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

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PUBLIC UTILITY COMMISSION
FILING CLERK

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

REDACTED

DIRECT TESTIMONY

OF

KARL NALEPA

ON BEHALF OF THE

OFFICE OF PUBLIC UTILITY COUNSEL

JUNE 6, 2019

405

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REDACTED DIRECT TESTIMONY OF KARL NALEPA

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Karl J. Nalepa. I am President of ReSolved Energy Consulting, LLC ("REC"), an independent utility consulting company. My business address is 11044 Research Boulevard, Suite A-420, Austin, Texas 78759.

Q. ON WHOSE BEHALF ARE YOU PRESENTING TESTIMONY IN THIS PROCEEDING?

A. I am presenting testimony on behalf of the Office of Public Utility Counsel ("OPUC").

Q. PLEASE OUTLINE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I have been a partner in REC since July 2011, but joined R.J. Covington Consulting, its predecessor firm, in June 2003. I lead our firm's regulated market practice, where I represent the interests of clients in utility regulatory proceedings, prepare client cost studies, and develop client regulatory filings. Before joining REC, I served for more than five years as an Assistant Director at the Texas Railroad Commission ("Railroad Commission"). In this position, I was responsible for overseeing the economic regulation of natural gas utilities in Texas, which included supervising staff casework, advising Commissioners on regulatory issues, and serving as a Technical Rate Examiner in regulatory proceedings. Prior to joining the Railroad Commission, I spent five years as a supervising consultant with Resource Management International, Inc., and then, I worked as an independent consultant advising clients on a broad range of electric and natural gas industry issues. I also served for four years as a Fuel Analyst at the Public Utility

Commission of Texas ("PUCT" or the "Commission"), where I evaluated fuel issues in electric utility rate filings, participated in electric utility-related rulemaking proceedings, and participated in the review of electric utility resource plans. My professional career began with eight years in the reservoir engineering department of Transco Exploration Company, which was an affiliate of Transco Gas Pipeline Company, a major interstate pipeline company.

I have a Master of Science degree in Petroleum Engineering from the University of Houston and a Bachelor of Science degree in Mineral Economics from Pennsylvania State University. I am also a certified mediator. My Statement of Qualifications is included in Appendix A.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I have testified on many occasions before both the PUCT and Railroad Commission on a variety of regulatory issues. A summary of my previously filed testimony is included in Appendix B. I have also provided analysis and recommendations in numerous local regulatory proceedings that resulted in settlements without written testimony.

II. PURPOSE AND SCOPE

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to present certain recommendations regarding CenterPoint Energy Houston Electric, LLC's ("CenterPoint Houston" or the "Company") request to increase rates.

Q. WHAT IS THE SCOPE OF YOUR TESTIMONY?

A. The scope of my testimony is to address certain cost of service issues, the prudence of plant added since CenterPoint Houston's last rate case, billing determinants, and certain cost allocation issues.

Q. IS OPUC SPONSORING OTHER WITNESSES IN THIS PROCEEDING?

A. Yes. OPUC is sponsoring Ms. June Dively, who presents certain accounting adjustments, and Ms. Anjuli Winker, who presents adjustments to the proposed rate of return.

III. SUMMARY AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS PROCEEDING?

A. I make the following recommendations regarding CenterPoint Houston's rate request:

1. The Company's test year vegetation management expenses are excessive and unreasonable. I recommend that the Company be allowed to recover vegetation management expenses of $28.126 million.

2. The Company's Smart Meter Texas ("SMT") expenses are based on forecasted expenses and are unreasonable. I recommend that the Company be allowed to recover an adjusted test year amount of $3.309 million for SMT expenses.

3. The Company's proposed Hurricane Harvey regulatory asset should be adjusted to remove unreasonable expenses. I recommend that the Company's regulatory asset for hurricane-related costs be reduced by $9.524 million.

4. The Company's carrying charges that it proposes to add to the Hurricane Harvey regulatory asset were improperly calculated. I recommend that the carrying charges be reduced by $1.275 million.

5. The Company's Annual Storm Loss Reserves amortization is unreasonable. I recommend that the target reserve be amortized over 5 years, so the annual amount is $6.043 million and the ratemaking adjustment is $1.893 million.

6. The Company's request to share its loss on the sale of land with its customers is unreasonable. The Company's shareholders should bear the entire loss, so the Company's request should be reduced by $0.738 million.

7. The Company's decision to change its capitalization policy on a going forward basis is reasonable, but it is unreasonable for the Company to implement the policy change between rate cases. As a result, $51.418 million should be removed from plant.

