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SOAH DOCKET NO. 473-19-3864
PUC DOCKET NO. 49421

APPLICATION OF CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC FOR AUTHORITY TO CHANGE RATES	§ § § § § § §	**BEFORE THE STATE OFFICES OF ADMINISTRATIVE HEARINGS**

COMMISSION STAFF'S INITIAL BRIEF

Respectfully Submitted,

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I. INTRODUCTION/SUMMARY [PRELIMINARY ORDER (PO) ISSUES 1, 2, 3]

This is not the typical proceeding where a utility voluntarily files a base rate case to increase revenues. On a total company basis, CenterPoint Energy Houston Electric, LLC's ("CEHE" or "Company") revenues are sufficient. CEHE's historical revenues have earned CEHE a generous net income, even without reducing CEHE's rate base or expenses for any of the multiple adjustments recommended by Staff and Intervenors in this proceeding. As the evidence shows, CEHE has been able to benefit financially from efficiencies in operations and growth in customers and sales since its last base rate case.[1] CEHE reported earnings for the year 2016 as providing CEHE a 9.6% return on equity.[2] Staff adjustments to the same earnings report to recalculate earnings for what Staff argues is an appropriate capital structure of 60% debt and 40% equity reflected a return on equity in the 10.5% to 10.6% range.[3] CEHE reported earnings for the year 2017 as providing CEHE a 9.33% return on equity, or 9.21% adjusted for weather.[4] CEHE's 2017 weather adjusted return on equity, using Staff's recommended capital structure is shown below:

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[1] *See e.g.*, TIEC Ex. 12, CenterPoint 1st Quarter 2019 Earnings Call ("Houston Electric – T&D core operating income, excluding merger-related expenses, was $84 million in Q1 2019 compared with core operating income of $99 million in Q1 2018, in line with expectations . . . . Nearly 41,000 Houston Electric customers added year over year.").

[2] TIEC Ex. 14 at 2.

[3] TIEC Ex. 14 at 3.

[4] Staff Ex. 10 at 7.

CEHE's 2017 Return on Equity Given Staff's Recommended Capital Structure			
	Staff Recommended Capital Structure	**Cost**	**Weighted Cost**
Equity	40%[5]	***10.53%***[6]	4.21%[7]
Debt	60%[8]	4.48%[9]	2.43%[10]
		Rate of Return	**6.64%**[11]

As may be seen above, CEHE earned a weather adjusted return on equity of 10.53% in 2017, using Staff's proposed capital structure of 60% debt and 40% equity as is recommended for transmission and distribution utilities in Staff's analysis of earnings monitoring reports.[12]

CEHE is not required to file an earnings report while a base rate case is pending. However, during 2017 and the test year, CEHE's short term incentives paid as a result of CenterPoint Energy Inc.'s (CenterPoint) earnings per share reached the highest achievement level in five years.[13] Xzzzzzzzzzzxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxzzzzz xxxxxxxxxxxxxxxxxxxxxxxxzz.[14] In fact, CEHE employees did not receive any short term incentive compensation based upon earnings per share goals in 2014 and 2015.[15] Xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx

[5] TIEC Ex. 14 at 3.

[6] 10.53% = Weighted Average Cost of Debt (4.21%) / Equity in Staff Recommended Capital Structure (40%).

[7] 4.21% = Overall Rate of Return (6.64%) – Weighted Average Cost of Debt (2.43%).

[8] TIEC Ex. 14 at 3.

[9] Staff Ex. 10 at 12.

[10] 2.43% = Debt from Staff Recommended Capital Structure (60%) x CEHE 2017 Cost of Debt (4.48%).

[11] Staff Ex. 10 at 7.

[12] TIEC Ex. 14 at 3.

[13] Staff Ex. 15a (Confidential).

[14] *Id.*

[15] *Id.*

xxxxxxxxx,[16] which is not indicative of a utility that is unable to earn a reasonable return in excess of its reasonable and necessary operating expenses. CEHE witness Kristie Colvin explained that it may be reasonable to expect CEHE employees to earn incentive compensation based on an earnings per share metric because the metric is based on CenterPoint earnings per share rather than CEHE's earnings.[17] However, for the test year, when CEHE employees earned their highest achievement level and earned their highest amount of short term incentives based upon earnings per share, CEHE's net income provided 91% of CenterPoint's net income.[18]

CEHE did not file this base rate case willingly in an effort to increase revenues. CEHE filed this case in order to comply with the rate case review schedule requirements under 16 Texas Administrative Code § 25.247(c)(2)(B) ("TAC") and its commitment to the timing of a rate filing in Project No. 47945, *Proceeding to Investigate and Address the Effects of the Tax Cuts and Jobs Act of 2017 on the Rates of Texas Investor-Owned Utility Companies*.[19] As such, this case provides the Commission with the opportunity to set CEHE's retail and wholesale rates at a level that will allow CEHE to earn a reasonable return in excess of its reasonable and necessary operating expenses.

CEHE may only support its requested $149 million increase by requesting an excessive rate of return based upon a capital structure of 50% equity and 50% debt and a 10.4% return on equity,[20] which results in an $88.1 million differential from Staff's recommended rate of return and taxes.[21] CEHE also requests the recovery of financially based incentive compensation, which is a $33.5 million differential from Staff's recommended level of reasonable incentives that has been permitted for recovery by recent precedent.[22] CEHE also employed an outside consultant to perform a weather normalization that has the effect of understating normal usage,

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[16] *Id.*

[17] Tr. at 1315:7 - 1317:3 (Colvin Cross) (June 28, 2019).

[18] Tr. at 1317:15-25 (Colvin Cross) (June 28, 2019).

[19] Direct Testimony of Kenny Mercado, CEHE Exhibit 6 at 12.

[20] CEHE Exhibit 6 at 17, 21.

[21] Staff Ex. 11.

[22] Direct Testimony of Mark Filarowicz, Staff Ex. 4A at 15.

thus increasing rates. CEHE also adjusted billing determinants for energy efficiency lost revenues, an argument that the Commission has historically rejected. Staff's witnesses, performing a routine weather normalization and removing CEHE's energy efficiency adjustment to billing determinants, further reduced CEHE's proposed rate increase by another $33.9 million.[23] Taking these three adjustments together and ignoring all others would result in a decrease to total revenues for CEHE.[24]

Staff's proposed revenues are also the result of multiple recommendations to: 1) reduce CEHE's rate base for imprudent investments, misclassified capital expenditures, and inappropriate regulatory assets; 2) reduce expenses for unreasonable costs not permitted for recovery from customers; and 3) determine present revenues at normal levels based upon a reasonable weather adjustment that is consistent with Commission precedent.

For collecting these proposed revenues, Staff's cost allocation, revenue distribution, and rate design proposals are reflective of cost causation, as permitting gradualism in this case is unnecessary and inappropriate for a transmission and distribution utility. Staff witnesses prepared a cost of service model using allocations and procedures consistent with Commission precedent. Staff's cost of service model and rate design should be adopted in this proceeding and used for number-running purposes and for developing TCRF and DCRF baselines.

Additionally, Staff requests that the ALJs recommend, and the Commission order, several financial protections to insulate CEHE from the risks of its parent corporation and its affiliates.

[23] Direct Testimony of Brian Murphy, Staff Ex. 2A at 50 ($33,884,510 = $2,129,484,979 - $2,095,600,469).

[24] The total of the three adjustments is $155.5 million, which is greater than CEHE's proposed revenue increase.

II. RATE BASE [PO ISSUES 4, 5, 10, 11, 12, 15, 16, 17, 18, 19]

A. Transmission and Distribution Capital Investment [PO Issues 4, 5, 10, 11, 12]

In the event that any plant disallowances are approved by the Commission, Staff recommends that CEHE be ordered to initiate a separate compliance proceeding to determine the exact refund amounts and the forms that the refund shall take.[25]

1. Capital Project Prudence

Transmission Capital Investment

Staff recommends a disallowance of $13,211,393 in transmission investment-related costs incurred by CEHE, as they were not prudently incurred. Under PURA § 36.006, CEHE has the burden of proof in this rate case.[26] Therefore, CEHE has the burden of proving that any costs incurred for capital investments were prudently incurred. Staff's witness Tom Sweatman reviewed the prudence of any transmission investment incurred between the test year in Docket No. 38339 and the test-year end in the Application.[27]

Initially, in his direct testimony, Mr. Sweatman recommended disallowing cost overruns for 11 projects, for a total of $20,328,742.[28] Mr. Sweatman sought disallowances for these projects because CEHE failed to establish that there was reasonable justification for incurring costs that exceeded 110% of the estimated construction costs. The 11 projects and reasons for disallowance are listed below:

- *Alexander Island Substation*: The filed initial estimated project cost for this substation was $358,000; the actual final cost was $732,052, a 104.5% variance. Mr. Sweatman recommended a disallowance of $338,252,[29,30] due to a mistake in which the foundations

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25 Staff Ex. 2A at 74.

26 PURA § 36.006.

27 16 TAC § 25.243(f) (DCRF reconciliation) states that "The commission shall reconcile investments recovered through a DCRF in the electric utility's next comprehensive base-rate proceeding[.]"

28 Staff Ex. 8 at 6.

29 Enlarged Copy of Attachment TS-4 to the Direct Testimony of Tom Sweatman, Staff Ex. 8A.

were located in the wrong place, which subsequently had to be removed and replaced. In Mr. Sweatman's opinion, the cost for avoidable mistakes, which he believes this one to be, should not be paid by CEHE's customers.[31,32]

- *La Marque Substation*: Initial estimate was $1,446,000, and actual final cost was $2,773,369, a 91.8% difference. Mr. Sweatman recommended a disallowance of $1,182,769,[33] due to design and location errors that were foreseeable.[34]
- *Sandy Point Substation*: Initial estimate was $2,619,000, and actual final cost was $4,957,565, an 89.3% variance. Mr. Sweatman recommended a disallowance of $2,076,665,[35] due to poor management, since labor costs increased due to a change in the substation site.[36]
- *Dow Substation*: Initial estimate was $48,000, and actual final cost was $72,463, a 51.0% difference. Mr. Sweatman recommended a disallowance of $19,663,[37] due to CEHE's failure to provide a clear response to RFIs by Staff; that is, CEHE in response to PUC RFI No. 1-38 stated that "[t]he project ... was not specific to a single customer"[38]; however, in its response to a subsequent RFI by Staff, namely, PUC RFI No. 6-24, CEHE states, "The final actual project cost was paid in full by the customer for this project. The company is not seeking recovery of these costs in this case[.]"[39] These are two contradictory responses.[40]

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30 This dollar-figure—the recommended disallowance—is a 90% reduction of the overrun, which will be the case in all the subsequent recommended disallowances in this section.

31 Staff Ex. 8 at 7.

32 This is Mr. Sweatman's belief as to every avoidable mistake for the subsequent projects in this list; that is, the ratepayers should not be on the hook for the costs of CEHE's errors.

33 Staff Ex. 8A.

34 Staff Ex. 8 at 7.

35 Staff Ex. 8A.

36 Staff Ex. 8 at 7.

37 Staff Ex. 8A.

38 Staff Ex. 8 at 26.

39 *Id.* at 62.

- *Flewellen – Fort Bend*: Initial estimate was $509,000, and actual final cost was $758,534, a 49.0% variance. Mr. Sweatman recommended a disallowance of $198,634,[41] due to CEHE's failure to give an explanation for the cost overrun[42].
- *Fort Bend – Rosenberg*: Initial estimate was $1,913,000, and actual final cost was $2,680,262, a 40.1% difference. Mr. Sweatman recommended a disallowance of $575,962,[43] due to mismanagement wherein significant changes in line routing were made, increasing labor costs.[44]
- *W.A. Parrish Substation*: Initial estimate was $380,000, and actual final cost was $420,531, a 10.7% variance. Mr. Sweatman recommended a disallowance of $2,531,[45] due to cost differences in labor and materials, an explanation that Mr. Sweatman finds lacking.[46]
- *Jones Creek*: Initial estimate was $52,900,000, and actual final cost was $68,422,609, a 29.3% difference. Mr. Sweatman recommended a disallowance of $10,232,609,[47] due to CEHE's failure to explain cost overruns for the entire project and the need for a distribution substation that was added to the project.[48]

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[40] Staff Ex. 8 at 7-8.

[41] Staff Ex. 8A.

[42] Staff Ex. 8 at 8.

[43] Staff Ex. 8A.

[44] Staff Ex. 8 at 8.

[45] Staff Ex. 8A.

[46] Staff Ex. 8 at 8.

[47] Staff Ex. 8A.

[48] Staff Ex. 8 at 8-9.

- *Springwoods*: Initial estimate was $11,600,000, and actual final cost was $13,505,096, a 15.8% variance. Mr. Sweatman recommended a disallowance of $745,096,[49] due to CEHE's failure to give an explanation for the transmission cost overrun.[50]
- *Tanner*: Initial estimate was $11,000,000, and actual final cost was $12,790,474, a 16.3% difference. Mr. Sweatman recommended a disallowance of $690,474,[51] due to CEHE's failure to give an explanation for the transmission cost overrun.[52]
- *Sandy Point*: Initial estimate was $6,160,000, and actual final cost was $11,042,088, a 79.3% deviation. Mr. Sweatman recommended a disallowance of $4,266,088,[53] due to CEHE's failure to give a sufficient explanation for an error in which the substation site changed, thereby increasing labor costs.[54]

However, after CEHE witness Martin Narendorf filed his rebuttal testimony,[55] Mr. Sweatman adjusted his total disallowance to $13,211,393, due to the additional information provided by CEHE regarding four particular projects, listed below:

- *Sandy Point Substation*: Mr. Narendorf explained why a change in substation siting would necessitate the building of a temporary bypass.[56] Thus, Mr. Sweatman removed his previously recommended disallowance of $2,076,665 for this project.
- *Flewellen – Fort Bend*: Mr. Narendorf refers to CEHE's response to PUC RFI No. 6-24[57] in explaining that the cost overrun was a result of the fact that the project was not fully

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49 Staff Ex. 8A.

50 Staff Ex. 8 at 9.

51 Staff Ex. 8A.

52 Staff Ex. 8 at 9.

53 Staff Ex. 8A.

54 Staff Ex. 8 at 9.

55 Rebuttal Testimony and Exhibits of Martin W. Narendorf Jr., CEHE Ex. 32 at 16-28.

56 *Id.* at 23-24.

57 *Id.* at 24.

budgeted in the estimate. Thus, Mr. Sweatman removed his previously recommended disallowance of $198,634 for this project.[58]

- *Fort Bend – Rosenburg*: Mr. Narendorf stated that a "change in line routing due to ROW [right-of-way] constraints" was cause for cost inflation.[59] As a result, Mr. Sweatman removed his previously recommended disallowance of $575,962 for this project.
- *Sandy Point*: Mr. Narendorf refers to CEHE's response to PUC RFI No. 6-24, to explain that the cost increase was a result of changing sites for a substation after the initial estimates.[60] Consequently, Mr. Sweatman removed his previously recommended disallowance of $4,266,088 for this project.[61]

CEHE only provided information that explain cost overruns for four projects. Because CEHE failed to present any additional information for the remaining seven projects, CEHE failed to satisfy its burden of proof. Thus, Staff recommends a disallowance of $13,211,393, relating to costs not prudently incurred.

Staff witness Blake Ianni also recommends a disallowance of $8,160, relating to transmission invested capital not prudently incurred.[62] CEHE did not dispute Mr. Ianni's recommended disallowance for transmission invested capital in its rebuttal testimony.[63]

2. Capital Project Accounting/Capitalization Policy Changes

Staff did not recommend any adjustments in this section. Staff reserves the right to address this issue in the reply brief.

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[58] *Id.*

[59] *Id.*

[60] *Id.* at 27.

[61] Staff Ex. 8B at 4.

[62] Direct Testimony of Blake Ianni, Staff Ex. 6, at 6.

[63] Rebuttal Testimony, Exhibits and Workpapers of Kristie L. Colvin, CEHE Ex. 35, at 54.

3. Land Costs

Staff recommends a disallowance of $6,795,685.47 of land costs, as these properties are not currently used and useful. CEHE incurred these amounts for land costs of properties that do not yet contain energized electric facilities.[64] In its response to Staff RFI No. 5-9, CEHE outlines three land costs for three separate substation projects *currently* under construction.[65] CEHE states that the expected completion dates for these three projects are outside of the test year.[66]

Title 16 TAC § 25.231(c)(2) provides:

> The rate base, sometimes referred to as invested capital, includes as a major component the original cost of plant, property, and equipment, less accumulated depreciation, *used and useful in rendering service to the public.* (emphasis added)

Because these projects do not include energized facilities, they should not be considered "used and useful" in rendering service to the public. Because these projects are not "used and useful," the amounts associated with the projects are not includible in rate base.

CEHE witness Ms. Colvin, in her rebuttal testimony, states that those land costs should be considered Plant Held for Future Use (PHFU) and, therefore, are appropriate rate base items.[67] However, CEHE did not provide specific information on the land costs (acreage, what specific substations, etc.), nor did it properly classify the costs as plant held for future use.[68] Thus, Staff maintains its recommendation to disallow $6,795,685.47, relating to distribution invested capital.

B. Line Clearance Project

Staff recommends a disallowance of $19,376,931, because CEHE inaccurately categorized Project Number HLP/00/1055 (years 2014-17) as a capitalized project. This amount

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[64] Staff Ex. 6 at 7.

[65] Staff Ex. 6 at 23 (Attachment BPI-4).

[66] *Id.*

[67] CEHE Ex. 35 at 54.

[68] Application of CenterPoint Energy Houston Electric, LLC for Authority to Change Rates filed on April 5, 2019, CEHE Ex. 1, at Bates 5,696 (WP/WP II-B-6 Adj 1, p. 5 of 6).

should have been designated as operations and maintenance (O&M) expenses, because CEHE incurred these amounts for work on *existing* transmission and distribution lines in order to comply with National Electrical Safety Code (NESC) clearance standards. Capitalizing this project would incorrectly enable CEHE to earn a rate of return on foreseeable, recurring O&M expenses, which CEHE performs on approximately 20% of its system each year.[69]

CEHE's rebuttal response to Staff's recommendation regarding the classification of Line Clearance Project costs is that "the work associated with this project includes modifications to, not maintenance of, existing transmission and distribution circuits which includes the replacement of retirement units such as poles, towers, conductors, and other capital facilities."[70] CEHE asserts that "[t]hese clearance issues develop over time and it is necessary to correct them to meet NESC requirements."[71]

However, the modifications CEHE seeks to capitalize are ongoing and analogous to vegetation management expenses, which are classified as O&M expenses because they can be predicted in a reasonable manner. The RFI response that he refers to in order to bolster his argument (CEHE's response to PUC RFI 6-22)[72] indicates that the clearance corrections are addressed by modifications to the transmission and distribution facilities. Thus, the corrections are maintenance expenses incurred for preserving the operating efficiency, or physical condition of the facilities.

