reliance on the amount of injuries and damages expense incurred for the first three to four months of 2019 is misplaced. And, by taking that approach, Staff erroneously concludes that CEHE's requested level of injuries and damages expense is too high. However, because of the timing throughout the year of when injuries and damages expense is incurred, it is not reliable to focus on only three or four months of activity. Instead, as CEHE explained in rebuttal testimony, reviewing costs over a twelve-month period is necessary. For the twelve-month period ending April 2019, the injuries and damages expense is only $9,634 higher than the unadjusted test year amount.[797] In addition, both of these actual amounts for those full,

[795] CEHE Ex. 2 at 158, Schedule II-D-2.
[796] CEHE Initial Brief at 107; Staff Initial Brief at 48-49.
[797] CEHE Ex. 35 at WP R-KLC-04 (Colvin Rebuttal).

twelve-month periods are higher than the injuries and damages expense CEHE requests and higher than Staff's recommended amount. Thus, Staff's adjustment to the Company's injuries and damages expenses should be rejected.

F. Hurricane Harvey Restoration Costs [PO Issues 54, 55]

Hurricane Harvey Restoration Costs and the related regulatory asset are discussed in Section II.H.2.

G. Self-Insurance Reserve [PO Issues 16, 33]

The evidence presented in this case establishes that CEHE's proposed self-insurance reserve annual accrual of $7.685 million is a reasonable and necessary expense.[798] The annual accrual consists of $3.575 million to provide for average annual expected O&M losses from certain loss events, and $4.11 million over three years to achieve the target reserve of $6.55 million.[799] Not a single party challenged the reasonableness of the annual expected loss accrual or the target reserve.

While COH/HCC did not dispute the amounts for annual losses or the target reserve, it proposed a disallowance of $2,750,000 to CEHE's annual accrual for CEHE's target reserve to prevent CEHE from "overfunding" the reserve in the event that CEHE does not come back in for a rate case in four years.[800] Instead COH/HCC suggests that CEHE's accrual to rebuild the reserve should be $1.543 million, for a total annual accrual (for annual losses and target reserve) of $5.118 million.[801] COH/HCC's proposal makes several unreasonable assumptions. First, COH/HCC assumes that CEHE will not have another rate case for eight years, despite the change in Commission rules that requires utilities to file rate cases as often as every four years.[802] Further, COH/HCC assumes that during the supposed eight years until CEHE's next rate case, CEHE will not experience any significant losses that would impact its ability to reach the target reserve, thereby accumulating a reserve of over $20 million.[803] This assumption is demonstrably unreasonable given that in the eight years since CEHE's last rate case, it has been unable to build a reserve and in fact currently has a deficit of over $5 million.[804]

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[798] *See generally* Direct Testimony of Gregory S. Wilson, CEHE Ex. 28.
[799] *Id.* at 2894-2895.
[800] COH/HCC Initial Brief at 28.
[801] *Id.*
[802] 16 TAC § 25.247.
[803] COH/HCC Initial Brief at 29.
[804] CEHE Ex. 28 at 2902-2903 (Wilson Direct)

OPUC also argues for a longer accrual period (five years) to build a target reserve.[805] OPUC claims that the accrual period should strike a balance between moderating impact on customer rates and achieving intergenerational equity as it applies to CEHE's regulatory assets and liabilities.[806] CEHE recognizes this as a standard ratemaking principle, but OPUC's application of the principle in this instance is misplaced. OPUC's claimed intergenerational difference of CEHE customers from three years to five years is small and given that larger losses could occur at any time, including during the accrual period, there may not be any intergenerational difference between who pays for the reserve and who receives the benefit. In addition, OPUC's longer accrual period ignores the likelihood that CEHE will not reach the target reserve level depending on what loss events occur during that period. OPUC notes that CEHE's proposed accrual period from its last rate case was 10 years.[807] It is true that CEHE proposed a 10-year accrual period for a much larger target reserve ($13.38 million).[808] However, CEHE's experience since that time made clear that such a long accrual period was problematic. As previously noted, over the eight years since the final order in Docket No. 38339, CEHE's reserve accrual ultimately accumulated a *deficit* of over $5 million.[809]. Given that CEHE's loss experience since 2011 resulted in a substantial negative reserve balance despite an annual accrual of $1.13 million to build a target reserve,[810] an amount only slightly less than that proposed by COH/HCC ($1.543 million) and OPUC ($1.893 million), the Commission should approve the three year accrual period to allow CEHE to accumulate its target reserve in a reasonable time frame and ensure CEHE has sufficient resources to use for loss events.

While it is unlikely that CEHE would accumulate a reserve amount that will be substantially greater than the target, in the event that CEHE does have excess amounts in its reserve, any reserve dollars above the target would be used for loss events in accordance with the terms CEHE outlined in its Application. Commission Staff argues in its post-hearing brief that CEHE should not be permitted to convert self-insurance reserve accrual in excess of the target level to shareholder earnings.[811] CEHE agrees that it would not convert any funds attributed to

[805] OPUC Initial Brief at 61.
[806] *Id.*
[807] *Id.* at 62.
[808] Docket No. 38339, Order on Rehearing at Finding of Fact 91.
[809] CEHE Ex. 28 at 2895 (Wilson Direct).
[810] Docket No. 38339, PFD at 77 (Dec. 2, 2010).
[811] Staff Initial Brief at 49.

the reserve for shareholder earnings. Accordingly, CEHE's proposed self-insurance accrual amounts should be approved.

H. Vegetation Management

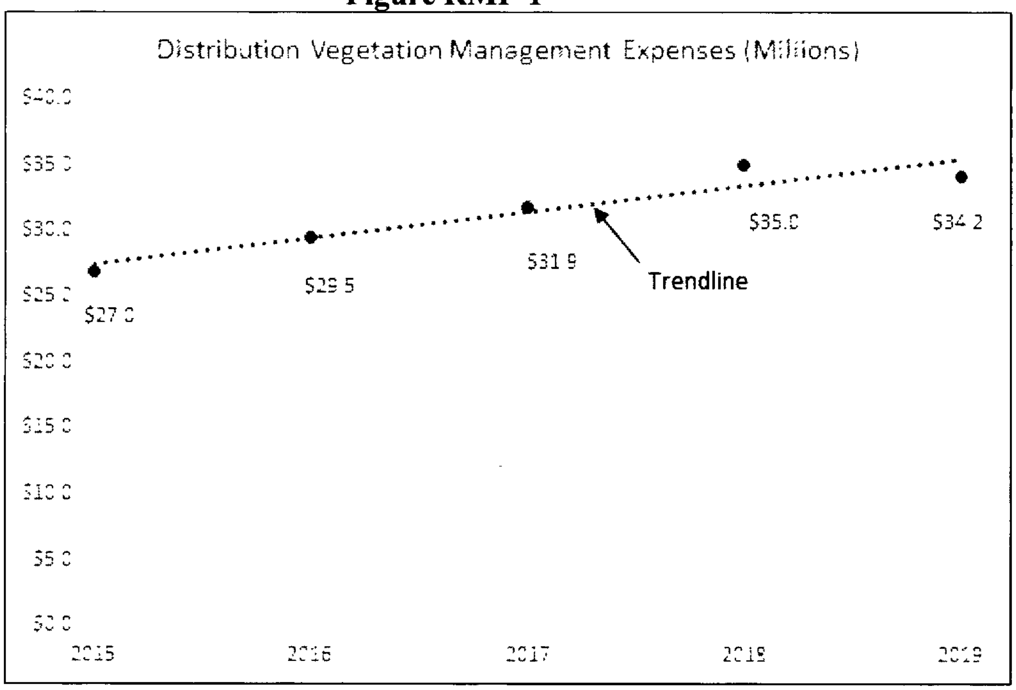
The proposals offered by OPUC and Staff with regard to vegetation management expense are both legally and factually flawed. From a legal perspective, OPUC's proposal to rely on a historic 2014-2017 average O&M to establish CEHE's vegetation management expense as well as Staff's proposed use of a 2015-2018 average for vegetation management expense conflicts with the statutory and Commission requirement that a utility's expenses be based on a historic test year. Additionally, as explained in CEHE's initial brief in Section IV.H, OPUC and Staff offered no compelling evidence to refute that CEHE's test year costs for proactive tree trimming, hazard tree removal and reactive tree trimming (collectively, "vegetation management") are representative of the ongoing costs to properly maintain and continue its current vegetation management program. While OPUC and Staff reject the required use of a historic test year, and instead propose various multi-year averages to establish vegetation management expense, the evidence proves that use of a historic average *understates* the costs CEHE currently incurs to support its vegetation management program and will continue to understate these costs in the future.[812] In fact, OPUC admits that in 2017 CEHE necessarily halted its vegetation management activities "for a significant period of time due to Hurricane Harvey."[813] Stated differently, CEHE's 2017 vegetation management expenses in the amount of $27.90 million do not reflect a full year of normal operations, but rather were the result of Hurricane Harvey, which caused CEHE to forgo 1.5 months of vegetation management activities.[814] Yet, both OPUC and Staff propose to include 2017 as part of their historic average approach.[815] Thus, as a threshold matter, both OPUC's or Staff's vegetation management expense proposals violate PURA and prevailing case law, which authorizes adjustments to test year data only "to make the test year data as representative as possible of the cost situation that is apt to prevail in the future."[816]

Moreover, while OPUC and Staff attempt to distinguish CEHE's test year vegetation management expense from that incurred in prior years, these parties do not dispute that the level

[812] Specifically, OPUC proposes to establish CEHE's vegetation management expense based on an outdated three-year 2015-2017 average of $28.16 million. OPUC Initial Brief at 64. Staff ignores current expense levels and norms by relying on a 2016-2018 three-year average of $31.64 million. Staff Initial Brief at 50.
[813] OPUC Initial Brief at 63-64.
[814] CEHE Ex. 31 at 26 (Pryor Rebuttal).
[815] *Supra* note 812.
[816] *Suburban*, 652 S.W.2d at 366.

of vegetation management activities that CEHE undertook during the test year were reasonable and necessary for the provision of electric service. And, there is *no factual evidence* to support Staff's suggestion that reduced vegetation management activity in 2017 impacted CEHE's vegetation management activities in 2018.[817] Rather, the evidence shows that CEHE did not increase its test year vegetation management activities in response to 2017's Hurricane Harvey; the circuit miles trimmed in 2018 are comparable to the miles trimmed in three prior years: 2011 – 5,606 miles, 2013 – 5,074 miles, and 2014 – 5,139 miles.[818] The evidence further establishes that if Hurricane Harvey had not occurred, the expected level of distribution vegetation management expense would have been $31.89 million for 2017, which is more in line with the upward trend in vegetation costs CEHE has experienced in recent years.

Figure RMP-1[819]



The growing cost trend shown above is further substantiated by the fact that vegetation management costs and expenditures are continuing to go up as the Company's service territory grows.[820] The trend in vegetation management costs has largely been driven by:

[817] While Staff makes this assertion in its Initial Brief, it offers no supporting evidentiary citation for this claim other than the unsubstantiated opinion of its witness and a misrepresentation of Mr. Pryor's rebuttal testimony; Staff Initial Brief at 50 and 51, n.207.
[818] CEHE Ex. 31 at 26-27 & 30, Exh. R-RMP-02 (Pryor Rebuttal).
[819] *Id.* at 26.
[820] *Id.* at 23.

- A 50% increase in contractor bid prices on a per mile basis from 2014 to 2017 for proactive tree trimming;[821]
- Over the past four years, the miles of overhead distribution line (feeder-main and laterals) that CEHE must maintain with tree trimming activities has increased by an average of 171 miles per year;[822]
- CEHE has increased the spend every year for the past four years on reactive tree trimming to address customer outages by spot tree trimming between proactive cycles;[823] and
- Vegetation growth driven by an increase in rainfall for the past several years has also increased the Company's required tree trimming activities.[824]

In sum, there should be no reasonable dispute that with more miles of distribution line to maintain, heavier rainfall, and ever increasing contractor prices, the Company's costs associated with tree trimming have increased and will continue to trend upward.[825] This is confirmed by CEHE's projected 2019 total vegetation management expenses for distribution system management of $34.033 million, which is consistent with the Company's 2019 budgeted amount of $34.23 million as well as the Company's actual 2018 test year costs of $35.022 million.[826] This information further illustrates that the vegetation management expense CEHE incurred in 2018 and expects to incur in the future is significantly higher than the amounts incurred in each of the three years that OPUC seeks to include in its three-year average (2015-2017) and is well above the three-year average proposed by Staff.[827] CEHE has demonstrated a continued year-over-year upward trend in vegetation management expense. CEHE's requested O&M expense in the amount of $35.02 million for vegetation management reflects the amount that the Company actually spent during the test year, and CEHE has shown that its test year vegetation management costs are in line with those expected to be incurred in the future. For these reasons, the Commission should approve CEHE's request level of O&M expense for vegetation management activities.