8. The Company's plant additions since its last rate case should be reduced by $166.466 million for imprudent or unreasonable costs.

9. Weather should be normalized based on a 10-year weather-normalization period, rather than the Company's requested 20-year normalization period. This change increases present revenues by $11.902 million.

10. The Company's proposed Energy Efficiency Program ("EEP") adjustment is unreasonable, constitutes an impermissible lost revenue adjustment, and should not be recoverable. Removing this adjustment increases present revenues by $1.205 million.

11. The Company's Hurricane Harvey-related costs should not be functionalized only to distribution, but instead, these costs should be functionalized between distribution and transmission.

12. The Company's Transmission Accounts and Support group is 100% dedicated to serving transmission customers, and therefore, these expenses should be directly assigned to transmission.

IV. OVERVIEW OF THE APPLICANT'S REQUEST

Q. WHAT IS CENTERPOINT HOUSTON SEEKING IN THIS PROCEEDING?

A. CenterPoint Houston requested the following:[1]

1. An increase in annual revenues of approximately $154.6 million, consisting of $149.2 million for retail electric delivery and $5.4 million for wholesale transmission,[2]

2. A prudency determination on all capital investment made in the system since January 1, 2010, totaling $2.34 billion for distribution plant[3] and $3.04 billion for transmission plant,[4]

[1] Application at 3. CenterPoint Houston's application also initially requested recovery of rate case expenses, but the rate case expense issue was severed into a separate proceeding.

[2] Direct Testimony of Matthew Troxle at 2 (as revised by the Company's Errata 1 Filing).

[3] Direct Testimony of Randal Pryor at 16.

[4] Direct Testimony of Martin Narendorf at 15.

3. The establishment of a rider to return to customers approximately $119 million for the excess deferred federal income tax unprotected balance that resulted from the Tax Cuts and Jobs Act of 2017 ("TCJA"),

4. Approval of updated depreciation rates, and

5. Approval to clarify and update various non-rate provisions in its Tariff for Retail Delivery Service.

Q. WHAT IS THE TEST YEAR IN THIS PROCEEDING?

A. The test year is the 12-month period ending December 31, 2018.[5]

V. COST OF SERVICE

A. Vegetation Management Expense

Q. WHAT LEVEL OF VEGETATION MANAGEMENT EXPENSE IS CENTERPOINT HOUSTON REQUESTING IN ITS FILING?

A. CenterPoint Houston is requesting its test year level of vegetation management expense, which is $35.022 million.[6]

Q. HOW DOES THIS REQUESTED AMOUNT COMPARE TO THE COMPANY'S PRIOR VEGETATION MANAGEMENT EXPENSES IN PRIOR YEARS?

A. CenterPoint Houston's tree trimming expenses between 2011 and 2017 averaged $26.78 million annually.[7] The 2018 tree trimming expense of $35.02 million was $8.24 million, or 31%, higher than the prior 7-year average. Table 1 below is a summary of the Company's expenditures in prior years compared to the test year, and Figure 1 below is a graphical representation of these costs. As demonstrated in Table 1 and

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[5] Application at 10.

[6] Direct Testimony of Randal Pryor, WP RMP-1 and response to COH RFI 1-27. *See* Attachment KJN-3 for copies of RFI responses referenced in my testimony.