Furthermore, Mr. Narendorf states that the work includes replacement of units such as poles, towers, conductors, and other capital facilities.[73] Yet, *Accounting for Public Utilities* states, "Removal or replacement of a part of the unit, for example a downguy or brace, is considered a maintenance expense and does not affect the asset value."[74]

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[69] Direct Testimony of Blake Ianni, Staff Ex. 6, at 12.

[70] Rebuttal Testimony of Martin Narendorf Jr., CEHE Ex. 31, at 13-14. (*See* CEHE's response to PUC RFI 6-22, which Mr. Narendorf refers to in his testimony, *see* CEHE Ex. 31 at Bates 69-70 Exhibit R-MWN-1).

[71] *Id.* at 14.

[72] *Supra* fn. 70.

[73] *Id.* at 13-14.

[74] Robert L. Hahne & Gregory E. Aliff, *Accounting for Public Utilities*, § 16.17 Continuing Property Records System (pp. 512-13), Release 33 (2016) (a copy is attached hereto).

Finally, Mr. Narendorf indicates that tower replacements are part of the corrections,[75] but CEHE's response to PUC RFI 6-22, to which he refers, does not include towers. In short, his rebuttal fails to explain why a modification or correction should be considered a capital expense and not a maintenance expense.

Thus, Staff recommends a disallowance of $19,376,931, as this amount should have been classified as an O&M expense.

C. Prepaid Pension Asset

Staff did not recommend any adjustments in this section. Staff reserves the right to address this issue in the reply brief.

D. Accumulated Deferred Federal Income Tax [PO Issue 17, 19]

Staff did not recommend any adjustments in this section. Staff reserves the right to address this issue in the reply brief.

E. Cash Working Capital [PO Issue 15]

Although Staff witness Mark Filarowicz of the Rate Regulation Division did not recommend any direct adjustments to cash working capital, he did recommend flow-through adjustments to inputs in the calculation of cash working capital based on other Staff recommended adjustments to operations and maintenance expenses, federal income taxes, payroll taxes, state franchise taxes, and ad valorem taxes.[76] Staff's calculation of cash working capital followed CEHE's methodology in its request.

If the Commission makes adjustments to CEHE's requested amounts for operations and maintenance expense, federal income taxes, or other taxes, it is appropriate to adjust the calculation of cash working capital based on the recommended adjustments to the respective inputs.

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[75] CEHE Ex. 31 at 13-14.

[76] Revenue Requirement Phase Direct Testimony of Mark Filarowicz, Staff Ex. 4A, at 37 and Bates 54 (Attachment MF-9).

F. Other Prepayments

Staff did not recommend any adjustments in this section. Staff reserves the right to address this issue in the reply brief.

G. Regulatory Assets and Liabilities [PO Issues 18, 19, 59]

1. Unprotected Excess Deferred Income Tax (UEDIT)

Staff supports CEHE's errata adjustment to gross up the unprotected excess deferred income tax amounts to be refunded to customers. Staff also recommends adjustments to the functionalization of the unprotected excess deferred income tax amounts in section VII.A.3. below.

2. Hurricane Harvey

Staff supports CEHE's errata adjustment to include carrying charges on the balance of Hurricane Harvey restoration costs through the date that rate recovery begins, as stated in section IV.F. below. Although Staff did not recommend any other adjustments to this regulatory asset in its direct testimony, as noted in section IV.C below, Staff does not oppose—from an accounting perspective—OPUC's recommendation to remove regulatory assets and liabilities from rate base and establish recovery of those regulatory assets and liabilities through separate riders. From a cost recovery perspective, however, Staff notes that it may be desirable to limit the number of separate riders at any given time.

3. Medicare Part D

Although Staff did not recommend any adjustments to this regulatory asset in its direct testimony, as noted in section IV.C below, Staff does not oppose—from an accounting perspective—OPUC's recommendation to remove regulatory assets and liabilities from rate base and establish recovery of those regulatory assets and liabilities through separate riders. From a cost recovery perspective, however, Staff notes that it may be desirable to limit the number of separate riders at any given time.

4. Texas Margins Tax

CEHE is proposing to recover a return on and a return of a regulatory asset for Texas margins tax. Staff opposes CEHE's request as CEHE was never authorized to record a regulatory asset for Texas margins tax; CEHE has never requested, and the Commission has never authorized, the recovery of such an asset in any base rate case since the date CEHE states that is was authorized to book the asset; there is no evidence that CEHE has not recovered its Texas margins taxes or gross receipts taxes on an ongoing basis through rates; and it would be inappropriate to charge customers again for expenses that CEHE's rates were previously set to recover.

CEHE witness Kristie L. Colvin testified that the Company currently books its Texas margins tax as a regulatory asset rather than as an accrual and is proposing in this proceeding to change this method to include the accrual amounts in base rates.[77] It is important to note that CEHE is the only utility that accounts for its Texas margins tax in such a manner. Ms. Colvin stated that the Company proposes this accounting change in response to a request from Staff in its DCRF proceedings for the Company to calculate its Texas margins tax the same way as other utilities.[78]

Ms. Colvin further testified that the Company is proposing to recover this requested regulatory asset over a three-year period at a cost to ratepayers of $6.5 million annually. Staff disagrees with this treatment and does not think that the Company's extraordinary accounting treatment now requires ratepayers to pay an annual amount of $6.5 million; instead, Staff thinks the Company can and should correct its accounting treatment without recording a regulatory asset that was never ordered or authorized by the Commission. Ms. Colvin claims that the Commission approved the Company's accounting practice in Docket No. 29526 and that, "[b]ecause the Commission has previously approved the Company's recovery of the regulatory asset related to TMT, the Company is requesting the same approval in this case, which will allow the Company to recover the regulatory asset."[79]

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[77] Direct Testimony and Exhibits of Kristie L. Colvin, CEHE Ex. 12, at 38-39.

[78] *Id.* at 39.

[79] *Id.* at 40.

Staff witness Mark Filarowicz explained that Docket No. 29526 was a proceeding to determine the amount of *generation* stranded costs and true-up balances pursuant to PURA § 39.262. The Commission approved recovery of a generation deferred debit. The findings of fact in that proceeding relate to how CEHE's predecessor company accounted for the state franchise tax prior to deregulation. It did not approve any deferrals (including regulatory assets) for the regulated T&D operations.[80] Mr. Filarowicz also cited the direct testimony of CEHE witness Charles Pringle who explained that the Texas margins tax was effective for returns due after January 1, 2008, and that, prior to that, companies paid a similar but different tax – the Texas franchise tax.[81]

In her rebuttal testimony, Ms. Colvin discusses how CEHE has interpreted generally accepted accounting principles (GAAP) related to the Texas margins tax and asserts that the requested regulatory asset represents an amount not yet recovered from ratepayers based on the Company's accounting methodology.[82] This is misleading. First, there is an amount of Texas Margins tax that will be recovered every year through CEHE's rates set in this proceeding. Second, the regulatory asset only exists on the Company's books because of the one-year lag created by the way it has chosen to account for the tax on its books. Mr. Filarowicz testified that he is not aware of any other Texas utility that has chosen to account for its Texas Margins tax in such a manner. Third, it is well established that GAAP accounting does not necessarily control regulatory treatment. Rather, the regulatory accounting policies as prescribed by state commissions determine the external reporting of the utility. GAAP recognizes this point and under ASC 980 articulates that cost-of-service rate-regulated enterprises should follow the ratemaking treatment of transactions.

Lastly, there is no evidence in the record that the Company's rates have excluded recovery of the tax in the past. In Docket No. 38339, the rates set for CEHE included an annual amount for Texas margin tax expense. It is inappropriate to say that amounts for Texas margin tax have not been recovered; they have been recovered to the same extent as any other line item included in the Company's revenue requirement in Docket No. 38339.

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[80] Staff Ex. 4A at 29, 30.

[81] Direct Testimony and Workpapers of Charles A. Pringle, CEHE Ex. 13, at 35.

[82] Rebuttal Testimony, Exhibits and Workpapers of Kristie L. Colvin, CEHE Ex. 35, at 27.

In her rebuttal testimony, Ms. Colvin attempts to rebut Mr. Filarowicz's testimony by saying the Commission ordered its method in Docket No. 29526.[83] As previously explained, Staff does not believe that the final order from that case—pertaining to generation stranded costs—ordered the Company to book a regulatory asset. Furthermore, as explained by Mr. Filarowicz, in its most recent base rate proceeding in Docket No. 38339, the Company did not present any information showing that it was booking a regulatory asset relating to Texas margins tax.[84] Finally, the final order in Docket No. 38339[85] did not order CEHE to book a regulatory asset for Texas margins tax (and it did explicitly order other regulatory assets for other accounting items).[86]

Mr. Filarowicz noted that CEHE elected to account for the margin tax in the manner that it does and the fact that it has used a method that is different from other utilities does not mean that its ratepayers should pay an additional $6.5 million annually (over and above the amount for Texas margins tax expense included rates) in order for the Company to conform its accounting for the Texas margins tax to that of the other Texas utilities.[87]

5. Smart Meter Texas

Although Staff did not recommend any adjustments to this regulatory asset in its direct testimony, as noted in section IV.C below, Staff does not oppose—from an accounting perspective—OPUC's recommendation to remove regulatory assets and liabilities from rate base and establish recovery of those regulatory assets and liabilities through separate riders. From a cost recovery perspective, however, Staff notes that it may be desirable to limit the number of separate riders at any given time.

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[83] *Id.* at 25-27.

[84] Staff Ex. 4A at 30.

[85] *Application of CenterPoint Electric Delivery Company, LLC, for Authority to Change Rates*, Docket No. 38339, Order on Rehearing (June 23, 2011).

[86] Staff Ex. 4A at 30.

[87] *Id.* at 30-31.

6. REP Bad Debt

Although Staff did not recommend any adjustments to this regulatory asset in its direct testimony, as noted in section IV.C below, Staff does not oppose—from an accounting perspective—OPUC's recommendation to remove regulatory assets and liabilities from rate base and establish recovery of those regulatory assets and liabilities through separate riders. From a cost recovery perspective, however, Staff notes that it may be desirable to limit the number of separate riders at any given time.

7. BRP Pension and Postretirement

Although Staff did not recommend any adjustments to this regulatory asset in its direct testimony, as noted in section IV.C below, Staff does not oppose—from an accounting perspective—OPUC's recommendation to remove regulatory assets and liabilities from rate base and establish recovery of those regulatory assets and liabilities through separate riders. From a cost recovery perspective, however, Staff notes that it may be desirable to limit the number of separate riders at any given time.

8. Other Regulatory Assets and Liabilities

Staff did not recommend any adjustments in this section. Staff reserves the right to address this issue in the reply brief.

H. Capitalized Incentive Compensation

Staff witness Mark Filarowicz recommends adjusting CEHE's request by removing all capitalized amounts relating to financially based incentive compensation and half (50%) of the capitalized amounts relating to other (non-financially based) incentive compensation, for a total removal of $2,365,000 from rate base.[88] The Commission has previously found that financially based incentive compensation is unreasonable and not necessary to provide utility service to the public for a TDU (see section IV.B.1 below). Mr. Filarowicz recommends removing such

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[88] *Id.* at 18.

amounts from CEHE's rate base so that it will not earn a return on properly disallowed amounts of invested capital.[89]

Staff also recommends removing amounts relating to incentive compensation expense below in section IV.B.1. Staff's methodology for removing capitalized amounts of incentive compensation follows the same methodology, based on Commission precedent, for removing expensed amounts of incentive compensation.

I. Capitalized Non-Qualified Pension Expense

Staff witness Mark Filarowicz recommends adjusting CEHE's request by removing from rate base all capitalized amounts relating to non-qualified pension expense.[90] The Commission has previously found that non-qualified pension expense is unreasonable and not necessary to provide utility service to the public for a TDU (see section IV.B.4 below). Mr. Filarowicz recommends removing such amounts from CEHE's rate base so that it will not earn a return on properly disallowed amounts of invested capital.[91] Staff's recommendation to remove capitalized amounts for non-qualified pension conforms to Commission precedent.[92]

Staff also recommends removing amounts relating to non-qualified pension expense below in section IV.B.4.

III. RATE OF RETURN [PO ISSUES 4, 5, 7, 8, 9]

A. Return on Equity [PO Issue 8]

The appropriate return on equity for CEHE is 9.45%. This return on equity is based on a multi-step methodology that is well-established at the Commission.[93] Specifically, Staff used a Single-stage Discounted Cash Flow ("DCF") methodology, a Multistage Discounted Cash Flow ("Multistage DCF") methodology, a Conventional Risk Premium Estimate, and a Capital Asset

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[89] *Id.*

[90] *Id.* at 20-21.

[91] *Id.*

[92] Staff Ex. 4A at 20. *See* Docket No. 46449, Order on Rehearing, Finding of Fact No. 129 (Mar. 19, 2018).

[93] Direct Testimony of Jorge Ordonez, Staff Ex. 3A at 13.

Pricing Model ("CAPM").[94] Staff's analysis included the use of a proxy group of utilities comparable to CEHE in developing its recommendation for the appropriate return on equity.[95]

Jorge Ordonez, Staff's expert witness, developed his proxy group of domestic electric utility companies by first starting with all the electric utility companies covered by Value Line's Ratings and Reports. Mr. Ordonez then selected those companies that share certain characteristics with CEHE without unreasonably restricting their number.[96] Mr. Ordonez selected twenty-one (21) companies that:

- Have a current capital structure with a long-term debt proportion between 40% and 60%;
- Have a positive forecast of earnings growth;
- Have not had recent dividend omissions, cuts, or stagnation;
- Are covered by either Moody's or S&P or both, have investment-grade credit ratings, and would not lose the investment-grade rating if downgraded one notch; and
- Have not had recent, planned, or expected merger activities or other major capital expansion or contraction.

After applying the filters, the 21 electric utilities selected by Mr. Ordonez included: Alliant Energy Corp., Ameren Corporation, American Electric Power Company, Inc., Black Hills Corporation, Consolidated Edison, Inc., DTE Energy Company, Duke Energy Corporation, El Paso Electric Company, Eversource Energy, Exelon Corporation, Fortis Inc., IDACORP, Inc., NextEra Energy, Inc., NorthWestern Corporation, OGE Energy Corp., Otter Tail Corporation, Pinnacle West Capital Corporation, Portland General Electric Company, Public Service Enterprise Group Incorporated, WEC Energy Group, Inc., and Xcel Energy, Inc.[97]

Out of the 21 electric utilities selected by Mr. Ordonez as part of his proxy group, 17 of those electric utilities were also part of CEHE witness Robert Hevert's proxy group of 24 electric utilities.[98]

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[94] *Id.* at 12.

[95] *Id.* at 13-14.

[96] *Id.*

[97] *Id.* at 14-15.

[98] *Id.* at 15; Direct Testimony of Robert B. Hevert, CEHE Ex. 26 at 29:1 (Table 3).

1. Single-stage Discounted Cash Flow and Multistage Discounted Cash Flow

Mr. Ordonez applied the two DCF models to his proxy group. Mr. Ordonez's DCF models are long-term, forward-looking models that project shareholder's cash flows from dividends.[99] The underlying theory of a DCF model is that the price of a share is equal to the present value of all future dividends.[100] Absent the sale of a stock, dividends are the only cash flows received by investors. The purpose of a DCF method is not to measure the rate at which CEHE will actually grow (which is primarily a function of regulatory actions, management ability, economic conditions, etc.), but rather the expectations for dividends growth that investors have embodied in the current price of the stock.[101]

Because of the relationship between earnings growth and dividends growth, the growth rate used in Mr. Ordonez's first DCF analysis is the projected earnings growth rates for each of the proxy companies, as forecasted by Value Line and Zacks. Mr. Ordonez relied on Value Line because it is one of the nation's largest, independent investment research services as well as a major money management institution, and he relied on Zacks because it compiles consensus earnings forecasts from groups of professional security analysts.[102] In Mr. Ordonez's first DCF, the stock's dividend growth is based on analysts' estimates of the utility's earnings growth over the next five years.[103]

Mr. Ordonez's second DCF analysis, the Multistage DCF, uses a two-stage approach. Stage one of Mr. Ordonez's Multistage DCF analysis lasts five years and uses the same analysts' estimates that are used in the first DCF analysis. Stage two, which covers years six through year 150, is based on a long-run nominal growth rate of 5.14%[104] consisting of (1) the 3.14% per year

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[99] Staff Ex. 3A at 18, 21.

[100] *Id.* at 15 - 16.

[101] *Id.* at 19.

[102] *Id.* at 20.

[103] *Id.* at 18.

[104] *Id.*

average real growth rate of GDP for the period 1951 through 2018 as calculated from data reported by the U.S. Bureau of Economic Analysis, and (2) the 2.00% rate of inflation forecast by the Federal Reserve System (FED) in its February 22, 2019, Monetary Policy Report.[105] The results of Mr. Ordonez's analysis are shown in the following table:[106]

	Range of Results	Average
Single-Stage DCF	6.09–10.95%	8.38%
Multistage DCF	7.51–10.22%	8.31%
Combined DCF	6.09-10.95%	8.34%

2. Conventional Risk Premium Estimate

Mr. Ordonez's "conventional risk premium" methodology estimates the cost of CEHE's equity by comparing the costs of equity authorized for electric utilities across the United States to the yields of large-company corporate bonds that are rated Baa by Moody's.[107] This risk premium approach relies on the historical relationship between two indices to forecast a value for one of the indices in a period for which it is unknown by using the known value of the other one during that same period.[108]

In order to account for the relationship between the authorized costs of equity and the bond yields required to quantify CEHE's cost of equity, Mr. Ordonez subtracted the bond yields from the historical authorized costs of equity to determine a risk premium for the riskier equity. The data were tested by performing a regression analysis, which showed with high confidence that there is a trend in the relationship between risk premiums and bond yields. It is an inverse trend, in which the risk premiums increase as bond yields decrease. On average, during the 1980

[105] *Id.* at 20-21.

