Account		Existing Life	Existing Curve	CENTERPOINT Proposed Life	CENTERPOINT Proposed Curve	TCUC Proposed Life	TCUC Proposed Curve
353	Station Equipment	47	R1	53	R0.5	56	R0.5
354	Towers and Fixtures	60	R4	59	R2.5	66	R2
362	Station Equipment	47	R1.5	48	R1	55	R0.5
364	Poles, Towers and Fixtures	35	R0.5	35	R0.5	45	R0.5
365	OH Conductors and Devices	40	R0.5	38	R0.5	40	R0.5
366	Underground Conduit	37	S6	62	R2.5	65	S1
367	Underground Conductor and Devices	31	R0.5	38	R0.5	42	L0
368	Line Transformers	28	R1	28	R1	32	L0
390	Structures and Improvements	40	R2	50	R4	58	R2

As explained in Mr. Watson's rebuttal testimony, Mr. Garrett's recommended life curves are derived from an arbitrary and unsound methodology that disregards Mr. Watson's SPR and actuarial analysis and the Company-specific plant data, operations and asset experience upon which Mr. Watson's recommendations are based. Instead, Mr. Garrett relies on the service lives approved for *other* utilities (two of which are from Oklahoma), without explaining the reasonableness of such reliance and without providing any of the evidence upon which the other utilities' service lives were determined.[690] His approach represents a significant departure from well-established depreciation practices and the depreciation methodologies relied upon by this Commission in prior cases.

Specifically, Mr. Garrett argues (incorrectly) that because the Conformance Index ("CI")[691] results for *some* (but not all) accounts are average or low, *all* of Mr. Watson's SPR analysis and the data upon which it is based is "unreliable."[692] He also argues that Mr. Watson should not rely on operational information from the Company because, he claims without any evidence, Company personnel would not be objective in their input.[693] To be clear, there is nothing "unreliable" about the Company's data or the SPR analysis itself, which the Company has used to set depreciation

[690] Rebuttal Testimony of Dane A. Watson, CEHE Ex. 41 at 15-20.
[691] The CI is one measure used to evaluate the SPR analyses and how well the Company's actual data conforms to the simulated Iowa Curves. Visual matching between actual and calculated balances is then used to expand the analysis, and review of Company's actual assets and experience are also used to confirm the recommendation. CEHE Ex. 25, Exh. DAW-1 at 2476-2479 (Watson Direct); CEHE Ex. 41 at 12-13 (Watson Rebuttal).
[692] Direct Testimony and Exhibits of David Garrett, TCUC Ex. 2 at 18-19, 25, 28-29 & 32.
[693] Mr. Watson specifically rebutted this assertion at the hearing and explained how he validates the information he includes in his study to ensure the reasonableness of his recommendations. Tr. at 342-345 & 349-353 (Watson Cross) (Jun. 25, 2019).

rates since as far back as 1985,[694] including the existing rates that were adopted by the Commission in Docket No. 38339.[695] In fact, as explained in Mr. Watson's rebuttal testimony, when a service life recommendation demonstrates a low CI result, it demonstrates that the assets in the account could be experiencing changes in life characteristics due to materials changes, operational changes or other external factors.[696] A low CI does not indicate that the data should simply be disregarded, but rather that the expert *should rely even more upon operational information obtained from Company personnel about the assets in the account*,[697] information that Mr. Garrett dismisses out of hand.[698] Moreover, Staff confirmed that the methods applied by Mr. Watson are appropriate and commonly relied on to determine reasonable life and survivor characteristics of property accounts.[699] In fact, Mr. Tuvilla arrived at the exact same results as Mr. Watson when he conducted his own independent SPR analysis.[700]

Mr. Garrett does not produce any evidence that demonstrates how the three utilities upon which he relies are comparable to the Company. He did not analyze those utilities' retirement units or capitalization policies to determine if they are comparable to CEHE's or demonstrate that the forces of retirement are similar[701] or that their accounting practices are comparable.[702] He does not present the depreciation studies for any of the utilities or any other evidence to demonstrate what prior commissions relied on in approving the service lives he points to. In fact, his reliance on other utilities contradicts long-standing Commission precedent[703] that defers to company-specific data in setting rates as well as state court precedent that finds "depreciation rates are company and account specific."[704] It also defies sound depreciation theory, which requires that

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[694] CEHE Ex. 41 at 4 (Watson Rebuttal) (citing Docket Nos. 6765, 12065, 22355, 32093, and 38339).
[695] *Id.*
[696] *Id* at 10-12.
[697] *Id.* at 11-12 (Watson Rebuttal) (quoting F. K. Wolf and W.C. Fitch, *Depreciation Systems* at 249-250 (1994) ("Uniformly low conformance indexes most often result because the life characteristics of the property have changed over time. . . . The analyst must rely on judgment to select a curve type and average age that are consistent with other knowledge about the property in the account.").
[698] Direct Testimony and Exhibits of David Garrett, TCUC Ex. 2 at 18-19, 25, 28-29 & 32.
[699] Staff Ex. 9 at 4-9 (Tuvilla Direct).
[700] Tr. at 827 (Tuvilla Cross) (Jun. 26, 2019); Staff Ex. 9 at 6 (Tuvilla Direct).
[701] CEHE Ex. 41 at Exh. R-DAW-1 (TCUC Response to CEHE 2-7) (Watson Rebuttal).
[702] *See* Tr. at 835 (Tuvilla Cross) (Jun. 26, 2019) (discussing differences in accounting practices among utilities).
[703] *See, e.g., Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 28840, Proposal for Decision (PFD) on Remand at 58 (Nov. 16, 2004) (indicating a preference for using a utility's own data to establish depreciation rates over that of other utilities).
[704] CEHE Ex. 41 at 15 (Watson Rebuttal) (citing *City of Amarillo v Railroad Commission of Texas*, 894 S.W.2d 491, 501 (Tex. App.—Austin 1995, writ denied) (". . . depreciation rates are company and account specific."); Docket No. 28840, PFD on Remand at 68).

depreciation rates be established on a utility-specific basis using the utility's own historical data[705] and only suggests relying on other utilities in extraordinary circumstances, such as when a utility lacks *any* plant data for its assets.[706]

With regard to the specific life recommendations for each of the nine accounts that Mr. Garett challenges, the Company's direct and rebuttal cases demonstrate that each of Mr. Watson's recommendations captures reasonable and representative life expectations as demonstrated in the SPR analysis, the CI and retirement experience index results, and specific information about the Company's plant base, operations and life expectations as culled from Mr. Watson's experience and interviews with Company engineers. These recommendations and the rebuttal of Mr. Garrett's recommendations are addressed in more detail in Mr. Watson's rebuttal testimony.

D. Affiliate Expenses [PO Issue 35]

PURA § 36.058 allows a utility to recover expenses paid by the utility to an affiliate entity if it demonstrates that its payments are "reasonable and necessary for each item or class of items as determined by the commission."[707] To recover these expenses, the utility must demonstrate two things: (1) the reasonableness and necessity of each item or class of items allowed; and (2) that the price to the electric utility is not higher than the prices charged by the supplying affiliate to its other affiliates or divisions or to a nonaffiliated person within the same market area or having the same market conditions.[708]

CEHE has met its burden under PURA § 36.058 to recover its reasonable and necessary affiliate costs, which totaled $293.4 million for the test year.[709] The evidence demonstrates that

[705] *Id* at 4-5.
[706] *Id.* at 10 & 16-17; *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, ...").
[707] *See* PURA § 36.058(a)(1)-(2) (Vernon 2016, Supp. 2018); *see also* 16 TAC § 25.231(b)(1)(A) (referring to PURA § 36.058 for cost of service standards for affiliate expenses); *Cities of Corpus Christi v. Pub. Util. Comm'n of Texas*, No. 03-06-00585-CV, 2008 WL 615417, at *10 (Tex. App.—Austin 2008, no pet. h) (noting that under PURA § 36.058 "the Commission may not include affiliate costs in a utility's rates unless the Commission makes a specific finding of reasonableness and necessity for each item or class of items, and also finds that the price charged by the affiliate to the utility is no higher than the price charged by the affiliate to other purchasers"); *Railroad Comm'n of Texas v. Rio Grande Valley Gas Co.*, 683 S.W.2d 783 (Tex. App.—Austin 1984, no writ).
[708] *See* PURA § 36.058(c).
[709] CEHE Ex. 15 at 1067-1115 (Townsend Direct); CEHE Ex. 12 at 918-926 (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); Direct Testimony of Shachella D. James, CEHE Ex. 17 at 1582-1586 (Bates Pages); Direct Testimony of Rebecca Demarr, CEHE Ex. 18 at 1654 (Bates

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Service Company and CERC provided services to CEHE during the test year.[710] Service Company and CERC are subsidiaries of CNP.[711] Services provided by Service Company included Corporate Services, Business and Operations Support, Technology Operations, and Regulated Operations Management.[712] CERC provided operational support in the form of periodic interval data recorder ("IDR") meter reading, GIS and computer-aided design services, fleet services, broadband services, damage prevention compliance reporting, and line locating.[713] No party challenged the reasonableness, necessity, or allocation methodology of any service.

The depth of the evidentiary record demonstrating the reasonableness of and necessity of each affiliate function is demonstrated through the unchallenged testimony of Company witnesses, as laid out in the table below.

Witness	Class	Affiliate	Pages
Kristie L. Colvin	Accounting	Service Company	920-926
	Executive Management	Service Company	913-918
	Chief Financial Officer	Service Company	918-920
Charles W. Pringle	Tax	Service Company	993-996
Robert B. McRae	Treasury and Investor Relations	Service Company	2862-2875
M. Shane Kimzey	Legal, Regulatory, and Government Affairs	Service Company	1668-1678
Kelly C. Gauger	Audit Services	Service Company	1695-1703
Lynne Harkel-Rumford	Human Resources	Service Company	1835-1839
Diane M. Englet	Corporate Communications and Community Relations	Service Company	1711-1738
John E. Slanina	Business & Operations Support	Service Company	1559-1571
Shachella D. James	Technology Operations	Service Company	1582-1586
Rebecca Demarr	Customer Operations	Service Company	1654
Michelle M. Townsend	Environmental Safety & Training	Service Company	1082
	Strategic and Financial Planning	Service Company	1082
	Distribution Support	CERC	1085-1088
	Distribution Support-General	CERC	1085-1088
	Meter Reading	CERC	1085-1088
	Transportation	CERC	1085-1088

Pages); CEHE Ex. 22 at 1835-1839 (Harkel-Rumford Direct); and Direct Testimony of Diane M. Englet, CEHE Ex. 21 at 1771-1738 (Bates Pages).

[710] CEHE Ex. 15 at 1070 (Townsend Direct).

[711] *Id.* at 1118 Exh. MMT-1.

[712] *Id.* at 1071.

[713] *Id.* at 1071-1072.

Additionally, the evidence demonstrates that:

- the provision of affiliate services to CEHE is pursuant to Service Level Agreements ("SLAs") that are executed annually between the Service Company, CERC and CNP affiliates;[714]
- the SLAs require that (1) the price charged for each service will be the same as that charged to every other CNP business unit for like services for a given period; (2) amounts charged for items not allowed for recovery in regulated rates must be separately identified and billed separately so that the amounts can be reported as required; (3) amounts charged must be reasonable and necessary in order to provide that service; and (4) any allocation should reasonably approximate the actual costs incurred in providing that service;[715]
- Service Company's rigorous budgeting preparation and review process, prior to approval, encourages the Service Company functions to be disciplined and careful in establishing their budgets;[716]
- prior to the start of the annual budget process and on a monthly basis, function leaders are monitoring actual costs to the budgeted amounts;[717]
- as an additional cost control measure, and on a monthly basis, CEHE also monitors the costs it receives from Service Company;[718]
- before expenses are processed, three committees, the Executive Committee, the Risk Oversight Committee and the Commitment Review Team, provide thorough corporate review, oversight and control of significant expenditures for all business units and Service Company expenses;[719]
- financial system controls, processed through SAP automation, assure that formulaic affiliate billings are accurate and timely;[720]
- all costs for a given service that are directly related to affiliates, including CEHE, are directly billed at cost;[721] and
- if allocated, costs are not higher than the prices charged by Service Company and CERC for the same class of items to the Company's affiliates or divisions.[722]

In total, the significant evidence presented by CEHE demonstrates that the affiliate costs for which CEHE seeks recovery meet the Commission's affiliate cost recovery standard and should be recovered in full through rates.

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714 *Id.* at 1090.
715 *Id.*
716 *Id.* at 1094.
717 *Id*
718 *Id.*
719 *Id.* at 1095-1096.
720 *Id.* at 1097.
721 *Id.* at 1099.
722 *Id.*

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1. Vectren Issues

To more accurately capture the normal, recurring activities of Service Company, an adjustment was made to normalize integration planning billings to reflect Service Company's employee labor that would have been billed to CEHE during this time if the integration planning for the Vectren transaction had not occurred.[723] Ms. Dively disagrees with this adjustment by arguing that it is not known and measurable.[724] She is incorrect. The adjustment is calculated based on CEHE's portion of total test year billings from the Service Company after removing the abnormal integration planning billings.[725] 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.[726] CEHE witness Michelle Townsend testified that 2018 Service Company planned billings to CEHE are representative of ongoing work performed by Service Company on behalf of CEHE.[727] Ms. Townsend also testified that work on Vectren integration activities is not part of the normal daily activities provided by Service Company to CEHE or other business units.[728] This testimony is uncontroverted. This information, in turn, allowed CEHE to calculate with reasonable accuracy the adjustment necessary to capture normal Service Company billings to CEHE that would have occurred if normal support activities had been performed during the test year. As a result, the adjustment reflects a necessary, known and measurable increase of $1.6 million in affiliate billings to CEHE that should be adopted.

2. Compensation for Use of Capital

Ms. Dively proposes to exclude $7,786,463[729] and Mr. Filarowicz recommends that the Commission disallow $4,942,320[730] for carrying charges associated with affiliate or shared assets. While Ms. Dively does not challenge the legitimacy of the payments, she argues that the Company did not meet its affiliate burden under the statute. In contrast, Mr. Filarowicz argues that the equity portion of carrying charges on Service Company's assets should be disallowed. Both Ms. Dively's and Mr. Filarowicz's arguments lack merit and should be rejected. Although Mr. Filarowicz argues that he has relied on Commission decisions in Docket Nos. 43695 and 46449 as support for

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723 CEHE Ex. 37 at 16 (Townsend Rebuttal).
724 OPUC Ex. 1 at 46-50 (Dively Direct).
725 CEHE Ex. 37 at 16-17 & 30-34, Exh. R-MMT-2 (Townsend Rebuttal).
726 CEHE Ex. 15 at 1112 (Townsend Direct).
727 *Id.* at 1111-1112.
728 *Id.*; CEHE Ex. 37 at 16-17 (Townsend Rebuttal).
729 OPUC Ex. 1 at 39-40 (Dively Direct).
730 Staff Ex. 4A at 27 (Filarowicz Direct).

his position, he admits that he has not fully followed the Commission's determination in those cases.[731] Moreover, CEHE was not a party to those cases and it is not clear whether the decisions in those cases were based on the facts of those particular cases or were intended to have broader effect.[732] Here, CEHE has shown that Service Company assets are used and useful and held for the benefit of the business units, including CEHE.[733] 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.[734] 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. This is consistent with PURA § 36.051.