[7] *Id.*

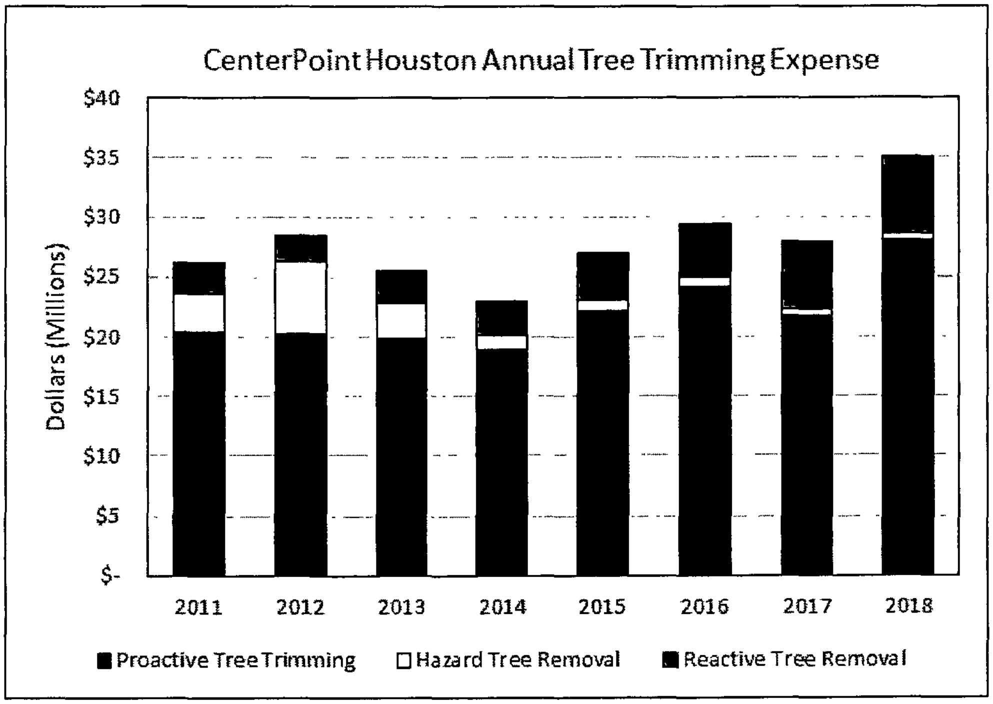
Figure 1, the Company's vegetation management expenses for the 2018 test year represent a significant increase from the prior years.

Table 1

CenterPoint Houston Annual Tree Trimming Expense

Program Description	2011	2012	2013	2014	2015	2016	2017	2018
Proactive Tree Trimming	20.39	20.31	19.89	18.98	22.15	24.18	21.73	28.02
Hazard Tree Removal	3.26	6.02	2.93	1.20	0.93	0.76	0.61	0.62
Reactive Tree Trimming	2.51	2.15	2.70	2.76	3.95	4.51	5.56	6.38
Total	26.16	28.48	25.52	22.94	27.03	29.45	27.90	35.02

Figure 1



Q. DID CENTERPOINT HOUSTON EXPLAIN THE SIGNIFICANT INCREASE IN VEGETATION MANAGEMENT EXPENDITURES IN THE TEST YEAR?

A. No. CenterPoint Houston claims that its contractor bid prices on a per mile basis have increased since 2014 and its overhead pole miles are increasing each year,[8] but this does not explain the large increase in expenses in 2018 over prior years.

Notably, in 2017, the Company's proactive trimming, reactive trimming, and hazard tree removal were halted for a significant period of time due to Hurricane Harvey.[9] It is not clear whether the reduced vegetation management activity in 2017 impacted the need for additional vegetation management in 2018. Even so, any "catch-up" work does not justify a permanent increase in annual vegetation management expense.

Q. HAS CENTERPOINT HOUSTON BEEN ABLE TO ADEQUATELY CONDUCT ITS TREE TRIMMING ACTIVITIES UNDER ITS PREVIOUS LEVELS OF VEGETATION MANAGEMENT EXPENDITURES?

A. Yes. With the average annual expenditures of $26.78 million that I described earlier, the Company has been able to trim on average more than 4,900 miles of overhead lines each year since 2011[10] (excluding 2017 because tree trimming activities were interrupted by Hurricane Harvey).[11] The number of miles trimmed during that period ranged from a high of 5,606 in 2011 to a low of 3,922 in 2017.[12]

Q. HOW IS SYSTEM RELIABILITY MEASURED BY THE COMMISSION?

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[8] Direct Testimony of Randal Pryor at 42-44.

[9] Response to PUC RFI 5-1.

[10] Response to COH RFI 8-4.

[11] Response to PUC RFI 5-1.

[12] *Id.*

A. Reliability is measured using the System Average Interruption Duration Index ("SAIDI"), which represents the average number of outage minutes per customer per year, and the System Average Interruption Frequency Index ("SAIFI"), which represents the average number of times that a customer's service is interrupted. The Company's SAIDI and SAIFI scores must not exceed by more than 5% the average of the Company's performance on SAIDI and SAIFI during the three-year period of 1998, 1999, and 2000.[13]

Q. HAS CENTERPOINT HOUSTON BEEN ABLE TO MEET THE COMMISSION'S RELIABILITY STANDARDS SINCE 2011?

A. Yes. Except in 2015, the Company's SAIDI and SAIFI scores have been well below the Commission's reliability standards[14] (meaning they have been better than the standards). In 2015, the Company's SAIDI score exceeded the Commission's reliability standard as a result of the Company's migration to a new Advanced Distribution Management System and adoption of new safety rules that limited crew approach distances.[15] However, the Commission granted the Company's request for an adjustment to allow the measurement of its performance using the three-year period of 2015, 2016, and 2017.[16] Consequently, the new SAIDI standard is 125.715, and the new SAIFI standard is 1.239.[17] Since 2016, the Company has again been below the Commission's reliability standards.