I. Smart Meter Texas Expense

No party has challenged CEHE's recovery of its SMT expenses related to its IBM contracts for the design, development, and operation of SMT. In fact, OPUC (the only party to challenge any of CEHE's SMT expenses) acknowledges that CEHE's use of its expected 2020 IBM contract

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821 *Id.* at 24.
822 *Id.*
823 *Id.*
824 *Id.*
825 *Id.*
826 *Id.* at 29, Exh. R-RMP-1.
827 *See* OPUC Initial Brief at 63; Staff Initial Brief at 50.

costs are an acceptable known and measurable change to CEHE's SMT expenses from the Test Year.[828] Although OPUC acknowledges that the Commission has updated the business requirements of SMT as a result of Docket No. 47472, and therefore the future contract costs are more appropriate, OPUC maintains that CEHE's other SMT expenses should be based on CEHE's 2018 costs which reflect its experience under the previous IBM contract.[829] As explained by CEHE witness John R. Hudson, CEHE should be allowed to recover its expenses related to the new contracts and the additional associated expenses that will result from that new contract including change requests for work outside the initial scope of work.[830]

As Mr. Hudson explained, large IT projects change in scope and therefore CEHE will incur additional charges associated with those changes.[831] In addition, the costs associated with SMT are different from CEHE's other O&M expenses because CEHE does not have the ability to unilaterally reject any change to the scope of work for SMT in order to reduce associated expenses.[832] Given the significant change to SMT functionality requirements and new contracts with IBM, CEHE's 2018 costs are not an accurate reflection of its future SMT costs.[833] If CEHE's SMT expense is based on its expected contract IBM expenses, the rest of its recovered expenses should be consistent with CEHE's costs associated with the updated SMT business requirements.

As OPUC recognizes, CEHE's request for SMT cost recovery is almost $400,000 less than what it incurred in the Test Year.[834] But OPUC would only have the Commission capture reductions in CEHE's expenses and not allow CEHE to recover its reasonable expenses based upon the new functionality of SMT 2.0 and the associated costs. OPUC's proposed reduction to SMT costs should be rejected and CEHE should be allowed to recover its proposed SMT expenses. In the alternative, CEHE should be allowed to recover SMT expense entirely based on CEHE's Test Year expense of $3.924 million.[835]

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[828] OPUC Ex. 5 at 14 (Nalepa Direct).
[829] OPUC Brief at 67.
[830] Rebuttal Testimony of John R. Hudson, CEHE Ex. 34 at 5 (Bates Pages).
[831] *Id.*
[832] Direct Testimony of John R. Hudson, CEHE Ex. 11 at 27-28 (Bates Pages).
[833] CEHE Ex. 34 at 5 (Hudson Rebuttal).
[834] OPUC Initial Brief at 67.
[835] CEHE Ex. 2 at WP/II-B-12d SMT.

J. Street Lighting Service

Despite clear evidence to the contrary, COH continues to argue that the Commission should disallow actual test year O&M costs associated with the Company's street lighting system. The following evidence is undisputed in the record:

- the Company incurred approximately $7.6 million in O&M costs for street lighting;[836]
- CEHE has standing work orders for all O&M costs associated with all streetlights in its territory;[837]
- CEHE has a warranty on its bulbs, but it only covers luminaire *replacement* not ongoing O&M;[838] and
- ongoing O&M costs associated with LED streetlights include fuse replacement, maintaining the post, conduit replacement, and clamp/connector replacement over its used and useful life to maintain standard performance.[839]

Although COH witness Kit Pevoto does not challenge the reasonableness of the Company's *total* actual test year O&M expense associated with servicing its streetlights, COH claims that O&M costs associated with LED lights, specifically, should be disallowed. To be clear, as explained in its initial brief, the Company does not track its O&M costs by lamp type, but it prepared a study for this proceeding to demonstrate the level of street lighting costs associated with all of the different types of lamps in the Company's system.[840] The study assigned to LED street lighting approximately $2.73 million of the Company's total $7.6 million in street lighting O&M costs.[841] However, regardless of what amount of costs were assigned to LED, that does not affect the fact that the Company incurred $7.6 million in street light related O&M during the test year and has requested this amount as part of its cost of service.

COH's attempts to confuse this issue should also be disregarded. For instance, COH argues that LED lights require less maintenance than HPS lights;[842] however, the fact that O&M expense is lower for LED street lighting does not mean that those assets will have no O&M at all. COH argues that the Company's warranty on lights means it will have no O&M for ten years[843] but Ms. Sugarek explained at the hearing that the warranty covers luminaire replacement; it does not

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[836] CEHE Ex. 2 at 2104 (H-I-J and CA Errata – 1, WP – Lighting revenue); Rebuttal Testimony of Mathew A. Troxle, CEHE Ex. 45 at 40; Rebuttal Testimony of Julienne P. Sugarek, CEHE Ex. 33 at 18-20 (Bates Pages).
[837] CEHE Ex. 33 at 18 (Sugarek Rebuttal).
[838] Tr. at 232-233 (Sugarek Cross) (Jun. 24, 2019).
[839] CEHE Ex. 33 at 18 (Sugarek Rebuttal).
[840] CEHE Ex. 2, Schedule H-I-J and CA Errata-1, WP-Streetlight Rate Design.
[841] *Id.*
[842] COH/HCC Initial Brief at 39.
[843] *Id.*

cover on-going O&M—including fuse replacement, maintaining the post, conduit replacement, and clamp/conductor replacement.[844] COH also implies that because projected LED O&M *savings* are close to test year LED O&M costs, that savings should offset those costs in the future.[845] The record is clear that savings related to LED lighting took place in the test year and were captured in the Company's cost of service;[846] the test year costs are the *actual* O&M costs the Company incurred during the test year to operate its street lighting system, which currently includes both LED and HPS bulbs. The costs do not offset one another. In essence, COH is asking the Commission to adopt a post-test year adjustment that would double count savings that are already reflected in the cost of service. The Company's $7.6 million in actual test year street lighting O&M costs should be approved.

K. Loss on Sale of Land

In its initial brief, OPUC continues to insist that customers should not be assigned 50% of Company's loss on the sale of land during the test year.[847] First, OPUC asserts that there is limited information in the record regarding the reasonableness of the loss.[848] OPUC is wrong. The evidence demonstrates that:

- the land at issue in this case included 14 tracts of land associated with the Company's transmission line project called the Brazos Valley Connection Project;[849]
- the Company completed construction on and energized the Brazos Valley Connection in March 2018;[850]
- when the land was originally purchased, entire lots had to be purchased (not just acreage for the proposed right-of-way easement) and many of the tracts included improvements, such as homes or other structures at the time of purchase;[851]
- to make the land useful for the project, the land was cleared requiring the demolition of these improvements;[852]
- upon completion of the project, the Company prudently sold off the excess areas of fee-purchased land that was no longer suitable for the utility to own;[853] and
- with the improvements no longer existing, the property could only be assessed for the value of the land, resulting in a reduction from the original purchase price and the Company

[844] Tr. at 232-233 (Sugarek Cross).
[845] COH/HCC Initial Brief at 39.
[846] Tr. at 237 (Sugarek Redirect).
[847] OPUC Initial Brief at 67-70.
[848] *Id.* at 68.
[849] CEHE Ex. 32 at 32 (Narendorf Rebuttal).
[850] *Id.*
[851] *Id.*
[852] *Id.*
[853] *Id.*

experienced a loss of $1.46 million on the tracts sold.[854]

OPUC does not challenge the prudence of the Company's actions or decisions—all of which are normal in the course of a large transmission line construction project such as the Brazos Valley Connection. OPUC also does not challenge the original purchase price of the land acquired for the project. OPUC simply asserts that it desired more information. Additional information is not required. The Company has shown that it: (1) acted prudently in acquiring land for the Brazos Valley Connection; (2) acted prudently to make the land useful for the project; and (3) acted prudently selling off the excess areas of fee-purchased land that was no longer suitable for the utility to own. OPUC's proposed disallowance should be rejected.

OPUC's contention that CEHE has misinterpreted the Commission's Order in Docket No. 38339 is also not persuasive.[855] As discussed in CEHE's initial brief, when the Commission approved the sharing treatment on land sales and losses in Docket No. 38339, it included Finding of Fact 137, which makes clear the Commission determined customers should share on any gain *or loss* resulting from the sale of land.[856] To find otherwise would allow customers to share on a gain on the sale of land, yet expect the utility to bear an entire loss, which is not a balanced result or a sound policy decision despite OPUC's argument to the contrary.[857] The Company's proposed apportionment of 50% of the loss on the sale of land correctly applies the Commission's decision in Docket No. 38339 and should be approved.

L. Federal Income Tax Expense [PO Issues 28, 29]

1. Amount of Federal Income Tax Expense [Issue 28]

Other than as may result from adjustments to other issues, CEHE's uncontested FIT test year expense totaled approximately $75.8 million.[858] It is reasonable and necessary and should be approved.

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[854] CEHE Ex. 2 at 1162, WP/II-B-13a Brazos Valley Connection Tracts.
[855] OPUC Initial Brief at 60-70.
[856] Docket No. 38339, Order on Rehearing at Finding of Fact 137. Finding of Fact 137 states, "land is not a depreciable asset, and customers have not paid any depreciation expense associated with the land. This does not mean ratepayers have no claim on any gain or loss resulting from the sale of land."
[857] OPUC Initial Brief at 60-70.
[858] CEHE Initial Brief at 114; CEHE Ex. 13 at 989 (Pringle Direct) and CEHE Ex. 2 at 324-327, Schedule II-E-3. *See also, e.g.*, Staff Initial Brief at 51-52 (describing potential flow-through adjustments).

2. Effect of TCJA [Issue 29]

CEHE properly reflected the reduction in tax rate from the enactment of the TCJA in its requested FIT expense and properly re-measured ADFIT to account for the estimated tax owed at the TCJA's rate of 21% rather than 35%.[859] No party asserts otherwise.

M. Taxes Other Than Income Tax [PO Issue 26]

1. Ad Valorem (Property) Taxes

CEHE's property tax payments in the test year totaled approximately $88.6 million, and CEHE expects to pay $94.4 million in property taxes based on 2018 taxes assessed plus taxes on capital additions placed in service in 2018.[860] Other than as may result from adjustments to other issues, no party asserts otherwise, and these amounts should be approved.[861]

2. Texas Margin Tax

Other than as may result from adjustments to other issues,[862] neither Intervenors nor Staff challenged the computation of the TMT expense, and the properly computed amount of $20,027,248 should be approved.[863] The parties' disputes with respect to the TMT regulatory asset are addressed in Section II.K.4.

3. Payroll Taxes

No party contests the properly computed payroll tax expense of approximately $11.6 million or the Company's proposed adjustments to payroll tax expense, other than as may result from adjustments to other issues.[864] Accordingly, these amounts should be approved.[865]

V. Wholesale Transmission Cost of Service [PO Issue 4, 5, 6, 37]

CEHE summarized this issue in its initial brief. Intervenors and Staff have challenged certain parts of the Company's wholesale TCOS or transmission cost allocations. These are addressed separately in Sections II, IV, VII, and VIII of CEHE's initial and reply briefs.

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[859] CEHE Initial Brief at 115.
[860] Direct Testimony of Justin J. Hyland, CEHE Ex. 14 at 1054, 1060 (Bates Pages).
[861] *See, e.g.*, Staff Initial Brief at 52 (describing potential flow-through adjustments).
[862] *Id.*
[863] CEHE Initial Brief at 116; CEHE Ex. 13 at 1023-1025 (Pringle Direct); CEHE Ex. 2 at 317-318, Schedule II-E-2 & 1148, WP/WP II-B-12 Adj 10.
[864] *See, e.g.*, Staff Initial Brief at 55 (describing potential flow-through adjustments).
[865] CEHE Initial Brief at 116; CEHE Ex. 2 at 317-318, Schedule II-E-2.