Ms. Dively's contention that CEHE's capital payment to Service Company should have been included on Schedule V-K-7 is equally unpersuasive.[735] The Commission's Schedule V-K-7 RFP Instructions require CEHE to list services by class and service category. Compensation for use of Capital is a return on investment applied to the Service Company assets.[736] It is not a class or service category, it is a cost associated with several of the classes and service categories.[737] 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.[738] Perhaps more importantly, CEHE provided detailed testimony from 11 witnesses describing the reasonableness and necessity of the services provided to CEHE from Service Company during the test year. These services necessarily encompass both Service Company labor and the use of Service Company assets. CEHE also provided evidence demonstrating that the costs are not higher than the prices charged by Service Company and CERC for the same class of items to CNP's other affiliates or divisions. Thus, the Shared Services amounts identified on V-K-7 are fully eligible for recovery in CEHE's rates and satisfy the applicable affiliate standard.

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[731] *Id.*
[732] CEHE Ex. 37 at 14 (Townsend Rebuttal).
[733] *Id.* at 13-14.
[734] *Id.* at 13.
[735] OPUC Ex. 1 at 37 (Dively Direct).
[736] CEHE Ex. 37 at 15 (Townsend Rebuttal).
[737] *Id.*
[738] *Id.*

3. Service Company Pension and Benefit Costs

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

4. Affiliate Carrying Charges

This issue is addressed in CEHE's Initial 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 Initial Brief at Section IV.B.3.a. Issues relating to payment and recovery of incentive compensation are addressed in CEHE's Initial 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 determines the level of expense that is likely to occur in 2019.[739] This amount is lower than the actual, unadjusted test year amount of $22.845 million.[740] Staff, however, recommends the Commission approve an amount for injuries and damages based on the average of the previous five years. Mr. Filarowicz claims the Company's requested amount is high compared to prior years, and he points to costs the Company recorded to FERC Account 925 during the first quarter (through March) and year-to-date 2019 (through April 2019) to support his position.[741] As a general matter, the Company disagrees with averaging as a method to determine test year expenses.[742] In addition, reviewing costs for only a three- or four-month period is not reflective or indicative of the costs for an entire year. Due to the timing throughout the year when injuries and damages costs are incurred, it is more reasonable to consider a full twelve-month period to analyze these costs. The balance in FERC Account 925 for twelve-month period ending April 2019 is $22.854 million, which is only $9,634 higher than the unadjusted test year amount for 2018.[743] In addition, both of these amounts are higher than the injuries and damages expense the Company is requesting and higher than Staff's recommended amount. Staff's adjustment to the Company's injuries and damages expenses should be rejected.

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739 CEHE Ex. 2 at 158, Schedule II-D-2.
740 CEHE Ex. 35 at WP R-KLC-04 (Colvin Rebuttal).
741 Staff Ex. 4A at 21-23 (Filarowicz Direct).
742 CEHE Ex. 35 at 23 (Colvin Rebuttal).
743 CEHE Ex. 35 at WP R-KLC-04 (Colvin Rebuttal).

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

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

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

CEHE has a self-insurance plan that was approved by the Commission in Docket No. 38339 with a property reserve accrual of $4.15 million annually, and a reserve target of $13.38 million.[744] The purpose of the self-insurance reserve is to provide for accruals to be credited to a reserve account to cover occurrences that result in losses of more than $100,000 in O&M expenses.[745] In this proceeding, CEHE proposes an annual accrual of $7.685 million and a new target property insurance reserve of $6.55 million.[746] The accrual is composed 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 from the current reserve deficit level of -$5.79 million.

It is necessary to build the self-insurance reserve to a level sufficient to cover the losses for each year, knowing that in any given year, actual losses may be different than average expected losses.[747] CEHE's annual expected losses are $3.575 million, based on a Monte Carlo simulation run on the loss history of CEHE, excluding storms with losses of more than $25 million.[748] The target reserve of $6.55 million is the amount of O&M damage expected from a 25-year event with total losses under $100 million.[749] It is necessary to accrue more than CEHE's annual expected losses in the target reserve to provide for extreme or catastrophic events in any one year.[750] The reserve target does not need to be high enough to cover every property loss that can occur, because large events are much less common.[751]

In accordance with Commission Substantive Rule § 25.231(b)(1)(G), CEHE demonstrated that its proposed self-insurance plan was based on a cost benefit analysis performed by a qualified independent insurance consultant and thus, is deemed to be in the public interest.[752] This cost benefit analysis confirmed that self-insurance is a lower cost alternative than obtaining insurance

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[744] Docket No. 38339, Order on Rehearing at Finding of Fact 91.
[745] Direct Testimony of Gregory S. Wilson, CEHE Ex. 28 at 2895 (Bates Pages).
[746] CEHE Ex. 28 at 2894 (Wilson Direct).
[747] *Id.* at 2896 (Wilson Direct).
[748] *Id.* at 2897.
[749] *Id.* at 2899.
[750] *Id.*
[751] *Id.* at 2901.
[752] *Id.* at 2891-2892.

from a third-party provider.[753] Further, the accrual amounts proposed by CEHE were shown to be prepared in accordance with Generally Accepted Actuarial Procedures, with certain adjustments to reflect the nature of ratemaking for public utilities. For example, CEHE did not project the cost of expected losses to the future period when they will be incurred, and no adjustment was made to reflect future increased exposure to loss if CEHE owns more property in the future.[754] Insurance companies would include expenses in policy premiums that include non-loss related expenses, premium taxes, and profits, none of which are present in self-insurance reserve costs.[755] CEHE has been unable to obtain insurance coverage at a reasonable cost for T&D assets damaged by storms.[756]

No party challenged CEHE's proposed target reserve, the amount to cover average annual expected losses, or the inclusion of the current reserve deficit balance as an asset in CEHE's rate base.[757] However, Mr. Garrett proposes an eight-year recovery period[758] and Mr. Nalepa proposes a five-year recovery period[759] for CEHE's self-insurance reserve. Both witnesses propose unreasonably long periods for CEHE to recoup losses it has previously incurred and to reach a target reserve level that will be sufficient to cover expected costs.[760] Extending the recovery period beyond the three years puts CEHE in a position of being subject to additional storm losses that could further deplete the reserve.[761] The COH and OPUC proposal should be rejected and CEHE's proposed self-insurance accrual and target reserve should be approved.

H. Vegetation Management

CEHE's requested O&M expense in the amount of $35.03 million for proactive tree trimming, hazard tree removal and reactive tree trimming (collectively, "vegetation management") is reasonable and should be adopted. There is no dispute that CEHE's customers benefit from the Company's vegetation management practices because proactive tree trimming, reactive tree trimming and hazard tree removal improve day-to-day reliability and reduce the impact of extreme storms. It is also undisputed that the Company's proactive tree trimming and hazard tree removal practices are consistent with 16 TAC § 25.95, which requires utilities to adopt storm hardening

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[753] *Id.* at 2903.
[754] *Id.* at 2902.
[755] *Id.* at 2903.
[756] *Id.* at 2904-2905.
[757] CEHE's rate base property insurance reserve balance is shown in CEHE Ex. 2 at 40-43, Schedule II-B-7.
[758] COH/HCC Ex. 2 at 54 (Garrett Direct).
[759] OPUC Ex. 5 at 23 (Nalepa Direct).
[760] CEHE Ex. 35 at 22 (Colvin Rebuttal).
[761] *Id.* at 23.

plans. CEHE's vegetation management activities are competitively bid with approximately 90% of the Company's proactive vegetation management work being based on a fixed price. CEHE performs inspections to ensure that vegetation management work is completed satisfactorily and reviews invoices to ensure accuracy. CEHE foresters and vendors also interface with the customers as needed to resolve issues and facilitate completion of the work. Unscheduled or reactive tree trim maintenance is performed by CEHE to address vegetation issues that require immediate attention. These efforts have led CEHE to spend $222.50 million on vegetation management over the eight-year period from 2011 to 2018. Notably, the costs associated with vegetation management activities continue to rise. For example, from 2011 to 2013, hazard tree expenditures increased due to drought conditions and the impact of pine bark beetles. Proactive tree trimming expenditures increased from 2014 to 2017 due to rising contractor labor rates.

While Intervenors and Staff do not question the reasonableness or necessity of the Company's need to properly maintain and continue its current vegetation management program or the level of its current activities, they reject the test year costs of these activities in favor of an outdated three-year average level of expense. Specifically, Mr. Nalepa proposes to establish CEHE's vegetation management expense based on an outdated three-year 2015-2017 average of $28.16 million.[762] Mr. Ianni proposes an equally outdated 2016-2018 three-year average.[763] Both Mr. Norwood's and Mr. Ianni's proposals were shown to be understated and unrepresentative of CEHE's ongoing vegetation management expenditures, especially in light of the disruption caused to these activities by Hurricane Harvey in 2017, and should be rejected. The evidence established that:

- CEHE has experienced a 50% increase in contractor bid prices on a per mile basis from 2014 to 2017 for proactive tree trimming;
- 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;
- 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; and
- vegetation growth driven by an increase in rainfall for the past several years has also increased the Company's required tree trimming activities.

[762] OPUC Ex. 5 at 7-11 (Nalepa Direct).
[763] Staff Ex. 6 at 11 (Ianni Direct).

The evidence further establishes that CEHE has taken proactive steps to control the cost of tree trimming in light of increasing contractor costs.

- In 2017, the Company divided its system into regions to better distribute tree trimming activities among its contractors and to provide the opportunity for contractors to bid on a larger scope of tree trimming work in an effort to realize economies of scale.
- The bidding and awarding process occurs in advance of the necessary work in order to afford contractors the opportunity to better plan their staffing resources.

Despite these efforts, the evidence shows that vegetation management costs have been trending upward and that CEHE's test year vegetation management costs are representative of its ongoing costs.

This is evidenced by the fact that contractor costs for 2019 proactive tree trimming work ($27.1 million) is very similar to the total amount spent for proactive tree trimming in 2018 ($28.0 million). Moreover, if the projected expenditures for reactive tree trimming and hazard tree work are included, the projected 2019 total for distribution system management is $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.[764] In short, both Mr. Nalepa's and Mr. Ianni's cost averaging proposal understates the costs CEHE must incur to support its vegetation management program.

I. Smart Meter Texas Expense

SMT is an ERCOT-wide website that provides end-use customers and other authorized parties, access to smart meter data.[765] SMT is jointly owned and operated by CEHE, Oncor, AEP Texas Inc., and TNMP under a joint development and operating agreement ("JDOA").[766] The parties to the JDOA contract with IBM for the design, development and operation of SMT.[767] In 2018, the Commission issued a final order in Docket No. 47472, which established the functionality of SMT 2.0. SMT 2.0 is expected to be available in December 2019.[768]

The revised business requirements for SMT 2.0 involve new contracts with IBM.[769] The costs associated with SMT are different from most of CEHE's other O&M costs because CEHE does not have the same ability to manage and reduce associated expenses.[770] As part of its

[764] CEHE Ex. 31 at 29, Exh. R-RMP-01, COH RFI No. 8-13 (Pryor Rebuttal).
[765] CEHE Ex. 11 at 794 (Hudson Direct).
[766] *Id.*
[767] *Id.*
[768] *Id.*
[769] *Id.* at 794-795.
[770] *Id.*

proposed recovery of costs in this case, CEHE used the SMT contract costs on the annual charges in 2020 through 2024, because the 2018 charges were under the previous contract and the 2019 charges will be unusually high because SMT 2.0 will be in the development phase.[771] The only intervenor witness to address these costs, Mr. Nalepa, agreed with CEHE's use of the 2020 contract costs.[772]

However, Mr. Nalepa also proposes using other costs incurred by CEHE from 2018.[773] Because the scope of the requirements for SMT have changed since 2018, CEHE's contract costs and other associated costs from 2018 are not reflective of what CEHE will experience when its proposed rates will be in effect. The IBM contracts have established charges on an annual basis, but they also have provisions that allow for change requests, and in the event the scope of the work changes under the contract, IBM will assess additional charges.[774] It is typical for large IT projects to change in scope and for CEHE to incur additional charges.[775] The majority of CEHE's costs for SMT are associated with the IBM contracts, but there are also employee travel and meal expenses, as well as other professional services expenses associated with administering the SMT contracts.[776] These expenses will also likely change from the test year given the new SMT functionality requirements and new contracts with IBM.[777] Mr. Nalepa's use of 2018 costs will not provide CEHE with adequate recovery of its associated SMT expenses, and therefore his proposed reduction should be rejected. CEHE's requested SMT expenses are required to implement a program dictated by the Commission and reflect the known changes to the IBM contracts and CEHE's other costs; they are therefore reasonable and necessary.[778]

J. Street Lighting Service

COH asserts the O&M cost for Light Emitting Diode ("LED") street lights should be excluded from transmission and distribution rates because, it alleges, there were no test year costs associated with operating and maintaining LED street lights.[779] As explained in the rebuttal testimony of CEHE witnesses Ms. Sugarek and Mr. Troxle, during the test year, the Company

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[771] *Id.* at 795.
[772] OPUC Ex. 5 at 14 (Nalepa Direct).
[773] *Id* at 13.
[774] Rebuttal Testimony of John R. Hudson, CEHE Ex. 34 at 4.
[775] *Id.* at 5.
[776] *Id.* at 4-5.
[777] *Id.* at 5.
[778] *Id.* at 6.
[779] The Company believes this subsection was mistakenly omitted from the parties agreed outline and has added it here to address issues in dispute.

incurred approximately $7.6 million in O&M costs for street lighting.[780] Because the Company does not track its O&M costs by lamp type, the Company prepared a study for this proceeding to determine the level of street lighting costs associated with all of the different types of lamps in the Company's system.[781] In the study, the Company assigned $2.73 million of its approximately $7.6 million in total O&M costs to LED street lighting O&M. This amount reflects the on-going O&M associated with LED street lights, including costs associated with fuse replacement, maintaining the post, conduit replacement, and clamp/connector replacement over its used and useful life to maintain standard performance.[782] Moreover, CEHE has a standing work order for all O&M costs associated with all street lights in its territory.[783] The Commission approved the same streetlight rate design and cost allocation method in prior rate case proceedings, Docket Nos. 38339 and 32093.[784]

Importantly, COH witness Kit Pevoto does not challenge the reasonableness of the Company's total actual test year O&M expense associated with servicing its street lights. Accordingly, regardless of how the Company assigns costs among its various lamp types for rate design purposes, the Company should be permitted to recover the entire $7.6 million in Street Lighting O&M costs.