[106] Staff Ex. 3A at 49 (Attachment JO-9).

[107] Staff Ex. 3A at 24.

[108] *Id.* at 12-13.

to 2018 time period, risk premiums increased 0.4392% for every 1.00% that bond yields decreased.[109] The results of this risk premium analysis indicate a cost of equity of 9.79%.[110]

3. Capital Asset Pricing Model

Mr. Ordonez used the CAPM as a qualitative check on the results of his other estimates. He did not directly use the CAPM in determining CEHE's cost of equity because it yielded a cost of equity that was markedly lower than the lowest of the other estimates.[111] The CAPM provides an additional indication that a low cost of equity is consistent with prevailing market conditions.[112]

The CAPM is one of the cornerstones of financial theory. The model describes the relationship between the risk of an asset and its expected return, and the model assumes that investors will not hold a risky asset unless they are adequately compensated for the risk.[113] The "adequate compensation" assumed by the model is the risk premium in excess of the returns offered by risk-free investments.[114] Additionally, CAPM analysis takes into account an asset's volatility relative to the overall equity market.[115] The adjusted risk premium is added to the rate of return offered by risk-free investments to determine the overall required rate of return.[116]

Mr. Ordonez used the CAPM method to determine the costs of equity for each company in his proxy group. In doing so, Mr. Ordonez used a risk-free rate of 2.81%, which was the average yield of the 20-year Treasury bond for the period from January 25, 2019 through April 26, 2019. For the market risk premium, Mr. Ordonez used a rate of 5.98%, which is the difference between the arithmetic mean return for large company stocks and the arithmetic mean

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[109] *Id.* at 24 – 25.

[110] Staff Ex. 3A at 2, 47 (Attachment JO-7).

[111] Staff Ex. 3A at 25.

[112] *Id.* at 26.

[113] *Id.* at 25 – 26.

[114] *Id.* at 26.

[115] *Id.* at 27.

[116] *Id.* at 26 – 27.

return for long-term government bonds as calculated by Duff and Phelps. Duff and Phelps's data rely on the 93-year period from 1926 to 2018. By applying the CAPM analysis to his proxy group, Mr. Ordonez calculated a cost of equity for CEHE of 6.50%.[117]

Using this adjusted CAPM result as a qualitative check on the DCF and Conventional Risk Premium analyses, Mr. Ordonez determined that the estimates of the cost of CEHE's equity using the DCF and the Conventional Risk Premium approaches were appropriate.[118]

4. Summary of Staff's Return on Equity Analysis

The results of each method utilized by Staff on CEHE's Return on Equity are as follows:[119]

Methodology	Point Estimate	Range
Single Stage DCF Analysis	8.38%	6.09 – 10.95%
Multistage DCF Analysis	8.31%	7.51 – 10.22%
Risk premium	9.79%	N/A
CAPM Analysis	6.50%	N/A
Return on Equity (ROE)	**9.45%** (excluding CAPM)	**8.34 – 9.79%**

Mr. Ordonez recommended an ROE for CEHE of 9.45% because (1) it lies in the middle of the upper half range of the estimates, (2) it aligns with recent Staff recommendations, and (3) it promotes the public interest by balancing the concerns of ratepayers with a reasonable opportunity for CEHE to earn a reasonable return on invested capital. Furthermore, Mr. Ordonez noted that there was an average authorized ROE of 9.42% for delivery-only[120] electric utilities in other jurisdictions as published by the S&P Global Market Intelligence RRA Regulatory Focus Report for the first quarter of 2019.[121]

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[117] Staff Ex. 3A at 27 – 28.

[118] *Id.* at 26.

[119] Staff Ex. 3A at 28, 49 (Attachment JO-9).

[120] As discussed below, Mr. Ordonez does not consider "delivery-only" electric utilities that also purchase and sell electricity a good proxy for CEHE because CEHE is a wires-only utility that does not purchase and sell electricity.

[121] *Id.* at 29.

B. Cost of Debt [PO Issue 8]

CEHE's proposed cost of debt of 4.38% is reasonable.

C. Capital Structure [PO Issue 7]

The appropriate capital structure for CEHE consists of 60% long-term debt and 40% common equity. This recommended capital structure is consistent with long-standing Commission precedent from Docket No. 22344, which found that a uniform capital structure consisting of 60% long-term debt and 40% common equity was appropriate for ratemaking purposes for all TDUs operating in Texas.[122] Following the unbundling of the Texas electric market in 2002, the Commission concluded that TDUs operating in Texas "would face substantially lower risks than those currently faced by the integrated utilities."[123] Mr. Ordonez believes that the Commission's conclusion in Docket No. 22344 remains relevant because of two reasons. First, Moody's and S&P characterize the Texas regulatory environment as "constructive" or "credit positive." Second, the Commission recently stated in its Report on Alternative Ratemaking Mechanisms in Project No. 46046 that it believes that: (1) the ratemaking mechanisms for TDUs that operate within the Electric Reliability Council of Texas (ERCOT) are not in need of major revision, (2) the existing streamlined methods of recovery are generally achieving their intended purposes, and (3) the existing paradigm, in which periodic rate proceedings are used in combination with already available streamlined recovery mechanisms, is an efficient and effective way to balance the interests of all stakeholders and ensure that electric rates are just and reasonable. Mr. Ordonez believes all these factors reflect the low risk environment for TDUs operating in ERCOT.[124]

CEHE presented the following three arguments to support its requested capital structure of 50% long-term debt and 50% common equity: (1) CEHE's exposure to business and

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[122] *Id.* at 36.

[123] *Id.*; *Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and Public Utility Commission Substantive Rule § 25.244*, Order No. 42, Docket No. 22344 (Dec. 22, 2000).

[124] Staff Ex. 3A at 37.

regulatory risks, (2) CEHE's need for a capital structure that supports an A- issuer rating, and (3) the capital structure of comparable companies.[125]

CEHE's exposure to business and regulatory risks

CEHE identified four business and regulatory risks: elevated capital expenditures risk, risk posed by the Tax Cuts and Jobs Act of 2017 (TCJA), risk of catastrophic damage from hurricanes, and regulatory risks.[126]

As for the elevated capital expenditure risk and the effect of the TCJA, the nature of the utility industry requires significant capital expenditures, and in Texas, the risk associated with the timely recovery of transmission and capital expenditures is mitigated by two mechanisms: (1) the interim transmission cost of service (Interim TCOS) mechanism, which permits CEHE to adjust its transmission rates twice a year to account for increases in transmission investment and transmission investment related expenses, and (2) the distribution cost recovery factor (DCRF) mechanism, which permits CEHE to adjust its distribution-related rates once per year to account for increases in distribution investment and distribution investment related expenses.[127]

As Mr. Ordonez discussed during the hearing, while certain of these mechanisms had been updated or enacted just prior to CEHE's last base rate case in Docket No. 38339, it was not apparent at the time how well these mechanisms would be utilized, but now we know "nine years later, [] these mechanisms work very well." Mr. Ordonez also discussed that "it takes some time for utilities to start taking advantage of the[se] mechanism[s]. That's what CenterPoint and other utilities have been doing in the last few years, you know requesting update of their capital [investment]; in other words, putting into rates investment in distribution and transmission assets."[128]

CEHE cites to risks posed by the TCJA. However, the risks posed by the TCJA may be mitigated through the authorized return on equity or authorized depreciation rates.[129] Staff is recommending the adoption of CEHE's proposed depreciation rates and that the effects of the

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[125] Direct Testimony of Robert B. McRae, CEHE Ex. 27 at 14.

[126] CEHE Ex. 27 at 15.

[127] Staff Ex. 3A at 31.

[128] Tr. at 699:6-7, 700:20 – 701:1 (Ordonez Redirect) (June 26, 2019).

[129] CEHE Ex. 27 at 21; Rebuttal Testimony of Robert B. McRae, CEHE Ex. 43 at 7.

TCJA be taken into account in the setting of the return on equity. As Mr. Ordonez notes, the TCJA affects all utilities, and therefore the risks posed by the TCJA have already been accounted for in his estimation of CEHE's return on equity. The objective of a comparable company analysis is to estimate the cost of equity for a subject company by estimating the cost of equity for companies with similar risk characteristics.[130] The companies chosen by Mr. Ordonez for his proxy group have all been subjected to the TCJA since its passage in 2017. Furthermore, CEHE was subject to the TCJA for the entire test year, and therefore the risks posed by the TCJA are already reflected in the credit rating of A3 from Moody's Investors Service (Moody's), A- from Fitch Ratings (Fitch), and BBB+ from Standard and Poor's Global Ratings (S&P). Lastly, while investors in a utility should be given a reasonable opportunity to recover their reasonable capital costs, it is not the role of the regulator to serve as a guarantor of a utility's targeted credit rating or particular level of creditworthiness.[131]

Regarding the risk of catastrophic damage from hurricanes, Texas law allows utilities that suffer hurricane damage to recover storm restoration costs including carrying charges.[132] Specifically, in this ratemaking proceeding, CEHE requested to recover $64 million in restoration costs for Hurricane Harvey, but inadvertently omitted carrying costs. Mr. Ordonez recommends CEHE should recover the omitted $9 million in carrying costs.[133] Thus, not only is CEHE authorized special recovery of its costs, it is compensated at the pre-tax weighted average cost of capital for the investment in the recovery effort.

With regards to the regulatory risk, both Mr. Ordonez and Mr. McRae point out that S&P and Moody's have characterized the Texas regulatory environment as "constructive" or "credit-positive."[134] This is because of the existing streamlined recovery methods—such as the Interim

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[130] Staff Ex. 3A at 31.

[131] *Id.* at 33.

[132] *Id.* at 32.

[133] *Id.* at 39.

[134] *Id.* at 32; CEHE Ex. 27 at 30.

TCOS mechanism and DCRF mechanism—available outside of a general ratemaking proceeding to TDUs that operate within the Electric Reliability Council of Texas (ERCOT).[135]

CEHE's need for a capital structure that supports an A- issuer rating

Mr. Ordonez does not agree with the Company's assertion that the Commission should provide extraordinary relief in helping CEHE maintain an A- issuer rating. Mr. Ordonez believes that, at a high level, it is the Commission's function to set just and reasonable rates based on PURA and the Commission's rules, and that it is the responsibility of CEHE's management to conduct operations in a manner that maintains CEHE's investment-grade rating and enhances overall creditworthiness.[136] PURA § 39.051 states that "In establishing an electric utility's rates, the regulatory authority shall establish the utility's overall revenues at an amount that will permit the utility a reasonable opportunity to earn a reasonable return on the utility's invested capital…" It is not the regulator's role, however, to serve as a guarantor of a particular credit rating for a utility. As TIEC witness Charles S. Griffey stated in his rebuttal testimony:

> A higher credit rating generally provides a lower cost of debt. However, the Commission must consider the measures that are necessary to achieve or maintain a higher credit rating, and the resulting costs to customers, to establish an appropriate return on equity and capital structure . . . . A utility's credit rating is a function of its financial strength, regulatory environment, and economic outlook. Access to lower-cost debt is a positive, but it may cause net harm to customers if it means higher rates and weak regulatory oversight.[137]

Mr. Ordonez finally points out that recommended return on equity of 9.45%, which lies at the midpoint of the upper half of his range of 8.34% to 9.79%, is based on a comparable group of companies with investment-grade ratings.[138]

The capital structure of comparable companies.

Mr. McRae points out that the average equity ratio of the companies in Mr. Hevert's proxy group, which includes vertically integrated utilities, is approximately 53%. He also points out that, according to the S&P Global Market Intelligence's RRA Regulatory Focus report for

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[135] Staff Ex. 3A at 32.

[136] *Id.* at 33.

[137] Direct Testimony of Charles S. Griffey, TIEC Ex. 4 at 8.

[138] Staff Ex. 3A at 34.

2018 (2018 S&P Global Market Intelligence RRA Report), the average equity ratio for delivery-only electric utilities authorized by other state regulatory commissions for calendar year 2018 was 49.91%.[139]

Mr. Ordonez pointed out that CEHE is a TDU. Therefore, a capital structure resulting from a proxy group that includes vertically integrated utilities is inappropriate. A capital structure resulting from delivery-only electric utilities in other jurisdictions is also inappropriate because, after reviewing the financial information of the delivery-only electric utilities in the 2018 S&P Global Market Intelligence RRA Report, Mr. Ordonez found that 14 of the 16 delivery-only electric utilities in the 2018 S&P Global Market Intelligence RRA Report purchase and sell electricity. Therefore, unlike CEHE, 14 of the 16 delivery-only electric utilities are exposed to commodity risk. The capital structures of the delivery-only electric utilities in the 2018 S&P Global Market Intelligence RRA Report, while a better proxy for CEHE than vertically integrated utilities, are not the most representative proxy for CEHE, which is a TDU (i.e., a wires-only utility) that does not purchase and sell electricity.[140]

D. Overall Rate of Return [PO Issue 8]

Once Staff's recommended return on equity of 9.45%, CEHE's proposed cost of debt of 4.38%, and Staff's proposed capital structure of 60% long-term debt and 40% common equity are taken into account, the rate of return is 6.41%.[141]

E. Financial Integrity [PO Issue 9]

Staff recommends that the Commission issue findings of fact, conclusions of law, and ordering paragraphs ordering CEHE to implement the financial protections recommended by Staff witness Darryl Tietjen to financially insulate CEHE from its parent company, CenterPoint Energy Inc. (CenterPoint), and its other subsidiaries in order to protect the financial integrity of the utility and ensure reliable service at just and reasonable rates to its customers.

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[139] *Id.* at 34 – 35; CEHE Ex. 27 at 34.
[140] Staff Ex. 3A at 35.

[141] *Id.* at 39.

CenterPoint, with $29 billion of assets,[142] is a large corporation that includes not only CEHE as a subsidiary, but also a number of other entities, such as:

- CenterPoint Energy Resources (CERC), a multi-state gas distribution company;
- CenterPoint Energy Services (CES), a natural gas marketing business that sells non-rate-regulated natural gas and related services in 33 states (as of September 2018);
- Enable Midstream Partners, LP, a publicly traded master limited partnership that owns, operates, and develops strategically located natural gas and crude oil infrastructure asset; and
- Vectren Corporation (Vectren), which CenterPoint acquired in February 2019 and which includes natural gas operations and vertically integrated electric utility operations in Indiana and Ohio.[143]

It is undisputed that the effects of financial instability or weakness in one entity could affect not only CenterPoint as the parent company, but other subsidiaries as well.[144] In an extreme case, an event that causes severe financial distress for CenterPoint could lead to its bankruptcy—a situation that, absent the presence of protective measures, could impact subsidiaries like CEHE dramatically and drag them along into the bankruptcy process.[145]

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[142] Direct Testimony of Darryl Tietjen, Staff Exhibit 1A at 6.

[143] Direct Testimony of Darryl Tietjen, Staff Exhibit 1A at 5-6.

[144] Tr. at 139:25 - 140:5 (Mercado Cross) (June 24, 2019); TIEC Exhibit 6, CEHE Form 10-k for the Fiscal Year Ended Dec. 31, 2017 at 7 ("***We [CEHE] are an indirect, wholly-owned subsidiary of CenterPoint Energy. CenterPoint Energy can exercise substantial control over our dividend policy and business and operations and could do so in a manner that is adverse to our business***." (emphasis in original) & 8 ("***The creditworthiness and liquidity of our parent company and our affiliates could affect our creditworthiness and liquidity***" (emphasis in original)); Direct Testimony of Darryl Tietjen, Staff Exhibit 1A at 6.; Rebuttal Testimony of Ellen Lapson, CEHE Exhibit 48 at 21 ("Most retail and integrated electric utilities have an obligation to reliably operate and maintain their systems for existing customers, and expand systems to meet customer growth. All of these activities require access to funding. Thus, it Is important for the utility to retain access to its own resources including its bank accounts, accounts receivable, and the ability to draw under its credit arrangements, even if its parent or a sister company is under stress. Also, most utilities must seek outside sources of capital from the debt capital market. Without adequate ring fencing, the utility's credit worthiness and access to the debt capital market could be impaired if its parent is in default or bankruptcy. Ring-fencing has been used to protect utilities from risky parents or sister companies to ensure the utility can continue to operate and serve its current and future customers."); Direct Testimony of Charles Griffey, TIEC Exhibit 4 at 11-12.

[145] Staff Exhibit 1A at 6-7 & 16-17; Rebuttal Testimony of Ellen Lapson, CEHE Exhibit 48 at 13 ("[I]f a utility is not ring-fenced, the financial and business risk of a utility's parent and affiliates can affect the credit rating of the utility even in the best of times. In financially challenging times, ring-fencing is essential to prevent a utility from being incorporated into a bankruptcy proceeding with its parent or affiliates. Giving the upstream parent full

The financial insulation measures recommended by Mr. Tietjen are warranted both by 1) CenterPoint's acquisition of Vectren, which increased the financial and operational risks to CenterPoint through a transaction that increased its leverage, and 2) the risks inherent in CenterPoint's business and its other subsidiaries prior to the Vectren acquisition. The increased risks arising from the Vectren acquisition are evident from the rating agencies' actions taken subsequent to the transaction. Moody's discussed how CenterPoint's acquisition of Vectren factored into its downgrade of CenterPoint's Issuer Rating and Senior Unsecured Rating from Baa1 to Baa2 and its downgrade of CenterPoint's subordinated debt rating from Baa2 to Baa3.[146] S&P likewise downgraded CenterPoint's credit rating because of the impact of the Vectren acquisition, lowering CenterPoint's issuer credit rating from A- to BBB+ and lowering the rating on senior unsecured and subordinated notes from BBB+ to BBB.[147] In that same report, S&P lowered CEHE's issuer credit rating from A- to BBB+.[148]

Even prior to the Vectren acquisition, CenterPoint's credit rating was rated lower than CEHE's by Moodys and Fitch.[149] Multiple ratings agency reports commented on the risk imposed on CenterPoint from its other subsidiaries.[150] And for two of the past three years, the other business operations of CenterPoint earned a negative net income for CenterPoint.[151] In the

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access to a utility's revenues during periods of financial distress can allow the utility to be "looted" to pay debtors and shareholders, which could prevent the utility from making investments and paying expenses necessary to provide reliable utility service. This could, in turn, compel utility regulators to take extreme and costly measures to maintain utility service, potentially at the expense of the utility's ratepayers.").