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[13] Direct Testimony of Dale Bodden at 31.

[14] *Id.* at 33-34 and Service Quality Reports to the Commission.

[15] Response to COH RFI 1-20.

[16] Direct Testimony of Dale Bodden at 34-35.

[17] *Id.* at 35.

Q. IS IT REASONABLE TO SET VEGETATION MANAGEMENT EXPENSE AT THE LEVEL REQUESTED BY CENTERPOINT HOUSTON?

A. No. The Company has demonstrated that it has been able to maintain its tree trimming schedule throughout the period since its last rate case, with no adverse impact on reliability. Therefore, the requested test year increase of $8.24 million above the prior 7-year average of $26.78 million is unnecessary and unreasonable.

Q. WHAT DO YOU RECOMMEND INSTEAD?

A. I recommend that vegetation management expense be set at $28.126 million, which is $6.896 million less than the Company's request. My recommendation is based on the average vegetation management expenses incurred by the Company during the 3-year period of 2015-2017. The average expenditures consist of expenses made in the years immediately before the 2018 test year and reflect the most recent tree trimming activity. The use of average expenditures addresses the year-to-year variation in expenses. The 3-year period reflects the next highest annual expenditures (excluding 2012, a year in which the Company had unusually high hazard tree removal costs).[18]

B. SMT Expense

Q. WHAT LEVEL OF SMT EXPENSES IS CENTERPOINT HOUSTON REQUESTING IN ITS FILING?

A. CenterPoint Houston is requesting two adjustments related to its SMT costs. First, the Company is requesting to amortize and recover its SMT regulatory asset of $6.939

[18] *See* Table 1 and Figure 1 for the relative hazard tree removal costs.

million over three years.[19] OPUC witness June Dively addresses the recovery of the SMT regulatory asset in her testimony. Second, the Company is requesting $3.565 million in base rates for ongoing SMT expenditures.[20] I address the ongoing SMT expenses.

Q. PLEASE DESCRIBE CENTERPOINT HOUSTON'S ONGOING SMT EXPENSES.

A. The Company incurs costs to participate in the SMT portal. SMT is an ERCOT-wide website that provides access to smart meter data to end-use retail customers, competitive retailers, and other customer-authorized third parties. SMT is jointly owned and operated by CenterPoint Houston, Oncor Electric Delivery Company, AEP Texas Inc., and Texas New Mexico Power Company under a Joint Development and Operations Agreement ("JDOA"). The parties to the JDOA contract with IBM for the design, development, and ongoing operation of the SMT website. Under the JDOA, CenterPoint Houston is responsible for a share of the annual SMT costs.[21]

Q. HOW WAS THE COMPANY'S PROPOSED SMT EXPENSE AMOUNT DERIVED?

A. Rather than using 2018 test year SMT expenses, the Company prepared an estimate of the costs "expected" to be incurred under the SMT program for the period 2020 through 2024.[22] The Company's requested amount includes an estimate of employee travel and

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[19] Direct Testimony of Kristie Colvin at 42-43 and WP/II-E-4.1.1.

[20] *Id.* at 32 and WP/II-D-1 Adj 10.

[21] Direct Testimony of John Hudson at 27-28.

[22] *Id.* at 28.

meal expenses, professional and legal expenses, contracted IT, and maintenance costs, plus an added 10% contingency factor.[23]

Q. IS IT APPROPRIATE TO USE A FORECAST OF EXPECTED COSTS TO SET RATES?

A. No. Under the Commission's rules, rates are generally set using a historical test year, adjusted for known and measurable changes.[24] In particular, the Company's forecast of a 10% contingency factor for "miscellaneous unexpected expenses"[25] is far from a known and measurable expense as required by the Commission's rule.

Q. HOW SHOULD THE SMT EXPENSE AMOUNT BE DETERMINED?

A. The Company's SMT expenses should be based on adjusted test year expenses. The Company's test year SMT expenses are $3.925 million.[26] I adjusted this amount for known and measurable changes.