K. Loss on Sale of Land

Mr. Nalepa claims that customers should not be assigned 50% of Company's loss on the sale of land during the test year and argues that the Company is misinterpreting the Commission's order in Docket No. 38339 by including the loss in its revenue requirement.[785] Specifically, Mr. Nalepa argues the Commission's "decision to share equally between shareholders and customers was limited to a *gain* on the sale of land."[786] Mr. Nalepa is mistaken. 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.[787] The Company completed construction on and energized the Brazos Valley Connection in March

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[780] 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; CEHE Ex. 33 at 18-20 (Sugarek Rebuttal).
[781] CEHE Ex. 2, Schedule H-I-J and CA Errata-1, WP-Streetlight Rate Design.
[782] CEHE Ex. 33 at 18 (Sugarek Rebuttal).
[783] *Id.*
[784] Docket No. 38339, Order on Rehearing.
[785] *Id.* at Finding of Fact 139B.
[786] OPUC Ex. 5 at 26-27 (Nalepa Direct).
[787] CEHE Ex. 32 at 32 (Narendorf Rebuttal).

2018.[788] 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.[789] In order to make the land useful for the project, the land was cleared requiring the demolition of these improvements.[790] Upon completion of the project, the Company sold off the excess areas of fee-purchased land that was no longer suitable for the utility to own.[791] 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 experienced a loss of $1.46 million on the tracts sold.[792] Mr. Nalepa questions none of these prudent actions – all of which are normal in the course of a large transmission line construction project such as the Brazos Valley Connection. Moreover, Mr. Nalepa's characterization of the effect of the Commission's order in Docket No. 38339 is incorrect. 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.[793] 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—not a balanced result. 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]

CEHE's FIT test year expense totaled approximately $75.8 million.[794] CEHE properly used the "return" method to calculate FIT expense using a statutory income tax rate of 21% (as adopted by the TCJA) and using the "stand-alone" approach—i.e., the requested FIT expense is based solely on those revenues and expenses that are contained within CEHE's cost of service.[795] This "stand-alone" approach ensures that the FIT expense requested by CEHE is based on test year revenues and expenses as adjusted for known and measurable changes without any additions or

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[788] *Id.*
[789] *Id.*
[790] *Id.*
[791] *Id.*
[792] CEHE Ex. 2 at 1162, WP II-B-13a Brazos Valley Connection Tracts.
[793] 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."
[794] CEHE Ex. 13 at 989 (Pringle Direct) and CEHE Ex. 2 at 324-327, Schedule II-E-3.
[795] CEHE Ex. 13 at 1011-1013 (Pringle Direct). *See also* PURA § 36.060.

reductions resulting from revenues or expenses not included in CEHE's request.[796] Further, the requirements of PURA § 36.059 regarding the treatment of certain tax benefits have been appropriately considered. No party contests the Company's test-year FIT expense. It is reasonable and necessary and should be approved.

2. Effect of TCJA [Issue 29]

The evidence demonstrates that CEHE's customers benefit in two primary ways from the enactment of the TCJA: (1) customers receive a reduction in tax rates and (2) customers benefit from the return of EDIT. CEHE's proposals in this proceeding fully and properly ensure that customers receive these benefits. The TCJA reduced the corporate FIT rate from 35% to 21%.[797] CEHE has properly addressed the benefits to customers of this reduction in corporate tax rate in its proposal by calculating FIT using the 21% rate.[798] No party asserts that CEHE failed to properly reflect this rate reduction in its request. Similarly, as discussed above, CEHE properly re-measured ADFIT to account for the estimated tax owed at the TCJA's rate of 21% rather than 35% and is proposing to return the resulting EDIT balance to customers via this proceeding, in the case of protected EDIT as described above, and unprotected EDIT via Rider UEDIT as described below.

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

1. Ad Valorem (Property) Taxes

CEHE must pay property taxes each year.[799] CEHE's property tax payments in the test year totaled approximately $88.6 million.[800] 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.[801] These additions are calculated by multiplying 2018 property taxes assessed by a factor that captures the change in taxable plant in service during 2018.[802] No party challenged these amounts and they should be approved.

2. Texas Margin Tax

CEHE computed its TMT on a stand-alone basis using its own financial information and applying the only method available under state law to compute such taxes.[803] The result is a

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[796] CEHE Ex. 13 at 1012–1014 (Pringle Direct).
[797] Pub. L. No. 115-97, Section 13001(b) (2017).
[798] CEHE Ex. 13 at 998 (Pringle Direct).
[799] Tex. Tax Code § 11.01 (Vernon 2005).
[800] Direct Testimony of Justin J. Hyland, CEHE Ex. 14 at 1060 (Bates Pages).
[801] *Id.* at 1054.
[802] *Id.*
[803] CEHE Ex. 13 at 1023-1025 (Pringle Direct).

properly computed TMT amount for the test year of $20,027,248.[804] No party contests the computation of the amount of TMT test year expense, and the TMT amount should be approved. The parties' disputes with respect to the TMT regulatory asset are addressed in Section II.G.4.

3. Payroll Taxes

Payroll taxes for the test year are approximately $11.6 million.[805] CEHE made an adjustment of $8,431 to increase Federal Insurance Contributions Act taxes, which is the related impact of the proposed wage adjustment.[806] An adjustment of ($116,620) was also made to remove energy efficiency cost recovery factor ("EECRF") costs as they are recovered through a separate EECRF tariff.[807] The details of these adjustments are provided on Schedule II-E-2. With the exception of flow-through adjustments proposed by Mr. Garrett and Mr. Filarowicz and discussed above, no party challenged the Company's payroll tax amounts or its proposed adjustments. Accordingly, they should be approved.

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

Pursuant to Rule 25.192(b)(1), CEHE's wholesale transmission rate is calculated by dividing its Commission-approved wholesale transmission cost of service ("TCOS") by the average of the "ERCOT coincident peak demand for the months of June, July, August, and September," known as the four-month coincident peak demand ("4CP"). The wholesale TCOS is collected from Distribution Service Providers ("DSPs"), including the Company (the Company is a DSP and a TSP), based on each DSP's proportional use of CEHE's transmission grid. The Company's proposed wholesale TCOS is calculated to be $394 million,[808] which results in a transmission service rate of $5.684962 per kW per month.[809] This calculation is uncontested and should be approved by the Commission.[810]

The rates for exports of power from ERCOT, as presented in the direct testimony of Mr. Troxle, are calculated in accordance with 16 TAC § 25.192(e) and ERCOT protocols.[811]

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[804] *Id.*; CEHE Ex. 2 at 317-318, Schedule II-E-2 & 1148, WP/WP II-B-12 Adj 10.
[805] CEHE Ex. 2 at 317-318, Schedule II-E-2.
[806] CEHE Ex. 12 at 882 (Colvin Direct).
[807] *Id.*
[808] CEHE Ex. 2 at 874, Schedule III-A-1 & 418-504, Schedule II-I-TRAN.
[809] CEHE Ex. 30 at 3739, Exh. MAT-10 at 8 (Troxle Direct).
[810] Just as CEHE, as a Transmission Service Provider ("TSP"), collects its wholesale TCOS from other DSPs in ERCOT, CEHE, as a DSP must pay TSPs in ERCOT for its proportional usage of the transmission grid. The amount that CEHE pays out to TSPs is the retail transmission revenue requirement is recovered in the retail Transmission Charge. These calculations can be found at CEHE Ex. 2 at 418-504, Schedule II-I-TRAN and CEHE Ex. 2 at 874, Schedule III-A-1.
[811] CEHE Ex. 30 at 3739, Exh. MAT-10 at 8 (Troxle Direct).

Intervenors and Staff have challenged certain parts of the Company's wholesale TCOS or transmission cost allocations. These are addressed separately in specific sections throughout the brief.

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

Billing determinants are necessary inputs in the design of the Company's proposed retail rates. These determinants establish the number of customers, kWh and kVa usage along with the non-coincident peak ("NCP") and 4CP demand the utility can expect when the rates go into effect to allow the Company to recover the revenue requirement set in this case.[812] The Company has made certain known and measurable adjustments to the test year to ensure that the billing determinants accurately represent the conditions that will exist when the rates go into effect.[813] Those include:[814] (1) customer adjustments to reflect the number of customers at the end of the test year; and (2) weather adjustments made to the test year load data as presented in Schedules II H-2 through II-H-2.3, and Schedules II-H-5 through II-H-5.3, sponsored by CEHE witness J. Stuart McMenamin. In this case, the Company also made known and measurable adjustments to annualize the impact of the Company's mandated energy efficiency programs that were implemented during the test year. These adjustments are necessary to ensure the test year billing and usage data is representative of conditions that are expected to exist once new rates go into effect, based on known and measurable changes and represent a fair and equitable method to allocate necessary cost recovery, and design rates.[815]

No party challenged the Company's customer adjustment. Only Staff and OPUC challenged the Company's weather normalization adjustment and Energy Efficiency Plan ("EEP") Adjustment.

A. Weather Normalization

The Commission should adopt Dr. 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.[816] In CEHE's most recent rate case, the Commission adopted a 30-year interval for normal weather following "the precedent consistently

[812] *Id.* at 3000.
[813] *Id.* at 3000-3001.
[814] *Id.* at 3000-3003.
[815] *Id.* at 3000.
[816] Rebuttal Testimony of J. Stuart McMenamin, CEHE Ex. 44 at 21.

established for CEHE."[817] More recently, however, the Commission has used a 10-year period to determine normal weather in an effort to better reflect recent weather trends.[818] This shift by the Commission to 10 years is consistent with Dr. McMenamin's survey data, which shows the use of 30-year periods dropping considerably by 2013 in favor of 10-year periods.[819] Even more recently, however, 10-year periods have given way to 20-year periods, which in 2017 and 2018 were the dominant method for determining normal weather.[820] Dr. McMenamin explained this even more recent reversal, noting that 10-year periods can cause the "normal" weather values to change significantly from year-to-year and that using a longer, 20-year period supports a more stable forecast.[821] The only witnesses who challenge Dr. McMenamin's use of a 20-year period are Mr. Nalepa and Staff witness Alicia Maloy, both of whom follow the more recent Commission cases and recommend a 10-year period.[822] However, neither Mr. Nalepa nor Ms. Maloy has performed any independent analysis, as Dr. McMenamin has, of current industry practice for determining normal weather.[823] 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 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."[824] Ms. Maloy criticizes Dr. McMenamin's regression modeling (a) for using only four years of data while using ten years to determine normal weather,[825] (b) for including test year data,[826] and (c) for including

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[817] Docket No. 38339, Order on Rehearing at Finding of Fact No. 181; *see* Tr. at 863 (Maloy Cross) (Jun. 26, 2019).
[818] *See* Direct Testimony of Alicia Maloy, Staff Ex. 5A at 19-21 (Bates Pages); OPUC Ex. 5 at 42-44 (Nalepa Direct).
[819] CEHE Ex. 44 at 26 (Figure SM-R13) (McMenamin Rebuttal).
[820] *Id.*
[821] Direct Testimony of J. Stuart McMenamin, CEHE Ex. 29 at 2951 (Bates Pages).
[822] Staff Ex. 5A at 19-21 (Maloy Direct); OPUC Ex. 5 at 42-44 (Nalepa Direct).
[823] CEHE Ex. 44 at 42, 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, 2018).
[824] OPUC Ex. 5 at 41 (Nalepa Direct).
[825] Staff Ex. 5A at 21-22 (Maloy Direct).
[826] *Id.* at 22.

some variables that she argues are not statistically significant at the 95% confidence level.[827] Dr. McMenamin addressed each of Ms. Maloy's issues.

First, he explained that (a) the definition of normal weather and (b) the estimation of the effects of abnormal weather on test-year energy usage are *independent* steps.[828] Ms. Maloy acknowledged the same.[829] Dr. McMenamin further explained that the use of four years of advanced meter system (AMS) data provides far richer modeling (1,400 data points) than the use of 10 years of monthly billing data (only 120 data points).[830] Second, Dr. McMenamin again emphasized that determining normal weather is a distinct and independent step from estimating weather effects on the test year.[831] The precedent cited by Ms. Maloy to support exclusion of the test year referred to the first step—the determination of normal weather.[832] 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.[833] Ms. Maloy conceded that, for reasons such as improving energy efficiency, more recent years provide a more accurate measure of how customers react to changes in weather.[834] Third, 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.[835] Despite her prior testimony, Ms. Maloy's testimony in this case includes no analysis of whether Dr. McMenamin's variables actually make theoretical sense. In contrast, 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.[836]

The Commission should adopt Dr. McMenamin's weather normalization adjustments. Dr. McMenamin was far and away the most experienced witness regarding weather

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[827] *Id.* at 23-24.
[828] CEHE Ex. 44 at 20 (McMenamin Rebuttal).
[829] Tr. at 867-870 (Maloy Cross) (Jun. 26, 2019).
[830] Tr. at 1083 (McMenamin Redirect) (Jun. 27, 2019); CEHE Ex. 44 at 4, Figure SM-R2, and at 15-16, Figure SM-R10 (McMenamin Rebuttal).
[831] CEHE Ex. 44 at 21 (McMenamin Rebuttal).
[832] *Application of Southwestern Public Service Co. for Authority to Change Rates*, Docket No. 43695, Finding of Fact No. 242 (Feb. 23, 2016) ("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, 2019).
[833] CEHE Ex. 44 at 21 (McMenamin Rebuttal).
[834] Tr. at 891 (Maloy Cross) (Jun. 26, 2019).
[835] *Id.* at 876-878.
[836] CEHE Ex. 44 at 22-24 (McMenamin Rebuttal).

normalization.[837] Despite recent Commission precedent, Dr. McMenamin has articulated a sound policy rationale for using a 20-year time period to determine normal weather. If, however, the Commission decides to continue using a 10-year period, Dr. McMenamin's rebuttal testimony includes the modeling necessary to apply his methodology using a 10-year period.[838]

B. Energy Efficiency Program Adjustment

The EEP adjustment is made to reflect the known and measurable impacts of the energy efficiency programs that were implemented during, but not fully captured in, the test year.[839] Energy efficiency programs reduce energy usage, which decreases the Company's billing determinants.[840] But because the test year only captures a portion of the energy efficiency savings attributable to measures installed throughout the year, the Company's test year billing determinants are too high—i.e., they do not reflect a full year of usage savings.[841] An annualization adjustment is necessary to capture the Company's actual energy usage based on the Company's operations at the conclusion of the test year, much like the Company's customer adjustment, which annualizes usage based on the number of customers on the Company's system at the conclusion of the test year.[842] The adjustment is required under PURA and Commission rules to create a representative test year.[843] The adjustment is known and measurable because it is based on energy efficiency programs that have already been implemented and because it is calculated using the Technical Reference Manual ("TRM"), which is used to calculate energy savings and set rates in the EECRF proceedings pursuant to 16 TAC § 25.181(q).[844] The adjustment is calculated in WP H-1.2 (EEP BD adjustment).