[146] Staff Exhibit 1A at 10-11. S&P and Fitch provide increasing risk and declining credit ratings for "investment grade" bonds ranging from **AAA** to **AA** to **A** to **BBB** (with "+" and "-" as sub-ratings or notches within these rating classes for relatively lower or higher risk, respectively). Moody's provides comparable investment-grade credit quality ratings of **Aaa** to **Aa** to **A** to **Baa** (with 1, 2, and 3 as sub-ratings or notches within these rating classes for relatively lower to higher risk, respectively). **Thus, the lowest investment-grade ratings are BBB- (using S&P and Fitch conventions) and Baa3 (using Moody's conventions).** Bonds rated **BB/Ba** (S&P/Moody's) or lower are often called junk bonds. Bonds rated **B/B**, **CCC/Caa**, **CC/Ca**, and **C/C** are considered speculative; bonds rated below these speculative grades reflect insolvency.

[147] Staff Exhibit 1A at 11.

[148] *Id.*

[149] CEHE Ex. 1a at Schedule II-C-2.10 (Confidential); *see also*, CEHE Ex. 48 at 16:17-19.

[150] CEHE Ex. 1a at Schedule II-C-2.10 (Confidential).

[151] Staff Exhibit 13, Excerpts from 2019 Annual Report.

test year, CEHE provided 91.3% of CenterPoint's net income despite the fact that CEHE made up only 30.5% of CenterPoint's gross revenues and 38.9% of CenterPoint's total assets.[152]

The transactions, business, operations, and leveraging activities of a parent company and its subsidiaries can have wide-ranging effects, not only on the credit profile and financial exposure of the parent, but on regulated utility affiliates as well.[153] This, in turn, can affect certain of the regulated utility's rate-related elements such as capital structure and cost of capital (both equity costs and debt costs).[154] If these circumstances lead to a higher cost of providing service for the regulated utility, it is possible—or likely—that the utility in its next rate proceeding will request that ratepayers bear the higher costs.[155] Accordingly, in the course of a rate case, when the Commission reviews a utility's financial risk as part of its fundamental task of establishing just and reasonable rates, pre-emptive Commission actions (such as requiring the utility to implement protective ring-fencing mechanisms) that help insulate a regulated utility company from possible financial-stress contagion are entirely—and appropriately—within the Commission's responsibility and authority.[156]

Staff witness Mr. Tietjen recommends the Commission order the following requirements to provide CEHE with meaningful protection against possible situations of financial distress by non-CEHE entities that are part of the CenterPoint organization:

Staff Proposed Financial Protections[157]
Staff Proposed Measures Currently Employed by CEHE: • CEHE's credit agreements and indentures must not contain cross default provisions by which a default by CenterPoint or its other affiliates would cause a default at CEHE; • The financial covenant in CEHE's credit agreement must not be related to any entity other than CEHE;

[152] *Id.*

[153] Staff Exhibit 1A at 11-12.

[154] Direct Testimony of Darryl Tietjen, Staff Exhibit 1A at 12.

[155] *Id.*

[156] PURA §§ 11.002, 14.001; *see also*, Staff Exhibit 1A at 12.

[157] Staff Exhibit 1A at 12-16.

- CEHE must not pledge its assets in respect of or guarantee any debt or obligation of any of its affiliates or CenterPoint; it is prohibited from pledging, mortgaging, hypothecating, or granting a lien upon the property of CenterPoint with only a few exceptions such as the first mortgage and general mortgage;

- CEHE must maintain its own stand-alone credit facility, and CEHE must not share its credit facility with any regulated or unregulated affiliate;

- CEHE's first mortgage bonds and general mortgage bonds shall be secured only with CEHE's assets;

- No CEHE assets may be used to secure the debt of CenterPoint or its non-CEHE affiliates;

Additional Staff Proposed Measures:

- Dividend Restriction Commitment. CEHE must limit the payment of dividends by CEHE to an amount not to exceed CEHE's net income (as determined in accordance with generally accepted accounting principles).

- CEHE Credit Ratings and Dividends. CEHE must work to ensure that its credit ratings at all three major ratings agencies (S&P, Moody's, and Fitch) remain at or above CEHE's current credit ratings, and if CEHE's credit rating at any one of the three major ratings agencies falls below BBB+[158] (or its equivalent) for CEHE's senior secured debt, then CEHE must suspend payment of dividends or other distributions, except for contractual tax payments, until otherwise allowed by the Commission. CEHE must notify the Commission if its credit issuer rating or corporate rating as rated by any of the three major rating agencies falls below investment-grade level.

- Debt-to-Equity Ratio Commitment. CEHE's debt must be limited so that its debt-to-equity ratio is at or below the debt-to-equity ratio established from time to time by the Commission for ratemaking purposes in CEHE rate proceedings. The Commission has authority to determine what types of debt and equity are included in a utility's debt-to-equity ratio. CEHE must not make any payment of dividends or other distributions, except for contractual tax payments, where such dividends or other distributions would cause CEHE to be out of compliance with the Commission-approved debt-to-equity ratio. Additionally, neither CenterPoint nor any of its affiliates may issue stock or ownership interest that supersede the foregoing obligations of CEHE.

- Regulatory Return on Equity (ROE) Commitment. If CEHE's issuer

[158] Staff Exhibit 1A at 15 ("This rating is two notches above the minimum investment-grade rating. The Commission may conclude a higher rating is appropriate for this threshold").

credit rating is not maintained as investment grade by S&P, Moody's, and Fitch, CEHE must not use its below-investment-grade ratings to justify an argument in favor of a higher regulatory ROE.

- Stand-Alone Credit Rating. Except as may be otherwise ordered by the Commission, CenterPoint must take the actions necessary to ensure the existence of a CEHE stand-alone credit rating.

- CEHE must not hold out its credit as being available to pay the debt of any CenterPoint affiliates.

- CEHE must not commingle its assets with those of other CenterPoint affiliates.

- No Pledging of Assets Commitment. CEHE must not pledge its assets with respect to, or guarantee, any debt or obligation of CEHE affiliates.

- Affiliate Asset Transfer Commitment. CEHE must not transfer any material assets or facilities to any affiliates, other than a transfer that is on an arm's-length basis consistent with the Commission's affiliate standards applicable to CEHE, regardless of whether such affiliate standards would apply to the particular transaction.

- No Inter-Company Lending and Borrowing Commitment. CEHE must not lend money to or borrow money from CenterPoint affiliates.

- No Debt Disproportionally Dependent on CEHE. Without prior approval of the Commission, neither CenterPoint nor any affiliate of CenterPoint (excluding CEHE) may incur, guaranty, or pledge assets in respect of any incremental new debt that is dependent on: (1) the revenues of CEHE in more than a proportionate degree than the other revenues of CenterPoint; or (2) the stock of CEHE.

- Non-Consolidation Legal Opinion. CenterPoint must obtain a non-consolidation legal opinion that provides that, in the event of a bankruptcy of CenterPoint or any of its affiliates, a bankruptcy court will not consolidate the assets and liabilities of CEHE with CenterPoint or any of its affiliates.

- No Bankruptcy Cost Commitment. CEHE must not seek to recover any costs associated with a bankruptcy of CenterPoint or any of its affiliates.

Each of Staff's proposed additional measures above has been approved by the Commission in previous cases.[159] This type of financial insulation has also proven instrumental in insulating Oncor from the bankruptcy of its parent company.[160] Consequently, for purposes of providing a reasonable set of protective measures designed to insulate CEHE's financial integrity from possible situations of CenterPoint's or its affiliates' financial distress, and to protect CEHE's ability to provide reliable service at just and reasonable rates, Staff requests that the ALJs recommend, and the Commission require, CEHE to implement the financial protection measures presented above.

IV. OPERATING AND MAINTENANCE EXPENSES [PO ISSUES 4, 5, 21, 22, 25, 26, 28, 29, 33, 35, 36, 38, 39, 54, 55]

A. Transmission and Distribution O&M Expenses [PO Issue 21]

Staff addresses this issue in other sections. Staff also reserves the right to address this issue in the reply brief.

B. Labor Expenses

1. Incentive Compensation

It is well established Commission precedent that financially based incentive compensation should be excluded from rates charged to customers because financial measures are of more immediate benefit to shareholders and are not measures that are necessary and

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[159] Staff Exhibit 1A at 7 (citing *Joint Report and Application of Oncor Electric Delivery Company LLC, Sharyland Distribution & Transmission Services, L.L.C., Sharyland Utilities, L.P., and Sempra Energy for Regulatory Approvals Under PURA §§ 14.101, 37.154, 39.262, and 39.915,* Docket No. 48929 Order (May 9, 2019); *Joint Report and Application of Oncor Electric Delivery Company LLC and Sempra Energy for Regulatory Approvals Pursuant to PURA §§ 14.101, 39.262, and 39.915,* Docket No. 47675, Order (Mar. 8, 2018); *Joint Report and Application of Oncor Electric Delivery Company LLC, Ovation Acquisition I, LLC, Ovation Acquisition II, LLC, and Shary Holdings, LLC for Regulatory Approvals Pursuant to PURA §§ 14.101, 37.154, 39.262(l)-(m), and 39.915,* Docket No. 45188, Order (Mar. 24, 2016); *Joint Report and Application of Oncor Electric Delivery Company and Texas Energy Future Holdings Limited Partnership Pursuant to PURA § 14.101,* Docket No. 34077, Order on Rehearing (April 24, 2008)).

[160] Staff Exhibit 1A at 17.

reasonable to provide T&D utility services.[161] Despite this precedent, CEHE requests to include all incentive compensation in rates. CEHE makes the same arguments to change Commission policy on incentive compensation that have been made and rejected in multiple base rate cases before the Commission.

In order to properly exclude financially based incentive compensation, Staff relies on the methodology for quantifying financially based incentive compensation that has consistently been ordered by the Commission in recent litigated cases.[162] For short-term incentive compensation, Staff witness Mark Filarowicz recommends adjusting CEHE's request by removing all (100%) of the amounts directly relating to financially based incentive compensation and half (50%) of the amounts relating to other (non-financially based) incentive compensation that are nonetheless only awarded if certain financial goals are met.[163] Mr. Filarowicz also excludes all long-term incentive compensation from rates because it is entirely financially based. This methodology for calculating Staff's adjustment is based on the Commission's precedent established in recent cases. CEHE disputes the characterization of short-term incentive compensation as financially based, but CEHE's argument relies on a case that is nearly ten years old and CEHE ignores the clear precedent established from recently litigated cases.

a. Short-Term Incentive Compensation

Staff's recommendation to remove financially based incentives from short-term incentive compensation aligns with recent Commission precedent.[164] In general, the benefits that arise from a utility achieving financial metrics tend to accrue to the benefit of Company shareholders and executives, not to the benefit of ratepayers.[165]

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[161] *Application of AEP Texas Central Company for Authority to Change Rates,* Docket No. 28840, Order, Findings of Fact Nos. 169 and 170 (Aug. 15, 2005).

[162] *Application of Southwestern Public Service Company for Authority to Change Rates,* Docket No. 43695, Order on Rehearing at 5 (Feb. 23, 2016).

[163] Staff Ex. 4A at 14 (citing *Application of Southwestern Public Service Company for Authority to Change Rates,* Docket No. 43695, Order on Rehearing at 5 (Feb. 23, 2016); *Application of Southwestern Electric Power Company for Authority to Change Rates* Docket No. 46449, Order on Rehearing, Finding of Fact Nos. 194-199 (Mar. 19, 2018)).

[164] *Id.*

[165] *Id.* at 11-12.

In quantifying the financially based short term incentives, Mr. Filarowicz used the amounts for individual FERC accounts as presented by CEHE in its response to RFI No. Staff 3-01 and the other locations identified in that RFI response.[166] The response is the only clear response by FERC account provided by CEHE in this proceeding. In RFI No. Staff 3-01, Staff explicitly asks for "all amounts included in rates in [CEHE's] request relating to financially based incentive compensation."[167] CEHE later claims in rebuttal testimony that Staff and intervenors used the wrong amounts, but CEHE should not be permitted to claim that Staff relied on incorrect information when CEHE is the source of the information. CEHE failed to supply alternative amounts by FERC account that were included in its request for rates; CEHE failed to update the responses to RFIs with any alternative amounts; and CEHE failed to include an explanation of why the amounts provided were incorrect or inaccurate. CEHE should not be permitted to claim that its own responses to an RFI are incorrect or unreliable.

Staff also notes that the Company's updated response to RFI No. Staff 3-01 included the same amounts by FERC account for direct-company short-term incentive compensation only in PUC03-01U Attachment 1 as were originally provided in PUC03-01 Attachment 1 (the same total for company-direct short-term incentive compensation only is $17,300,749).[168] In removing all the payments related to financially based short-term incentive compensation, Mr. Filarowicz applies the percentages of financial metrics as presented in CEHE's response to RFI No. COH 3-17 to the total test-year amounts by FERC account as presented in WP V-K-6.1 and referred to by CEHE in its response to RFI No. Staff 3-01.[169]

CEHE believes that the metric relating to operations and maintenance expense is operational. Staff disagrees and asserts that this metric is financial in nature as it is related to maximizing profit.[170] In general, a metric should be considered to be financial if its achievement

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[166] *Id.* at 16 and Bates 57-60 (Attachment MF-11, CEHE's First Response to PUC RFI 3-01 (May 8, 2019)).

[167] *Id.*

[168] *Id.* at Bates 57-60 (Attachment MF-11, CEHE's First Response to PUC RFI 3-01 (May 8, 2019)) and Bates 63-65 (Attachment MF-11, CEHE's Updated Response to PUC RFI 3-01 (May 17, 2019)).

[169] *Id.* at 16 *et seq.* and Bates 60 (Attachment MF-11, CEHE's WP V-K-6.1). *See also* Bates 57-60 (Attachment MF-11, CEHE's First Response to PUC RFI 3-01 (May 8, 2019)) and Bates 67-68 (Attachment MF-11, CEHE's Response to COH RFI 3-17 (May 13, 2019)).

[170] *Id.* at 17.

or calculation is based on inputs that relate to a utility's balance sheet or income statement. In this case, the metric for savings in operations and maintenance expense relates to CEHE's income statement.[171]

Overall, Staff's recommendation to remove amounts relating to financially based and non-financially based incentive compensation conforms to Commission precedent. Staff disagrees with CEHE's arguments that this precedent should be changed or should not apply to CEHE.

Staff also recommends removing amounts for capitalized incentive compensation above in Section No. II.H.

b. Long-Term Incentive Compensation

Consistent with the precedent and methodology for removing amounts of incentive compensation, Staff witness Mark Filarowicz recommends removing all long-term incentive compensation included in rates because CEHE represented that 100% of its long-term incentive compensation is financially based.[172]

Commission precedent disallowed financially based incentive compensation from rates because such compensation benefits shareholders and executives (at the expense of ratepayers) and is not a reasonable and necessary expense in providing electric service to the public. Precedent disallowing financially based incentive compensation for TDUs go back to Docket Nos. 28840 and 33309. Many more recent examples abound as well.[173] (As explained in section IV.B.1.a above, recent precedent goes further by disallowing all financially based incentive compensation and half of all other, non-financially based incentive compensation whose payments are based on financial triggers. Here, all of CEHE's long-term incentive compensation is financially based.)

In its response to RFI Nos. Staff 3-01 and TIEC 1-09, CEHE provided the amounts of financially based long-term incentive compensation included in the Company's request in this

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[171] *Id.* at 16-17.

[172] *Id.* at 16 and Bates 57-68 (Attachment MF-11).

[173] *Id.* at 12-14.

docket: $1,795,944 for direct company long-term incentive compensation and $9,454,090 for affiliate long-term incentive compensation.[174]

2. Executive Employee Related Expenses

Staff did not recommend any adjustments in this section; Staff notes, however, that the adjustment it recommends regarding non-qualified (supplemental) pension expense in section IV.B.4. relates to compensation of executives. Staff reserves the right to address this issue in the reply brief.

3. Payroll Adjustments

Staff did not recommend any adjustments in this section; Staff notes, however, that the adjustment it recommends regarding removing the amounts for 32 employees who were terminated as a result of the Vectren acquisition in section IV.D.1 relates to payroll. Staff reserves the right to address this issue in the reply brief.

4. Pension and Other Postemployment Benefits (OPEB) Expense

Staff witness Mark Filarowicz recommends adjusting CEHE's request by removing all amounts relating to non-qualified pension expense.[175] Non-qualified pension expense relates to amounts paid for employee-sponsored retirement plan for key executives who earn wages far in excess of average wages.[176]

Staff's recommendation to remove capitalized amounts for non-qualified pension conforms to long-standing and unambiguous Commission precedent. The Commission has previously found that non-qualified pension expenses "are not reasonable or necessary to provide utility service to the public, are not in the public interest, and should not be included in [...] cost of service."[177]

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[174] *Id.* at Bates 57-65 (Attachment MF-11, CEHE's First Response to PUC RFI 3-01 (May 8, 2019), CEHE's Response to TIEC RFI 1-09 (May 6, 2019), and CEHE's Updated Response to PUC RFI 3-01 (May 17, 2019)).

[175] *Id.* at 19.

[176] *Id.* at 18.

[177] *See id.* at 19-20 (citing Docket No. 46449, Order on Rehearing, Finding of Fact No. 204 (Mar. 19, 2018) and Docket No. 40443, Order on Rehearing, Finding of Fact No. 227 (Mar. 6, 2014)).

5. Other Benefits

Staff did not recommend any adjustments in this section. Staff reserves the right to address this issue in the reply brief.

C. Depreciation and Amortization Expense [PO Issue 25]

Depreciation

Staff recommends approval of CEHE's proposed depreciation rates.[178] The results of Staff's depreciation study support an annualized depreciation and amortization expense for CEHE of approximately $366 million, consisting of $41 million for intangible plant and $325 million for transmission distribution and general property.[179] This represents an overall decrease of approximately $2.3 million compared to the Company's annualized depreciation and amortization expense at current rates.