VI. Billing Determinants [PO Issue 4, 5, 45]

A. Weather Normalization

The Commission should adopt CEHE witness J. Stuart McMenamin's weather normalization adjustments. Based on extensive surveys of utilities across the country, Dr. McMenamin properly chose a 20-year period (1998-2017) to determine normal weather.[866] Dr. McMenamin does not dispute testimony by Mr. Nalepa and Staff witness Alicia Maloy, that more recently the Commission has used a 10-year period to determine normal weather in an effort to better reflect recent weather trends.[867] However, he did testify that this shift by the Commission to 10 years is consistent with his survey data, which shows the use of 30-year periods dropping considerably by 2013 in favor of 10-year periods,[868] and that even more recently, 10-year periods have given way to 20-year periods, which are now the dominant method for determining normal weather.[869] On cross examination, Ms. Maloy conceded that while other Commission rules now prescribe a 10-year window for other purposes (e.g., earnings monitoring reports), the Commission's rate filing package instructions for general rate cases still do not require that any specific time period be used.[870]

Neither Mr. Nalepa nor Ms. Maloy has performed any independent analysis, as Dr. McMenamin has, of current industry practice for determining normal weather.[871] Instead, they attempt to undermine the credibility of his survey findings. Staff argues only that Dr. McMenamin "admitted" that his group at Itron conducted the studies.[872] It is a curious critique, as his personal oversight of the process should make his reliance on the surveys *more* appropriate, not less so. OPUC complains that Dr. McMenamin "did not provide any of the underlying data on which the surveys were based, nor did he provide any details regarding the facts that other jurisdictions relied on to support their selected time period."[873] Neither criticism is true in any meaningful way. Dr. McMenamin provided sufficient "underlying data" about the surveys. He testified that Itron

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[866] Rebuttal Testimony of J. Stuart McMenamin, CEHE Ex. 44 at 21.
[867] *See* Direct Testimony of Alicia Maloy, Staff Ex. 5A at 19–21; Direct Testimony of Karl Nalepa, OPUC Ex. 5 at 42–44 (Nalepa Direct).
[868] CEHE Ex. 44 at 28–29 (Figure SM-R13) (McMenamin Rebuttal).
[869] *Id.*
[870] Tr. at 866 (Maloy Cross) (Jun. 26, 2019).
[871] CEHE Ex. 44 at 44, Exh. R-JSM-2 (McMenamin Rebuttal) ("Mr. Nalepa has not performed a study or analysis of the periods used by utilities or regulators in other states to determine normal weather."); Tr. at 866 (Maloy Cross) (Jun. 26, 2019).
[872] Staff Initial Brief at 55.
[873] OPUC Initial Brief at 72.

runs an annual benchmarking survey,[874] that it often asks about the basis used for normal weather,[875] that the survey usually has 60-80 electric utility respondents,[876] and that the 2018 survey had 74 respondents representing more than half of electricity sales in North America.[877] He then provided the results of the survey.[878] OPUC does not explain what additional "underlying data" Dr. McMenamin should have provided. As for the "facts that other jurisdictions relied on," Dr. McMenamin did state that the surveys do not ask about reasons for changes in time periods; but he also testified that he has had conversations in which "the main reason that is consistently reported is that normal values can change significantly from year to year when the 10-year window is rolled forward."[879] OPUC's criticisms sound good, but they mean little as a practical matter. The Commission should adopt Dr. McMenamin's 20-year period for determining normal weather, which recognizes the need to shorten the period from 30 years to recognize recent trends but avoids the significant variations that result from use of a 10-year period.

The Commission should also adopt the rest of Dr. McMenamin's weather normalization modeling—his regression models used to quantify the effect of abnormal weather on test year energy usage. Mr. Nalepa takes no issue with the rest of Dr. McMenamin's modeling and acknowledges that Dr. McMenamin's regression models "are quite detailed and rely on data obtained from [the Company's] fully deployed advanced meter systems that have provided actual customer demand for every 15-minute interval in every day of every month."[880] Only Ms. Maloy criticizes Dr. McMenamin's regression modeling. Ms. Maloy appeared to be an honest witness attempting to do a difficult job, but Staff's claim that she "has 7 years' experience in performing and reviewing weather normalization analyses" is unsupported even by her own testimony. She acknowledged that of the 26 proceedings listed on her resume, there was only one in which she had filed testimony regarding weather normalization.[881] Ms. Maloy could not even recall that she had filed weather normalization testimony in a second docket not listed on her resume.[882] Filing testimony over an 11-year career in just two proceedings—one of which she could not even remember—does not make Ms. Maloy an expert with "7 years' experience." Her relative

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[874] CEHE Ex. 44 at 28 (McMenamin Rebuttal).
[875] *Id.*
[876] *Id.*
[877] *Id.*
[878] *Id.* at 28–29, Figure SM-R13.
[879] *Id.* at 29.
[880] OPUC Ex. 5 at 41 (Nalepa Direct).
[881] Tr. at 867 (Maloy Cross) (Jun. 26, 2019).
[882] *Id.* at 870.

inexperience is important in evaluating this issue because Staff relies entirely upon Ms. Maloy to question the weather normalization methodology used by Dr. McMenamin, a witness with advanced degrees and over 40 years of direct, relevant experience.

Staff first criticizes Dr. McMenamin for using only four years of data in his regression modeling while using twenty years to determine normal weather.[883] Staff relies on Ms. Maloy's testimony that this creates "a mismatch where the heating and cooling degree day weather coefficients . . . are determined using four years of weather data and the normalized heating and cooling degree days are determined using the 20-year normalized time period."[884] But Ms. Maloy never explains why such a mismatch is a problem. It isn't. The definition of normal weather and the estimation of the effects of abnormal weather on test-year energy usage are *independent* steps.[885] Ms. Maloy acknowledged the same.[886] There is no theoretical or practical reason why the period used to define normal weather should be the same as the period used to determine how abnormal weather likely affected electricity demand in the test year.[887]

Dr. McMenamin's four years of daily AMS data provides 1,400 data points compared to just 120 points provided by Ms. Maloy's 10 years of monthly data. The four years of AMS data used by Mr. McMenamin to determine the effect of abnormal weather produce a "strong stable picture of how weather works in recent years."[888] In contrast, the 10 years of billing cycle data used by Ms. Maloy produce results that make it hard to see much of a relationship at all between abnormal temperature and electricity sales.[889] For example, Ms. Maloy's 10 data points for the month of May (one point per year) suggest that the two years with the least number of cooling degrees have the largest level of electricity use—a result that defies logic and should have caused her to question her data and methodology.[890] As Dr. McMenamin testified, Ms. Maloy's estimated weather response coefficients for heating and cooling are inconsistent with facts that are visibly obvious from the daily AMS data, and the weather adjustments computed using her coefficients are therefore wrong and should not be used.[891]

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[883] Staff Initial Brief at 56-57; Staff Ex. 5A at 21–22 (Maloy Direct).
[884] Staff Initial Brief at 57; *see* Staff Ex. 5A at 22 (Maloy Direct).
[885] CEHE Ex. 44 at 23 (McMenamin Rebuttal).
[886] Tr. at 867–870 (Maloy Cross) (Jun. 26, 2019).
[887] CEHE Ex. 44 at 23 (McMenamin Rebuttal).
[888] *Id.* at 6, Figure SM-R2 & 23.
[889] *Id.* at 17–18.
[890] *See id.*
[891] *See id.* at 21.

In an apparent attempt to question the propriety of Dr. McMenamin's use of *daily* AMS data, Staff quotes the Commission RFP as requiring utilities to provide "data for the Test Year on a *monthly* basis by weather station."[892] Once again, Staff confuses the two basic steps in weather normalization. The quoted instruction is for schedule II-H-5.1, which is weather station data—*temperature data* to be used for the first step, to determine normal weather. CEHE provided monthly temperature data as required.[893] However, Dr. McMenamin uses daily AMS *energy demand data* for the second step, to determine how abnormal weather affects test year energy demand. A completely different portion of the Commission's RFP instructions request "hourly demand data (or demand data for intervals shorter than one hour)" when available.[894] When such granular data is not available, the instructions impose additional requirements on the utility to explain how it developed load numbers in the absence of such data. Dr. McMenamin's use of AMS data for his regression analysis is entirely in keeping with the RFP instructions.

Staff next criticizes Dr. McMenamin for including test year data in his regression analysis.[895] Once again, however, determining normal weather is a distinct and independent step from estimating weather effects on the test year.[896] Ms. Maloy concedes that the precedent she originally cited to support exclusion of the test year referred to the first step (the determination of normal weather) and not to the second step (regression analysis to determine the impact of abnormal weather on *test year* electricity demand).[897] She nevertheless clings to her criticism and suggests that inclusion of the test year in the regression analysis "may also create a bias."[898] But Ms. Maloy concedes that the entire point of the regression analysis is that "you're trying to remove the impacts of weather *from the test year*."[899] What data could be more relevant regarding customer reaction to abnormal weather *in the test year* than data regarding electric demand *in the test year*? Ms. Maloy eventually acknowledged that more recent years (the test year being the most recent of all) give us a more accurate read on how customers react to weather changes.[900]

[892] Staff Initial Brief at 59 (emphasis added).
[893] CEHE Ex. 1, RFP at 4337-4340 (Schedule II-H-5.1).
[894] Transmission & Distribution (TDU) Investor-Owned Utilities Rate Filing Package for Cost-of-Service Determination, Project No. 39548, Adopted at Commission's Open Meeting at 63, Section IV (Rate Design), Schedule J: Rate Design, IV-J-4 (Load Research Data) (Nov. 19, 2015).
[895] Staff Initial Brief at 57; Staff Ex. 5A at 22 (Maloy Direct).
[896] CEHE Ex. 44 at 23 (McMenamin Rebuttal).
[897] Docket No. 43695, Final Order at Finding of Fact 242 ("It is reasonable for SPS to exclude the test year from the time period used to develop normal weather . . . ."); Tr. at 874 (Maloy Cross) (Jun. 26, 2016).
[898] Staff Initial Brief at 57; Staff Ex. 5A at 22 (Maloy Direct).
[899] Staff Initial Brief at 57; Tr. at 887 (Maloy Cross) (Jun. 26, 2019).
[900] Tr. at 891 (Maloy Cross) (Jun. 26, 2019).

Dr. McMenamin excluded the test year in determining normal weather, but properly included it to determine how customers *in the test year* reacted to variances from normal weather *in the test year*.[901]

Third, Staff criticizes Dr. McMenamin for including in his regression analysis some variables that Ms. Maloy argues are not statistically significant at the 95% confidence level.[902] However, Ms. Maloy has previously testified that the inclusion of variables with a confidence level below 95% may still be valid to include in regression models if the variable makes theoretical sense.[903] Dr. McMenamin testified that his variables do make theoretical sense (day of week effects, holidays) and would not have changed his results significantly if removed.[904] Ms. Maloy offered no such analysis.

The Commission should adopt Dr. McMenamin's weather normalization adjustments. Dr. McMenamin was far and away the most experienced witness regarding weather normalization. Dr. McMenamin has articulated a sound policy rationale for using a 20-year period to determine normal weather; but if the Commission decides to use a 10-year period, Dr. McMenamin's rebuttal testimony includes a full set of weather adjustment results using his methodology but applied to a 10-year normal period.[905]

B. Energy Efficiency Program Adjustment

Commission Staff and OPUC were the only parties to file testimony regarding the Company's proposed Energy Efficiency Plan ("EEP") adjustment to billing determinants.[906] Lost in their arguments is the fact that this Commission's rules *require* the Company to adjust billing determinants to reflect known and measurable changes in usage. 16 TAC § 25.234 states that "[r]ates *will be* determined using revenues, billing and usage data for a historical test year adjusted for known and measurable changes . . . ." The EEP adjustment is known and measurable because it is based on programs that were put in place during the test year and because the energy usage impacts on test year billing determinants are calculated using the Commission's own deemed savings standards in the Technical Reference Manual ("TRM"), which is used in other proceedings

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901 CEHE Ex. 44 at 23–24 (McMenamin Rebuttal).
902 Staff Ex. 5A at 23–24 (Maloy Direct).
903 Tr. at 876-878 (Maloy Cross) (Jun. 26, 2019).
904 CEHE Ex. 44 at 24–25 (McMenamin Rebuttal).
905 *Id.* at 33, 37-38 & Exh. R-JSM-1.
906 ARM addressed this issue briefly in its initial brief but did not file any testimony on the issue or offer any unique arguments. ARM Initial Brief at 2-4.

to set rates.[907] Accordingly, the adjustment is not only appropriate but required under Commission rules.

1. The EEP Adjustment is a billing determinant adjustment tied to historical test year data adjusted for known and measurable changes

Test year adjustments (also referred to as pro-forma adjustments) are used to change test year data to reflect the full year effect of known and measurable changes in ongoing expense levels or other ratemaking elements including billing determinants.[908] They come in two types: in-period adjustments and out-of-period adjustments.[909] In-period adjustments include normalization adjustments (like a weather normalization adjustment), which remove the known and measurable effects of abnormal conditions on expense levels or other ratemaking elements *during the test year*, and annualization adjustments (like a customer adjustment or payroll adjustment), which account for known and measurable changes in expense levels or other ratemaking elements that occur *during the test year* if such changes are reasonably expected to continue beyond the test year.[910] In-period adjustments are routinely made in rate cases—for example an adjustment for increases in customers during the test year or an increase in the number of employees or for pay raises that occurred late in the test year.[911] Out-of-period adjustments (or post-test year adjustments) are less frequently made and require a higher burden for approval but are still common at the Commission.[912] Out-of-period adjustments are intended to account for known and measurable changes in a utility's expense levels or other ratemaking elements that are expected to occur *after the test year*, for example an adjustment for expenses associated with a known contract change that has not taken effect yet.[913]

The Company's energy efficiency adjustment in this case is an *in-period annualization adjustment* to account for changes to various ratemaking elements that occurred *during the test year* to reflect the full year effect of those changes.[914] The energy efficiency adjustment is based on the fact that the Company implemented energy efficiency programs during in every month of

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[907] CEHE Ex. 45 at 32-33 (Troxle Rebuttal). *See also* Docket No. 43695, PFD at 13 (holding that "A known and measurable change is a transaction or event that is: (a) fixed in time; (b) known to occur (not speculative, possible, or uncertain); and (c) measurable in amount").
[908] CEHE Ex. 45 at 27-28 (Troxle Rebuttal).
[909] *Id.*
[910] *Id.*
[911] *Id.*
[912] *Id.*
[913] *Id.*
[914] *Id.* at 29.

the test year. As energy saving measures are installed use of the Company's system is reduced and installed energy efficiency measures will continue to reduce the customers usage beyond the test year. But because the programs were implemented throughout the year, the Company's test year data reflects only a portion of the impacts of these programs on customer usage. The Company requires an in-period annualization adjustment to calculate the impacts of those programs as if they had been in place for the whole year, because this is representative of the conditions that will exist once rates take effect.