Staff argues the adjustment should be rejected because it is similar to a lost revenue adjustment mechanism ("LRAM"), which this Commission has previously rejected, and because the TRM is not sufficiently accurate to be used as a measure of known and measurable changes.[845]

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[837] *See id.* at 27 and 38-42 (McMenamin Rebuttal); Tr. at 866-867 (Maloy Cross) (Jun. 26, 2019) (establishing that Ms. Maloy's resume includes only one case involving weather normalization and that she performed no studies of periods used by other utilities or regulators to determine normal weather).
[838] CEHE Ex. 44 at 30-31 (McMenamin Rebuttal).
[839] CEHE Ex. 30 at 3002 (Troxle Direct).
[840] *Id.* at 3002-3003.
[841] *Id.*
[842] *Id.* at 3003-3004.
[843] CEHE Ex. 45 at 25-26 (Troxle Rebuttal). *See also Oncor Elec. Delivery Co. v. Public Util. Comm'n of Tex.*, 507 S.W.3d 706, 717 (Tex. 2017) (stating that "the PUC was required to take [known and measurable changes] into account").
[844] CEHE Ex. 30 at 3004 (Troxle Direct).
[845] Direct Testimony and Workpapers of William Abbott, Staff Ex. 7 at 11-12 (Bates Pages).

As explained in Mr. Troxle's direct and rebuttal testimony, the adjustment is not an LRAM or even similar to an LRAM.[846] An LRAM is a *forward-looking* mechanism used to recover incremental revenues lost in between rate cases.[847] The EEP Adjustment is a billing determinant adjustment based on *historical* test year data.[848] It is required under 16 TAC § 25.234, which states that "[r]ates *will be* determined using revenues, billing and usage data for a historical test year adjusted for known and measurable changes . . . ." It is also necessary to allow the Company a reasonable opportunity to earn a reasonable return on its invested capital in excess of its reasonable and necessary operating expenses, as required by PURA and Commission rules.[849] Moreover, the 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 TRM, which is used in other proceedings to set rates.[850]

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

Based on its class cost of service study, the Company has allocated its revenue requirement to functions and rate classes consistent with the National Association of Regulatory Utility Commissioners ("NARUC") cost allocation manual, the Company's past practices, Commission precedent, and principles of cost causation.[851] To the extent possible, the Company directly assigned costs to one or more customer classes.[852] Other costs involving more than one customer class were allocated consistent with cost-causation principles based on whether the costs were customer-related, demand-related, energy-related, revenue-related, or a combination thereof.[853] Generally, costs characterized as fixed costs are classified as customer-related or demand-related costs and costs characterized as variable cost are classified as energy-related or revenue-related.[854]

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[846] CEHE Ex. 30 at 3005-3006 (Troxle Direct); CEHE Ex. 45 at 29-30 (Troxle Rebuttal).
[847] *Id.*
[848] CEHE Ex. 30 at 3005-3006 (Troxle Direct).
[849] PURA § 36.051; 16 TAC § 25.231(a) ("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) ("In 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.").
[850] CEHE Ex. 45 at 32-33 (Troxle Rebuttal). *See also Application of Southwestern Pub. Serv. Co. for Authority to Change Rates*, Docket No. 43695, PFD at 13 (Oct. 12, 2015) (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").
[851] CEHE Ex. 30 at 3006-3019 (Troxle Direct); CEHE Ex. 45 at 14-18 (Troxle Rebuttal).
[852] CEHE Ex. 30 at 3008 (Troxle Direct).
[853] *Id.* at 3008.
[854] *Id.* at 3008-3009.

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A. Functionalization

The Company functionalized its costs and revenues, where appropriate, following the three-tier process prescribed by RFP General Instruction No. 11.[855] Parties challenged the Company's functionalization of costs for the Texas Margins Tax expense, Account 930.2 Miscellaneous General Expense, and the unprotected EDIT refund. As explained below, the Company adopted some of the recommendations of the other parties. The remaining intervenor or Staff proposals should be rejected.

1. Texas Margins Tax Expense (and associated accounts)

The Company's functionalization of the TMT expense based on total revenue requirement is appropriate and no parties dispute this method. Staff, however, recommended that Texas Gross Margins Tax expenses, associated with ERCOT transmission payments in FERC account 565 be allocated to retail customers.[856] In rebuttal, the Company agreed to adopt Staff's allocation of these costs.[857]

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.[858] Staff witness Brian Murphy accepted the Company's payroll functionalization factor for support services included in this account but argued that Technology Operations services expenses related to personnel should be functionalized based on payroll and customer-related expenses should be functionalized based on total O&M expense.[859] Mr. Murphy also argued that Telecommunication Services expenses are to be directly assigned to retail cost of service.[860] In its rebuttal case, the Company adopted Staff's position.[861] The Company's proposed functionalization and allocation of Account 930.2 expenses are reasonable.

3. Unprotected Excess Deferred Income Tax

The Company proposed to allocate its unprotected EDIT refund to its retail customers. Staff recommended that unprotected EDIT be functionalized among wholesale transmission and retail delivery using the Commission-approved amounts in Docket Nos. 48065 and 48226. With

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[855] CEHE Ex. 12 at 844 (Colvin Direct).
[856] Direct Testimony of Brian Murphy, Staff Ex. 2A at 26-34 (Bates Pages).
[857] CEHE Ex. 35 at 47 (Colvin Rebuttal).
[858] CEHE Ex. 2 at RFP Workpapers (redacted).XLS," worksheet "WP VI-L.2," at Microsoft Excel row 42.
[859] Staff Ex. 2A at 36-38 (Murphy Direct).
[860] *Id.*
[861] CEHE Ex. 35 at 48 (Colvin Rebuttal).

respect to the retail portion, Staff accepted the Company's proposal to refund the amounts under Rider UEDIT. With respect to the wholesale portion, Staff recommended the Company create a new wholesale transmission service rate rider with a refund period of one year and include the rider in a compliance tariff filing.

The Company's proposed allocation of the refund to retail customers is reasonable. However, if the Commission determines it is necessary to allocate a portion of the refund to wholesale transmission customers, the amortization period should be consistent with that proposed for the retail customers and returned to customers over a three year period. The requested three-year period is the same time-period approved in Docket No. 38339 to recover regulatory assets and recovery of rate case expenses in prior dockets.[862] A three-year period also more closely aligns the return or recovery of costs with the customers that existed at the time the costs were incurred.[863]

4. Accounts 5860 and 5970

COH argued that FERC Accounts 5860-Meter Expenses and 5970-Maintenance of Meters should be functionalized to the meter function when determining the payroll allocator. In rebuttal, the Company agreed that these accounts should be assigned to the meter function when determining the payroll allocator.[864]

B. Class Allocation

1. Class Allocation of Transmission Costs

CEHE proposed to use the Company's unadjusted 4CP allocation factor based on the ERCOT peak summer month periods to allocate its capacity-related transmission and distribution costs ("CEHE 4CP").[865] For transmission costs, demand is calculated at the meter. For distribution costs, the allocation factors are determined at two points of service on the distribution system: the substation and the overhead distribution lines.[866]

TIEC and Staff agree that the Company should use the 4CP method but, with regards to capacity-related transmission costs, argue that the Company should use the ERCOT system-wide peak demand ("ERCOT 4CP") instead of the CEHE 4CP. They allege that using ERCOT 4CP is

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862 *Id.* at 42.
863 *Id.*
864 *Id.* at 48.
865 CEHE Ex. 30 at 3012 (Troxle Direct); CEHE Ex. 1 at 4251-4268, Schedule II-H-1.3.
866 CEHE Ex. 30 at 3012-3013 (Troxle Direct). Since some customers are served exclusively on the underground line distribution system and do not use the overhead line facilities, having the allocation factors determined at the substation and the overhead distribution line level allows certain costs of the underground line facilities to be allocated exclusively to those classes that have customers served from those facilities. *Id.*

necessary to "match" how costs are billed to the Company with how it bills those costs to its customers. HEB argues the Company should utilize the NCP instead of either ERCOT 4CP or CEHE 4CP to allocate costs. As explained below, the Company's proposed allocation using the CEHE 4CP is reasonable and the positions of Intervenors and Staff should be rejected.

a. "CenterPoint 4CP" versus "ERCOT 4CP" Class Allocation (separately for both transmission and for distribution)

Coincident Peak Demand is the maximum amount of electricity demanded by each customer at the time that peak demand on the entire relevant electric system occurs.[867] Electric utilities like CEHE use the Coincident Peak Demand method to allocate transmission costs to retail customer classes because it reflects each customer's and each customer class's contribution to the system peak.[868] The basic premise behind the use and application of this demand allocator is that utilities build infrastructure to meet peak system demand.[869] Therefore, a class's contribution to peak system demand directly influences investment and supporting operations, justifying the Coincident Peak Demand method as the basis for cost allocation.[870] The use of the 4CP method coincides with the four-month time period electricity demand is highest, such as the summer months of June, July, August and September.[871] The CEHE 4CP is based on the peak demand of the CEHE system, while the ERCOT 4CP is based on the peak demand of the entire ERCOT system, which encompasses CEHE's system plus the transmission systems of other electric utilities in the ERCOT region.[872] The NCP is the peak demand of each individual customer or customer class, irrespective of CEHE's or the ERCOT's system peaks.[873]

CEHE's system is built primarily to serve the Company's peak demand.[874] 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. Pursuant to 16 TAC § 25.192, the ERCOT 4CP sets the rate that all TSPs in ERCOT must charge and all DSPs in ERCOT must pay for wholesale transmission service, based on how all the DSPs contribute to the whole ERCOT system peak

[867] CEHE Ex. 45 at 6 (Troxle Rebuttal).
[868] *Id.*
[869] *Id.*
[870] *Id.*
[871] *Id.*
[872] *Id.*
[873] *Id.* at 6-7.
[874] *Id.* at 7.

demand. 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.

Contrary to TIEC's and Staff's claims, the Commission does not dictate how a DSP's transmission costs should be allocated to the various rate classes. Although TIEC witness Jeffry Pollock and Mr. Murphy point to Rule 25.192, the rule does not dictate how wholesale transmission costs are to be allocated to the customer classes.[875] It addresses how TSPs charge DSPs for transmission service, not how DSPs allocate those costs to retail customers.[876] Moreover, there is no requirement that CEHE should match how it is charged transmission costs by ERCOT with how it allocates those costs to its customer classes.[877] In fact, principles of cost-causation recommend using the Company's approach. This is a CEHE rate case, not an ERCOT system rate case, and accordingly it is appropriate to allocate CEHE's system costs based upon the coincident peak demand on the Company's system and not ERCOT's system.[878] The use of CEHE 4CP reflects cost-causation within the CEHE service area.[879]

Moreover, according to the percentages in Mr. Pollock's direct testimony,[880] using the ERCOT 4CP would shift significant costs away from transmission customers to the residential and small commercial classes.[881] Furthermore, 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.[882] Under the Company's proposal, it would be harder to "game the system," as a 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.[883] CEHE's use of the CEHE 4CP better ensures that all customers pay for the costs they have caused the Company to incur to build its system to meet their demands.

[875] *Id.* at 8.
[876] *Id.*
[877] *Id.*.
[878] *Id.*.
[879] *Id.*.
[880] Direct Testimony of Jeffry Pollock, TIEC Ex. 1 at 15-16 (Bates Pages).
[881] CEHE Ex. 45 at 9 (Troxle Rebuttal).
[882] *Id.* at 9-10.
[883] *Id.* at 10.

b. Transmission and Distribution Demand Allocation Factors (4CP vs NCP class allocation separately for both transmission and for distribution)

The Company's transmission and distribution systems are designed to serve the maximum load requirement of each individual retail customer at the same time.[884] It is reasonable to utilize the 4CP method instead of the NCP method to allocate costs because CEHE's peak demand is during the summer months of June, July, August, and September.[885] All costs driven by system peak loads have been allocated to the classes based upon their contribution to the summer peak loads.[886] The 4CP component of the Company's proposed allocator accomplishes this goal by isolating class contributions to system peak load during those four months.[887] A 4CP demand allocation method captures the cost causation associated with the maximum coincident load of each rate class on the Company's distribution system.[888]

While HEB argues that using the 4CP method incentivizes customers to "game the system" by reducing load at the time of the ERCOT 4CP, the Company's proposal would make it almost impossible to "game the system" because an entity would need to not only accurately predict the CEHE 4CP to influence the class allocation but also the ERCOT 4CP to influence its billing determinants.[889]

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

TIEC proposes that 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.[890] Alternatively, TIEC proposes that the Commission should take a gradualist approach in adjusting the TCRF 4CP allocation factors to avoid rate shock.[891] Notwithstanding that this rate proceeding is clearly not the appropriate forum to argue for changes to Rule 25.193, TIEC has made similar requests in prior proceedings and the Commission has rejected those requests each time.[892] Moreover, TIEC's concerns are overstated. The Commission now requires all electric utilities to file a comprehensive rate proceeding every

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884 CEHE Ex. 30 at 3013 (Troxle Direct).
885 *Id.*
886 *Id.*
887 *Id.*
888 *Id.*
889 CEHE Ex. 45 at 10 (Troxle Rebuttal).
890 TIEC Ex. 1 at 32-43 (Pollock Direct).
891 *Id.* at 37-38.
892 *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).

four years, at which time the allocation factors will be updated.[893] 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.[894]

2. Municipal Franchise Fees [PO Issue 46]

No party contests the reasonableness of the *amount* of CEHE's municipal franchise fee expenses.[895] The only criticism—from Mr. Pollock—involves the *allocation* of those expenses. CEHE has allocated municipal franchise fees to the customer classes based upon *in-city* kWh sales but proposes to collect the fees from *all* customers within each customer class.[896] This treatment is consistent with CEHE's last rate case and with Commission precedent.[897] Mr. Pollock recommends that municipal franchise fees be allocated among customer classes based not only on in-city kWh sales, but also based on differences in per kWh franchise fee amounts among those cities.[898] Mr. Pollock made the exact same recommendation in CEHE's last rate case.[899] The Commission rejected his proposal then,[900] and the Commission should do so again. Mr. Troxle explained that CEHE's allocation of municipal franchise fees takes into account the different customer class sales mix among different cities and follows Commission precedent.[901] Mr. Nalepa confirms that CEHE's allocation method is consistent with principles of cost causation, consistency, and simplicity.[902] The Commission should affirm CEHE's allocation of municipal franchise fees and reject (again) Mr. Pollock's proposed change.

3. Transmission and Key Accounts

The Transmission and Key Accounts Department is one of four departments within the Power Delivery Solutions Division.[903] The Transmission and Key Accounts Department is, in turn, divided into three groups: Transmission Accounts and Support, Key Accounts, and Street

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[893] CEHE Ex. 45 at 22 (Troxle Rebuttal).
[894] *Id.*
[895] The amount to be recovered in CEHE's base rates for municipal franchise fees is addressed in CEHE's Initial Brief at Section XI.B.6 [PO Issue 28].
[896] CEHE Ex. 45 at 12 (Troxle Rebuttal).
[897] Docket No. 38339, PFD at 156 (Dec. 3, 2010); CEHE Ex. 45 at 12 (Troxle Rebuttal); Cross-Rebuttal Testimony of Karl Nalepa, OPUC Ex. 7 at 10.
[898] TIEC Ex. 1 at 20-21 (Pollock Direct).
[899] *See* Docket No. 38339, PFD at 156; CEHE Ex. 45 at 12 (Troxle Rebuttal); OPUC Ex. 7 at 8-9 (Nalepa Cross-Rebuttal).
[900] Docket No. 38339, Order on Rehearing at Finding of Fact No. 179; *see* CEHE Ex. 45 at 12 (Troxle Rebuttal); OPUC Ex. 7 at 8-9 (Nalepa Cross-Rebuttal).
[901] CEHE Ex. 45 at 11-12 (Troxle Rebuttal).
[902] OPUC Ex. 7 at 10-11 (Nalepa Cross-Rebuttal).
[903] Direct Testimony of Julienne P. Sugarek, CEHE Ex. 10 at 665-666 (Bates Pages).