Commission Staff witness Reginald J. Tuvilla specifically addressed CEHE's depreciation study and resulting rates. Staff reviewed CEHE witness Mr. Dane Watson's SPR and actuarial analysis and results and also performed its own SPR and actuarial analyses, using its own Excel-based models, on individual transmission, distribution, and general plant accounts to analyze the reasonableness of CEHE's proposed life parameters.[180] Staff further considered Mr. Watson's reliance on Company-specific operations information and reviewed his removal cost study.[181] Mr. Watson's service life estimates were based on his judgement with primary factors such as statistical analysis of data; information gathered from field personnel, engineers, and managers; and the survivor curve estimates from the study performed by Alliance Consulting Group on CEHE. Staff's study for the survivor curve shape and average service life (life parameters) for each individual account was based on the following: 1) analysis of the depreciation study filed by CEHE; and 2) workpapers provided by CEHE for Mr. Watson's

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[178] Direct Testimony of Reginald Tuvilla, Staff Ex. 9 at 3.

[179] Direct Testimony of Dane A. Watson, CEHE Ex. 25, at 1.

[180] Staff Ex. 9 at 3.

[181] *Id.* at 5-6.

testimony which include unadjusted booked additions and balances.[182] Based on its comprehensive review and independent analysis, Staff is not recommending any adjustments to the Company's proposed life parameters or net salvage rates.[183] All of Staff's adjustments to the deprecation rates are pass-through results of Staff's proposed adjustments to the Company's cost of service and not the service lives or net salvage ratios recommended in CEHE's study.[184]

Amortization

Staff witness Mark Filarowicz recommends amortizing CEHE's regulatory assets and liabilities over a five-year period, instead of the three-year period that CEHE requested.[185]

The Commission should adopt the five-year amortization period instead of CEHE's requested three-year period to minimize the likelihood that CEHE over-collects amounts relating to these regulatory assets. Because it is likely that there will be more than three-years between the final order in this docket and the final order in CEHE's next base rate proceeding, it is appropriate to use a longer amortization period for regulatory assets and liabilities to prevent over-recovery.

Mr. Filarowicz's testimony presents the amount of reduction to annual amortization to reflect amortization of all of CenterPoint's regulatory assets over a five-year period, should the Commission adopt Staff's recommendation on removing the regulatory asset for Texas margins tax—that is, a reduction of $1,044,184 to annual amortization expense. Mr. Filarowicz's testimony also presents the amount of reduction to annual amortization to reflect amortization of all of CEHE's regulatory assets over a five-year period, should the Commission choose not to adopt Staff's recommendation removing the regulatory asset for Texas margins tax—that is, a reduction of $3,661,194 to annual amortization expense.[186]

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182 *Id.* at 3.

183 *Id.* at 12.

184 Rebuttal Testimony of Dane A. Watson, CEHE Ex. 41, at 7.

185 *Id.* at 31.

186 *Id.* at 32.

Alternatively, OPUC's witness June Dively recommended removing regulatory assets and liabilities from base rates and recovering these amounts through separate riders.[187] From an accounting perspective, Staff does not oppose this approach, as noted in Mr. Filarowicz's direct Testimony.[188] Recovery through riders prevents the chance for over-recovery by limiting recovery to an amount certain. Recovery through riders also prevents the Company from earning a return on these assets in rate base after they have been fully amortized and should no longer generate a return for the Company.

D. Affiliate Expenses [PO Issue 35, 36]

1. Vectren Issues

CEHE identified 32 full-time equivalent ("FTE") positions that are no longer positions with CEHE due to the acquisition of Vectren.[189] CEHE included in its request for rates $1,651,956.65 related to these 32 FTEs whose positions were terminated after the closing of the Vectren acquisition on February 1, 2019.[190] The reduction in force from the Vectren acquisition should have been made as a known and measurable adjustment to the request based on test-year amounts.

Staff recommends that all expenditures related to these 32 FTEs be removed from CEHE's rate base. CEHE has acknowledged that it terminated these 32 employees, and, consequently, it will not incur the expenses associated with these 32 FTEs going forward.

Ms. Colvin, in her rebuttal testimony, takes the position that severance costs should be allowed in annual rates;[191] Staff believes that severance costs are a one-time expense relating to the termination of these positons as a direct result of CenterPoint's decision to acquire Vectren. The rebuttal testimonies of Ms. Colvin, Ms. Harkel-Rumford, and Mr. Myerson fail to demonstrate that severance costs related to the Vectren acquisition are ongoing and representative of costs that CEHE will continue to incur in the rate year and each year going

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[187] Redacted Direct Testimony of June Dively, OPUC Ex. 1, at 12.

[188] Direct Testimony of Mark Filarowicz, Staff Ex. 4A at 32.

[189] *Id.* at Bates 96 (Attachment MF-14, CEHE's Response to PUC RFI 2-15 (May 7, 2019)).

[190] *Id.* at Bates 98-99 (Attachment MF-14, CEHE's Response to PUC RFI 7-02 (May 28, 2019)).

forward. Further, those rebuttal testimonies do not provide convincing arguments that Vectren-acquisition-related expenses of any type are reasonable and necessary expenses that Texas ratepayers should bear. Therefore, it would be inappropriate to include the Vectren severance costs in annual base rates.

2. Compensation for Use of Capital

The only adjustment that Staff recommends relating to compensation for use of capital is the adjustment to affiliate carrying charges on shared assets in section IV.D.4 below. Staff reserves the right to address this issue in the reply brief.

3. Service Company Pension and Benefit Costs

The only adjustment that Staff recommends relating to service company pension and benefits costs is the adjustment to pension and other postemployment benefits (OPEB) expense in section IV.B.4 above. Staff reserves the right to address this issue in the reply brief.

4. Affiliate Carrying Charges

Staff witness Mark Filarowicz recommends an adjustment of ($4,942,320) to remove the equity portion of carrying charges associated with affiliate or shared assets, as identified by CEHE in its response to RFI No. Staff 2-37.[192]

Staff's recommendation follows the Commission precedent in Docket Nos. 43695 and 46449, wherein the Commission disallowed such carrying charges on affiliate assets, finding that such "carrying costs are unnecessary and unreasonable." [193] In Docket No. 43695, the Proposal for Decision further elaborated, "The cost of a profit to an affiliate is an unnecessary and unreasonable expense to Texas ratepayers and is inconsistent with case law."[194]

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[191] CEHE Ex. 35 at 19-20.

[192] Staff Ex. 4A at Bates 101 (Attachment MF-15, CEHE's Response to PUC RFI 2-37 (May 6, 2019)).

[193] *See id.* (citing Docket No. 43695, Order on Rehearing, Finding of Fact No. 137 (Feb. 23, 2016), and Docket No. 46449, Order on Rehearing, Finding of Fact No. 212 (Mar. 19, 2018)).

[194] Docket No. 43695, Proposal for Decision at 158 (Oct. 12, 2015).

Staff recommended that CEHE be permitted to net against the recommended disallowed amount ($4,942,320) the equity portion of any charges that it charged to its affiliates on shared assets, consistent with the precedents in Docket Nos. 43695 and 46449;[195] however, CEHE failed to provide, either in response to RFIs or in the rebuttal testimony of Company witness Michelle M. Townsend, the requisite information regarding what amount, if any, CEHE charged to its affiliates for carrying charges on shared assets.

Ms. Townsend, in her rebuttal testimony, states that she does not find the Commission's decisions in Docket Nos. 43695 and 46449 persuasive, in large part because CEHE was not party to those dockets.[196] Staff disagrees. The same factors and legal considerations that motivated the Commission to disallow the equity portion of carrying charges on shared assets in those cases apply to CenterPoint and its circumstances in this proceeding.

E. Injuries and Damages

Staff witness Mark Filarowicz proposes an adjustment of ($2,293,936) to CEHE's request of $20.528 million (rounded) for injuries and damages. Mr. Filarowicz recommends this adjustment because CEHE's requested annual amount for injuries and damages (that of the test year) is inconsistent with CEHE's previous years' amounts for injuries and damages.[197]

Further evidence that the test-year amount for injuries and damages is unusually large and does not represent a normal, annual amount is the fact that CEHE is not on pace in 2019 to spend as much on injuries and damages as it did in the test year. In response to an RFI, the Company provided the amount of injuries and damages incurred for the first three months of 2019 (and later updated for the first four months of 2019); that amount, when annualized, suggests that CEHE is on pace to spend less than the test-year amount in 2019 and further supports the need for an adjustment to the Company's request.[198]

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[195] Staff Ex. 4A at 27.

[196] Rebuttal Testimony and Exhibits of Michelle M. Townsend, CEHE Ex. 37, at 14.

[197] Staff Ex. 4A at 21.

[198] *Id.* at 23 and Bates 71-74 (Attachment MF-13, CEHE's Response and Updated Response to PUC RFI 9-06 (May 28 and 31, 2019)).

Mr. Filarowicz was conservative when coming up with his recommended disallowance because he used an average incorporating the last five years of expense (including the test year) to calculate his recommended disallowance. Had Mr. Filarowicz used a three-year average, consistent with how the Commission has ruled in previous dockets, the recommended disallowance would have been greater.[199]

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

CEHE's requested amount of $8,742,497 for carrying costs related to restoration costs incurred to repair damage associated with Hurricane Harvey is reasonable under PURA § 36.402(b).

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

Staff recommends approval of CEHE's proposed annual accrual to reach its proposed target self-insurance reserve. Staff recommends that the proposed annual accrual of $7.685 million and a new target property insurance reserve of $6.55 million proposed by CEHE witness Gregory S. Wilson is reasonable. This represents an overall decrease of approximately $6.83 million compared to the Company's current reserve target.

However, Staff recommends that one issue be clarified. Of the $7.685 million annual accrual, $4.11 million is designed to be accrued annually for three years to achieve the target reserve of $6.55 million from the current reserve deficit level of $5.791 million. However, if the target reserve level of $6.55 million is reached, the Company must still accrue the $4.11 million to the self-insurance reserve, even if it means that the self-insurance reserve balance exceeds its target level. CEHE should not be permitted to convert the self-insurance reserve accrual to shareholder earnings if the target reserve level is met.

H. Vegetation Management

CEHE is requesting that $35.02 million be included in its rate base for vegetation management—the amount it spent on tree-trimming O&M expenses during the test year of

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[199] *Id.* at 24.

2018.[200] Staff is recommending a \$3.38 million reduction to CEHE's request, arguing the total amount allowed to be recovered should be \$31.64 million.[201]

A comparison of CEHE's tree-trimming costs for the years since its last rate case demonstrates that from 2011 to 2017, its annual costs ranged from a low of approximately \$22.94 million (2014) to a maximum of approximately \$29.45 million (2016). CEHE's 2018 costs (\$35.02 million) were \$5.57 million more (18.9% higher) than its previous highest spending year, 2016 (\$29.45 million). The median cost that CEHE spent on tree-trimming from 2011-2018 was approximately \$27.47 million, and the average spent during this same timeframe was \$27.81 million.[202]

CEHE's 2018 tree-trimming costs are not a reasonable representation of the annual tree-trimming cost it will require going forward. This is because the \$35.02 million, by CEHE's admission, included a large amount of tree-trimming expenses that should have been incurred in 2017, if not for Hurricane Harvey. That is to say, 2018 essentially covers the costs of more than one year and, thus, is over-stated.[203]

Staff witness Blake Ianni recommends \$31.64 million as the reasonable level of distribution tree-trimming cost by taking the average of CEHE's pro-active tree-trimming expenses for the past three years (2016-18). Using this average reduces the proactive tree-trimming allowance from the proposed \$28.02 million to \$24.64 million per year. Mr. Ianni then adds CEHE's 2018 values of \$620,000 for Hazard Tree Removal and \$6.38 million for Reactive Tree Trimming (figures that align with amounts from prior years).[204] Staff's proposed annual budget of \$31.64 million, a \$3.38 million reduction to CEHE's requested \$35.02 million, represents a net increase of \$2.19 million in tree-trimming spending over the previous highest-spending year going back to 2011—that is, \$29.45 million in 2016.[205]

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200 Direct Testimony of Blake Ianni, Staff Ex. 6, at 8.

201 *Id.* at 11.

202 *Id.* at 9.

203 *Id.* at 10.

204 *Id.* at 11.

205 *Id.*

CEHE's response to Mr. Ianni's recommendation is contained in Randal M. Pryor's Rebuttal Testimony. In that testimony, Mr. Pryor states that any kind of multi-year average should not be used to calculate O&M costs as it relates to vegetation management; that only the costs for the test-year, 2018, should be used in calculating CEHE's tree-trimming expenses going forward.[206]

Although that premise may be correct in theory, it should not apply in this case because, as previously stated above, 2018 was not a normal year for vegetation management activity for CEHE. By CEHE's own admission it had to make up for a significant amount of tree-trimming in 2018 that should have taken place the year prior, 2017, but could not, due to Hurricane Harvey's landfall in the Houston area.[207]

I. Smart Meter Texas Expense

Staff did not recommend any adjustments in this section. Staff reserves the right to address this issue in the reply brief.

J. Loss on Sale of Land

Staff did not recommend any adjustments in this section. Staff reserves the right to address this issue in the reply brief.

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

Although Staff witness Mark Filarowicz did not recommend any direct adjustments to federal income tax, he did recommend flow-through adjustments to inputs in the calculation of federal income tax based on other Staff recommended adjustments to return on rate base and weighted component cost of debt.[208]

Both CEHE and Staff calculate the amount of federal income tax included in revenue requirement by using a Tax Method 1 calculation.[209]

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[206] Rebuttal Testimony, Exhibits and Workpapers of Randal M. Pryor, CEHE Ex. 31, at 23, 26-27.

[207] *Id.* at 26.

[208] Staff Ex. 4A at 36.

[209] *Id.*

If the Commission makes an adjustment to CEHE's requested amount of return on rate base, it is appropriate to update the amount of return on rate base used as the starting point in the calculation of federal income tax. If the Commission makes an adjustment to CEHE's requested weighted component cost of debt, it is appropriate to adjust the reduction in synchronized interest used in the calculation of federal income tax based on the adjustment to component cost of debt.

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

1. Ad Valorem (Property) Taxes

Although Staff witness Mark Filarowicz did not recommend any direct adjustments to *ad valorem* tax expense, he did recommend a flow-through adjustment based on other Staff recommended adjustments to plant in service.[210] Staff's calculation of its adjustment to *ad valorem* tax expense computed an effective rate of 0.818104% (rounded) based on CenterPoint's request and applied the effective rate to Staff's recommended adjustment to plant in service.[211]

If the Commission makes adjustments to CenterPoint's requested amount for plant in service, it is appropriate to adjust the calculation of *ad valorem* tax expense accordingly based on an effective rate.

2. Texas Margin Tax

Although Staff witness Mark Filarowicz did not recommend any direct adjustments to Texas margins tax (TMT) expense, he did recommend a flow-through adjustment based on other Staff recommended adjustments to revenue requirement.[212] Staff's calculation of Texas margins tax expense followed CEHE's methodology in its request.

In its application, CEHE uses the cost-of-goods-sold (COGS) method in calculating its requested amount for TMT expense. Mr. Filarowicz also uses the COGS method in calculating Staff's adjustment. (Staff is not proposing any adjustment to CEHE's COGS for the purpose of

[210] *Id.* at 37 and Bates 52 (Attachment MF-7).

[211] *Id.* at 33-34 and Bates 52 (Attachment MF-7).

[212] *Id.* at 34 and Bates 53 (Attachment MF-8).

TMT in this docket.)[213] Mr. Filarowicz's calculation multiples Staff's total revenue requirement adjustment by the TMT rate of 0.75% to arrive at his recommended adjustment to the TMT expense.[214]

If the Commission makes adjustments to CEHE's requested amount for total revenue requirement, it is appropriate to adjust the calculation of Texas margins tax expense accordingly.

3. Payroll Taxes

Although Staff witness Mark Filarowicz did not recommend any direct adjustments to payroll taxes, he did recommend flow-through adjustments based on other Staff recommended adjustments to payroll expense.[215] Staff's calculation of its adjustment to payroll taxes used the current FICA rate of 7.65%.[216] If the Commission makes adjustments to CEHE's requested amount for direct payroll expense in this proceeding, it is appropriate to adjust the amount of payroll taxes accordingly.

M. Adjustment to Wholesale Transmission Changes in Retail Cost of Service (not in agreed outline)

Staff recommends adoption of Staff-adjusted CEHE ERCOT transmission payments in the amount of $927,700,584, a decrease of $14,702,361 to CEHE's requested ERCOT transmission payments of $942,402,945.[217] These amounts result from all flow through impacts from Staff's recommended adjustments to wholesale transmission cost of service.

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[213] *Id.* at 35.

[214] CEHE Ex. 31 at 35.

[215] *Id.* and Bates 38-45 (Attachment MF-1).

[216] *Id.*

[217] Staff Ex. 2A at 41.

V. WHOLESALE TRANSMISSION COST OF SERVICE [PO ISSUE 4, 5, 6, 37]

Staff recommends the adoption of the Staff-adjusted wholesale transmission cost of service (TCOS), $336,923,105, representing a decrease of $58,873,468 to CenterPoint's requested wholesale transmission cost of service.[218]

Please see below for a table comparing Staff's adjusted and CEHE's requested wholesale transmission costs.[219]

Comparison of CEHE's Requested and Staff's Recommended Wholesale Transmission Revenue Requirement (amounts in thousands of dollars)

	CEHE Request	Staff Adjustment	Staff-adjusted Wholesale TCOS
Operating and Maintenance Expenses	106,519	-16,110	90,409
Depreciation & Amortization Expenses	79,657	-1,686	77,972
Taxes Other Than Federal Income Tax	43,928	-6,458	37,470
Federal Income Tax	27,265	-9,258	18,007
Return on Invested Capital	174,743	-25,362	149,381
Minus: Other revenues	36,316	0	36,316
Wholesale TCOS	**395,797**	**-58,873**	**336,923**

VI. BILLING DETERMINANTS [PO ISSUE 4, 5, 45]

Staff-adjusted present base revenues are $2,129,484,979, 1.6% greater than CenterPoint's calculation of present base revenues at $2,095,600,469.[220]

A. Weather Normalization

Staff recommends adoption of a 10 year weather normalization to test year sales based on Commission precedent. Staff's weather normalization uses a 10 year regression model to best match the 10 year weather normalized time period to prevent a bias for any time period. Staff's

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218 Staff Ex. 2A at 39.