2. It is necessary to make known and measurable adjustments to capture accurate billing determinants.

PURA § 36.051 states that "the regulatory authority *shall* establish the utility's overall revenues at an amount that will permit the utility a reasonable opportunity to earn a reasonable return on the utility's invested capital used and useful in providing service to the public in excess of the utility's reasonable and necessary operating expenses." 16 TAC § 25.234 states that "[r]ates *will be* determined using revenues, billing and usage data for a historical test year adjusted for known and measurable changes." 16 TAC § 25.231(a) states that "rates are to be based upon an electric utility's cost of rendering service to the public during a historical test year, adjusted for known and measurable changes." 16 TAC § 25.231(b) states that "[i]n computing an electric utility's allowable expenses, only the electric utility's historical test year expenses as adjusted for known and measurable changes will be considered." Therefore, to meet the statutory mandate of establishing a "utility's overall revenues at an amount that will permit the utility a reasonable opportunity to earn a reasonable return," the Commission's rules clearly require a utility's test year data to be adjusted for known and measurable changes.

As explained above, if known and measurable increases or reductions to usage are *not* applied to the calculation of the Company's rates, the Company's rates will not accurately capture the Company's cost of service and revenue requirement as approved by the Commission in this proceeding.[915] The Company will then not be given a fair opportunity to recover its revenue requirement as required by PURA § 36.051 because the billing determinants used to set rates would be too high since they only reflect a partial year of program activity, which in turn causes the rate

[915] *Id.* at 28.

to be too low.[916] This puts the Company in a state of under-recovery from the first day that new rates take effect.[917]

3. The EEP adjustment is not "substantively identical" to a lost revenue adjustment mechanism.

OPUC and Commission Staff attempt to obscure the appropriateness of this adjustment by continually pointing back to the Commission's prior consideration of a lost revenue adjustment mechanism ("LRAM") that would have captured future energy efficiency program savings. The Company's proposal in this case is not an LRAM. An LRAM is an out-of-period adjustment, intended to adjust test year revenues (or capture changes in revenue levels) based on changes in usage that are expected to occur *after the test year* due to energy efficiency programs.[918] It adjusts the *revenue requirement* to account for revenues the Company will not recover in the future based on future energy usage reductions caused by the programs.[919] Here, the Company's energy efficiency adjustment is an in-period *billing determinant* adjustment based entirely on usage known and measurable at the end of the test year, consistent with 16 TAC §§ 25.231 and 25.234.[920]

In fact, the Company is not aware that this Commission has *ever* reviewed an adjustment similar to the one requested by the Company, nor has any party identified one. The LRAMs previously reviewed by the Commission in previous proceedings cited by Commission Staff and OPUC were based on *projected post-test year* energy savings.[921] In fact, the Company specifically modified this adjustment so that it was nothing like an LRAM.[922] Staff and OPUC do not even address the fact that, unlike prior LRAMs, the EEP adjustment is based *entirely* on *historical in-period annualized test year* data.[923] It captures no future impact of the programs; it projects no future savings from the programs; it simply adjusts test-year billing determinants using the test year data impacts of the program. Instead, they mischaracterize the EEP adjustment as an LRAM because it "fundamentally involves"[924] an increase to rates. This is overly simplistic. The EEP adjustment is no more an LRAM than the customer adjustment or weather normalization adjustment, which can also "fundamentally involve" increased rates.

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[916] *Id.*
[917] *Id.*
[918] *Id.* at 29.
[919] *Id.*
[920] *Id.*
[921] *Id.*
[922] *Id.* at 30.
[923] *Id.* at 29.
[924] OPUC Initial Brief at 77.

4. **The EEP Adjustment is similar to other adjustments commonly approved by this Commission.**

Staff and OPUC argue that this adjustment is distinct from a customer adjustment or weather normalization adjustment because those adjustments are identified in the Commission's TDU RFP instructions. But this argument proves too much. The Commission's TDU RFP instructions do not specifically provide for annualized adjustments to payroll expense, yet such adjustments are common.[925] In fact, form Schedule II-H-4.1 includes a requirement to provide information "associated with other" adjustments.[926]

5. **The Commission's deemed savings standards are a reasonable means for measuring energy usage savings.**

Given that known and measurable adjustments are required and typically approved by this Commission, the only real issue raised by Staff or OPUC is a qualitative one: whether the Commission's own deemed savings are sufficient for purposes of making known and measurable adjustments to test year data. The answer is clearly yes.

While OPUC and Staff claim the TRM is not "precise" enough to be used as a basis for making known and measurable adjustments, they ignore the fact that this Commission utilizes the *exact same information* to calculate energy savings and the performance bonus in the EECRF proceedings under PURA § 39.905 and 16 TAC § 25.181.[927] The TRM is reviewed and vetted by the Commission's third-party auditor Tetra Tech and is used to determine savings for every energy efficiency program under the Commission's purview.[928] While Staff claims there is a "higher threshold" for meeting the known and measurable standard,"[929] it does not explain what that threshold is or why these savings are sufficient for setting rates in the EECRF but not here. It defies logic that the deemed savings calculations are reliable enough to be used to set rates in one proceeding but not in another. On that note, OPUC's argument that the TRM is only supposed to apply to "certain markets"[930] and is not "tailored to CenterPoint Houston's specific service area" is also without merit. The TRM is used to estimate energy savings and set rates in the Company's service territory every year.[931]

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925 CEHE Ex. 45 at 35 (Troxle Rebuttal).
926 *Id.*
927 *Id.* at 32.
928 *Id.*
929 Staff Initial Brief at 62.
930 OPUC Initial Brief at 75.
931 CEHE Ex. 45 at 32 (Troxle Rebuttal).

Staff and OPUC's arguments that energy efficiency programs do not "automatically" lead to energy savings is dubious. PURA § 39.905 and this Commission's policy underlying the promulgation of the energy efficiency rule are specifically intended to "allow each customer to reduce energy consumption" with the goal of achieving significant demand and energy reductions *overall*.[932] That reduced energy is measured using the TRM. Moreover, we know *for a fact* that energy efficiency programs result in reduced usage: If a security light that uses 100 watts and runs at night is replaced with a light that uses 10 watts, over the same period, usage is reduced. Moreover, if a highly efficient LED bulb is installed in November of the test year and will be in place for the next 10 years, it is certainly appropriate to adjust test year billing determinants to properly reflect the impact of a full year of that light's energy usage savings on the Company's billing determinants, as required by 16 TAC § 25.234.

VII. Functionalization and Cost Allocation [PO Issues 4, 5, 43, 44, 46]

A. Functionalization

1. Texas Margin Tax Expense (and associated accounts)

Staff stated that it is not appropriate to uplift the Texas Margin Tax expense associated with the Company's total ERCOT transmission payments to wholesale TCOS and that base revenues be adjusted accordingly.[933] In rebuttal, the Company agreed to adopt Staff's position for the allocation of the Texas Margin Tax associated with these ERCOT transmission payments.[934] The Company's functionalization of Gross Margins Tax expense is reasonable.

2. Miscellaneous General Expense (account 930.2)

In its direct case, the Company proposed to functionalize 96.4% of its Account 930.2 expense in proportion to payroll and to directly assign 3.6% to the customer service function.[935] Staff witness Brian Murphy accepted the Company's payroll functionalization factor for support services included in this account but argued that TO services expenses related to personnel should be functionalized based on payroll and customer-related expenses should be functionalized based on total O&M expense.[936] Mr. Murphy also argued that Telecommunication Services expenses are to be directly assigned to retail cost of service.[937] In its rebuttal case, the Company adopted

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932 PURA § 39.905; 16 TAC § 25.181(a)(2) & (e).
933 Direct Testimony of Brian Murphy, Staff Ex. 2A at 26-34.
934 CEHE Ex. 35 at 47 (Colvin Rebuttal).
935 CEHE Ex. 2 at RFP Workpapers (redacted).XLS," worksheet "WP/VI-L.2," at Microsoft Excel row 42 (native file).
936 Staff Ex. 2A at 36-38 (Murphy Direct).
937 *Id.*

Staff's position.[938] The Company's proposed functionalization and allocation of Account 903.2 expenses are reasonable.

3. Unprotected Excess Deferred Income Tax

CEHE fully addressed this issue in its initial brief.

4. Accounts 5860 and 5970

CEHE fully addressed this issue in its initial brief.

B. Class Allocation

1. Class Allocation of Transmission and Distribution Costs

Pursuant to 16 TAC § 25.192, the ERCOT 4CP sets the rate that all Transmission Service Providers ("TSPs") in ERCOT must charge and all Distribution Service Providers ("DSPs") in ERCOT must pay for wholesale transmission service based on how all the DSPs contribute to the whole ERCOT system peak demand ("ERCOT 4CP"). This issue is distinct from how CEHE *allocates* its portion of those transmission costs among its classes, and both of these issues are distinct from how the Company ultimately *bills* its customers for their usage on the transmission or distribution system. As explained below, in this proceeding, the Company proposes to allocate its transmission and distribution costs using the Company's coincident peak during the months of June, July, August and September ("CEHE 4CP"). It proposes to bill its customers for their transmission and distribution usage using per-kWh usage, 4CP, or non-coincident peak ("NCP"), depending on the class. As explained more below, the Company's proposal is reasonable.

a. Apportionment of System-wide ERCOT Transmission Costs to TSPs

Although it is not entirely clear from its brief, H-E-B appears to argue that the Commission should disregard 16 TAC § 25.192 and its requirement that the 4CP method is used to apportion wholesale transmission costs among DSPs and instead use the NCP.[939] To the extent this is H-E-B's proposal, changing the way this Commission *requires* costs to be apportioned to DSPs using the ERCOT 4CP is not appropriate in the context of this proceeding,[940] as the Company has little control over how ERCOT apportions transmission cost among the DSPs. If H-E-B seeks to change how ERCOT apportions these costs, it is better addressed in a rulemaking.

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[938] CEHE Ex. 35 at 48 (Colvin Rebuttal).
[939] H-E-B Initial Brief at 38-39.
[940] Contrary to the assertions in H-E-B's initial brief (H-E-B Initial Brief at 38), the Company has not proposed using the CEHE 4CP to apportion transmission costs. The Company has no control over how ERCOT transmission costs are apportioned to it.

b. "CenterPoint 4CP" versus "ERCOT 4CP" Class Allocation

(1) Transmission Costs

TIEC and Staff agree that the Company should use the 4CP method to allocate transmission costs but argue that the Company should use the ERCOT 4CP instead of the CEHE 4CP to allocate those costs to customer classes. They allege that using ERCOT 4CP is necessary to "match" how costs are billed to the Company with how it bills those costs to its customers. However, the Company's proposed allocation using the CEHE 4CP is reasonable. CEHE's transmission system is built primarily to serve the Company's peak demand.[941] Rates should be set for the CEHE service territory based upon the Company's demand characteristics, not the demand characteristics of ERCOT as a whole.[942] The CEHE 4CP should be used to allocate those costs among its own customer classes based on how those customers contribute to the Company's own system peak demand.

Staff and TIEC argue that because Rule 25.192 apportions costs to CEHE using the ERCOT 4CP, the Company should allocate those costs based on their usage at the ERCOT 4CP. But Rule 25.192 does not dictate how a DSP's transmission costs should be allocated to the various rate classes, only how TSPs charge DSPs for transmission service.[943] There is no requirement that CEHE must "match" how it is charged transmission costs by ERCOT with how it allocates those costs to its customer classes. Moreover, Staff and TIEC ignore the fact that a portion of the costs apportioned to CEHE from ERCOT are CEHE's own transmission system costs that are uploaded to ERCOT.[944] At the end of the day, this is a CEHE rate case, not an ERCOT system rate case, and it is appropriate to allocate its portion of ERCOT transmission costs based on how it builds its system based on its own coincident peak demand. Moreover, using the ERCOT 4CP shifts significant costs away from transmission customers to the residential and small commercial classes.[945]

Finally, using the ERCOT 4CP allows more sophisticated customers to curtail their load during the ERCOT 4CP to avoid being charged for transmission costs they cause to be incurred on the system.[946] Under the Company's proposal, it is harder to "game the system," because a

[941] CEHE Ex. 45 at 6-8 (Troxle Rebuttal).
[942] *Id.*
[943] *Id.* at 8.
[944] *Id.*
[945] *Id.* at 9.
[946] *Id.* at 9-10.

customer would need to not only accurately predict the CEHE 4CP to influence the class allocation but also the ERCOT 4CP to influence their billing determinants.[947] CEHE's use of the CEHE 4CP better ensures that all customers pay for the costs they have caused the Company to incur.