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Lighting.[904] The test-year expense for the entire department was $2,034,463.[905] The Transmission Accounts and Support group supports the transmission function and the Key Accounts and Street Lighting groups support the distribution function.[906] This is acknowledged by Mr. Nalepa.[907] Mr. Nalepa contends that $678,154 of the costs associated with the Transmission and Key Accounts Department, which resides within the Company's Power Delivery Solutions Division should be directly assigned to the transmission function.[908] All of this was explained by Ms. Sugarek on behalf of CEHE.[909]

Expenses associated with these three groups have been directly assigned by CEHE in this application to the respective functions and included in Schedule II-1-TRAN.[910] Mr. Nalepa, on the other hand, proposes to "assign" the costs by allocating the costs equally among the three departments. Dividing the O&M expenses of the Key Accounts Department by three, Mr. Nalepa urges that $678,154 be assigned to the transmission function.[911] Mr. Nalepa's effort to functionalize these costs by simply dividing these costs among the three groups would necessarily shift a portion of the distribution costs that reside in the Key Accounts and Street Lighting groups to the transmission function.

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

CEHE's Rate Base Schedule II-B-12 shows the correct functionalization for the Regulatory Assets for Hurricane Harvey between transmission and distribution and uses the same percentages as stated in Mr. Nalepa's testimony.[912] The Company made a necessary revision to Schedule E-E-4.1 as well as to its testimony to reflect the amortization expense resulting from the functionalization.[913]

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[904] CEHE Ex. 10 at 668 (Sugarek Direct).
[905] *Id.* at 670.
[906] *Id.* at 668-669.
[907] OPUC Ex. 5 at 51 (Nalepa Direct). Mr. Nalepa correctly noted that the Key Accounts group is responsible for maintaining relationships with major *distribution* customers and that Key Accounts personnel serve as major distribution customers' primary point of contact. Likewise, the Street Lighting Design group designs lighting systems for roadways, bridges, walkways, hike and bike trails, and parks at the request of municipal governments and residential and commercial customers. The Street Lighting Design group interfaces regularly with the *distribution* operations groups responsible for installation, maintenance, and repair of street lighting systems.
[908] *Id.* at 50-52 (Nalepa Direct).
[909] CEHE Ex. 10 at 668-669 (Sugarek Direct).
[910] CEHE Ex. 2 at 418-504, Schedule II-I-TRAN.
[911] OPUC Ex. 5 at 50-52 (Nalepa Direct).
[912] CEHE Ex. 35 at 38-39 (Colvin Rebuttal).
[913] *Id.*

5. Other Cost Allocation Issues [PO Issue 46]

Ms. Pevoto recommends changing the allocation factor for 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 from an O&M allocator or plant allocator to a payroll allocator.[914] As explained in the rebuttal testimony of Mr. Troxle, the allocation factors used for these accounts have long been employed by the Company and these exact same allocators were approved by this Commission in the Company's last rate case.[915] The allocation factors are also consistent with the NARUC Cost Allocation Manual.[916] 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.[917]

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.[918] This approach should also be rejected. The use of lamp count for allocating cost to the lighting classes instead of the number of customers recognizes that some customers, like COH, have many lamps[919] and, as explained by Mr. Troxle at the hearing, Account 907-10 costs will vary depending on the number of lamps a customer uses.[920] Because there are more costs associated with serving customers with more lamps, the use of the lamp count allows the Company to accurately allocate the cost of the lighting class and adhere to the cost causation principle.[921]

VIII. Revenue Distribution and Rate Design [PO Issues 4, 5, 43, 44, 49, 50]

The Company's proposed delivery system charges were designed using the processes summarized in Schedule IV-J-1 Revenue Summary. The summary shows total cost of service requirements by function and by rate class. The total cost of service or revenue requirement by rate class is divided by total billing determinants to derive a rate per class.[922] The per-class rate

[914] Direct Testimony of Kit Pevoto, COH/HCC Ex. 3 at 11.
[915] CEHE Ex. 45 at 14-16 (Troxle Rebuttal); Tr. at 1059 (Troxle Cross) (Jun. 27, 2019).
[916] *Id.*
[917] CEHE Ex. 45 at 15 (Troxle Rebuttal); Tr. at 1059 (Troxle Cross) (Jun. 27, 2019).
[918] COH/HCC Ex. 3 at 18 (Pevoto Direct).
[919] CEHE Ex. 45 at 18 (Troxle Rebuttal).
[920] Tr. at 1048 (Troxle Cross) (Jun 27, 2019).
[921] CEHE Ex. 45 at 18 (Troxle Rebuttal).
[922] CEHE Ex. 30 at 3019-3020 (Troxle Direct).

calculations are shown on Schedules IV-J-7 Proof of Revenue Summary. The adjusted billing determinants are indicated in Schedule IV-J-5.

The retail delivery rate classes are Residential Service, Secondary Service Less than or Equal to 10 kVA, Secondary Service Greater Than 10 kVA, Primary Service, Transmission Service and Lighting Services.[923] Each rate class schedule, except for Lighting Services, includes a Customer Charge, Metering Charge, Distribution System Charge, and Transmission System Charge.[924] The current and proposed revenue by rate class and the charges by rate class are shown in Exhibits MAT-4 and MAT-5 to the direct testimony of Mr. Troxle, respectively.

The Customer Charge and Metering Charge include costs that are incurred regardless of system usage.[925] The Customer Charge for each rate schedule is based on the class revenue requirement for the Customer Service function from the Company's class cost of service study, divided by the total test year adjusted annual meter count for each class.[926] The Metering Charge for each rate schedule (other than Lighting Services, which has no Metering Charge) is based on the class revenue requirement for the Metering function from the Company's class cost of service study, divided by the total test year adjusted annual meter count for each class.[927] The Company proposes making one change to how it bills the Customer and Metering Charge, charging on a per-meter basis instead of a per-customer basis.[928] The change provides an accurate representation of billed customers; each meter will represent one Electric Service Identifier account.[929]

The Distribution System Charge for each rate schedule is based on the class revenue requirement for the Distribution function from the Proposed Class Cost of Service Study, divided by the total test year adjusted annual distribution billing determinants for that class.[930] For Residential and Secondary Less Than or Equal to 10 kVA Service, the Transmission System Charge is developed using the respective total test year adjusted kWh.[931] For the Secondary Greater Than 10 kVA and Primary rate schedules, the Transmission System Charge is developed

[923] *Id.* at 3020.
[924] *Id.*
[925] *Id.*
[926] *Id.*
[927] *Id* at 3022. However, for rate classes that have both IDR and non-IDR meter categories, both the revenue requirement and the annual meter count are calculated separately for each category. *Id.*
[928] *Id.* at 3020.
[929] *Id.*
[930] *Id* at 3023.
[931] *Id.*

based on IDR or non-IDR meter billing determinants.[932] For the Transmission Service rate schedule, the Transmission System Charge is developed using 4CP kVA.[933]

Certain parties have challenged the Company's proposed residential customer charge, the use of a per-meter customer charge, and the calculation of O&M associated with LED street lights. These proposals should be rejected for the reasons explained below.

A. Residential Customer Charge

Ms. Pevoto has recommended the Company employ gradualism by reducing its proposed customer charge from $2.46 to $1.75 per meter. Ms. Pevoto ignores the fact that the Company charges customers two fixed charges on their bills: a customer charge and a meter charge.[934] When combined, the two proposed fixed charges are a $0.94 decrease from the current charges.[935] Also, 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.[936] Moreover, looking at the fixed charge alone does not take into account the usage charges.[937] The argument that a customer will experience rate shock from any individual fixed components of their bill is without merit.

Notably, if the Commission were to approve the Company's proposed rates in this proceeding, the Company would be in the middle of the residential distribution rates for other transmission and distribution utilities in ERCOT, as shown below:

Utility	Fixed Charges + Distribution Charge +_ DCRF Charge at 1,000 kWh[938]
TNMP	$33.52
AEP Texas-North	$31.04
CEHE (Proposed)	$27.18
Oncor	$23.44
AEP Texas-Central	$22.81

[932] *Id.*
[933] *Id.* at 3024.
[934] CEHE Ex. 45 at 38 (Troxle Rebuttal).
[935] *Id.*; CEHE Ex. 30 at 3056, Exh. MAT-5 at 1 of 7 (Troxle Direct).
[936] 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.
[937] CEHE Ex. 45 at 38 (Troxle Rebuttal).
[938] 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.

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

Mr. Presses and Ms. Pevoto challenge CEHE's proposal to assess Customer Charges and Meter Charges on a per meter basis rather than a per customer basis.[939] Ms. Pevoto argues that CEHE has presented no reason for the change.[940] Mr. Troxle noted in his direct testimony that non-rate changes to CEHE's tariff were intended to clarify the tariff and to reflect CEHE's experience in operating under the tariffs.[941] On rebuttal, Mr. Troxle further explained that a per meter charge is consistent with language in the current CEHE rate schedules, which apply to customers taking delivery through *one point of delivery* measured through *a single meter* and provide that additional meters will require an additional charge.[942] Ms. Pevoto asserts that per meter charges will "fundamentally change how customers will be charged" and that customers with multiple meters will receive multiple bills every month.[943] Mr. Troxle explained that the change is hardly "fundamental," because 99.976% of CEHE's customers take service through a single meter[944] and there is no reason why multiple bills would be necessary for the few who do not.[945]

Mr. Presses alleges that "a per customer charge more accurately reflects the administrative costs associated with the provision of service."[946] Mr. Presses, however, has no relevant experience with metering costs and has not performed any studies to support his statement.[947] Mr. Troxle explained that assessing the Customer Charge and Meter Charge on a per meter basis would not affect CEHE's revenue requirement,[948] but would only assure that each customer pays its share of metering and customer service expenses without subsidization by customers with only a single meter.[949] He explained that there is greater expense—both metering costs and customer service costs—associated with customers who request multiple meters.[950] The Commission should approve the proposed change, which more clearly reflects the intent of the existing tariff

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[939] Direct Testimony of George W. Presses, HEB Ex. 1 at 27; COH/HCC Ex. 3 at 29-30 (Pevoto Direct).
[940] COH/HCC Ex. 3 at 30 (Pevoto Direct).
[941] CEHE Ex. 30 at 3043 (Troxle Direct).
[942] CEHE Ex. 45 at 46-47 (Troxle Rebuttal).
[943] COH/HCC Ex. 3 at 30 (Pevoto Direct).
[944] CEHE Ex. 45 at 46 (Troxle Rebuttal).
[945] *Id.* at 47.
[946] HEB Ex. 1 at 27 (Presses Direct).
[947] Tr. at 398-400 (Presses Cross) (Jun. 25, 2019).
[948] Tr. at 973-974 (Troxle Cross) (Jun. 27, 2019).
[949] CEHE Ex. 45 at 45 (Troxle Rebuttal); Tr. at 973-974 and 990 (Troxle Cross) (Jun. 27, 2019).
[950] CEHE Ex. 45 at 47 (Troxle Rebuttal) (metering costs); Tr. at 984-985 (Troxle Cross) (Jun. 27, 2019) (customer service costs).

language, has no effect on CEHE's revenue requirement, and eliminates subsidization of customers who request additional meters by those who do not.

C. Transmission Service Rate

CEHE proposes to include its TCOS in its base rates. This is addressed in Section X.A.

D. Transmission Service Facility Extensions

Mr. Pollock also suggests changes to the Company's Transmission Service Facility Extension Policy based on an apparent concern that the Company does not have a tariff provision that requires CEHE to refund a customer's contribution in aid of construction payment if actual costs end up being lower than estimates.[951] Mr. Pollock also incorrectly states that the customer may enter into a Utility Construction Services Study Agreement to determine the scope of the construction services and would be responsible for covering the costs of the services upfront.[952] However, the Utility Construction Services Study Agreement he references, which is proposed Tariff Section 6.3.4.7, is not used for transmission customers. This agreement is for other non-standard types of service such as premium rollover distribution service.[953]

Additionally, the evidence demonstrates that Section 5(b)(ii) of the Company's Transmission Facility Extension Agreement is a placeholder for negotiated payment terms.[954] This section of the agreement states that at the completion of the Project, the difference between the Actual Facilities Extension Cost and the sum of any Project Payment made by the customer will be calculated.[955] If the Actual Facilities Extension Cost is less than the Project Payments, a refund will be issued.[956] If the Actual Facilities Extension Cost is greater than the Project Payments, an invoice will be issued.[957] Moreover, while Mr. Pollock expresses concern about the possibility that certain customer facilities might be subsequently used to serve other customers, he provides no example of such a possibility occurring in the Company's service territory or reason to change the Company's current method related to customer-funded facilities. Because CEHE determines which facilities are needed solely to interconnect a transmission customer—and are therefore not eligible for rate recovery, the customer pays upfront for those facilities.[958] Thus, any refund for

[951] TIEC Ex. 1 at 42 (Pollock Direct).
[952] *Id.*
[953] CEHE Ex. 33 at 24 (Sugarek Rebuttal).
[954] *Id.*
[955] *Id.*
[956] *Id.* at 24-25.
[957] *Id.* at 25.
[958] *Id.*

facility costs under Mr. Pollock's hypothetical costs would occur between customers—not between CEHE and a new customer behind another customer's facility.

E. Street Lighting Service

CEHE has proposed to establish LED Luminaires as the new street light standard lamp type for Street Lighting Services and Miscellaneous Lighting Services under Lighting Services section 6.1.1.1.6 of the Tariff.[959] Recent advances in LED technology and declining LED prices have resulted in LED for street lighting as an attractive alternative to existing street lighting options due to the potential customer and energy savings that could be achieved with more efficient light technology.[960] CEHE will continue 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).[961] Consequently, installation of a non-LED lamp type—metal halide or high pressure sodium ("HPS"), e.g.—will only be in circumstances where LED lighting lamp installation is not possible or cost effective.[962]

Mr. Murphy has challenged the Company's proposal to shift to LED as the standard lighting offer. Specifically, Mr. Murphy claims that moving the Company's standard lighting installation to LED will eliminate customer choice in lighting options and will result in higher upfront costs and replacement lighting costs on the customer in the short term. Mr. Murphy also expresses concerns about the payback period for LED lighting services and that LED lighting will fail prior to yielding any financial benefits. Mr. Murphy's concerns ignore significant evidence to the contrary.