219 Staff Ex. 2A, Table BTM-7, at 39.

220 Staff Ex. 2A at 50.

regression analysis also excludes the test year based on Commission precedent. Finally, Staff's weather normalization model only employs statistically significant variables. Staff's weather normalization analysis was performed by Staff witness Alicia Maloy, who has 7 years' experience in performing and reviewing weather normalization analyses.[221]

10 Year Weather Normalization Period

Ms. Maloy recommends use of a ten year normalized period based on Commission precedent. Commission orders in Docket Nos. 40443, 43695, and 46449 all adopt the use of a 10-year weather normalization period. Commission orders in Dockets Nos. 40443 and Docket No. 46449 rejected the use of a 30-year weather normalization period as not reasonable.[222] The Commission Order in Docket No. 46449, in adopting a 10-year weather normalization period, stated "[t]he use of 10 years of data is more sensitive to weather patterns during the test year."[223] Furthermore, Distribution Cost Recovery Factor applications are required to use a 10 year weather normalized period.[224] In the Order for the rulemaking adopting the section for Distribution Cost Recovery Factor, the Commission stated the following for the weather normalization time period: "[t]here can be weather trends, and the Commission concludes that the use of ten years of data is a reasonable means of capturing such trends."[225]

CEHE advocates for the adoption of a 20-year weather normalized period. Dr. McMenamin advocates for the use of a 20-year normalized period stating that "[b]ased on industry surveys, the utility industry has shifted to a 20-year average as the most frequently used period for defining normal weather."[226] During the hearing, Dr. McMenamin admitted that these surveys were conducted by his group at Itron, where he is employed as the Director of Forecasting.[227]

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[221] Direct Testimony of Alicia Maloy, Staff Ex. 5A at 27 (Exhibit AM-1).

[222] Staff Ex. 5A at 19 – 20.

[223] *Id.* at 20.

[224] 16 Texas Administrative Code (TAC) § 25.243(b)(5).

[225] Staff Ex. 5A at 20; *Rulemaking Relating to Periodic Rate Adjustments*, Project No. 39465, Order Adopting New § 25.243 as Approved at the September 15, 2011 Open Meeting (Sept. 27, 2011).

[226] Direct Testimony of J. Stuart McMenamin, CEHE Ex. 29 at 5.

[227] Tr. at 366:16-24 (Re-cross of J. Stuart McMenamin) (June 25, 2019).

10 Year Weather Regression Model

In order to best match the Commission precedent for a ten year weather normalization, Ms. Maloy's weather normalization regression models use the same 10-year time period (2008-2017) as the normalized time period.[228] CEHE's weather normalization regression models use a 4-year time period (2015-2018) that includes the test year.[229] Ms. Maloy recommends that the weather regression models use the same time period as the normalized time period. If the normalized time period does not match the time period used by the weather regression models, the equation used to calculate the impact of weather on energy sales has a mismatch.[230] A representation of the equation is:[231]

$$\text{Weather Impact}_t = (HDD_t - NHDD_t)*Chdd_t + (CDD_t - NCDD_t)*Ccdd_t$$

Where:

- Weather Impact_t is the overall weather adjustment to sales for the customer class.
- HDD_t and CDD_t are the actual heating and cooling degree days in test year 2018 for month t.
- $NHDD_t$ and $NCDD_t$ are the normalized heating and cooling degree days for the ***normalized time period*** for month t.
- $Chdd_t$ and $Ccdd_t$ are the heating and cooling degree day weather coefficients ***determined from regression models*** for month t. The weather coefficients express the relationship of how an increase or decrease in temperature impacts kilowatt hour sales.

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228 Staff Ex. 5A at 21.

229 CEHE Ex. 29 at 9; Tr. 358:13-20 (Cross of J. Stuart McMenamin) (June 25, 2019).

230 Staff Ex. 5A at 22.

231 *Id.* at 7 – 8.

Here, NHDD and NCDD are calculated using the normalized time period and the coefficients, Chddt and Ccddt are determined using the time period for the regression models. In the case of CEHE's recommendation, there would be a mismatch where the heating and cooling degree day weather coefficients in the equation are determined using four years of weather data and the normalized heating and cooling degree days are determined using the 20-year normalized time period.[232] During the hearing, Ms. Maloy did note that in Docket No. 45414, she used a different normalized time period than the time period she used for her weather regression models.[233] However, Ms. Maloy explained that this was because Sharyland did not have sales data for the weather regression models prior to 2012.[234] Thus, it was not possible to properly match the weather normalization period to the regression analysis period. Staff also notes that an order was never issued in Docket No. 45414 and that the proceeding was dismissed.[235]

Additionally, Ms. Maloy recommends excluding test year data from the weather regression models. Ms. Maloy explained that it is Commission precedent to exclude test year data in the calculation of normal weather for the normalized time period. Specifically, the order in Docket No. 43695, a prior ratemaking case filed by Southwestern Public Service Company, stated that "[i]t was reasonable for SPS to exclude the test year from the time period used to develop normal weather because including the test year creates a bias in the weather variance analysis."[236] As Ms. Maloy explained during the hearing, the statement in the order in Docket No. 43695 does relate to inclusion of the test year data in setting a normalized time period, but including the test year in weather normalization regression models may also create bias toward the actual test year weather and "you're trying to remove the impacts of weather from the test year."[237]

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[232] *Id.* at 22.

[233] Tr. at 872:7-8 (Cross of Alicia Maloy) (June 26, 2019).

[234] Tr. at 885:16-18 (Re-direct of Alicia Maloy) (June 26, 2019).

[235] *Review of the Rates of Sharyland Utilities, L.P., Establishment of Rates for Sharyland Distribution & Transmission Services, L.L.C, and Request for Grant of a Certificate of Convenience and Necessity and Transfer of Certificate Rights*, Docket No. 45414, Order Dismissing Proceeding (Sept. 29, 2017).

[236] *Application of Southwestern Public Service Company for Authority to Change Rates*, Docket No. 43695, Order on Rehearing at 44 (Dec. 18, 2015).

[237] Tr. at 887:13-18 (Re-direct Examination of Alicia Maloy) (June 26, 2019).

Lastly, Staff recommends adoption of Ms. Maloy's models because all of Staff's weather normalization regression include variables statistically valid at the 95% confidence level. In contrast, all of CEHE's weather normalization regression models include variables that are not statistically significant at the 95% confidence level. Within CEHE's residential weather normalization regression model, 18 variables that are included are below the 95% confidence level. Variables with low statistical significance are not meaningful to the model and should not be included.[238]

Dr. McMenamin's Rebuttal Model

In his rebuttal testimony, Dr. McMenamin attempts to criticize Ms. Maloy's weather normalization models stating that her estimated slope parameters are wrong and should not be used.[239] However, Dr. McMenamin does not criticize Ms. Maloy's model. Rather, Dr. McMenamin manipulates Ms. Maloy's model, changes the inputs, and changes variables to create a completely different model, which Dr. McMenamin then uses as a an example to compare Ms. Maloys model to and to criticize Ms. Maloy's model.[240] Staff notes that the changes Dr. McMenamin makes are the exact opposite of the recommendations made by Ms. Maloy. Dr. McMenamin's rebuttal analysis is nothing more than a criticism of Ms. Maloy's weather normalization analysis for not performing the same weather normalization performed by Dr. McMenamin. However, as stated above, Staff's weather normalization is based on Commission precedent and the use of variables that are statistically significant and exclude the test year.

Dr. McMenamin stated that he evaluated Ms. Maloy's models in order to "develop a set of slopes that [he] believe[d] would be correct. . . ."[241] In his evaluation, Dr. McMenamin compared what he termed the Daily AMS model or rebuttal model to Maloy 1 and Maloy 2 (Ms. Maloy's models). In performing his comparison, Dr. McMenamin used different years of data in his rebuttal model than Ms. Maloy did in her weather regression models by using four years of

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[238] Staff Ex. 5A at 23 – 24.

[239] Rebuttal Testimony of J. Stuart McMenamin, CEHE Ex. 44 at 5 – 6.

[240] CEHE Ex. 44 at 9.

[241] Tr. at 1071:7-11 (Re-direct of J. Stuart McMenamin) (June 27, 2019).

daily compared to the ten years of monthly data used by Ms. Maloy.[242] Dr. McMenamin also used different variables than Ms. Maloy and includes variables that are statistically insignificant in his rebuttal model.[243] In fact, Dr. McMenamin emphasizes the use of daily AMS data as a "powerful basis for determining what these slopes should be."[244] Dr. McMenamin also emphasizes the use of daily AMS data in his direct testimony as supporting more powerful and accurate models.[245] However, the rate filing package requires utilities to provide "data for the Test Year on a monthly basis by weather station."[246]

Furthermore, Dr. McMenamin also includes separate constant terms in his rebuttal model and Ms. Maloy's models use a single constant term.[247] In other words, the rebuttal model and Ms. Maloy's models differ in their inputs, variables, and constant terms. According to Dr. McMenamin, these changes were made to Ms. Maloy's model and termed the rebuttal model in order to demonstrate that Ms. Maloy's "data is wrong" and "her models therefore reflect incorrectness."[248] However, because Dr. McMenamin changes data, the variables, and the constant terms in designing his rebuttal model – the comparison between the rebuttal model is not an analogous comparison and should not be considered. Rather, Dr. McMenamin manipulates Ms. Maloy's models and terms it the rebuttal model in order to obtain his desired result that the slopes are incorrect. Moreover, Dr. McMenamin creates new models in rebuttal testimony to compare to Ms. Maloy's models, but does not recommend the results from the rebuttal model for his weather normalization adjustment.[249]

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[242] CEHE Ex. 44 at 9.

[243] *Id.*

[244] *Id.* at 4 – 6.

[245] CEHE Ex. 29 at 5.

[246] Transmission & Distribution (TDU) Investor-Owned Utilties Rate Filing Package for Cost-of-Service Determination, Project No. 39548, Adopted at Commission's Open Meeting at 57 (Nov. 19, 2015) (a copy is attached hereto).

[247] CEHE Ex. 44 at 9.

[248] Tr. at 1086:8-14 (Re-cross Examination of J. Stuart McMenamin) (June 27, 2019).

[249] CEHE Ex. 44 at 35.

B. Energy Efficiency Program Adjustment

Staff recommends rejection of CEHE's proposed adjustment to reduce its test year kWh billing determinants for certain rate classes by an estimated amount of kWh savings due to energy efficiency measures installed during the test year due under CEHE's energy efficiency programs (EEP).[250] Similar requests have been rejected in previous proceedings,[251] and, as a result, the Commission declined to include consideration of this issue in CEHE's last base rate case.[252]

CEHE refers to its proposed reduction to test year billing determinants as the Energy Efficiency Plan, or EEP, adjustment.[253] It states that the proposed reduction in billing determinants is based on an annualization of energy efficiency measures in place during a portion of the test year, using the energy efficiency "savings" associated with those measures, as established in the Texas Technical Reference Manual (TRM) required under the Commission's energy efficiency program rule, 16 TAC § 25.181.[254]

This EEP adjustment has the effect of artificially decreasing present revenues, and, if the Commission adopts CEHE's request, it would increase base rates for certain classes that participate in energy efficiency programs.[255] CEHE therefore carries the burden of proof with regards to this proposed adjustment to increase rates.

Under 16 TAC § 25.234(b), rates will be determined using revenues, billing and usage data for a historical test year adjusted for known and measurable changes, and costs of service . . . ."

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250 Direct Testimony of William Abbott, Staff Ex. 7 at 6.

251 *Id.* at 15 – 16.

252 *Id.* at 15 – 16.

253 *Id.* at 8.

254 *Id.*

255 *Id.* at 6.

CEHE argues that the amount of energy efficiency savings are known because the measures were installed during the test year, and that the savings are measurable, because it uses the Technical Reference Manual required by 16 TAC § 25.181(q).[256]

However, as stated in the TRM, these are estimated values, not known quantities (emphasis added):[257]

> The purpose of the statewide Technical Reference Manual (TRM) is to provide a single common reference document for **estimating** energy and peak demand savings resulting from the installation of energy efficiency measures promoted by utility-administered programs in Texas. This document is a compilation of deemed savings values previously approved by the Public Utility Commission of Texas (PUCT) for use in **estimating** savings for energy efficiency measures.[258]

Regarding the deemed savings values that CEHE maintains are known and measurable, the TRM states (emphasis added):

> Deemed savings refers to an approach for **estimating** average or typical savings for efficiency measures installed in relatively homogenous markets with well-known building characteristics and usage schedules. Previous market research and building simulation tools have been used to develop **estimates** of "average" or deemed energy or peak savings per measure as a function of building type, capacity, weather, building schedules and other input variables. Using this approach, program savings can be **estimated** by multiplying the number of measures installed by the deemed or estimated savings per measure based on previous research on the average operating schedules, baseline efficiencies and thermal characteristics of buildings in a given market.[259]

Because the energy savings due to the energy efficiency measures are imprecise estimates, they cannot be known and measurable changes under the Commission's rules.[260] Additionally, CEHE explicitly disclaims any guarantee of energy efficiency savings for customers that receive energy efficiency measures.[261] Although the estimated energy efficiency

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[256] *Id.* at 9.

[257] *Id.* at 9 – 10.

[258] Staff Ex. 7 at 10.

[259] *Id.*

[260] Staff Ex. 7 at 5.

[261] *Id.* at 12.

savings from the TRM may satisfy the requirements of the energy efficiency program mandated by PURA § 39.905 and 16 TAC § 25.181, they do not meet the requirements for a "known and measurable" adjustment to increase rates in a rate proceeding.

The Commission's report to the legislature on alternative ratemaking mechanisms also noted the difficulties associated with attempting to establish rates based on energy efficiency savings estimates.[262] Moreover, although estimated energy efficiency savings values are necessary in order to implement PURA 39.905 and 25.181, and are sufficient for the purpose of the mandated energy efficiency programs, the estimates do not meet the higher threshold necessary in order to warrant artificially decreasing test year usage, and, consequently, increasing base rates.

Because CEHE's proposal to adjust its billing determinants by an estimated amount of kWh savings due to energy efficiency measures installed during the test year fails to comply with the language of the rule and Commission precedent for similar requests, Staff recommends rejection of CEHE's proposal.

VII. FUNCTIONALIZATION AND COST ALLOCATION [PO ISSUES 4, 5, 43, 44, 46]

A. Functionalization

Staff recommends adjustments to the functionalization of FERC Account 408.1 (Texas Gross Margins Tax), FERC Account 930.2 (Miscellaneous General Expenses), and the Unprotected Excess Deferred Income Taxes under Rider UEDIT.[263]

1. Texas Gross Margins Tax Expense (and associated accounts)

Staff recommends rejection of CEHE's functionalization of the Texas Margins Tax expense, and adoption of Staff's functionalization.[264] CEHE's functionalization is inconsistent with cost causation, due to the fact that a portion of CEHE's revenues associated with transmission system charges, associated with usage of the ERCOT grid, will be collected from

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262 *Report to the 85th Legislature – Alternative Ratemaking Mechanisms*, Project No. 46046, Christensen Report at 24 (Jan. 12, 2017).

263 Staff Ex. 2A at 25.

264 *Id.* at 28 and Table BTM-2 at 32.

CEHE's retail customers under its retail rates, not its wholesale rates.[265] In its rebuttal testimony, CEHE agreed with Staff's recommended functionalization.[266]

The flaw in CEHE's approach is equating the transmission functional revenue requirement, which is a component of its retail cost of service, with its wholesale transmission revenue requirement.[267]

Because the transmission system charge revenues will be collected from retail customers, the Texas Margins Tax levied on those revenues are appropriate for the retail revenue requirement, not the wholesale revenue requirement, as proposed by CEHE in the allocation of the Texas Margin Tax.[268]

Adopting CEHE's proposal results in uplifting a portion of the Texas Margins Tax expense associated with CEHE's total ERCOT transmission payments, which are incurred to serve CEHE's retail customers across its own service territory, to wholesale transmission cost of service, which is charged to wholesale customers across the entire ERCOT grid, which is inconsistent with cost causation.[269]

Thus, Staff recommends adoption of its functionalization of the Texas Margins Tax Expense, which prevents uplifting of retail delivery costs to wholesale transmission costs, and is consistent with cost causation.

To implement Staff's approach in the cost study, Staff recommends that the functionalization data used to calculate the TOTREV functionalization proportions be adjusted in order to align with Staff's recommended functionalization.[270] Retail delivery revenues associated with ERCOT transmission payments must be reallocated amongst distribution,

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[265] *Id.* at 28 – 29.

[266] Rebuttal Testimony of Kristie Colvin, CEHE Ex. 35 at 47.

[267] Staff Ex. 2A at 30.

[268] *Id.* at 29.

[269] *Id.* at 31.

[270] *Id.* at 33.

metering, and customer service functions in proportion to the functional cost of service prior to the adjustment.[271]

2. Miscellaneous General Expense (account 930.2)

CEHE requests $146.2 million in FERC Account 930.2.[272] Staff supports CEHE's approach of directly assigning 3.6% of the expenses in FERC Account 930.2 to customer service, but recommends a more granular approach to the functionalization of the balance of the requested amount, which better reflects cost causation.[273] In its rebuttal testimony, CEHE agreed with Staff's recommendation.[274]

For the remaining amount of miscellaneous general expenses, approximately $141 million, CEHE uses the last-resort functionalization basis, rather than the preferred approach of directly assigning costs according to its function.[275] CEHE's approach would only be appropriate if the expenses in FERC Account 930.2 varied in proportion to payroll expense, but they do not.[276]

CEHE provided an itemization of the expenses, which allowed Staff to sort the expenses into three general categories: (1) support services provided to CEHE staff, (2) Technology Operations expenses, and (3) Telecommunications Service expenses.[277]

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[271] *Id.*

[272] *Id.* at 34.

[273] *Id.* at 35.

[274] CEHE Ex. 35 at 48.

[275] Staff Ex. 2A at 35.

[276] *Id.* at 35.

[277] *Id.* at 36 and workpapers.