(2) Distribution Costs

For the same reason that transmission costs should be allocated based on the CEHE 4CP, so should distribution costs. The Company builds its distribution system to address the Company's peak demands, and the CEHE 4CP captures those demands.[948] The CEHE 4CP demand allocation method captures the cost causation associated with the maximum coincident load of all rate classes on the Company's distribution system.[949] No party other than H-E-B and Texas Competitive Power Advocates ("TCPA") challenges the Company's proposed use of the CEHE 4CP method to allocate these costs.

c. Transmission and Distribution Demand Allocation Factors (4CP vs. NCP)

(1) Transmission

H-E-B and TCPA argue that the Commission should require the use of the NCP method rather than the 4CP method to allocate transmission costs to the classes. However, the Company's transmission system is designed to serve the maximum load requirement of each individual retail customer at the same time—during the months of June, July, August, and September[950]—not each individual class' maximum load throughout the year.[951] It is reasonable to utilize the 4CP method instead of the NCP method because costs should be allocated to the classes based on their contribution to the Company's summer peak loads.[952] The 4CP component of the Company's proposed allocator accomplishes this goal by isolating class contributions to system peak load during those four months.[953]

H-E-B argues that using the 4CP method incentivizes customers to "game the system" by reducing load at the time of the ERCOT 4CP. In fact, using the CEHE 4CP proposal would make it almost impossible to "game the system" because an entity would need to accurately predict not only the CEHE 4CP to influence the class allocation but also the ERCOT 4CP to influence its

[947] *Id.*
[948] CEHE Ex. 30 at 3012 (Troxle Direct).
[949] *Id.*
[950] *Id.*
[951] *Id.* at 3013.
[952] *Id.*
[953] *Id.*

billing determinants.[954] In fact, subject to its preference to use the NCP for allocation purposes, H-E-B supports use of the CEHE 4CP over the ERCOT 4CP for this very reason.[955]

(2) Distribution

For the same reasons that using the 4CP instead of the NCP for allocation of transmission costs is reasonable, it is also reasonable to use the 4CP to allocate distribution costs. The Company's distribution system is built to meet peak demand, not the various different demands of each class throughout the year.

d. 4CP Rate Design vs. NCP Rate Design

This issue addresses how the Company determines the amount of usage to bill each customer. For distribution charges, Residential and Secondary Less than 10 kVA are billed on a per kWh basis, Secondary Greater than 10 kVA are billed using the NCP, Primary is billed using NCP, and Transmission is billed using CEHE 4CP.[956] For transmission charges, Secondary Greater than 10 kVA are billed using the ERCOT 4CP (for IDR meters) or NCP (for non-IDR meters), and Transmission are billed using ERCOT 4CP.[957] H-E-B appears to be arguing that the NCP method should be used for setting billing determinants, but it does not explain which class this should apply to. For distribution usage, the Company already bills its Secondary Greater than 10 kVA Primary classes using NCP.[958] For transmission costs, Secondary Greater than 10 kVA, Primary and Transmission are billed using ERCOT 4CP because that is how the Company's systemwide usage is apportioned to CenterPoint Houston from ERCOT.[959]

e. Moderating the Update to the 4CP Class Allocation Factor

TIEC proposes that if the CEHE 4CP allocation is applied, the Commission should re-open the rulemaking for 16 TAC § 25.193 to implement a dynamic 4CP allocator that adjusts more frequently to capture growth and shrinkage within the customer classes.[960] Alternatively, TIEC proposes that the Commission take a "gradualist" approach in adjusting the 4CP allocation factors to avoid rate shock.[961] Notwithstanding that this rate proceeding is clearly not the appropriate forum to argue for changes to Rule 25.193, TIEC's concerns are overstated. The Commission now

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[954] CEHE Ex. 45 at 10 (Troxle Rebuttal).
[955] H-E-B Initial Brief at 41.
[956] CEHE Ex. 30 at 3021 (Troxle Direct).
[957] *Id.*
[958] *Id.*
[959] *Id.*
[960] Direct Testimony of Jeffry Pollock, TIEC Ex. 1 at 32-43.
[961] *Id.* at 37-38.

requires all electric utilities to file a comprehensive rate proceeding every four years, at which time the allocation factors will be updated.[962] Accordingly, the marginal shifts in the allocation factors among classes will be captured in rates every four years, mitigating any real risk of the rate shock.[963] Moreover, TIEC' has made similar requests in prior proceedings and the Commission has rejected those requests each time.[964]

2. Other Cost Allocation Factors

COH claims the Company's allocation methodology contain "certain flaws"[965] in the allocation of Accounts.[966] There is nothing "flawed" in the allocation factors applied to these accounts, which as explained in the rebuttal testimony of Mr. Troxle have long been employed by the Company and approved by this Commission in the Company's last rate case.[967] The allocation factors are also consistent with the NARUC Cost Allocation Manual.[968] What COH refers to as "flaws" are merely the allocation preferences of his witness. However, Ms. Pevoto presents no evidence that the costs in these accounts vary directly with payroll expense or that the Company's current allocation factors are unreasonable. The Company's allocations should be approved.[969]

COH also recommends the Company allocate FERC Account 907-10 Customer Service Administration and Community Relations costs to the lighting class based on customer count instead of lamp count.[970] It claims street lights are the "only class for which CEHE allocates on the basis of something other than customers."[971] This approach should also be rejected. The use of lamp count recognizes that some customers, like COH, have many lamps[972] and, as explained by Mr. Troxle at the hearing, Account 907-10 costs will vary depending on the number of lamps a customer uses.[973] The Company's proposed allocation for this account is reasonable.

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[962] CEHE Ex. 45 at 22 (Troxle Rebuttal).
[963] *Id.*
[964] *See, e.g.,* Project No. 37909, Order Adopting Amendment To §25.193 as Approved at the September 29, 2010 Open Meeting at 18 (Oct. 5, 2010).
[965] COH/HCC Initial Brief at 6-7.
[966] The Accounts at issue are Intangible Plant FERC account 303.02, General Plant FERC accounts 389 through 398, A&G FERC accounts 920, 921, 925, 926, 930.1, 930.2, 931 and 935, Other Rate Base Items in FERC accounts 1650, 2540, 2282, 2283, 1823 and Taxes Other Than Income Taxes in FERC accounts 4081.
[967] CEHE Ex. 45 at 14-16 (Troxle Rebuttal); Tr. at 1059 (Troxle Cross) (Jun. 27, 2019).
[968] CEHE Ex. 45 at 14-16 (Troxle Rebuttal).
[969] *Id.* at 15; Tr. at 1059 (Troxle Cross) (Jun. 27, 2019).
[970] Direct Testimony of Kit Pevoto, COH/HCC Ex. 3 at 18.
[971] COH/HCC Initial Brief at 40.
[972] CEHE Ex. 45 at 18 (Troxle Rebuttal).
[973] Tr. at 1048 (Troxle Cross) (Jun 27, 2019).

3. Municipal Franchise Fees [PO Issue 46]

The Commission should adopt CEHE's allocation of municipal franchise fees among customer classes, which is expressly supported by COH/HCC as "consistent with cost causation principles."[974] As noted in CEHE's initial brief, "[n]o party contests the reasonableness of the *amount* of CEHE's municipal franchise fee expenses,"[975] rather TIEC, and TIEC alone, contests the *allocation* of such fees.[976] TIEC acknowledges that its witness "made a similar proposal in CEHE's last [rate] case and the Commission adopted CEHE's proposal instead."[977] Nevertheless, TIEC asserts that its proposal "is not at odds with the Commission's actual findings in Docket No. 38339."[978] TIEC relies on the absence of any explicit rejection of its proposal in the single finding of fact that addressed the allocation of municipal franchise fees in Docket No. 38339.[979] However, in their Proposal for Decision in that proceeding, the ALJs explicitly discussed TIEC's position, explicitly discussed CEHE's arguments against TIEC's position, and explicitly rejected TIEC's position, stating that "[t]he ALJs agree with the arguments presented by CenterPoint and Staff and, therefore, recommend that the Commission approve CenterPoint's proposed allocation of municipal franchise fees."[980] The Commission's Order on Rehearing adopted not just the ALJs' findings of fact, but also the proposal for decision.[981] Thus, the Commission *has* previously considered and rejected TIEC's proposal and should do so again for the same reasons.

4. Transmission and Key Accounts

The Transmission and Key Accounts Department is one of four departments within the Power Delivery Solutions Division.[982] The Transmission and Key Accounts Department is, in turn, divided into three groups: Transmission Accounts and Support, Key Accounts, and Street Lighting.[983] OPUC contends that costs associated with the Transmission Accounts and Support group should be directly assigned to transmission.[984] CEHE does not disagree. In fact, as explained in CEHE's initial brief, expenses associated with these three groups have been directly

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[974] COH/HCC Initial Brief at 35.
[975] CEHE Initial Brief at 127.
[976] *See* TIEC Initial Brief at 67-70; *see also*, Docket No. 38339, TIEC's Initial Post-Hearing Brief at 37-40 (Oct. 22, 2010).
[977] TIEC Initial Brief at 66.
[978] *Id.*
[979] *Id. and see* Docket No. 38339, Order on Rehearing at Finding of Fact 179.
[980] Docket No. 38339, PFD at 156-157.
[981] *Id.* at Order on Rehearing, Ordering Paragraph No 1.
[982] Direct Testimony of Julienne P. Sugarek, CEHE Ex. 10 at 665-666 (Bates Pages).
[983] *Id.* at 668.
[984] OPUC Initial Brief at 78-79.

assigned by CEHE in this application to the respective functions and included in Schedule II-1-TRAN.[985] Thus, no allocation of costs as suggested by OPUC is appropriate or necessary.[986]

5. Allocation of Hurricane Harvey Restoration Costs [PO Issue 56]

CEHE addressed the Allocation of Hurricane Harvey Restoration Costs fully in its initial brief.

6. Other Cost Allocation Issues [PO Issue 46]

CEHE addresses this issue in Section VII.B.2 of its reply brief.

VIII. Revenue Distribution and Rate Design [PO Issues 4, 5, 43, 49, 50]

A. Residential Customer Charge

COH argues the Company's residential customer charge is "excessive" but introduced no evidence that the customer charge fails to accurately capture the TDCS costs upon which the charge is calculated.[987] Nor did COH explain why it would be reasonable to shift these costs to the Distribution function, increasing the Distribution charge.[988] Since deregulation, the Commission has favored setting rates at the cost of service without implementing gradualism principles.

Nor did COH address the fact that, when looking at the Company's *combined* fixed charges (customer and meter), the charges are decreased by $0.94 compared to the current fixed charges.[989] In fact, the Company's combined fixed charges are $3.32 less than TNMP's fixed charge ($7.85 to $4.53), $3.65 less than the current AEP Texas-North charges, and $2.21 less than the current AEP Texas-Central charges.[990] Moreover, looking at the fixed charge alone does not take into account the usage charges.[991] In fact, if the Commission were to approve the Company's proposed revenue requirement in this proceeding, the Company's total distribution charges would be in the middle of the residential distribution rates for other transmission and distribution utilities in ERCOT:

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[985] CEHE Initial Brief at 127-128; CEHE Ex. 2 at 418-504, Schedule II-I-TRAN.
[986] OPUC Initial Brief at 79.
[987] The Company's customer charge is calculated based on the revenue requirement functionalized to the Transmission & Distribution Customer Service ("TDCS") function. CEHE Ex. 45 at 37 (Troxle Rebuttal).
[988] CEHE Ex. 45 at 37 (Troxle Rebuttal).
[989] *Id.* at 38; CEHE Ex. 30 at 3056, Exh. MAT-5 at 1 of 7 (Troxle Direct).
[990] PUCT Comparison of Utilities Generic T&D Rates, Schedule Commission-1 (March 1, 2019), *available at* https://www.puc.texas.gov/industry/electric/rates/Trans/TDGenericRateSummary.pdf.
[991] CEHE Ex. 45 at 38 (Troxle Rebuttal).

Utility	Fixed Charges + Distribution Charge + DCRF Charge at 1,000 kWh[992]
TNMP	$33.52
AEP Texas-North	$31.04
CEHE (Proposed)	$27.18
Oncor	$23.44
AEP Texas-Central	$22.81

Clearly, there is nothing extraordinary or unreasonable about the Company's proposed rates in comparison to other TDUs.