Q. WHAT CHANGE DID YOU MAKE TO THE SMT EXPENSE?

A. CenterPoint Houston witness John Hudson noted that the contract between the JDOA parties and IBM was amended to cover the changes necessary to comply with the SMT 2.0 requirements resulting from Docket No. 47472.[27] The SMT costs in 2019 are higher than costs anticipated in 2020 and after because the 2019 SMT costs include the IBM costs for updating the SMT website to comply with the SMT 2.0 requirements.[28]

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[23] WP/II-D-1 Adj 10.

[24] 16 TAC § 25.231(a).

[25] WP/II-D-1 Adj 10.

[26] WP/II-B-12d SMT.

[27] Direct Testimony of John Hudson at 28.

[28] *Id.*

Because the SMT costs for 2020 and after are based on actual contract costs, I used these SMT costs to calculate the ongoing SMT expenses, instead of the 2018 test year IBM contract amount.

Q. WHAT ARE THE CONTRACT AMOUNTS?

A. The 2018 test year contract amount is $3,450,044. The 2020 contract amount is $2,834,772.

Q. WHAT IS THE RESULT OF YOUR ADJUSTMENT?

A. My adjustment results in an adjusted SMT expense amount of $3.309 million,[29] which is $0.256 million less than the Company's request of $3.565 million.

C. Hurricane Harvey Regulatory Asset

Q. WHAT IS CENTERPOINT HOUSTON REQUESTING FOR ITS HURRICANE HARVEY REGULATORY ASSET?

A. CenterPoint Houston is requesting to amortize and recover the balance of its regulatory asset for Hurricane Harvey restoration costs of $64.406 million over three years,[30] plus $8.742 million in carrying charges.[31] OPUC witness June Dively addresses the recovery of the regulatory asset in her testimony. I address the hurricane-related expenses included in the regulatory asset and the calculation of carrying charges.[32]

Q. WHAT HURRICANE-RELATED COSTS COMPRISE THE REGULATORY ASSET?

[29] $3.925 million - $3.450 million + $2.834 million = $3.309 million.

[30] WP/II-E-4.1.1.

[31] CenterPoint Houston Errata 1 Filing.

[32] OPUC witness Ms. Dively recommends moving the Hurricane Harvey costs to a rider and addressing carrying costs in a separate compliance docket. I address the calculation of carrying costs in the event that they are addressed in this proceeding.

A. The Company's regulatory asset balance for Hurricane Harvey restoration costs as of December 31, 2018, was $64.406 million, which includes operating and maintenance ("O&M") costs of $75.693 million, less actual insurance proceeds of $11.287 million.[33] The Company's Errata 1 filing also added a request for $8.742 million in carrying charges to the regulatory asset.

Q. HAVE YOU IDENTIFIED ANY EXPENSES THAT SHOULD BE REMOVED FROM THE REGULATORY ASSET?

A. Yes. I have identified several categories of expenses that should be removed from the regulatory asset.

Q. PLEASE DESCRIBE THE EXPENSES THAT SHOULD BE REMOVED FROM THE REGULATORY ASSET.

A. There are two sources for these expenses. The first source is the results from the internal audit conducted by CenterPoint Houston to validate expenses for Hurricane Harvey related costs. The second source is the Company's known and measurable changes to the regulatory asset.

Q. WHAT WAS THE PURPOSE OF CENTERPOINT HOUSTON'S INTERNAL AUDIT?

A. The primary objectives of the Company's internal audit review included the following:[34]

[redacted]

[redacted]

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[33] Direct Testimony of Kristie Colvin at 34-35 and response to PUC RFI 8-14e, Attachment 1.

[34] Response to PUC RFI 7-6, Hurricane Harvey EOP Expense Validation Review at 3 (Confidential).

[redacted]

[35] *Id.* at 4.

[redacted]

[36] *Id.* at 6.

[37] [redacted]

[38] Response to PUC RFI 7-6, Hurricane Harvey EOP Expense Validation Review at 8-9 (Confidential).

[39] [redacted]

[40] [redacted]

[41] Response to PUC RFI 7-6, Hurricane Harvey EOP Expense Validation Review at 13 (Confidential).

[42] [redacted]

Q. WHAT IS YOUR RECOMMENDATION BASED ON THESE INTERNAL AUDIT FINDINGS?

A. [redacted] The Company has the burden of proving its expenses are reasonable, and if the Company cannot [redacted], then the expenses must be removed from the Company's request. Therefore, I recommend that the expenses identified above be disallowed, which reduces the regulatory asset by $9.505 million,[43] along with associated carrying charges.