Grouping of Expenses in Account 930.2[278]

Group	
1. Staff-adjusted Support Services to CEHE staff[279]	$79,242,055
2. Technology Operations expense in Account 930.2	$29,527,374
3. Telecommunications Services	$15,135,947
Staff-adjusted Account 930.2 in "Trial Balance" WP	$123,905,376
Source: Workpaper "CEHE RFP workpapers.XLS," at worksheet TB Year to Date.	

For the first category, Staff supports CEHE's proposal to use PAYXAG as the functionalization basis, as the costs relate to personnel, and PAYXAG is a payroll-based functionalization factor.[280]

For the second category, Technology Operations, Staff sorted the costs according to the way in which they were itemized by CEHE, in order to facilitate directly assigning the costs, instead of using the last-resort method, the least preferred method of functionalization. Staff divided the Technology Operations expenses between two categories: personnel-related and customer-related, as demonstrated in the table below:[281]

Classification of Technology Operations Services expenses (millions of dollars)[282]

Service	Personnel	Customer
Desktop Data Device[283]	18.684	
Mainframe CPU Utilization[284]		4.612
Data Management[285]		0.718

[278] *Id.*, Table BTM-4 at 36.

[279] As adjusted by Staff witness Filarowicz.

[280] Staff Ex. 2A at 36.

[281] Staff Ex. 2A, Table BTM-5 at 37.

[282] Staff Ex. 2A at 37.

[283] Staff Ex. 2A at 37.

[284] *Id.*

[285] *Id.*

Distributed Systems[286]		37.814
Enterprise App Dev & Support	14.502	
App Dev & Support[287]		26.663
Telephony Service	2.503	
Telecom Add/Move/Change	0.145	
Data & Cyber Security Mgmt	3.895	
Subtotal	39.729	69.807
Share of Total	36.3%	63.7%

For the third category, Telecommunications Service, Staff recommends directly assigning the full amount to retail cost of service, as the costs are not incurred in connection with the provision of wholesale transmission service.[288]

Thus, Staff recommends adoption of Staff's functionalization for $141 million of the $146 million in FERC Account 930.2, as it is consistent with cost causation. Staff's proposed functionalization results in a downward adjustment to FERC Account 930.2 expenses, as illustrated below:[289]

Functionalization of Account 930.2, Miscellaneous General Expense[290]

Function	Allocation proportion		$s in thousands	
	CEHE	Staff	CEHE	Staff
Wholesale Transmission	0.1912	0.1356	27,953	16,956
Distribution	0.7115	0.7079	104,028	88,508
Metering	0.0018	0.0378	266	4,724
Customer Service	0.0955	0.1187	13,965	14,839
Total	1.0000	1.0000	146,212	125,027

286 *Id.*

287 *Id.*

288 *Id.* at 38.

289 Staff Ex. 2A at 39.

290 *Id.*, Table BTM-6 at 39.

3. Unprotected Excess Deferred Income Tax

Staff recommends rejection of CEHE's proposed assignment of UEDIT that remains to be returned to customers directly to retail distribution rates as the credit was incurred and is due to be credited to both wholesale and retail customers.[291] A rider is a mechanism by which a utility may issue a credit back to customers outside of base rates.[292] In the Application, CEHE requests Rider UEDIT, in order to refund to customers the balance of unprotected excess deferred income taxes resulting from the Tax Cuts and Jobs Act of 2017.[293]

CEHE proposes to directly assign the full amount of UEDIT to retail cost of service.[294] However, some portion of Rider UEDIT is properly assigned to wholesale transmission, as wholesale customers paid into the UEDIT balance in the form of the income-tax component of wholesale rates, giving rise to the proposed credit.[295]

In Docket No. 48065, CEHE revised its wholesale transmission rates, and Docket No. 48226 was a distribution cost recovery factor (DCRF) proceeding. In both of these proceedings, CEHE functionalized 24.5% of UEDIT to transmission, and 75.5% to distribution.[296]

Here, CEHE's proposal assigns 0% of UEDIT to wholesale transmission, and 100% to retail delivery, effectively transferring the entirety of the wholesale portion of the UEDIT credit approved in Docket No. 48065 to retail customers for recovery.[297]

CEHE fails to explain why it re-functionalizes the amounts by assigning the amounts solely to the retail cost of service.[298] Thus, Staff recommends rejection of CEHE's approach and functionalizing Rider UEDIT among wholesale transmission and retail delivery using the amounts approved by the Commission in Docket Nos. 48065 and 48226, as demonstrated below:

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[291] *Id.* at 69.

[292] *Id.* at 68.

[293] Direct Testimony of Matthew Troxle, CEHE Ex. 30 at 45.

[294] Staff Ex. 2A at 68.

[295] *Id.* at 69.

[296] Staff Ex. 2A at 69.

[297] *Id.*

[298] *Id.* at 70.

Functionalization of UEDIT[299]

	Docket Nos. 48065 and 48226	Functionalization Proportion	Assigned amount of UEDIT
Wholesale transmission	5.1	0.2452	-$7,934,344
Retail Delivery	15.7	0.7548	-$24,424,319
	20.8	1.0000	-$32,358,663

With respect to the retail delivery portion, Staff agrees with CEHE's proposal to refund the amounts under Rider UEDIT.[300]

With respect to the wholesale transmission portion, Staff recommends that the Commission order CEHE create a new wholesale transmission service rate rider with a refund period of one year, and to include the rider in its compliance tariff filing, to be reviewed by the Commission in the compliance phase.[301]

In rebuttal testimony, CEHE states that the total Rider UEDIT should be amortized over a three-year period.[302] In response to Staff witness Mr. Murphy, CEHE states that it is appropriate to apply the UEDIT benefit to retail customers, but defers to the Commission as to appropriate functionalization of the associated costs.[303]

B. Class Allocation

Staff recommends adoption of Staff's class cost of service, as demonstrated by the table below.[304] These amounts are all flow through impacts of Staff's recommended adjustments.

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299 *Id.*, Table BTM-14 at p. 70.

300 *Id.*

301 *Id.*

302 CEHE Ex. 35 at 61.

303 CEHE Ex. 45 at 45.

304 Staff Ex. 2A, Table BTM-10 at 48.

Class Cost of Service(thousands of dollars)

Class	CEHE[305]	Staff[306]
Residential	1,217,815	1,164,020
Secondary Small	30,607	28,898
Secondary Large	739,867	710,523
Primary	70,090	66,283
Transmission	162,434	146,540
Lighting - SLS	58,265	51,458
Lighting - MLS	3,127	2,687
TOTAL	2,282,205	2,170,409

1. Class Allocation of Transmission Costs

Several intervenors raised issues related to 4CP, each of which will be addressed in turn.

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

Staff recommends adoption of Staff's proposal to adhere to Commission precedent and allocate wholesale transmission charges (ERCOT transmission payments) in proportion to class demand coincident with ERCOT 4CP at source and rejection of CEHE's proposal to use the summer peak demands on its distribution system to allocate the costs.[307] Staff's proposal would directly align CEHE's retail cost recovery of transmission expenses with the customer classes causing those transmission expenses to be incurred, is required by the rule.[308] TIEC's witness, Jeffry Pollock, also recommends Staff's proposed allocation.[309]

Staff's recommendation is consistent with cost causation, the Commission's rules, and with Commission precedent, including the decision in CEHE's last base rate case, a fully

[305] CEHE Ex. 30 at 2.

[306] *See* Staff Ex. 2C.

[307] Staff Ex. 2A at 43 – 44.

[308] 16 TAC § 25.192.

[309] Direct Testimony of Jeffry Pollock, TIEC Ex. 1 at 13-14.

litigated contested case, where CEHE's class allocation of ERCOT transmission payments was a contested issue.[310] ERCOT 4CP has been adopted in all fully litigated base rate proceedings since unbundling.[311]

The coincident peak factor is a class allocation factor that determines the amounts that each class will pay. The ERCOT 4CP is calculated from the ERCOT peak load during the months of June, July, August, and September, divided by four, and is used as the billing determinant for the next calendar year.[312] The distribution service provider (DSP), in this case CEHE as it relates to its retail delivery system, is charged ERCOT transmission payments by the 4CP demand that is coincident with the ERCOT 4CP.[313] Thus, CEHE's class load coincident with the ERCOT 4CP causes CEHE to incur ERCOT transmission payments.[314]

CEHE argues that the CEHE 4CP is the appropriate 4CP allocation factor to use, not the ERCOT 4CP, because it is "not an ERCOT Rate Case".[315] However, the relevant rule clearly states that the billing units used for billing transmission service use the four intervals coincident with ERCOT system peaks, not the respective company's system peaks.[316]

CEHE proposes to use class loads at the time of the peak of CEHE's distribution system, which are not the same as the loads coincident with ERCOT 4CP, and do not drive CEHE's ERCOT transmission payments.[317] Thus, CEHE's proposal to use the CEHE 4CP is inconsistent with cost causation.[318] Staff recommends rejection of CEHE's proposal and adoption of Staff's proposal to use the ERCOT 4CP.

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[310] Staff Ex. 2A at 43; *see* Final Order, Docket No. 38339, Finding of Fact 171 at 32 (May 12, 2011).

[311] *Id.* at 46.

[312] 16 TAC § 25.192(d).

[313] 16 TAC § 25.192(b): "The monthly transmission service charge to be paid by each DSP is the product of each TSP's monthly rate as specified in its tariff and the DSP's previous year's average of the 4CP demand that is coincident with the ERCOT 4CP."

[314] Staff Ex. 2A at 44.

[315] Staff Ex. 29.

[316] 16 TAC § 25.192(b) and (d).

[317] Staff Ex. 2A at 44.

[318] *Id.* at 44-45.

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

TCPA and HEB's proposal is unclear, as it conflates cost allocation with rate design while discussing the 4CP and NCP issue. For sake of completion, Staff addresses the issue of 4CP and NCP as it relates to cost allocation separately from the discussion as it relates to rate design.

While CEHE proposes the usage of the CEHE 4CP for both transmission and distribution demand-related costs, HEB and TCPA instead propose to use a non-coincident peak (NCP) class allocation factor for both transmission and distribution demand-related costs.[319]

Staff recommends usage of the ERCOT 4CP class allocation factor for transmission cost allocation and rejection of HEB's and TCPA's proposal to use NCP allocation factor for cost allocation.[320] An ERCOT 4CP allocation is appropriate for these transmission costs as explained above.[321] At off-peak times, excess capacity is available on the transmission system, so non-coincident peak usage does not drive the costs of the transmission system.

However, Staff is not opposed to using the NCP allocation factor for distribution costs.[322] Using the NCP cost allocation factor for demand-related distribution costs is reasonable, and is consistent with standard Commission practice.[323] An NCP allocation is appropriate for distribution costs because most elements of the distribution system must be sized to handle localized loads that may peak at times different than the system peak.

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[319] Cross-Rebuttal Testimony and Workpapers of William Abbott, Staff Ex. 7B at 8.

[320] Staff Ex. 7B at 9, 10.

[321] *Id.* at 31.

[322] *Id.* at 9.

[323] *Id.* at 31.

c. 4CP Rate Design versus NCP Rate Design (separately for both transmission and for distribution)

While the directly preceding issue involves the amount of costs allocated to particular classes of customers, this issue involves how customers within a class are charged based on their load or energy usage.

Staff recommends approval of CEHE's proposed 4CP transmission rate design and rejection of HEB's and TCPA's proposal to use an NCP rate design with respect to transmission charges. As discussed above, it is CEHE's load at the time of the ERCOT 4CP that causes CEHE to incur wholesale transmission charges. Customers that reduce their load at the time of the ERCOT 4CP therefore cause CEHE to incur a lesser amount of wholesale transmission charges.

Under a 4CP rate design, customers are charged based upon their individual load at the times of system peaks.[324] Under NCP rate design, the customer is billed based upon the individual customer's peak load, regardless of when that customer's peak load occurs and of what the customer's load was at the time of the system peak.[325] The 4CP rate design provides the customer with an incentive to reduce its load when doing so would reduce the transmission charges incurred by CEHE, while an NCP rate design would not provide such an incentive. The 4CP rate design therefore mitigates the "free rider" issue that would occur under an NCP rate design (or under a class allocation of transmission costs on a basis other than the ERCOT 4CP). Under an NCP rate design a customer with no load on the system at the times of the ERCOT 4CP would incur significant charges even though they caused no transmission costs to be incurred, in other words, costs would be shifted from those who cause the costs to be incurred (load at the time of the ERCOT 4CP) onto other customers (those with higher NCP loads off-peak).

If TCPA and HEB advocates usage of NCP rate design for transmission charges, then Staff recommends rejection of that proposal, as it is inconsistent with precedent and cost

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324 *Id.* at 30.

325 *Id.* at 9 and 30.

causation. However, NCP rate design is appropriate for distribution charges under Commission precedent, and Staff is unopposed to that proposal.[326]

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

Staff agrees with CEHE's proposal to set class revenue requirements at cost, and disagrees with TIEC's recommendation to moderate the update to the 4CP class allocation factor, as it fails to comply with the language of the rule and Commission precedent.[327] Additionally, failing to set rates at cost introduces cross-subsidization into the TDU rates, which hurts competition. In determining standard ratemaking treatments for TDUs in the competitive market, the Commission stated:

> CHAIRMAN WOOD:
> ...the cost causation ought to totally drive this. We ought to be as pure as possible in these rates because if we will continue to perpetuate all these subsidies and cross-subsidization mistakes of the past in the future, that will, I think in the long term, hurt competition. ...
> COMM. WALSH: I think you're right.[328]

Establishing rates at cost is required under 16 TAC § 25.234, and per Commission precedent, is required, unless a class demonstrates that it would otherwise experience "rate shock" if rates were moved to cost. No party has demonstrated that it would experience rate shock, and, thus, gradualism is not necessary in this case.

Under 16 TAC § 25.234:

> Rates shall not be unreasonably preferential, prejudicial, or discriminatory, but shall be sufficient, equitable, and consistent in application to each class of customers, and shall be based on cost. (emphasis added)

Here, TIEC argues that setting class revenues at cost would result in the Transmission Service class facing a 22.1% increase of its 4CP allocation factor, characterizing the shift as

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326 Staff Ex. 7B at 9 – 10.

327 *Id.* at 24.

328 Open Meeting Transcript, June 29, 2000, at 120 – 21.

"extreme" and resulting in rate shock.[329] TIEC presents moderation of the changes in 4CP allocation factor as a solution to temper the shift.[330]

While framed in terms of moderating the update to the TCRF allocation factor, TIEC's proposal amounts to supporting gradualism in this proceeding. Gradualism is a mechanism to mitigate customer impacts where setting revenues at cost would result in "rate shock." Implementing gradualism is only appropriate if a particular customer class would experience rate shock. It should be implemented sparingly, if at all, because, when deployed, a portion of the costs for the customer class experiencing rate shock and are shifted to another class, and the other class must bear the burden of paying the amount that was shifted. Such an outcome should be avoided if possible as it runs counter to the requirements of PURA § 36.003 that rates may not be unreasonably preferential or prejudicial, but must be equitable and consistent in application to each class.

In the Application, CEHE's proposal sets the class revenues at cost, and Staff supports this proposal.[331] Gradualism is not necessary in this proceeding. In Docket No. 43695, the Commission found that an increase of 29% for a particular class did not warrant rate moderation.[332] Under CEHE's unadjusted proposal, the Transmission Service class would only face a 13.42% increase in rates,[333] falling to 11.8% when factoring in the Rider UEDIT credit, not the 22.1% suggested by TIEC.[334] On a standalone basis, these rate impacts do not rise to the level of rate shock that would justify departing from the requirement for cost-based rates.

Additionally, while TIEC focuses on the percentage changes between the proposed TCRF allocation factor and the previously approved factor, this comparison overstates the actual rate impact presented. The Commission has previously stated that "any gradualism methodology

329 TIEC Ex. 1, Table 8 at 31.

330 *Id.* at 32 – 33.

331 Staff Ex. 2A at 55.

332 *Id.* at 55.

333 Staff Ex. 7B at 18; *also see* Application, Rate Filing Package at Schedule II-I.

334 *Id.* at 18.

should evaluate the differences in rates that customers pay."[335] When evaluated on a total-bill basis, as required under Commission precedent, the bill impacts are even lower.[336] Rate shock is not a concern in this proceeding.

In the course of the discussion regarding TIEC's proposal to moderate the update to the 4CP class allocation factor, TIEC raised concerns regarding the limitations of the TCRF rule.[337] If the Commission wishes to address TIEC's concern regarding the TCRF rule, instead of moderating the update to the 4CP allocation factor in this proceeding, it would be reasonable to require CEHE to submit compliance applications to update the 4CP class allocation factors used in TCRFs on an annual or biennial basis.[338]

2. Municipal Franchise Fees [PO Issue 27]

Staff did not recommend any adjustments in this section. Staff reserves the right to address this issue in the reply brief.

3. Transmission and Key Accounts

Staff did not recommend any adjustments in this section. Staff reserves the right to address this issue in the reply brief.

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

Staff did not recommend any adjustments in this section. Staff reserves the right to address this issue in the reply brief.

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[335] *Id.* at 22, citing *Application of Southwestern Electric Power company for Authority to Change Rates*, Docket No. 46449, Final Order at 8 (Mar. 19, 2018).

[336] *Id.* at 23.

[337] TIEC Ex. 1 at 22-35. (Pollock Direct).

[338] Staff Ex. 7B at 25.

VIII. REVENUE DISTRIBUTION AND RATE DESIGN [PO ISSUES 4, 5, 43, 49, 50]

On an overall basis, Staff finds that the Company's revenues must be decreased by $11,120,997, calculated as follows:

Staff's Recommended Overall Change in Revenues[339]

	Present Base Revenues-$s	Base Revenue Requirement-$s	Change-$	Change-%
Wholesale transmission	388,968,021	336,923,105	-$52,044,916	-13.4
Retail Delivery	2,129,484,979	2,170,408,898	+$40,923,919	+1.9
TOTAL	2,518,453,000	2,507,332,003	-$11,120,997	-0.5

Additionally, Staff supports CEHE's proposal to set revenues at cost.[340] As discussed above, Staff recommends a finding that gradualism (or rate moderation) is not necessary in this proceeding because at all levels of retail revenues proposed by parties no revenue increase to any one customer class would be particularly harsh or excessive or promote rate shock.[341]

A. Residential Customer Charge

Staff did not recommend any adjustments in this section. Staff reserves the right to address this issue in the reply brief.