B. Customer Charge on Per Meter Basis vs. Per Customer Basis

The Commission should approve CEHE's proposal to bill the Customer Charge and Metering Charge in its tariffs on a per meter basis instead of a per retail customer basis.[993] Doing so does not change CEHE's revenue requirement,[994] but it does ensure that those few customers with multiple meters are not subsidized by the vast majority who take service through a single meter.[995] The proposed change is consistent with longstanding tariff language indicating that each of CEHE's rate schedules is applicable to Retail Customers taking delivery to one Point of Delivery measured through *one Meter* and that any other metering options requested by a Retail Customer will be provided at an additional charge.[996]

COH/HCC opposes the change to per meter assessments.[997] COH/HCC's opposition is based on two assertions: that "customers with multiple meters would receive multiple bills" and that Mr. Troxle "acknowledged that there would be some customer confusion in switching to per-meter charges."[998] The first assertion is incorrect; the second mischaracterizes Mr. Troxle's testimony. Mr. Troxle testified that each invoice sent to a REP will include the number of meters covered by the bill and that he does not foresee a need to send multiple bills to customers.[999] Mr. Troxle also expressly testified, "I do not foresee a significant risk of confusion."[1000] COH/HCC cite cross examination in which Mr. Troxle "indicated . . . that there was some

[992] PUCT Comparison of Utilities Generic T&D Rates, Schedule Commission-1 (March 1, 2019), *available at* https://www.puc.texas.gov/industry/electric/rates/Trans/TDGenericRateSummary.pdf.; CEHE Ex. 30 at 3056, Exh. MAT-5 at 1 of 7 (Troxle Direct).
[993] *See id.* at 3020.
[994] Tr. at 973 (Troxle Cross) (Jun. 27, 2019).
[995] CEHE Ex. 45 at 45 (Troxle Rebuttal).
[996] CEHE Ex. 30 at Exh. MAT-9 (Troxle Direct) (Sections 6.1.2.2 and 7 of CEHE Tariff); CEHE Ex. 45 at 45-46 (Troxle Rebuttal).
[997] *See* COH/HCC Initial Brief at 37-38.
[998] *Id.* at 38.
[999] CEHE Ex. 45 at 47 (Troxle Rebuttal).
[1000] *Id.*

confusion."[1001] What COH/HCC does not explain is that Mr. Troxle was referring to confusion on the part of an earlier *cross examiner*, not on the part of *customers*. Earlier in the hearing, counsel for ARM had challenged Mr. Troxle's statement that the per meter assessment would not generate more revenue.[1002] He noted that if CEHE charges on a per meter basis and a customer has more than one meter, it will generate additional revenue.[1003] Mr. Troxle responded that *counsel's* confusion was the result of counsel and Mr. Troxle using terms differently.[1004] Mr. Troxle then explained that CEHE would receive more revenue from some individual customers (those with multiple meters) but that CEHE's overall revenue would not change.[1005] COH/HCC distorts Mr. Troxle's testimony to create an illusion of impending *customer* confusion. Notably, ARM and TEAM, the intervenors representing REPs, do not argue that the change to a per meter charge will lead to either customer confusion or multiple bills. If either outcome were likely, one would have expected the REPs—who bill customers—to have expressed concern.

ARM also opposes the change to a per meter assessment, but ARM's argument is little more than a lengthy version of "we've never done it that way before."[1006] On the one hand, ARM argues that the approximately 600 customers served by more than one meter will see their assessment at least double, apparently wanting to impress upon the Commission the burden on such customers.[1007] Just one paragraph later, however, ARM argues that a change is not warranted because any subsidization of such customers by others "is negligible."[1008] ARM seems to be arguing that the roughly 600 customers with multiple meters can save lots of money if the Commission will let them continue to spread the cost of their extra meters over the large number of customers—99.976% of customers[1009]—who have just one meter. That cynical position is inconsistent with cost causation principles and should be rejected.

H-E-B, which had previously opposed the switch to a per meter assessment, appears to have abandoned this argument as it is not addressed in H-E-B's initial brief.

[1001] COH/HCC Initial Brief at 38 (citing Tr. at 1029 (Troxle Cross)).
[1002] Tr. at 973 (Troxle Cross) (Jun. 27, 2019).
[1003] *Id.*
[1004] *Id.* at 973-974.
[1005] *Id.*
[1006] ARM Initial Brief at 6-7.
[1007] *Id.* at 6.
[1008] *Id.* at 7.
[1009] CEHE Ex. 45 at 46 (Troxle Rebuttal).

C. Transmission Service Rate

CEHE proposes to include its transmission cost of service in its base rates. This is addressed in Section X.A of CEHE's initial brief.

D. Transmission Service Facility Extensions

CEHE has reviewed TIEC's proposed tariff language submitted with its initial brief and has no objection to modifying the proposed Transmission Facility Extension Agreement ("FEA") included in the proposed tariff changes sponsored by Mr. Troxle to include a true-up of actual construction costs and the exclusion of "System Improvement Costs."[1010] As Ms. Sugarek noted at hearing, the true-up of construction costs within 30 days of completion of an FEA project (where "completion" means after all CEHE work orders associated with the project have been closed out) and exclusion of System Improvement Costs is already part of CEHE's normal practice relating to transmission service facility extensions.[1011] CEHE also has no objection to deleting the word "nonrefundable" in Section 2.1 of the Company's Construction Services Policy (Chapter 6.1.2.2 of its proposed tariff) under the "Costs" provision of that Section. CEHE does, however, object to TIEC's proposal for CEHE to issue a refund to a customer if the customer later uses its facility to serve another separate customer.[1012] The Company is unaware of such a situation ever arising in the past with respect to a CEHE-owned transmission facility paid for by a customer through a CIAC except perhaps in a subtractive metering arrangement, where the original customer that paid the CIAC conveys part of its customer premises to a second customer, and rather than requiring the second customer to execute a second transmission FEA for a new facility extension to serve that portion of the premises conveyed to it, the Company agrees to enter into a subtractive metering arrangement with both customers. In that situation, any refund of the initial CIAC paid by the first customer should occur between it and the second customer. Put differently, if a customer has built and owns a facility, any subsequent customer that wants to use that facility should negotiate with the customer that built and paid for the facility regarding its use, not CEHE.

E. Street Lighting Service

Staff continues to challenge CEHE's proposal to establish LED Luminaires as the new street light standard lamp type for Street Lighting Services and Miscellaneous Lighting Services

[1010] *See* TIEC Initial Brief at 75-76 and Attachment A (specifically, new subsections (a) and (b) on pages 91 and 92 of TIEC's brief).
[1011] Tr. at 1234-1235 (Sugarek Cross) (Jun. 27, 2019).
[1012] TIEC Initial Brief at 76-77.

under Lighting Services Section 6.1.1.1.6 of the Tariff.[1013] And, while the Company addressed its proposal extensively in its initial brief, certain comments in Staff's initial brief merit a reply. For instance, Staff claims that "LED lighting is an emerging technology with no established record of performance."[1014] One need only visit a local hardware store to see that LED lighting is now the standard—not a new and untested technology. The evidentiary record likewise confirms LED luminaire installations for streets and roadways across the country increased from 3% in 2010 to 28.3% in 2016.[1015] And, it is undisputed that GE announced in 2015 that it was discontinuing production of certain traditional lighting products as of January 1, 2016 and is prioritizing more efficient LED and smart light technology.[1016]

Further, while the Company is sympathetic to Staff's argument as it relates to customer choice,[1017] it respectfully submits that the prioritization of customer choice above all else under these facts and circumstances is not good policy. Specifically, while Staff characterizes the magnitude of "financial implications" of LED lighting as unclear,[1018] the uncontroverted evidence demonstrates that LED luminaires provide up to approximately 60% kWh energy savings for the end use customer.[1019] Similarly, Staff ignores the Company's uncontroverted evidence that over the life of the asset, the cost of an LED luminaire is less than the cost of an equivalent HPS luminaire.[1020] Staff likewise ignores the undisputed fact that maintaining an inventory of all luminaire types will result in additional costs that will ultimately be borne by ratepayers.[1021] The more prudent and cost-effective approach is to allow CEHE to install LED lighting in place of the other non-LED lamp types under its normal replacement cycle (i.e., as lights fail and reach the end of their useful lives).[1022] Consequently, installation of a non-LED lamp type—metal halide or high

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[1013] Staff Initial Brief at 77-81.
[1014] *Id.* at 78.
[1015] CEHE Ex. 33 at 22 (Sugarek Rebuttal).
[1016] *Id.* at 22-23.
[1017] Staff Initial Brief at 79.
[1018] *Id.*
[1019] CEHE Ex. 33 at 22 (Sugarek Rebuttal).
[1020] As explained in Ms. Sugarek's rebuttal testimony, the life of an HPS luminaire is estimated to be 29 years and the capital cost of installation is $153.78. Given that the life of the bulb is only five years, on average, a luminaire will require five bulb replacements over its used and useful life. These replacements cost $66.89 per replacement. Thus, the total cost of ownership is $488.23 [$153.78 + (5 * $66.89)]. The life of an LED luminaire is estimated to be 15 years and the capital cost is $201.20. Given that the life of an LED bulb is equivalent to that of a luminaire, no bulb replacements should be required. Two LED luminaire replacements will be required over 30 years. Thus, the total cost of ownership is $402.40 ($201.20 * 2). *Id.* at 21-22.
[1021] *Id.* at 23.
[1022] CEHE Ex. 10 at 686 (Sugarek Direct).

pressure sodium ("HPS"), e.g.—will only be in circumstances where LED lighting lamp installation is not possible or cost effective.[1023]

Finally, Staff's comment that CEHE "is capitalizing the LED installation costs and the ongoing operations and maintenance expenses associated with LED installations"[1024] was shown to be false at hearing. Ms. Sugarek testified that there are no operations and maintenance expenses associated with LED *installations*.[1025] However, once an LED light has been installed, there are various O&M costs, including but not limited to: fuse replacement, maintaining the post, conduit replacement, and clamp/connector replacement.[1026] In sum, it is reasonable for the Company to shift to LED as its standard offer street light. The Company's proposal should be approved.

F. Discretionary Services - Pre-Interconnection Study Costs

Solar Energy Industries Association ("SEIA") and Enel X North America, Inc. ("Enel X") argue that the Company has failed to provide sufficient information regarding the basis for its updated pre-interconnection study fee. In fact, the Company addressed the basis for all of its discretionary service fees in its direct case. Mr. Troxle explained that the Company proposed to update its discretionary service charges "to reflect the current cost of providing that service," described the process used by the Company to calculate the appropriate costs of each discretionary service, and included the proposed updated charge in Exhibit MAT-8 to his direct testimony.[1027] No party—including SEI and Enel X—raised this in their direct testimony. In fact, SEIA and Enel X did not even introduce direct testimony on the issue.[1028] The issue was in fact first raised in their initial brief, so this is the first time the Company has had the opportunity to address it.

The Company met its burden to support its discretionary services costs. No party introduced evidence challenging whether the current cost of providing this service is unreasonable. The Company's proposed pre-interconnection study fee is reasonable.

G. Other Rate Design Issues

CEHE has addressed all rate design issues identified in the direct testimonies filed by intervenors and Staff.

[1023] *Id.*
[1024] Staff Initial Brief at 79.
[1025] Tr. at 1054 (Troxle Cross) (Jun. 27, 2019).
[1026] CEHE Ex. 33 at 18 (Sugarek Rebuttal).
[1027] CEHE Ex. 30 at 3039-3040 & 3308, Exh. MAT-8 (Troxle Direct).
[1028] SEIA and Enel X filed a joint Statement of Position but did not address the pre-interconnection study fee specifically. Moreover, the statement of position is not evidence.

IX. Riders [PO Issues 4, 5, 43, 51, 52]

A. Rider UEDIT [PO Issue 51]

With respect to GCCC's assertion that "CenterPoint proposes to use the second year of the Rider's revenue requirement for all three years, subject to true-up in the final year," the evidence demonstrates that GCCC's witness, Mr. Kollen (and consequently GCCC) continues to misunderstand the Company's proposal. As shown in IV-J-7 UEDIT of the Company's H-I-J and CA Errata – 1, the Company calculated the Rider UEDIT amount by taking the total unprotected EDIT refund amount, with interest, and amortized it over a three-year period.[1029] A second year was not used. Mr. Kollen may be confused simply because his year two amount is $39,653,689.60 and the three-year average proposed by the Company is $39,654,022.[1030] The amounts are close, but Mr. Kollen remains incorrect. Thus, Staff supports the Company's calculation as it relates to retail delivery.[1031] As to Staff's argument that Rider UEDIT should be functionalized to both wholesale and retail customers[1032] the Company will defer to the Commission as to the appropriate functionalization.[1033]

1. Recovery Period for Rider UEDIT

Only TIEC argues that the Company's entire balance of TCJA-related unprotected EDIT should be returned to customers over a shorter time period than three years.[1034] Staff is fine with the Company's recovery period for retail delivery, but suggests that the wholesale portion should be refunded over one year (presumably because at $7.9 million, the wholesale portion is relatively small in proportion to the whole balance).[1035] Both proposals contain inherent inconsistencies and present potential problems. Specifically, that:

- the Company's EDIT balance may change significantly over time if a change in tax laws occurs or specific guidance from the Treasury or IRS is issued;[1036]
- the three-year period for returning unprotected EDIT to customers proposed by the Company is consistent with the period requested by CEHE for other regulatory assets and liabilities;[1037] and

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1029 CEHE Ex. 45 at 44 (Troxle Rebuttal).
1030 CEHE Ex. 2 at IV-J-7 UEDIT (Errata Schedules).
1031 Staff Initial Brief at 68.
1032 *Id.*
1033 CEHE Ex. 45 at 45 (Troxle Rebuttal).
1034 TIEC Initial Brief at 79.
1035 Staff Initial Brief at 68.
1036 CEHE Ex. 13 at 1007 (Pringle Direct).
1037 *See also Application of Houston Lighting and Power Company*, Docket No. 8425, Order at Finding of Fact 245 (Jun. 20, 1990) (addressing unprotected deferred taxes when the federal income tax rate decreased in 1986 and 1987

- a one-year return period would be much shorter than the unprotected EDIT refund periods approved in other *Texas* utility rate cases.[1038]

Put differently, TIEC—based on the opinion of an expert who has never testified in Texas before, cites only non-Texas cases in support of her recommendation, and reviewed limited materials in support of her opinions—would risk a potential incorrect refund to customers and treat CEHE differently on this issue than any other utility in the state, all for the sake of a faster refund. This should not be the case.