As LED has become more widely adopted, suppliers are providing more LED lighting options, including various wattages, lumen and color temperatures.[963] Today, LED-equivalents of all of CEHE's current standard and decorative street lighting options are available, giving customers a variety of choices to fulfill their street lighting needs.[964] Furthermore, CEHE plans to convert non-LED lamps to their LED-equivalent at no cost to the customer during the normal course of maintenance when individual lamps burn out and, for new installations, the cost of installing the LED-equivalent standard offering is the same as the non-LED equivalent, resulting

[959] CEHE Ex. 10 at 686 (Sugarek Direct).
[960] *Id.*
[961] *Id.*
[962] *Id.*
[963] CEHE Ex. 33 at 20 (Sugarek Rebuttal).
[964] *Id.*

in no additional upfront cost to the customer.[965] Moreover, over the life of the asset, the cost of an LED luminaire is less than the cost of an equivalent HPS luminaire.[966] Also, as evidenced in the U.S. Department of Energy's 2017 report on "Adoption of Light-Emitting Diodes in Common Lighting Applications," HPS lamp installations for streets and roadways declined from 85.9% in 2010 to 61.9% in 2016 while LED luminaire installations increased from 0.3% in 2010 to 28.3% in 2016.[967] This significant shift is affecting the manufacture of lighting alternatives and portends product availability issues going forward.[968] Based on these factors, it is reasonable for the Company to shift to LED as its standard offer street light.

F. Other Rate Design Issues

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

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

A. Rider UEDIT [PO Issue 51]

1. Recovery Period for Rider UEDIT

It is undisputed that Rider UEDIT will return approximately $119 million in net unprotected EDIT to customers over the next three years.[969] This three-year period for returning the benefits to customers is consistent with the period requested by CEHE for other regulatory assets and liabilities.[970] Further, the evidence is undisputed that the Company's protected EDIT balance may change significantly over time.[971] For example, a change in law—or specific guidance from the Treasury or IRS—could affect what amounts are properly characterized as protected EDIT or unprotected EDIT.[972] Consequently, the three-year time period of Rider UEDIT

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965 *Id.* at 21.

966 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.

967 *Id.* at 22.

968 *Id.* & 108-111, Exh. R-JPS-18.

969 CEHE Ex. 2, Schedule H-I-J and CA Errata – 1, IV-J-7 UEDIT tab; CEHE Ex. 6 at 57 (Mercado Direct); CEHE Ex. 12 at 880 (Colvin Direct).

970 *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 FIT rate decreased in 1986 and 1987 and concluding that "[t]he evidence supports a three year amortization period for unprotected excess deferred income taxes").

971 CEHE Ex. 12 at 909-910 (Colvin Direct).

972 CEHE Ex. 13 at 1007 (Pringle Direct).

allows CEHE to appropriately track the balance and record an over- or under-balance of amounts collected under the Rider UEDIT compared to the actual net UEDIT liability amount and to address this balance in the next base rate proceeding.[973] This ensures that customers receive all of—but not more or less than—the properly computed unprotected EDIT balance.

Only Ms. LaConte asserts that components of unprotected EDIT in Rider UEDIT should be returned to customers over a shorter period of time than three years.[974] Ms. LaConte's proposal should be rejected. The evidence demonstrates that a three-year amortization period is fair to both CEHE and its customers.[975] The three-year period was properly derived from the time period related to regulatory asset recovery approved in Docket No. 38339 to recover regulatory assets.[976] Ms. LaConte's proposed refund period is also much shorter than the unprotected EDIT refund periods approved in other Texas utility rate cases.[977] While Ms. LaConte points to two other cases where unprotected EDIT was returned to customers in a time period of less than three years, neither case involves a Texas utility.[978] Her proposal should be denied.

2. Amounts Included in Rider UEDIT

No party disputes CEHE's proposal to return unprotected EDIT to customers through Rider UEDIT. However, Mr. Kollen asserts that Rider UEDIT should also include $200.35 million of EDIT related to ADFIT associated solely with certain Transition Bonds and System Restoration Bonds (each, defined below).[979] Mr. Kollen's proposal should be rejected.

As noted above, GAAP required CEHE to recognize the effects of the TCJA upon enactment.[980] CEHE was thus required to record the effects of the TCJA in December 2017 and accordingly revalued deferred taxes associated with the securitized Transition Bonds and securitized System Restoration Bonds issued by certain of its subsidiaries. This resulted in $158 million that CEHE took to income in December 2017.[981] The $158 million related to charges associated with the following:

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[973] CEHE Ex. 12 at 909-910 (Colvin Direct).
[974] TIEC Ex. 3 at 6, 11-13 (LaConte Direct).
[975] CEHE Ex. 35 at 61-62 (Colvin Rebuttal).
[976] *Id.*
[977] *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).
[978] TIEC Ex. 3 at 12-13 (LaConte Direct).
[979] GCCC Ex. 1 at 56, 61 (Kollen Direct).
[980] ASC 740-10-25-47.
[981] CEHE Ex. 84 at 56 (Optional Completeness to TCUC Ex. 27).

- Senior Secured Transition Bonds, Series A issued by CenterPoint Energy Transition Bond Company II, LLC ("Schedule TC 2") (regarding charges relating to true-up amounts and other qualified costs);
- Senior Secured Transition Bonds issued by CenterPoint Energy Transition Bond Company III, LLC ("Schedule TC 3") (regarding charges relating to [CTC] amounts pursuant to HB 624);
- Senior Secured Transition Bonds issued by CenterPoint Energy Transition Bond Company IV, LLC ("Schedule TC 5" and, together with Schedule TC 2 and Schedule TC 3, the "Transition Charges") (regarding charges relating to true-up remand amounts); and
- Senior Secured System Restoration Bonds issued by CenterPoint Energy Restoration Bond Company, LLC ("Rider SRC") (regarding charges relating to Hurricane Ike system restoration costs).[982]

The Transition Charges relate to the need to compensate CEHE for transition costs resulting from the "unbundling" of the Texas electric market approximately 20 years ago.[983] Rider SRC was established to reimburse CEHE for system restoration costs associated with the devastation caused by Hurricane Ike in 2008 and was approved pursuant to PURA storm securitization provisions.[984] The Transition Charges and Rider SRC were effectively securitized, as discussed further below, reducing costs to CEHE's customers through the issuance of low-cost "Transition Bonds" (in the case of Transition Charges) and "System Restoration Bonds" (in the case of Rider SRC).

The evidence at hearing clearly established that all future and potential ADFIT issues related to transition costs and storm restoration costs were settled in agreements approved by the Commission. Specifically, with respect to ADFIT and any associated benefits on Transition Bonds, the need to adjust the ADFIT balance relating to Transition Charges and any related benefit was identified by the Company and Staff in pre-filed testimony in Docket No. 39504.[985] Yet, those issues were settled "forever" (in the language of the settlement agreement itself)[986] in a settlement agreement that subsumed those issues[987] and the amount given up by the Company in settlement was substantial. In fact, the black box reduction amount in Docket No. 39504 was nearly three

[982] CEHE Ex. 35 at 64 (Colvin Rebuttal); *see also* CenterPoint Energy, Inc., 3rd Quarter 2017 Debt and Liquidity Schedules, *available at*: http://files.shareholder.com/downloads/HOU/5975594469x0x962554/5B43BA9D-A272-4979-A7F0-038641979773/Q3_2017_Debt_and_Maturity_Schedules_11.3.17.pdf.
[983] CEHE Ex. 35 at 63–64 (Colvin Rebuttal).
[984] *Id.*
[985] CEHE Ex. 62 at bates pages 30-33 (testimony of Walter Fitzgerald in Docket No. 39504); CEHE Ex. 64 at 11-12 (testimony of Darryl Tietjen at 11-12).
[986] CEHE Ex. 65 at bates page 9.
[987] CEHE Ex. 65 at bates page 10; *See also*, Tr. at 798-799, 802-806 (Tietjen Cross) (Jun. 26, 2019).

times the additional amount of EDIT Mr. Kollen now suggests should be added to Rider UEDIT and consisted of:

- A ***$600 million adjustment*** to the Company's original request;
- No additional carrying costs accruing on the true-up balance (which were accruing at over $1 million per day prior to the settlement);
- CEHE paying COH and GCCC rate case expenses;
- CEHE bearing the cost of its own rate case expenses; and
- CEHE bearing the up-front qualified costs of securitizing the true-up balance (which ran into the millions also).[988]

In short, the ratepayer benefit derived from the settlement agreement "forever" settling ADFIT issues in Docket No. 39504 related to all transition charges alone demonstrates that Mr. Kollen's proposal to reopen those issues is unreasonable on its face.

Further, as Mr. Tietjen acknowledged, the statutory framework surrounding securitizations is unique.[989] From a statutory standpoint, Chapter 39, Subchapter G of PURA sets forth a statutory framework to "enable utilities to use securitization financing to recover" certain amounts relating to unbundling, including competition transition charges.[990] Chapter 36, Subchapter I of PURA provides a similar framework to "enable an electric utility to obtain timely recovery of system restoration costs and to use securitization financing to recover these costs."[991] The procedures and standards outlined in Chapter 39, Subchapter G of PURA largely govern the issuance of both Transition Bonds and System Restoration Bonds.[992]

For instance, both types of bonds are issued pursuant to financing orders approved by the Commission that specify the specific amount of stranded costs and system restoration costs that can be securitized pursuant to the statutory framework.[993] Further, and importantly, financing orders are intended to be final: PURA specifically provides that "the financing order, together with the transition charges authorized in the order, shall thereafter be irrevocable and not subject to reduction, impairment, or adjustment by further action of the commission, except as permitted by Section 39.307."[994] This provision is bolstered by a pledge of the State of Texas that provides in relevant part:

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[988] CEHE Ex. 65; Tr. at 802-806 (Tietjen Cross) (Jun. 26, 2019).
[989] Tr. at 802 (Tietjen Cross) (Jun. 26, 2019).
[990] Tex. Util. Code § 39.301.
[991] *Id.* § 36.401.
[992] *Id.* § 36.403.
[993] *Id.* § 39.303.
[994] *Id.* § 39.303(d).

> The state pledges . . . for the benefit and protection of financing parties and the electric utility, that it will not take or permit any action that would impair the value of transition property, or, except as permitted by Section 39.307, reduce, alter, or impair the transition charges to be imposed, collected, and remitted to financing parties, until the principal, interest and premium, and any other charges incurred and contracts to be performed in connection with the related transition bonds have been paid and performed in full.[995]

The individual financing orders for each series of CEHE's Transition Bonds and System Restoration Bonds set forth the terms and conditions of recoverable transition costs and recoverable system restoration costs. Consistent with the statutes set forth above, ***each financing order provides that it is final and not subject to rehearing by the Commission***,[996] and each contains the pledge pursuant to Section 39.310 of PURA.[997]

In addition, the System Restoration Bonds also include an adjustment provision to take into account any ADFIT credit associated with system restoration costs and associated insurance recoveries.[998] The Commission's financing order establishes a separate negative credit for any such amounts and includes a separate tariff to determine amounts payable on the ADFIT credit. Similar to the settlement agreement relating to the Transition Bonds, the ADFIT credit applied to the storm restoration balance was substantial – including a return on the storm restoration related ADFIT of $207,006,452, plus a return of and on a principal amount of $6,500,000 over the life of the bonds at ***11.075%***.[999] In this context, parties to the proceeding establishing the financing order for Rider SRC expressly agreed that

> [t]he ADFIT Credits are 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. The Signatories agree that ADFIT benefits associated with such system restoration costs shall not be applied to reduce the securitizable balance and that the ADFIT balance shall not be used to reduce rate base in future proceedings.[1000]

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[995] *Id.* § 39.310 (emphasis added).
[996] *Application of CenterPoint Energy Houston Electric, LLC for Financing Order*, Docket No. 30485, Financing Order, Conclusion of Law No. 45 at 66 (Mar. 16, 2005); *Application of CenterPoint Energy Houston Electric, LLC for Financing Order*, Docket No. 34448, Financing Order, Conclusion of Law No. 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 No. 46 at 62 (Oct. 27, 2011); *Application of CenterPoint Energy Houston, LLC for a Financing Order*, Docket No. 37200, Financing Order, Conclusion of Law No. 47 at 67 (Aug. 26, 2009).
[997] Docket No. 30485, Schedule TC 2 Order, Conclusion of Law No. 41 at 65; Docket No. 34448, Schedule TC 3 Order, Conclusion of Law No. 45 at 68; Docket No. 39809, Schedule TC 5 Order, Conclusion of Law No. 42 at 61; Docket No. 37200, Rider SRC Order, Conclusion of Law No. 43 at 66.
[998] Docket No. 37200, Rider SRC Order, Finding of Fact No. 8(B) at 19.
[999] CEHE Ex. 66 at 2-3.
[1000] *See* CEHE Ex. 66, Settlement Agreement at 4 (emphasis added).

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Again, the language of the SRC settlement agreement is critical. The use of the word "potential" is clear evidence of the parties' then-existing understanding that tax laws and rates might change in the future. Nevertheless, the substantial benefit of forever settling that issue when combined with a healthy credit for ratepayers, outweighed any need to threaten the statutory guarantee of recovery for bond holders in the future.

The relevant provisions of PURA also set forth an unambiguous statutory framework intended to protect securitized costs from intervening events. The pledge contained in Section 39.310 and the irrevocability of financing orders pursuant to Section 39.303 (along with Section 36.403) work in tandem to ensure that securitized costs are ironclad and not subject to further legislative or regulatory interference or, except as otherwise expressly provided, changes in facts. The financing orders of the securitization bonds echo this intent and mirror the statutory language. As Mr. Tietjen recognizes, these statutory protections are essential in order for customers to realize the benefits of the securitizations.[1001] 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.

In furtherance of this framework, PURA and the related financing orders lay out the ***exclusive*** means by which securitized costs can be adjusted, and even in these limited circumstances, Transition Charges and Rider SRC are protected.[1002] All such adjustments, with the exception of the ADFIT credit included in the Rider SRC, focus on the ability to pay the obligations under the securitization bonds as required. Moreover, the evidence demonstrates that the TCJA does not impact the payment obligations on the securitization bonds and, therefore, cannot impact the Transition Charges and Rider SRC intended to service such bonds. In determining the amount of securitizable costs, the Commission had to consider many factors and made voluminous findings of fact related thereto. Over time, any number of the variables and assumptions that had been included in the Commission's equation may have changed. What has remained unchanged, however, are the obligations pursuant to the securitization bonds. As long as these obligations remain unchanged, it is inconsistent with Texas law to jeopardize the cash flows intended to pay for them.

[1001] Staff Ex. 1A at 26-27 (Tietjen Direct).
[1002] *See* Tex. Util. Code § 39.303(b).

B. Merger Savings Rider

Mr. Kollen argues that the Company should adopt a merger savings rider or an adjustment should be made to the revenue requirement for merger-related savings.[1003] At this time, savings estimates resulting from the Vectren acquisition are just that—estimates; they are not known.[1004] For instance, the evidence demonstrates that the most significant unknown is the cost to integrate technology systems.[1005] This is due to the fact that the Company must standardize all of its processes for operations, customer experience, accounting, and finance.[1006] In addition, many of the Company's expected savings will be impacted by factors that include the future cost of goods and services and labor.[1007] Some examples include labor costs for electric line skills that are being affected by increases in demand in California; increased cost of materials because of new or increased tariffs on goods from China and Mexico, such as computers and transformers; and increased cost of services that are due to events in non-CNP jurisdictions, such as costs of insurance premiums.[1008] No one can project how these factors will ultimately impact net savings at this point. Further, it is not known what the net amount of any savings CNP or CEHE may realize.