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

Staff did not recommend any adjustments in this section. Staff reserves the right to address this issue in the reply brief.

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[339] Staff Ex. 2A at 51-52.

[340] *Id.* at 55.

[341] *Id.* at 55.

C. Transmission Service Rate

Staff did not recommend any adjustments in this section. Staff reserves the right to address this issue in the reply brief.

D. Transmission Service Facility Extensions

Staff did not recommend any adjustments in this section. Staff reserves the right to address this issue in the reply brief.

E. Street Lighting Service

Staff recommends rejection of CEHE's proposal to amend provisions in its Lighting Services Tariff to mandate installation and usage of LED lights for the 160 municipalities in its service territory.[342] Customers should continue to have the ability to choose the type of lighting service based upon such factors as their lighting needs and the costs of the facilities. Customers should not be required to accept a lighting alternative that will increase utility bills, in this proceeding or in a future rate proceeding when the costs of the conversion to that alternative is reflected in rates.

CEHE provides street lighting services to municipalities, government agencies, real estate developers, and other entities that require street lighting services.[343] The Lighting Tariff includes a street lighting schedule and a miscellaneous lighting schedule, where the former applies to street lighting customers where CEHE owns the installations, and the latter governs flood and area lighting customers who own part or all of the lighting installations.[344] CEHE proposes to amend the tariff language in its lighting rate schedule as follows:[345]

> The Company's standard Lamp type for all street lighting service installations and replacements is Light Emitting Diode (LED). A Retail

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342 *Id.* at 67.

343 Staff Ex. 2A at 57; Exhibit MAT-8 at 38.

344 *Id.* at 57.

345 Exhibit MAT-9 at 101, Tariff rate schedule no. *6.1.1.1.6, Lighting Services (Street Lighting and Miscellaneous Lighting Services).*

> customer's request for a non-standard Lamp type will be subject to the availability of the Lamp type in Company's inventory. The Company is no longer procuring non-standard Lamp types for its inventory.[346]
>
> . . .
>
> Conversion to LED. Existing ~~mercury vapor installations~~ non-LED Lamps will be converted to their LED-equivalent at no cost to Retail Customer during the normal course of maintenance when individual lamps burn out ~~Mercury vapor installations will be converted to high pressure sodium lamps or LED equivalents, depending upon the standard street light installation, as selected by the Retail Customer, for the area in which the mercury vapor light resides, at no upfront cost to the~~ unless Company and Retail Customer agree on ~~LED Street Lights At this time there is not an LED replacement option for all existing Lamp Types. The rate at which LED street lights are converted or installed will be at the sole discretion of the Company, may be based upon~~ a ~~negotiated deployment~~ different conversion schedule~~., and will reflect, at a minimum, the capital requirements associated with the project, any customer required contribution in aid of construction, the physical capability to replace/install the LED street lights, and the availability of manufacturers to supply the requested LED luminaires. LED street lights are an emerging technology with no established industry standard.~~[347]

Staff has one over-arching concern regarding this proposal: the elimination of consumer choice with respect to lamp type. The elimination of customer choice is particularly troublesome in consideration of the uncertain financial benefits of LED lighting – an emerging technology with no established record of performance.[348]

CEHE's proposal essentially eliminates customer choice.[349] Under the proposed amendments to the tariff language, with respect to new installations and replacements of existing installations, LED lighting would be installed, unless the customer requests a non-LED lamp type. CEHE would only fulfill the customer's request if it had the non-LED alternative available

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346 Exhibit MAT-8 at 33.

347 *Id.* at 38.

348 *See* Exhibit MAT-8; *also see* CEHE Ex. 33 at 22 (Sugarek Rebuttal), where Ms. Sugarek states: "LED lighting is a new technology and these numbers will be evaluated and refined."

349 Staff Ex. 2A at 60.

in its inventory.[350] Additionally, CEHE is not planning on replenishing its current inventory of non-LED lamp types.[351]

CEHE argues that customers have a choices from a wide array of LEDs,[352] but Staff's concern lies in the customer's ability to choose between LED and a non-LED alternative, not just which type of LED. The proposed language does not give customers a meaningful choice.

This lack of choice could have significant financial implications, but the magnitude of the financial impacts is unclear.[353] CEHE states that it did not perform an analysis comparing the all-in cost of an LED installation to a non-LED installation.[354] Generally, CEHE projects that the LED installations will require higher upfront capital expenditures, but will lower operations and maintenance expenses.[355] CEHE states that customers will not have to pay now for conversion to LED lighting. However, it is unclear the extent to which LED conversion costs are simply being deferred, how the Company plans to recover deferred LED conversion costs, and from which customer classes. It appears that the Company plans to seek recovery of ongoing and historical LED conversion costs (including the extensive LED conversions for the City of Houston which began in 2015) in future distribution cost recovery factor proceedings. In the meantime, CEHE is capitalizing the LED installation costs and the ongoing operations and maintenance expenses associated with LED installations. Due to the mechanics of ratesetting under the DCRF,[356] in a DCRF proceeding the deferred LED conversion costs may be spread not only among non-LED customers within the lighting class, but also among customer classes which do not receive any lighting services from the Company, absent a ratemaking treatment to

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[350] *Id.* at 57.

[351] Staff Ex. 2A at 57.

[352] Rebuttal Testimony of Julienne Sugarek, CEHE Ex. 33 at 19-20.

[353] Staff Ex. 2A at 61.

[354] *Id.* at 61.

[355] Staff Ex. 2A at 58.

[356] 16 TAC § 25.243(d) (pertaining to the calculation of the DCRF): "ALLOC[CLASS] = Rate Class Allocation Factors approved in the last comprehensive base-rate proceeding." Since the class allocation factors are frozen in DCRF proceedings, there is no express provision in the DCRF rule that would support the direct assignment of LED conversion costs to the lighting class or to LED lighting customers within the lighting class under the DCRF.

shield the customers from cost-shifting. Because CEHE has not performed the side-by-side analysis comparing the cost of the non-LED installations to LED equivalent installations, has not shown the customer impacts of its proposal when the LED conversion costs eventually hit rates, has not been transparent regarding its plan for the recovery of capitalized LED conversion costs from non-LED lighting customers and non-lighting customer classes, and has not adequately explained why it is necessary to remove the customer's discretion to opt out of LED lighting, CEHE's proposal to amend its tariff to mandate LED lighting for all new lighting installations and ongoing replacements should be rejected.

Thus, Staff recommends rejection of CEHE's proposal to eliminate customer choice with respect to LED or non-LED lighting installation.[357] Staff notes that CEHE has requested that its tariff be amended to provide that LED lighting be the standard for new installations, replacing high pressure sodium. Staff can accept this aspect of the Company's proposal, on the condition that the Company (1) continues to offer non-LED lighting alternatives for new installations for customers who wish to opt out of LED lighting, (2) informs lighting customers that they can choose a non-LED option for a new installation or a replacement, (3) maintains an inventory of non-LED options to meet customer demand, and (4) maintains its in-kind replacement lighting policy with an option for the customer to opt expressly for LED conversion. Staff reserves the right to seek ratemaking treatments designed to insulate customers who do not receive LED lighting services from LED conversion costs in future rate proceedings.

Staff does not oppose LED lighting. Staff opposes a mandate under the lighting tariff that the lighting customer must switch to LED. Staff is not arguing that the financial benefits of LED lighting are not sufficient to support a customer's choice to convert to LED. Rather, Staff is arguing that there is sufficient uncertainty regarding the financial benefits that a mandated switch to LED for new installations and conversions is not prudent at this time. For example, the useful life of an LED installation is uncertain.[358]

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[357] *Id.* at 67.

[358] Staff Exhibit 2A at 66: "In CEHE's analysis, the standard deviation [5 years] around its estimated useful life of 15 years represents 33% of the estimate, which means that the estimated useful life of an LED installation is uncertain."

The Company has acknowledged that its lighting customers are capable of deciding for themselves what street lighting option best fits their needs.[359] Staff supports the customer's choice.[360]

F. Other Rate Design Issues

1. Retail Class Rate Design

With the exception of Staff's non-opposition to HEB's proposal for an NCP rate design for the distribution service charge applicable to retail transmission customers, Staff accepts the Company's proposed rate design and recommends adoption of Staff's recommended retail rates in Staff witness Mr. Murphy's Direct Testimony, Attachment BTM-7.

IX. RIDERS [PO ISSUES 4, 5, 43, 51, 52]

A. Rider UEDIT [PO Issue 51]

Staff did not make any adjustments in this section. Staff reserves the right to address this issue in the reply brief.

B. Merger Savings Rider

Staff did not make any adjustments in this section. Staff reserves the right to address this issue in the reply brief.

C. Other Riders

Staff did not make any adjustments in this section. Staff reserves the right to address this issue in the reply brief.

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[359] Staff Exhibit 40: "CenterPoint Houston agrees that its end use customers may choose the street lighting option that best fits their needs."

[360] Staff Exhibit 2A at 68: "[Under Staff's recommendation] Customers who wish to choose LED options would still be able to do so without being forced to."

X. BASELINES FOR COST-RECOVERY FACTORS [PO ISSUE 4, 5, 43, 53]

A. Transmission Cost of Service

Staff did not make any adjustments in this section. Staff reserves the right to address this issue in the reply brief.

B. Transmission Cost Recovery Factor

Staff did not make any adjustments in this section. Staff reserves the right to address this issue in the reply brief.

XI. OTHER ISSUES [INCLUDING BUT NOT LIMITED TO PO ISSUES 13, 14, 20, 30, 31, 32, 40, 41, 42, 47, 48, 57, 58, 59]

A. Contested Issues

1. Wholesale Transmission Rates

There are two types of wholesale transmission rates: access fees for wholesale transmission service within ERCOT, and transmission service fees related to delivery of power to be exported from ERCOT.[361] Staff's adjustment to the wholesale transmission rate results from Staff's adjustment to the transmission cost of service.

[361] Staff Ex. 2A at 40.

The table below demonstrates Staff's adjustments as compared to CEHE's request:

Wholesale Transmission Rates[362]

	CEHE Requested[363]	Staff Recommended	Billing Basis
Annual access fee	$5.7056723	$4.8569719	per kilowatt of ERCOT AVG 4CP demand
Monthly On-Peak Export Rate	$1.426418	$1.214243	per kilowatt-month
Monthly Off-Peak Export Rate	$0.475473	$0.404748	per kilowatt-month

B. Uncontested Issues

XII. CONCLUSION

For the foregoing reasons, Staff respectfully requests that the ALJs issue a proposal for decision consistent with Staff's recommendations on financial protections, revenue requirements, cost allocation, revenue distribution, and rate design.

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362 *Id.*, Table BTM-8 at 44.

363 Exhibit MAT-10.

SOAH DOCKET NO. 473-19-3864
PUC DOCKET NO. 49421

CERTIFICATE OF SERVICE

I certify that a copy of this document will be served on all parties of record on June 9, 2019 in accordance with. 16 TAC § 22.74

Rachelle N. Robles

outflows include costs for freight, fuels, accounts payable, payroll, and debt obligations. The details for investment income and debt obligations are stored in an integrated module covering both types of deals.

Once integrated, shortfalls can be monitored and analysis can be performed to determine if additional working capital is needed. Treasury management forecasting also includes the ability to plan for both short and long term investment opportunities.

The forecasting system should gather data from multiple sources and has the ability to simulate alternative scenarios.

§ 16.16. Fleet Management Information System

[1] Fleet Maintenance

The core functionality required for managing and maintaining a fleet of vehicles and equipment includes:

1. Fleet Inventory: Records all data related to additions and deletions of vehicles and equipment in the fleet inventory. Maintains records on each vehicle and piece of equipment regardless of whether it is leased or owned by the utility. Specific information is first entered into the system whenever the vehicle or equipment is acquired. When the vehicle is disposed of, retirement information is processed for accounting and financial reporting according to the utility's plant in service record and lease accounting practices.
2. Preventive Maintenance: Schedules preventive maintenance and license renewal activities. Records and maintains all data related to the maintenance of each vehicle or piece of equipment, including labor, parts and other associated costs.
3. Corrective Maintenance: Records all data related to the repair of fleet items. When vehicle operators identify problems requiring repair procedures, a repair order is normally prepared. Actual labor and spare parts costs are charged to the repair order. A history of repairs and the associated costs is retained for fleet performance and budget analysis.
4. Parts Inventory: Maintains an inventory of parts used for the repair and maintenance of the fleet

[2] Operating Cost Distribution

The actual cost to own, operate and maintain vehicles is accumulated within each class of vehicle, usually within clearing accounts. Some utilities also collect costs by vehicle class within designated areas of management responsibility.

Typically, utilities compute an estimated distribution rate per hour for each class of vehicle on the basis of historical operating costs. When vehicles are used, the hours are recorded to orders or other account codes, and the hourly rate (distributed rate) is charged to that order or account code. This has the effect of redistributing, or "clearing," the clearing account where the cost to own, operate and maintain the vehicle has been accumulated. The distribution rate is adjusted periodically to reflect the over-or under-clearing that occurs at the end of the accounting period.

§ 16.17. Continuing Property Records System

The Continuing Property Records (CPR) function maintains asset cost records and serves as a detailed sub-ledger to several general ledger accounts (e.g., account 101, plant in service). The system performing that function may be a single application, part of a larger accounting system, or a module within an Enterprise Resource Planning System (ERP). In all cases, the CPR must be tightly integrated into the ERP and Enterprise Asset Management (EAM) systems, as part of management of the entire asset life cycle or at least to source transactions for processing additions and retirements to asset accounts. Assets are defined as units of property and are tracked based on the date they were physically put in service. The work order for that unit of property may continue to collect charges some time after the plant is declared in service from an asset perspective.

A unit of property typically relates to a compatible unit, which is an engineering unit of design and includes the cost of a significant piece of material or equipment and the cost of installation. For example, a 50-foot pole is a unit of property, including the pole itself, the crossarm, down guys, anchors, and other minor hardware. When a work order is closed, the total cost is unitized, creating assets that represent the various units of property that were installed on the work order. When the pole is taken out of service, the entire unit of property is considered retired and the fully unitized cost of that pole is removed from the plant-in-service balance. Removal or replacement of a part of the unit, for example a downguy or brace, is considered a maintenance expense and does not affect the asset value.

The core functionality required to maintain Continuing Property Records includes:

1. maintain an electronic catalog defining units of property, coding and nomenclature;
2. maintain book and tax basis costs for assets at a unit of property level, by vintage year;
3. process addition, retirement, and transfer transactions originating in the work management system/module;
4. compute book and tax depreciation;
5. provide reporting of asset values by property tax jurisdiction, in support of filings to taxing authorities;
6. provide reporting of insured property for insurance arrangements and claims;
7. provide reporting of specific assets or groups of assets, such as pollution control equipment, to various governmental and regulatory agencies and industry associations;
8. prepare property ledgers and various financial and management reports.

§ 16.18. Tax Management Systems

A utility may have several systems in use to support the activities of the tax department. The continuing property records system as containing book basis assets, reserves, and depreciation calculations (see § 16.14, above). The continuing property records system may also contain tax basis records. It is more common, however, to use a separate system for tax basis assets, reserves, and depreciation calculations. The tax basis property system contains only the level of detail needed for tax purposes (as opposed to the considerable detail necessary for book basis records). A tax basis property system maintains tax basis asset and depreciation reserve records, tracks book-tax basis differences, calculates depreciation and amortization, and performs other record keeping for tax regulations in effect for each vintage. The system must also address unique tax requirements of states, cities, or other taxing entities.

Tax management systems often record tax accruals and payments and the composition of deferred tax balances for federal and state jurisdictions. They may also be able to model taxes under various assumptions about factors such as rates and deferrals. Tax management systems may consist of a series of spreadsheets or software packages using similar methods.

§ 16.19. Shareholder Records System

A shareholder records system is used to maintain records of securities owners, make dividend payments, manage mailings to shareholders, and handle changes in securities structures such as stock splits. The utility company may operate the shareholder records system, or it may outsource part or all of this function.

§ 16.20. Account Coding Considerations

The heart of an integrated financial information system is the design of the accounting codes used to classify and to process data. The utility must consider problems that may develop if field personnel are required to code long, complex accounting data code groups on transaction source documents. If this occurs, field personnel often become indifferent toward correct coding. There is often a short string used by field personnel that will then derive the remaining accounting string to simplify the user experience and minimize user error. A project or work order is often a key field for field personnel.

On the other hand, it must be recognized that management information requirements demand the ability to analyze information from many different perspectives. For example, the same costs may be classified for various reporting purposes with account coding that includes:

- company and/or business unit;
- responsibility area (sponsor);

II-H-4: Revenue Impacts of Adjustments

II-H-4.1: Revenue Impact Data

Provide the following Test Year data on revenue impacts of kWh sales and kW/kVa demand adjustments by rate class. Also provide data by jurisdiction if kWh sales and kW/kVa demand adjustments are performed on this basis

1. Unadjusted Test Year revenues, showing components separately.
2. Revenue associated with any rate annualization adjustments, showing components separately.
3. Revenues associated with kWh customer adjustments, showing components separately.
4. Revenues associated with kW customer adjustments, showing components separately.
5 Revenues associated with kWh weather adjustments, showing components separately.
6 Revenues associated with kW weather adjustments, showing components separately.
7. Revenues associated with other kWh adjustments, showing the revenues associated with each adjustment individually, listing components separately.
8. Revenues associated with other kW adjustments, showing the revenues associated with each adjustment individually, listing components separately.
9. Total adjusted revenue, showing components separately.

II-H-4.2: Revenue Calculation Methodologies

Provide a narrative explanation of the methodologies used to calculate the revenue items in this schedule.

II-H-5: Weather Data

II-H-5.1: Weather Station Data

Provide the following data for the Test Year on a monthly basis by weather station. Provide the name of each weather station and the applicable service territory. State how the degree days are defined including all calculations:

1. Actual heating degree days.
2. Actual cooling degree days.
3. Normal heating degree days.
4. Normal cooling degree days

II-H-5.2: Adjusted Weather Station Data

Furnish the data provided in Schedule II-H-5.1, after weighting and billing cycle adjustments. Provide, with examples, an explanation of the utility's weighting and billing cycle adjustment procedures. If the utility is unable to provide weighted weather data, furnish billing cycle adjusted data:

1. Actual heating degree days.