On the subject of Ms. LaConte's lack of expertise and TIEC's reliance on her statements in briefing, the evidence demonstrates that Ms. LaConte (and consequently TIEC) mischaracterize how ADFIT balances function. Specifically, Ms. LaConte and TIEC argue that they function as long-term, interest free loans from ratepayers.[1039] Yet, the Commission explicitly rejected this characterization long ago in the Company's first stranded cost proceeding, Docket No. 29526 noting:

> The Commission concludes that the ADFIT balance should not be deducted from stranded costs. In reaching this conclusion, the Commission rejects the characterization as a "loan from ratepayers" that must be repaid. The evidence presented during this proceeding indicates that ADFIT is not a loan from anyone.[1040]

Similarly, TIEC (again quoting Ms. LaConte) appears to argue that the mere existence of Congress' mandate to return protected EDIT balances under ARAM suggests that a faster return of unprotected EDIT balances is appropriate.[1041] This argument further demonstrates Ms. LaConte's, and hence TIEC's, misunderstanding of the issue. Congress, in mandating the use of ARAM came to the exact opposite conclusion of Ms. LaConte—that the most equitable approach, when it comes to returning EDIT, is generally to return EDIT over a *longer period*—consistent with the lives of the assets to which that EDIT is related.[1042] Despite Ms. LaConte's and TIEC's assertions otherwise, Congress could have allowed, but chose not to allow, EDIT to flow through to ratepayers over the shortest possible time period. In short, Ms. LaConte's

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and concluding that "[t]he evidence supports a three year amortization period for unprotected excess deferred income taxes").

1038 *See, e.g., Application of Oncor Electric Delivery Company LLC for Authority to Decrease Rates*, Docket No. 48325, Order at No. 3 (April. 4, 2019) (10-year amortization period); Docket. No. 48401, Order at No. 18 (5-year amortization period).

1039 TIEC Initial Brief at 78 (citing Ms. LaConte's Direct Testimony at 4).

1040 Docket No. 29526, Order on Rehearing at 78.

1041 TIEC Initial Brief at 79.

1042 CEHE Ex. 13 at 1004-1005 (Pringle Direct).

educational background does not include a background in tax,[1043] she is unfamiliar with the Commission's decisions on this and other issues, and her recommendations appear to reflect that lack of expertise and experience. For all these reasons, her (and TIEC's) proposals should be rejected.

A three-year time period of Rider UEDIT allows CEHE to appropriately track the Company's balances of protected EDIT and unprotected EDIT, take any changes into account if prompted by a change in the tax law or IRS guidance during that time period if they occur, and to record an over- or under-balance of amounts collected under the Rider UEDIT compared to the actual net liability amount.[1044] It is fair to both CEHE and its customers.[1045] And, Staff provides no justification at all as to why the wholesale portion should be returned over a shorter and thus, inconsistent time period.[1046] The Company's proposed recovery period should be approved.

2. Amounts Included in Rider UEDIT

GCCC continues to assert that Rider UEDIT should also include $200.35 million of EDIT related to ADFIT associated solely with the Transition Bonds and System Restoration Bonds,[1047] while Staff's initial brief was silent on this issue.[1048] TIEC, for the first time in briefing, picks up GCCC's argument.[1049] GCCC initially accuses the Company of attempting to "cloud the issue" by simply pointing out how Transition Bonds and System Restoration Bonds are paid.[1050] Unfortunately for GCCC, nothing is cloudy about the facts here. These issues have been fully litigated before; have been finally settled to the benefit of customers, CEHE, and the State of Texas; and should not be litigated again.

It is undisputed that the regulatory assets and contra regulatory assets that give rise to the balances at issue were not included in the Company's rate base and have been consistently excluded in prior rate cases and filings.[1051] And, contrary to TIEC's assertion that "CEHE should have brought this issue to the Commission's attention and obtained approval before taking a

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[1043] *See* Direct Testimony of Billie LaConte, TIEC Ex. 3 at 5 (Noting that Ms. LaConte has a B.A. in Mathematics and a Master's in Business Administration. She is not an accountant).
[1044] CEHE Ex. 12 at 909-910 (Colvin Direct).
[1045] CEHE Ex. 35 at 61-62 (Colvin Rebuttal).
[1046] Staff Initial Brief at 68; Staff Ex. 2 at 70 (Murphy Direct).
[1047] GCCC Initial Brief at 33-39.
[1048] Staff Initial Brief at 81.
[1049] TIEC Initial Brief at 5-7.
[1050] GCCC Initial Brief at 36.
[1051] CEHE Ex. 35 at 71 (Colvin Rebuttal).

windfall at ratepayers' expense,"[1052] it is undisputed that the Company was transparent with the Commission as to how it treated those assets when the Commission asked every utility in the state to quantify the impacts of the TCJA.[1053] It also remains undisputed that:

- all future and potential ADFIT issues related to transition costs and system restoration costs were settled in agreements approved by the Commission;[1054]
- GCCC and TIEC were signatories to those settlements;[1055]
- with respect to ADFIT issues related to transition costs, those issues were settled "*forever*"[1056] in a settlement agreement where the Company settled for an amount *$600 million lower than* the Company's original request and agreed to bear millions of dollars of up-front qualified costs;[1057]
- all of the ADFIT issues regarding system restoration costs were settled as part of a "full and complete settlement of all issues and *all potential issues* regarding treatment of the ADFIT associated with the system restoration costs being securitized;"[1058] and
- the ADFIT credit with respect to the system restoration costs applied to the system restoration cost balance included a return on the system restoration cost related ADFIT of $207,006,452, plus a return of and on a principal amount of $6,500,000 over the life of the System Restoration Bonds at *11.075%.*

Thus, it remains to be seen as to how GCCC and TIEC can characterize the Company's retention of securitization-related EDIT as a "windfall" in light of the substantial sacrifices made by the Company to settle these issues years ago.

Those same settlement amounts directly refute GCCC's and TIEC's arguments that ratepayers have "paid for the stranded cost and storm recovery balances"[1059] and that the settlement balances are "ratepayer money."[1060] It is undisputed that the ratemaking associated with determining customer benefit on the stranded cost and storm recovery balances was different than traditional ratemaking related to ADFIT.[1061] As such, once the cases were settled, given the almost $1 billion in benefits provided by those settlements, ratepayers were compensated fully. For this

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[1052] TIEC Initial Brief at 6.
[1053] Tr. at 806-810 (Tietjen Cross) (Jun. 26, 2019) (Mr. Tietjen's review of the Company's response to Commission Staff's discovery in Docket No. 47945 showing the treatment of transition and restoration bonds and CEHE's proposed treatment of EDIT).
[1054] CEHE Ex. 65 (Docket No. 39504 Settlement Agreement); CEHE Ex. 66 (Docket No. 37200 Settlement Agreement).
[1055] *Id.*
[1056] *Id.* at bates page 9.
[1057] CEHE Ex. 65; Tr. at 799-800 (Tietjen Cross) (Jun. 26, 2019).
[1058] *See* CEHE Ex. 66, Settlement Agreement at 4. (emphasis added).
[1059] GCCC Initial Brief at 36.
[1060] TIEC Initial Brief at 5.
[1061] Tr. at 786-788 (Tietjen Cross) (Jun. 26, 2019).

reason, it was appropriate for Mr. Tietjen to acknowledge in his direct testimony: "I believe that some amounts of the ADFIT balances may not be attributable to ratepayer supplied capital."[1062] In truth, by giving up $600 million in the settlement of Docket No. 39504, the Company more than compensated ratepayers for any benefits they could ever be owed. In the same vein, TIEC's comment that CEHE is proposing to "keep all the EDIT for itself"[1063] is undisputedly false. The record clearly reflects that through the return of protected EDIT in base rates and unprotected EDIT in Rider UEDIT, ratepayers will receive over $835 million in returned EDIT.[1064]

It is likewise disingenuous for TIEC to pronounce that the Commission assumed the federal corporate tax rate would remain 35% when determining the appropriate level of ADFIT related to securitization bonds.[1065] Mr. Tietjen admitted at hearing that the "forever" and "potential" language in the securitization and restoration final orders is unique.[1066] That uniqueness is logically related to the parties' reasonable expectation that tax rates can and do change over time and is evidence that the parties anticipated just the type of event that was the TCJA. Certainly, if the corporate tax rate had gone up, GCCC and TIEC would be pointing to that same settlement language if the Company were to argue for an increase in tax expense recovery to recognize a required then future tax cost. In short, the ratepayer benefits derived from settlement agreements that "forever" settled all "potential" ADFIT issues alone demonstrates that GCCC's (and now TIEC's) proposal to reopen these issues—let alone return *all* of the securitization-related EDIT to customers without consideration of the benefits those customers already received vis-à-vis the prior settlement of these issues—is misplaced.

To put this issue in its most simple terms, the entire ADFIT balance associated with the bonds at issue is $158 million. Neither GCCC, TIEC, or even Staff's filed testimony on this issue suggest a scenario where any re-measuring of the ADFIT benefit associated with the Transition Bonds or System Restoration Bonds could possibly *exceed* the benefit already provided to ratepayers through the $600 million black box reduction agreed to in Docket No. 39504 (by itself) or when combined with the $207 million ADFIT balance earning an 11.075% interest rate returned through the agreement in Docket No. 37200. Ratepayers are benefiting and will continue to benefit from the TCJA. Accordingly, there is no need for the Commission to further consider this issue.

[1062] Redacted Direct Testimony of Darryl Tietjen, Staff Ex. 1A at 25 (Bates Pages).
[1063] TIEC Initial Brief at 5.
[1064] CEHE Ex. 35 at 75 (Colvin Rebuttal).
[1065] TIEC Initial Brief at 6.
[1066] Tr. at 801-802 (Tietjen Cross) (Jun. 26, 2019).

GCCC and TIEC should not be permitted to challenge settlement agreements to which they are each a signatory. Ratepayers were well (and finally) compensated years ago so as to ensure that they received a full ADFIT benefit on Transition Bonds and System Restoration Bonds that would never need re-measuring.

Finally, as Mr. Tietjen acknowledged at hearing, the statutory framework surrounding securitizations is unique.[1067] Financing orders are intended to be final.[1068] To this end, the financing orders for each series of CEHE's Transition Bonds and System Restoration Bonds note that the financing order is final and not subject to rehearing by the Commission.[1069] The evidence demonstrates that these statutory protections are essential in order for customers to realize the benefits of the securitizations,[1070] because only by eliminating virtually all credit risk from the securitization bonds could the securitization bonds receive AAA credit ratings and a consequently lower cost of capital that could be enjoyed by customers. To put future securitizations at risk—which Mr. Tietjen's direct testimony and testimony at hearing confirms could result from reopening settled securitization cases[1071]—is simply unnecessary and would be poor public policy, especially given the undisputed customer benefit amounts in the record.

B. Merger Savings Rider

GCCC's call for a "merger savings rider" or an adjustment to the Company's revenue requirement for savings associated with the Vectren acquisition also continues to be without merit.[1072] It is undisputed that, at this time, savings associated with the Vectren acquisition that may be realized by CNP are not known.[1073] The cost to integrate technology systems[1074] and the degree to which savings may be achieved in light of the future cost of goods and services and labor are unknown.[1075] It is also undisputed that CNP's gas operations and corporate services are

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1067 Tr. at 801-802 (Tietjen Cross) (Jun. 26, 2019).
1068 Tex. Util. Code § 39.303(d).
1069 *Application of CenterPoint Energy Houston Electric, LLC for Financing Order*, Docket No. 30485, Financing Order, Conclusion of Law 45 at 66 (Mar. 16, 2005); *Application of CenterPoint Energy Houston Electric, LLC for Financing Order*, Docket No. 34448, Financing Order, Conclusion of Law 49 at 69 (Sept. 18, 2007); *Application of CenterPoint Energy Houston Electric, LLC for a Financing Order*, Docket No. 39809, Financing Order, Conclusion of Law 46 at 62 (Oct. 27, 2011); *Application of CenterPoint Energy Houston, LLC for a Financing Order*, Docket No. 37200, Financing Order, Conclusion of Law 47 at 67 (Aug. 26, 2009).
1070 Tr. at 804-805 (Tietjen Cross) (Jun. 26, 2019).
1071 Staff Ex. 1A at 25 (Tietjen Direct).
1072 GCCC Ex. 1 at 48 (Kollen Direct).
1073 Rebuttal Testimony of Jeffrey S. Myerson, CEHE Ex. 47 at 18 (Bates Pages).
1074 *Id.* at 9.
1075 *Id.*

expected to benefit most from savings and synergies—not CEHE.[1076] In short, no one can project how these factors will ultimately impact net savings at this point and it is not known what net amount of any savings CNP may realize, much less what the appropriate attribution of those net savings is to CEHE.