The evidence is also clear that in order to properly reflect *all* of the impacts of the Vectren acquisition, both cost savings *and* costs necessary to achieve those savings must be captured and considered.[1009] The costs to achieve are substantial and currently exceed any near-term estimated savings. CEHE witness Jeffrey Myerson's rebuttal testimony, which is CEHE Exhibit 47, sets forth the *confidential* estimate of the costs to achieve.[1010] Thus, the evidence demonstrates that if the actual costs to achieve the savings attributable to the Vectren acquisition were included in the proposed "Merger Savings Rider," the result for 2019 would be a *surcharge* to customer bills—not a refund.[1011]

Regardless, as explained earlier, any concerns Mr. Kollen has concerning potential savings associated with the Vectren acquisition are addressed through the protections already in place through the annual EMR filing process. Per Commission Rule 25.73, the Commission uses the

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[1003] GCCC Ex. 1 at 48 (Kollen Direct).
[1004] CEHE Ex. 47 at 18 (Myerson Rebuttal).
[1005] *Id.* at 9.
[1006] *Id.*
[1007] *Id.*
[1008] *Id.*
[1009] CEHE Ex. 35 at 63 (Colvin Rebuttal).
[1010] CEHE Ex. 47 at 13 (Myerson Rebuttal).
[1011] *Id.* at 19.

EMR as the way to properly monitor a utility's earnings; in fact, the Commission's order approving the EMR filing package in Project No. 39040 states that the "report has been used as a tool to review a utility's actual earnings for an historical period."[1012] The EMR provides information necessary to determine if a utility is earning above its authorized return, which means at *any* point in time the Company can be compelled to file a base rate case if the Commission believes it is over-earning.[1013] It also means that, if the Company is over-earning, it will be prohibited from filing a DCRF during the following year.[1014] Also mitigating Mr. Kollen's concerns is the fact that, under the recently implemented 16 TAC § 25.246, CEHE will be required to file a base rate case approximately four years following the implementation of rates in this case, at which point any potential costs and savings will be captured through a comprehensive rate case filing.[1015]

C. Other Riders

Rider CTC—Competition Transition Charges, Rider SBF—System Benefit Fund, Schedule TC—Transition Charges, and Rider AMS—Advanced Metering System Surcharge are no longer applicable and CEHE proposes to delete them from its tariff.[1016] No party contests their removal.

Rider NDC (Nuclear Decommissioning Charges) was approved by the Commission in Docket No. 49082.[1017] Pursuant to 16 TAC §§ 22.33 and 25.303(g)(3), any future changes to Rider NDC will be made in a separate proceeding.[1018]

Rider TCRF—Transmission Cost Recovery Factor will be updated at the conclusion of this case consistent with the Commission's TCRF rule.[1019] Intervenor proposals regarding CEHE's TCRF are addressed in Section X of CEHE's Initial Brief.

CEHE proposed changes to Rider RCE—Rate Case Expenses Surcharge to recover rate case expenses approved in this docket. However, rate case expense recovery has been severed to a separate docket.

1012 *Project to Revise Earnings Monitoring Report Forms for Electric Utilities,* Docket No. 39040, Final Order at 31 (Jan. 7, 2012).
1013 CEHE Ex. 35 at 63 (Colvin Rebuttal).
1014 CEHE Ex. 47 at 19 (Myerson Rebuttal).
1015 *Id.*
1016 CEHE Ex. 30 at 3031, 3033 (Troxle Direct).
1017 *Id.* at 3031.
1018 *Id.* at 3032.
1019 *Id.*

CEHE proposes no changes to Rider DCRF—Distribution Cost Recovery Factor other than to change the rates contained therein to reflect the results of this rate case.[1020]

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

The Company proposes that its retail transmission costs—i.e., the costs it pays to the other TSPs in ERCOT—should be recovered in base rates through the transmission charge for each delivery rate schedule and that its TCRF should be reset to zero.[1021] The proposed TCRF allocation factors will also be updated to reflect the December 31, 2018 test year unadjusted 4CP allocation factors used for the allocation of transmission cost in the proposed class cost of service study.[1022] This means that the TCRF will be used to recover the *incremental* differences between the Company's transmission charges and the amount of costs approved to be included in base rates. This approach has been approved for the Company since the deregulation of the electric market and the creation of the TCRF.[1023]

A. Transmission Cost of Service

The amount of transmission costs to be included in base rates before other revenue is $979,966,163 and after accounting for other revenue is $941,839,163.[1024] To fully recover its wholesale transmission costs, CEHE calculates a wholesale component in accordance with 16 TAC § 25.192 and will utilize the baseline factors established in this rate case.[1025] To allocate retail transmission costs, CEHE has reasonably used the unadjusted 4CP allocation factor based on the ERCOT peak summer month periods to allocate capacity-related transmission costs.[1026]

CEHE's TCOS is supported by 16 TAC § 25.192(c)(1), which defines facilities that are deemed to be transmission assets. CEHE explained that it determines the allocation of assets between transmission and distribution plant in-service based on that rule.[1027] For the period January 1, 2010 through December 31, 2018, CEHE's transmission capital investments total approximately $3.0 billion.[1028] The evidence establishes that these capital investments are used and useful in providing service to the public and that this investment was reasonable and necessary to ensure a reliable transmission system that complies with applicable NERC standards and enable

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[1020] *Id.* at 3037; *See also* CEHE Initial Brief Appendix 2.
[1021] CEHE Ex. 45 at 19 (Troxle Rebuttal).
[1022] *Id.*
[1023] *Id.*
[1024] CEHE Ex. 2 at 418-504, Schedule II-I-TRAN.
[1025] *See* CEHE Ex. 30 at 3032 (Troxle Direct); *See also* CEHE Initial Brief Appendix 2.
[1026] *Id* at 3012.
[1027] CEHE Ex. 8 at 333 (Narendorf Direct).
[1028] *Id.* at 343.

increased transfers across constrained transmission interfaces identified by ERCOT.[1029] Details of the Company's transmission investment were thoroughly explained in CEHE witness Martin W. Narendorf's direct and rebuttal testimonies and is detailed in the Company's briefing of Issue 12.

CEHE also demonstrated that test year O&M expenditures for transmission operations in the amount of $58.7 million were reasonable, necessary, and based on well-established, prudent practices.[1030] For instance, CEHE employs a five-year physical inspection cycle for its transmission facilities, and a one-year aerial inspection cycle. CEHE follows NERC standard PRC-005-6 for Bulk Electric System protection equipment testing and maintenance, which specifies types of equipment requiring testing and the designated testing intervals.[1031] Work orders for equipment designated in PRC-005-6 are automatically generated and available to Substation Operations in advance to allow enough time to complete the work well before deadlines.[1032] All High Voltage Operations maintenance plans are made up of maintenance strategies, which set frequencies, and task lists that set the job scope and hourly standards.[1033] The Company compares maintenance practices with other utilities at peer conferences and working groups.[1034] Maintenance interval recommendations from equipment manufacturers and CEHE's own failure analysis data is also used to establish best practices and metrics for maintenance.[1035] Further, all High Voltage Operations departments perform budget analysis monthly to monitor O&M spend.[1036] In sum, the cost of service data, Company testimony, and supporting materials demonstrate that CEHE's transmission capital expenditures and test year O&M expense for High Voltage Operations are reasonable, necessary, and representative of the costs to provide service to customers of CEHE and should be included in the Company's cost of service.

B. Transmission Cost Recovery Factor

TIEC argues that all transmission costs should be recovered through the Company's Rider TCRF instead of through base rates. It reasons that because the TCRF includes a load growth adjustment, including all transmission costs in the TCRF would mitigate the potential for "over-recovery" of these costs.[1037] This proposal should be rejected.

[1029] *Id.* at 357.
[1030] *Id.* at 339.
[1031] *Id.* at 340.
[1032] *Id.*
[1033] *Id.*
[1034] *Id.*
[1035] *Id.*
[1036] *Id.*
[1037] TIEC Ex. 1 at 31 (Pollock Direct).

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."[1038] This constitutes the incremental differences between a DSPs actual costs and what is included in its base rates.[1039] The Company's approach is consistent with Rule 25.193 and the requirements in the Commission's TDU RFP instructions, which on page 59 refers to the allocation of the functional requirements and on page 63 refers to the revenue requirements by the function (Transmission is one of the functions).[1040] Further, in the RFP sample forms, the rate design sheets are clearly designed to reflect a transmission charge in base rates.[1041] In fact, the Company is not aware of *any* rule that suggests or requires a DSP to capture its entire TCOS through a rider.[1042]

Moreover, TIEC's concerns about the over-recovery of transmission costs are over-stated. While load growth can affect a utility's cost recovery, other impacts can drive down cost recovery at the same time.[1043] For instance, an electric utility that serves more load will have increased O&M costs and will be required to make increased investments in its system.[1044] In addition, there are other factors that affect usage, costs, and revenues, like weather, economic conditions, and changes in tax rates, all of which are reviewed by the Commission in the Company's annual Earnings Monitoring Reports.[1045] Furthermore, there is no guarantee that load growth will occur every year, as growth can fluctuate like any other factor, and CEHE must absorb the risk of reduced load usage, for instance related to customer attrition or increased energy efficiency.[1046] That is the consequence of traditional ratemaking; there are risks of both over-recovery and under-recovery. Mr. Pollock presumes a lot of potential benefits to the Company without taking into account the potential detriment and risks.[1047]

TIEC's concerns are also mitigated by the recently implemented 16 TAC § 25.246, which requires all investor-owned electric utilities to file a rate case every four years.[1048] Accordingly,

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[1038] CEHE Ex. 45 at 20 (quoting 16 TAC § 25.193(b)) (Troxle Rebuttal).
[1039] *Id.*
[1040] *Id.*
[1041] *Id.*
[1042] *Id.*
[1043] *Id.* at 21.
[1044] *Id.*
[1045] *Id.*
[1046] *Id.*
[1047] *Id.*
[1048] *Id.* at 22.

the Company's entire cost of service will be subject to review approximately every four years to ensure it is not over-recovering its transmission or any other costs.[1049] In the interim, the Company is still required to file earnings monitoring reports and the Commission retains the authority to require a rate case sooner than every four years if it determines the need for one.[1050] With all of these protections in place, there is simply no justification to deviate from the RFP and Commission's rules in order to shift all transmission costs into the TCRF.[1051]

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. HEB Service Complaint

The evidence demonstrates that CEHE provides reliable service to the customers in its service territory. In all but two years between 2008 and today, CEHE's SAIDI has been better than the Commission standard.[1052] Among ERCOT investor-owned utilities, CEHE is consistently the least penalized utility for violations of the Commission's SAIDI standard.[1053] Indeed, COH notes the "high level of customer satisfaction with CEHE's service reliability."[1054] This is true despite the fact that CEHE is located in a climate that produces above average rainfall, routine thunderstorm and lightening activity, and annual exposure to tropical depressions, storms, and hurricanes.[1055] Only one party, HEB, alleges a lack of reliability in CEHE's service.[1056] HEB's allegations, however, are limited to the experience of only a single customer (HEB) and are based on unreliable data and incomplete analysis.

First, CEHE serves over 2.5 million customers.[1057] It is inappropriate to draw conclusions about CEHE's reliability based on a single customer, even one that takes service at 166 locations (0.00000664% of CEHE's total).

[1049] *Id.*
[1050] *Id.*
[1051] *Id.*
[1052] CEHE Ex. 9 at 609-611 (Bodden Direct); CEHE Ex. 33 at 4-5 (Sugarek Rebuttal).
[1053] CEHE Ex. 33 at 5 (Sugarek Rebuttal).
[1054] COH/HCC Ex. 1 at 9 (Norwood Direct).
[1055] CEHE Ex. 33 at 6 (Sugarek Rebuttal).
[1056] HEB Ex. 1 at 5-7 (Presses Direct).
[1057] Tr. at 1252 (Sugarek Cross) (Jun. 27, 2019).

Second, the data presented by HEB is not reliable. Ms. Sugarek provided a variety of statistics related specifically to HEB's facilities that show good reliability and facts very different from those alleged by Mr. Presses.[1058] Mr. Presses acknowledges that HEB has outage records for some, but not all of its facilities.[1059] HEB's only outage records are for its facilities that have on-site generation installed.[1060] In contrast, Ms. Sugarek presented comprehensive data for all of HEB's locations.[1061]

Third, Mr. Presses' analysis is incomplete, because it does not account for problems caused by HEB's own equipment. Mr. Presses testified on redirect that none of the outages described in his testimony were the result of problems with HEB's equipment and that they were all the result of CEHE outages.[1062] He stated that the issues could not possibly be on HEB's side of the meter, because HEB only recorded outages when its on-site generation came on and that the on-site generation only comes on in response to a CEHE outage.[1063] On cross examination, however, Mr. Presses acknowledged an event in June 2018 in which an HEB location "was left without power during a failed transition from generator power to CenterPoint power," and all of the corrective actions "involved work on HEB's side of the meter, not on CenterPoint's side of the meter."[1064] Mr. Presses likewise acknowledged an event in July 2018 involving a "malfunction with equipment owned by [HEB] or [its] on-site generation provider [that] prevented this facility from being connected to CenterPoint's power, even though CenterPoint was ready and able to provide power," where again all of the corrective actions taken involved equipment on HEB's side of the meter.[1065] These instances undermine Mr. Presses assurances that all of the outages he describes are the fault of CEHE, not HEB's own equipment.

Ms. Sugarek testified that HEB's own on-site generation equipment is likely the root cause of a material portion of HEB's outages.[1066] According to CEHE's research and the findings of first responders dispatched to HEB locations as a result of outages, when HEB is receiving power from its on-site generation equipment and then attempts to transfer back to receiving power from CEHE, the voltage and/or phase angles between the generator and the Company's system should

[1058] CEHE Ex. 33 at 8 (Sugarek Rebuttal).
[1059] HEB Ex. 1 at 10 (Presses Direct).
[1060] *Id.* at 11.
[1061] CEHE Ex. 33 at 7 (Sugarek Rebuttal).
[1062] Tr. at 413-414 (Presses Redirect) (Jun. 25, 2019) (Declassified).
[1063] *Id.*
[1064] Tr. at 407–408 (Presses Cross) (Jun. 25, 2019).
[1065] *Id.* at 408–409.
[1066] CEHE Ex. 33 at 13-14 (Sugarek Rebuttal).

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be (but often are not) within certain limits that allow for proper synchronization.[1067] Over time, this has caused the fuses of several transformers serving HEB locations to melt, resulting in outages.[1068] In April 2019, CEHE proposed engaging a third party, at its expense, to further study the issues relating to the melting transformer fuses, and a meeting was scheduled for May 28, 2019 to discuss that action, but Mr. Presses canceled it and has yet to respond to CEHE's request to reschedule.[1069]

Even if Mr. Presses' allegations concerning reliability at HEB locations—0.0000664% of the meters served by CEHE—were completely true, it would say nothing about CEHE's overall reliability of service, which the evidence shows has been better than average for most of the past decade. Moreover, Mr. Presses' data is incomplete and unreliable and his analysis fails to consider compelling evidence of issues created by HEB's own equipment. The Commission should disregard his testimony.