However, the evidence is clear that savings do not occur without CNP first having to incur costs to achieve those savings.[1077] Specifically, before savings can be achieved, CNP must incur costs to integrate Vectren into CNP and costs related to employee separations.[1078] The evidence submitted by the Company in CEHE witness Jeffrey S. Myerson's rebuttal testimony, at CEHE Exhibit 47, sets forth the *confidential* early estimate of CNP's costs to achieve—and it is *substantial*.[1079] Mr. Myerson's testimony demonstrates that if the *actual* costs to achieve the acquisition-related savings were included in GCCC's proposed "Merger Savings Rider," the result for 2019 would be a *large surcharge* to customer bills—not a refund.[1080]

GCCC's proposed Merger Savings Rider is also beyond the Commission's lawful authority as it violates the prohibition against retroactive ratemaking. The prohibition against retroactive ratemaking is well-settled. It requires that utility rates generally have only prospective effect and prohibits the Commission from setting rates that would allow a utility to recoup past loses or refund excess profits to consumers.[1081] GCCC's proposed Merger Savings Rider does precisely this.

Regardless, the evidence demonstrates that the Commission already has an effective tool that monitors the Company's cost of service on an annual basis—the Company's Earnings Monitoring Report ("EMR"). Per Commission Rule 25.73, the Commission uses the EMR to properly monitor a utility's earnings and has acknowledged that the "report has been used as a tool to review a utility's actual earnings for an historical period."[1082] The Commission uses the EMR to determine if a utility is earning above its authorized return, regardless of the cause, and can be used to inform the Commission's decision as to whether to require a utility to file a base rate

[1076] *Id.* at 13-14.
[1077] *Id.* at 9.
[1078] *Id.* at 14-15.
[1079] *Id.* at 13.
[1080] *Id.* at 19.
[1081] *Office of Pub. Util. Counsel v. Pub. Util. Comm'n of Tex.*, 888 S.W.2d 804, 808 (Tex. 1994); *State v. Pub. Util. Comm'n*, 833 S.W.2d 190, 199 (Tex. 1994); *Cent. Power & Light Co./Cities of Alice v. Pub. Util. Comm'n of Tex.*, 36 S.W.3d 547, 554 (Tex. App.—Austin 2000, pet. denied).
[1082] *Project to Revise Earnings Monitoring Report Forms for Electric Utilities,* Docket No. 39040, Final Order at 31 (Jan. 7, 2012).

case.[1083] It likewise ensures that if CEHE is earning above its authorized return, it will be prohibited from filing a DCRF.[1084] Finally, it is undisputed that under 16 TAC § 25.246, CEHE may be required to file a base rate case approximately four years following the implementation of rates in this case.[1085]

C. Other Riders

CEHE addressed its Other Riders fully in its initial brief.

X. Baselines for Cost-Recovery Factors [PO Issue 4, 5, 43, 53]

A. Transmission Cost of Service

CEHE addressed Transmission Cost of Service fully in its initial brief.

B. Transmission Cost Recovery Factor

Although addressed in the Transmission Service Rate Section of its brief, TIEC's real argument is with the Transmission Cost Recovery Factor. TIEC argues that, "to prevent over-recovery," all transmission costs should be recovered through the Company's Rider TCRF instead of through base rates. This proposal flies in the face of the clear language of Rule 25.193 and should be rejected.[1086]

The TCRF is intended to capture the "the amount of wholesale transmission cost changes approved or allowed by the commission to the extent that such costs vary from the transmission service cost utilized to fix the base rates of the DSP"—i.e., the incremental differenced in costs.[1087] It was *never* intended to collect all transmission costs.[1088] The Company's approach is consistent with Rule 25.193 and the requirements in the Commission's TDU RFP instructions.[1089] Further, in the RFP sample forms, the rate design sheets are clearly designed to reflect a transmission charge in base rates.[1090] Notable, TIEC only points to *settled* cases in which this novel treatment of the TCRF mechanism is applied.[1091] The Company is not aware of a litigated case in which the Commission has required an electric utility to act contrary to the obvious intent of the rule.

[1083] CEHE Ex. 35 at 63 (Colvin Rebuttal).
[1084] CEHE Ex. 47 at 19 (Myerson Rebuttal).
[1085] *Id.*
[1086] TIEC Initial Brief at 71-74.
[1087] CEHE Ex. 45 at 20 (quoting 16 TAC § 25.193(b)) (Troxle Rebuttal).
[1088] *Id.*
[1089] *Id.* (citing page 59 of the Instructions, which refers to the allocation of the functional requirements, and on page 63, which refers to the revenue requirements by the function (Transmission is one of the functions)).
[1090] *Id.*
[1091] TIEC Initial Brief at 72-73.

Moreover, TIEC's concerns about load growth ignore other impacts of load growth can drive down cost recovery at the same time,[1092] like increased O&M, increased investments in its system,[1093] changes in weather, economic conditions, or tax rates, increased customer attribution, or energy efficiency.[1094] These concerns are also mitigated by 16 TAC § 25.246, which requires all investor-owned electric utilities to file a rate case every four years,[1095] at which point the Company's entire cost of service will be subject to review.[1096] In the interim, the Commission retains the authority to require a rate case any time.[1097] Accordingly, there is simply no justification to deviate from the RFP and Commission's rules in order to shift all transmission costs into the TCRF.[1098]

XI. Other Issues

A. Contested Issues

1. Securitization-related EDIT

Section IX.A.2 of CEHE's initial brief explains why Mr. Kollen's proposal to include in Rider UEDIT $200.35 million of EDIT related to certain Transition Bonds and System Restoration Bonds should be rejected.

2. H-E-B Service Complaint

The only reliable, system-wide data in this case confirms that CEHE provides reliable electric service that meets or exceeds the standards established by the Commission.[1099] H-E-B remains the lone intervenor raising service complaint issues in this proceeding. In its initial brief, H-E-B states that it has had ongoing concerns with the service it receives from CEHE and as a result, opposes certain of CEHE's requests in this docket, including reimbursement for certain capital projects and CEHE's proposed return on equity.[1100] H-E-B's argument suffers two critical flaws: its data is limited to fewer than 200 locations out of 2.5 million in CEHE's service territory and its data is unreliable even as to those few locations.

[1092] CEHE Ex. 45 at 21 (Troxle Rebuttal).
[1093] *Id.*
[1094] *Id.*
[1095] *Id.* at 22.
[1096] *Id.*
[1097] *Id.*
[1098] *Id.*
[1099] CEHE Initial Brief at 146.
[1100] H-E-B Initial Brief at 4, 9-10.

Even if taken as true, H-E-B's allegations concerning its 166 locations would not present an accurate picture of the overall reliability of CEHE's service. In contrast to H-E-B's depiction of its own experience, Scott Norwood, on behalf of the City of Houston, stated:

> [o]ver the last five years CEHE has received only approximately 120 customer complaints per year related to outages or adequacy of service. This number of complaints represents less than 0.005% of the Company's 2.5 million customers, which indicates a high level of customer satisfaction with CEHE's service reliability.[1101]

CEHE's System Average Interruption Duration Index ("SAIDI") levels from 2008 have nearly always met Commission standards.[1102] In the test year of 2018, CEHE anticipates no penalties with respect to SAIDI levels.[1103] Mr. Norwood describes the SAIDI levels as ". . . translat[ing] to average customer service reliability of approximately <u>99.98%, which is very good</u>."[1104] It would be inappropriate to adjust CEHE's revenue requirement—whether through disallowance of capital expenditures or adjustments to CEHE's requested ROE or capital structure—based on the experience of one customer, even a customer with 166 locations, out of 2.5 million.

Further, H-E-B does not offer reliable data to back up its assertions even as to its own facilities. H-E-B's data come only from its facilities that have on-site generation installed, and only since such generators were installed.[1105] Mr. Presses admitted that "H-E-B does not have any engineering documentation regarding reliability studies at our own facilities."[1106] Ms. Sugarek, on the other hand, provided detailed information with respect to all H-E-B locations.[1107] Ms. Sugarek's data shows a less serious outage problem than the information put forth by H-E-B.[1108]

H-E-B is also unable to prove the extent to which the service issues it describes are the result of CEHE's reliability issues. Mr. Presses claims that all outages described in his testimony are necessarily limited to those caused by CEHE because "[w]e have a system on the distributed generation side that records the drop in voltage" and because "we also have no lights and refrigeration in our stores."[1109] However, during cross examination, Mr. Presses conceded that on at least two occasions there were outages meeting those same criteria that nevertheless required

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[1101] COH/HCC Ex. 1 at 9 (Norwood Direct).
[1102] CEHE Ex. 33 at 4-5 (Sugarek Rebuttal).
[1103] *Id.* at 5.
[1104] COH/HCC Ex. 1 at 9 (Norwood Direct).
[1105] Direct Testimony of George W. Presses, H-E-B Ex. 1 at 10.
[1106] Tr. at 401 (Presses Cross) (Jun. 25, 2019).
[1107] CEHE Ex. 33 at 7 (Sugarek Rebuttal).
[1108] *Id.* at 7-8.
[1109] Tr. at 417 (Presses Cross) (Jun. 25, 2019).

corrective action solely on the H-E-B side of the meter.[1110] He further acknowledged that on one occasion a representative from the distributed generation provider stated that an electrical outage was caused by an issue in the store.[1111] In its initial brief, H-E-B even states that ". . . H-E-B does occasionally experience outages that are due to failures of H-E-B's equipment. . ."[1112] The evidence demonstrates that some of H-E-B's outages are due to problems with H-E-B's own equipment, and that H-E-B cannot reliably distinguish which outages are the result of CEHE service disruptions as opposed to H-E-B equipment failures. Furthermore, H-E-B's argument that CEHE granted it permission to operate its distributed generation equipment is nothing but a red herring; the evidence establishes that CEHE has been working over recent months to investigate and address the unique issues associated with that equipment.

CEHE offered to look into the issue, proposing to engage a third party at CEHE's own expense, to study H-E-B's concerns. Although a meeting was scheduled for May 28, 2019, Mr. Presses canceled the meeting and has not responded to CEHE's attempt to reschedule.[1113]

Significantly, only one party to this proceeding—H-E-B—has questioned the reliability of CEHE's service. Indeed, another party—COH—argues that CEHE is *too* reliable. CEHE disputes H-E-B's allegation that CEHE failed to provide reliable service to H-E-B. Nevertheless, even if H-E-B's contentions were to be true, the record has shown that CEHE provides reliable service to its customer base *as a whole*. CEHE should be judged with how it performs overall and not with respect to a single customer that represents only 0.0000664% of CEHE's total customer base.[1114]

3. 45-Day Notice Issue

ARM and TEAM argue that REPs should be given at least 45 days prior to rates taking effect in order to accommodate the 45-day notice they are required to provide their customers when rates change. To be clear, under PURA, rates take effect on the date requested by the utility unless the rates are suspended.[1115] If the Commission suspends rates, the rates will go into effect 150 days after the date the rate change would otherwise be effective.[1116] However, because the Company has already agreed to extend the statutory deadline in this case by five days until October

[1110] *Id.* at 406-09.
[1111] *Id.* at 409-10.
[1112] H-E-B Initial Brief at 17.
[1113] *Id.* at 15-16.
[1114] On page 146 of its Initial Brief, CEHE mistakenly included an extra zero in this number. The number was stated correctly on page 148 and is stated correctly here. It is, in any event, *de minimis*.
[1115] PURA § 36.102(a).
[1116] *Id.* § 36.108(a)(2).

12, 2019, it does not believe that further suspension of the deadline is appropriate or necessary. The regulatory construct currently in place has required TDUs and REPs to work together to address timing issues just like this since deregulation, and the Company has worked with REPs in its service area to address these concerns in the past. The issue ARM and TEAM raise is a broader concern that affects all REPs and TDUs and should be addressed in a rulemaking and not by manipulation of the effective date required by PURA.

B. Uncontested Issues

CEHE's initial brief addresses all uncontested issues.

XII. Conclusion

CEHE respectfully requests that the Commission approve the rates requested in its application and grant the Company such other relief to which it has shown itself entitled.

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CERTIFICATE OF SERVICE

I hereby certify that on this 16th day of July 2019, a true and correct copy of the foregoing document was served on all parties of record in accordance with 16 Tex. Admin. Code § 22.74.

Patrick H. Peters III