B. Uncontested Issues

1. Allowance for Funds Used During Construction [PO Issue 12]

No party challenged CEHE's AFUDC accrual rates or the amount included in the Company's invested capital.[1070]

2. Construction Work in Progress [PO Issue 14]

CEHE has not requested the inclusion of CWIP.[1071]

3. Cash Working Capital [PO Issue 15]

The Company commissioned a lead-lag study to derive a CWC requirement in the amount of $26.2 million that was included in the Company's rate base.[1072] The lead-lag study provides an accurate representation of the Company's CWC requirement during the test year;[1073] the study methodology is consistent with the lead-lag study approved in the Company's most recent rate case proceeding, Docket No. 38339; and the study complies with the requirements included in 16 TAC § 25.231(c)(2)(B)(iii).[1074]

[1067] *Id.*
[1068] *Id.*
[1069] *Id.* at 15-16.
[1070] TCUC Ex. 87.
[1071] CEHE Ex. 12 at 895 (Colvin Direct).
[1072] *Id.* at 901-902.
[1073] Direct Testimony of Timothy S. Lyons, CEHE Ex. 24 at 2007 (Bates Pages).
[1074] *Id.* at 2007.

4. Post-Test Year Changes to Rate Base [PO Issue 20]

CEHE proposed no post-test year adjustments to its requested rate base.

5. Rate Case Expenses [PO Issues 23, 24, 42]

Pursuant to SOAH Order No. 5, this issue has been severed into SOAH Docket No. 473-19-5174/PUC Docket No. 49595.

6. Municipal Franchise Fees [PO Issue 27]

CEHE's requested recovery of municipal franchise fees was not challenged. CEHE demonstrated that the recovery of approximately $153.2 million in municipal franchise fees as shown on Schedule II-E-2 of the Company's RFP is reasonable and necessary and should be recovered in base rates.[1075]

7. Liberalized Depreciation [PO Issue 30]

This issue is not applicable to this base rate proceeding.

8. Advertising Expense, Contributions, and Donations [PO Issue 31]

Charitable contributions and donations, dues, and certain advertising expenses do not exceed the thresholds specified in 16 TAC § 25.231(b)(1)(E).

9. Nuclear Decommissioning [PO Issue 32]

This issue is not applicable to this base rate proceeding.

10. Competitive Affiliates [PO Issue 36]

CEHE has one competitive affiliate, CenterPoint Energy Intelligent Energy Solutions, LLC.[1076] The only affiliate costs included in CEHE's rate filing relate to services provided to CEHE by Service Company and CERC.[1077]

11. Revenues Received for Power Exports or Imports to ERCOT [PO Issue 37]

Revenues Received for Power Exports or Imports to ERCOT are included in Schedule II-E-5 and Schedule III-A-1.[1078]

12. Executive Salaries, Advertising Expenses, Legal Expenses, etc. [PO Issue 38]

The Company's rate request complies with Commission Rule 25.231(b)(2) by excluding from the cost of service expenses for legislative advocacy, political or religious causes, support of or membership in various clubs or organizations, consumption, advertisement, and similar types

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[1075] CEHE Ex. 19 at 1678-1680 (Kimzey Direct).
[1076] TEAM Ex. 2.
[1077] CEHE Ex. 15 at 1071-1072 (Townsend Direct).
[1078] CEHE Ex. 2 at 407, Schedule II-E-5 & 874, Schedule III-A-1).

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of activities.[1079] The evidence also shows the cost recovery thresholds for charitable contributions and donations, dues, and certain advertising expenses were not exceeded.[1080] Therefore, the requested amounts for those items shown on Schedule II-D-2.3 are properly recovered through rates. In addition, CEHE is not requesting recovery of any expenses recorded below-the-line such as donations or penalties.[1081] Issues related to costs for executive salaries are addressed in Section IV.B.3.e.

13. Amounts for Transmission Expenses and Revenues under FERC Tariffs [PO Issue 40]

The only expenses and revenues related to services provided pursuant to the Company's FERC-approved tariff are those associated with exports from ERCOT based on rates approved by this Commission.[1082] These amounts are included in CEHE Ex. 2, Schedule III-A-1.[1083]

14. Rates for Power Exports from ERCOT [PO Issue 47]

The rates for exports of power from ERCOT, as presented in the direct testimony of Matthew A. Troxle, are calculated in accordance with 16 TAC § 25.192(e) and ERCOT protocols.[1084]

15. Allocation of Customer-Specific Contracts and FERC-Approved Tariff Revenues and Expenses [PO Issue 46]

The Company has no expense or revenue related to customer-specific contracts. The only revenues and expenses related to services provided pursuant to the Company's FERC-approved tariff are those associated with exports from ERCOT, which are all functionalized to the transmission function.[1085]

16. Provision of Wholesale Power at Distribution Voltage [PO Issue 48]

CEHE does not serve any wholesale customers at distribution voltage.

17. Request for Exceptions to Commission Rules [PO Issue 57]

CEHE requested no exceptions to the Commission's rules.

[1079] CEHE Ex. 12 at 843 (Colvin Direct).
[1080] *Id.*
[1081] *Id.*; CEHE Ex. 2 at 402, Schedule II-E-4.2 (Below the Line Expenses).
[1082] The Company's FERC Electric Tariff, Sixth Revised Volume No. 1 is available on the Company's website at https://www.centerpointenergy.com/en-us/Documents/RatesandTariffs/HoustonElectric/FERC-Transmission-Tariff.pdf.
[1083] Revenues associated with exports are identified in CEHE Ex. 2 at CEHE RFP Workpapers (redacted) Errata 1, WP II-E-5.2. Expenses associated with exports are included in the Company's wholesale transmission cost of service.
[1084] CEHE Ex. 30 at 3739, Exh. MAT-10 at 8 (Troxle Direct).
[1085] CEHE Ex. 2 at CEHE RFP Workpapers (redacted) Errata 1, WP II-E-5.1.

18. Rate Filing Package Waiver Requests [PO Issue 58]

CEHE did not request any waivers of the Commission's RFP requirements.

19. Compliance with Commission's Final Order in Docket No. 38339 [PO Issue 59]

CEHE has complied with the Commission's Final Order in Docket No. 38339 in all respects.

XII. Conclusion

It is beyond dispute that a fiscally strong utility is in the interest of all stakeholders. CEHE's application in this case supports its need to increase rates to recover its reasonable and necessary costs, to be given a reasonable opportunity to earn a fair return on its investment, and to remain financially strong so it can continue providing safe and reliable service.

The Intervenors and Staff ask the Commission to reduce CEHE's rates by hundreds of millions of dollars, yet they identify no specific areas of the Company's operations that should be streamlined, replaced, or altered. Not only are the Intervenor and Staff proposals results-driven, instead of evidence-driven, but the record in this case compels the conclusion that any rate reduction is both unjustified and harmful to the health and well-being of CEHE, and therefore to the public interest.

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

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Respectfully submitted,

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COUNSEL FOR CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC

CERTIFICATE OF SERVICE

I hereby certify that on this 9th 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

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I. PROCEDURAL HISTORY

On April 5, 2019, CenterPoint Energy Houston Electric, LLC ("CEHE") filed an application and rate filing package to change rates with the Public Utility Commission of Texas ("Commission") and with each municipality in CEHE's service territory that has not ceded its original jurisdiction over rates to the Commission.[1] The Commission has exclusive jurisdiction over the rates, operations, and services of CEHE for areas outside of municipal boundaries,[2] as well as over transmission rates,[3] and municipalities have original jurisdiction over CEHE's rates, operations, and service within their boundaries.[4] After some jurisdictional municipalities failed to take timely action on CEHE's requested rate change and thereby approved the requested rate change,[5] CEHE appealed[6] the municipal approvals to the Commission where they have been consolidated with this docket.[7] CEHE provided proper notice of its Application in compliance with statute,[8] the Commission's procedural rules,[9] and the requirements of the filing package.[10]

The Commission referred this proceeding to the State Office of Administrative Hearings ("SOAH") on April 8, 2019.[11] The Commission issued its Preliminary Order on May 9, 2019, setting forth 59 issues to be addressed in this proceeding. The Preliminary Order also stated that the following issues would not be addressed in this proceeding: (1) whether CEHE should be permitted to install voltage-regulation battery assets; and (2) whether CEHE should be permitted to modify its tariff to add an additional allowance for facility extensions to electric vehicle charging stations. The statutory deadline for final action by the Commission is October 12, 2019.[12] The SOAH Administrative Law Judges ("ALJs") issued Order Nos. 2 and 6, which, among other things, established procedural deadlines in compliance with the 185-day jurisdictional deadline set out in PURA.[13]

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[1] CEHE Ex. 1. The list of municipalities that have ceded original jurisdiction to the Commission is listed in Exhibit A to CEHE Ex. 1.
[2] Public Utility Regulatory Act, Tex. Util. Code § 32.001(a)(1) ("PURA"); *see also* PURA § 14.001.
[3] PURA § 35.004(d).
[4] PURA § 33.001.
[5] PURA § 36.108(c).
[6] *See* PURA §§ 32.001(b), 33.051, 33.053.
[7] SOAH Order No. 7 (June 18, 2019).
[8] PURA § 36.103.
[9] 16 TAC § 22.51.
[10] Investor Owned Utility Transmission and Distribution Cost of Service Rate Filing Package, General Inst. No. 13. CEHE's notice is contained in CEHE Ex. 7; CEHE Ex. 5 (Notice Affidavit of Alice S. Hart).
[11] Order of Referral (April 8, 2019).
[12] *See* SOAH Order No. 10 (July 2, 2019).
[13] SOAH Order No. 2 at 4 (May 1, 2019); SOAH Order No. 6 at 5 (June 4, 2019).

The following entities were granted intervenor status in this case: The Office of Public Utility Counsel ("OPUC"); The Gulf Coast Coalition of Cities ("GCCC"); Texas Industrial Energy Consumers ("TIEC"); Texas Coast Utilities Coalition ("TCUC"); The City of Houston and the Houston Coalition of Cities ("COH/HCC"); Alliance for Retail Markets ("ARM"); Texas Energy Association for Marketers ("TEAM"); Calpine Corporation ("Calpine"); Texas Competitive Power Advocates ("TCPA"); Olin Corporation ("Olin"); Generation Park Management District ("GPMD"); McCord Development Inc. ("McCord"); HEB LP ("HEB"); Solar Energy Industries Association ("SEIA"); Enel X North America, Inc. ("Enel X"); and Walmart Inc. ("Walmart").

On June 4, 2019, SOAH granted CEHE's unopposed motion to sever the consideration of rate case expenses incurred in PUC Docket Nos. 38339, 45747, 47032, 47364, 48226, and 49421 (including applicable appeals), and ordered that the issues associated with the rate case expenses incurred in those dockets be severed into and considered in PUC Docket No. 49595.[14]

Intervenors filed direct testimony on June 6, 2019. Commission Staff filed direct testimony on June 12, 2019. Intervenors and Staff filed cross-rebuttal testimony June 19, 2019. On June 19, CEHE filed rebuttal testimony. A prehearing conference was conducted on June 24, 2019. During the prehearing conference, CEHE's motion to dismiss intervenor Olin was granted based on Olin's failure to file direct testimony or a statement of position. Additionally, CEHE's motion to strike portions of the cross-rebuttal testimony of George W. Presses, filed on HEB's behalf, was granted.

The hearing on the merits commenced on June 24, 2019, and lasted 5 days, concluding on June 28, 2019. The hearing on the merits was presided over by SOAH ALJs Steven D. Arnold (appearing telephonically), Meaghan Bailey, and Fernando Rodriguez. The following parties participated in the hearing on the merits: CEHE, COH, HCC, OPUC, TCUC, Commission Staff, GCCC, TIEC, ARM, TEAM, Calpine, TCPA, GPMD, McCord, HEB, SEIA, Enel X, and Walmart. The record remained open for the filing of post-hearing briefs. On July 16, 2019, the parties filed their reply briefs and the record closed. The parties requested that the ALJs submit their Proposal for Decision by September 16, 2019, to allow the Commission to consider it at the October 11, 2019 open meeting.

[14] SOAH Order No. 5 (June 4, 2019).

DCRF Baseline Rate Case Values

PUBLIC UTILITY COMMISSION OF TEXAS
CENTERPOINT ENERGY HOUSTON ELECTRIC
P.U.C. DOCKET NO. 49421
FOR THE TEST YEAR ENDED 12/31/2018

Description	Reference	Residential	Secondary <=10 KVA	Secondary > 10 KVA	Primary Voltage	Transmission Voltage	Lighting Total	Total
$DIC_{RC\text{-}Class}$	wp/Schedule J/3 1	$2,295,570,886	$55,144,811	$1,207,642,811	$93,631,648	$9,921,957	$315,625,516	$3,977,537,629
ROR_{AT}	wp/Schedule J/3 2	7 39%	7 39%	7 39%	7 39%	7 39%	7 39%	7 39%
$DEPR_{RC\text{-}Class}$	wp/Schedule J/3 3	$155,442,317	$4,608,598	$77,890,940	$6,116,600	$1,617,540	$19,490,176	$265,166,171
$FIT_{RC\text{-}Class}$	wp/Schedule J/3 5	$27,553,247	$661,490	$14,357,623	$1,104,530	$96,479	$3,782,492	$47,555,860
$OT_{RC\text{-}Class}$	wp/Schedule J/3 4	$41,881,538	$1,067,682	$21,860,993	$1,718,632	$255,298	$5,640,780	$72,424,924
$DISTREV_{RC\text{-}Class}$	$(DIC_{RC} * ROR_{AT}) + DEPR_{RC} + FIT_{RC} + OT_{RC}$	$394,519,790	$10,412,971	$203,354,360	$15,859,142	$2,702,550	$52,238,174	$679,086,986
$ALLOC_{CLASS}$	wp/Schedule J/3 9	57.7240%	1 3860%	30 3651%	2 3553%	0 2489%	7.9208%	100 00%

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
Interim Update Wholesale Transmission Cost of Service

Line No.	Description		Total Approved Docket No. 49421 (1)	Schedule / Workpaper Reference
1	Operation & Maintenance	$	106,384,421	Docket No. 49421
2	Depreciation and Amortization		79,574,913	Schedule E-1
3	Taxes Other Than Income Taxes		43,989,201	Schedule E-2
4	Federal Income Tax		27,063,632	Schedule E-3
5	Return on Rate Base		173,663,954	Schedule B
6	Total Revenue Requirement	$	430,676,121	
7	Other Revenues	$	(36,316,000)	Docket No. 49421
8	**Total**	**$**	**394,360,121**	
9	ERCOT AVERAGE 4 CP-in MW		69,368.9635	
10	Wholesale Rate $/MW	**$**	**5,684.96**	

Docket No. 49421, Schedule III-A-1	$	5,685
Check	$	(0)