Q. DID YOU IDENTIFY ANY CHANGES THAT CENTERPOINT HOUSTON PROPOSES TO MAKE TO THE EXPENSES INCLUDED IN THE REGULATORY ASSET?

A. Yes. CenterPoint Houston has proposed three "known" changes to the regulatory asset:[44]

1. A reduction to labor and materials of $3,735, of which $2,911 was allocated to expense;
2. Employee awards and gifts of $29,434, of which $6,493 was incorrectly capitalized; and
3. Capital costs of $15,678, of which $12,220 should have been expensed.

These expenses total $15,802, which the Company proposes to add to the regulatory asset.

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[43] [redacted] = $9.505 million.

[44] WP/II-B-12 Adj 2.

Q. SHOULD THESE EXPENSES BE INCLUDED IN THE COMPANY'S REGULATORY ASSET?

A. No. Items 2 and 3 should not be included in the Company's regulatory asset. Item 2 reflects employee awards and gifts that provide no benefit to customers and should not be recoverable. Item 3 is a cost that was initially capitalized, but the Company now says should be largely expensed. It did not describe the nature of the capital cost and provided no evidence to support the change in character of the cost.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Hurricane Harvey regulatory asset be further reduced by the purported "known" changes related to employee awards and gifts and expensed capital cost, which total $18,713.

Q. DO YOU HAVE ANY OTHER ADJUSTMENTS TO THE COMPANY'S HURRICANE HARVEY REGULATORY ASSET?

A. Yes. If CenterPoint Houston is permitted to recover carrying charges on its Hurricane Harvey regulatory asset, I recommend a correction to the Company's calculation of the carrying charges reflected in its Errata 1 filing.

Q. WHAT AMOUNT OF CARRYING CHARGES IS THE COMPANY REQUESTING FOR THE HURRICANE HARVEY REGULATORY ASSET?

A. The Company's application did not initially request carrying charges for the Hurricane Harvey regulatory asset; however, the Company's Errata 1 filing added a request for $8.742 million in carrying charges for the Hurricane Harvey regulatory asset.[45]

[45] CenterPoint Houston's Errata 1 Filing.

Q. WHAT AUTHORITY IS CENTERPOINT HOUSTON RELYING ON TO RECOVER CARRYING CHARGES ON THE HURRICANE HARVEY REGULATORY ASSET?

A. CenterPoint Houston's Errata 1 filing did not identify the legal authority that the Company is relying on to recover carrying charges on the Hurricane Harvey regulatory asset. However, at the technical conference on June 4, 2019, the Company indicated that it was relying on Sections 36.401 to 36.403 of PURA, which authorize electric utilities to securitize storm restoration costs.[46]

Q. DO THESE STATUTORY PROVISIONS IN PURA APPLY TO CENTERPOINT HOUSTON'S REQUEST?

A. No. These sections of PURA apply to securitization proceedings for storm restoration costs, and CenterPoint Houston is not seeking to securitize its Hurricane Harvey costs in this case.

Q. DO THESE STATUTORY PROVISIONS IN PURA PROVIDE GUIDANCE ON HOW TO CALCULATE CARRYING CHARGES FOR SYSTEM RESTORATION COSTS?

A. Yes. Under PURA § 36.402(b), system restoration costs include carrying costs at the utility's weighted average cost of capital ("WACC").

Q. HOW DID CENTERPOINT HOUSTON CALCULATE ITS CARRYING CHARGES?

[46] "System restoration costs" are the reasonable and necessary costs of restoring service and infrastructure associated with electric power outages resulting from various weather-related events and natural disasters, including hurricanes. PURA § 36.402(a).

A. CenterPoint Houston calculated the carrying charges on the Hurricane Harvey regulatory asset balance, less insurance proceeds, using the appropriate WACC for the periods in which it incurred the Hurricane Harvey costs. However, the Company applied a monthly "compound interest" formula to determine the charges.[47]

Q. WHAT IS THE FINANCIAL IMPACT OF USING A MONTHLY COMPOUND INTEREST FORMULA?

A. Using a monthly compound interest formula allows the Company to over-collect the carrying costs on the regulatory asset.

Q. HOW SHOULD THE COMPANY APPLY INTEREST FOR THE HURRICANE HARVEY REGULATORY ASSET?

A. The return component of the cost of service is determined by applying the utility's WACC to its rate base on an annual basis. If CenterPoint Houston is permitted to recover carrying costs, this annual "simple interest" formula is the same methodology that should be applied to calculating carrying charges on the regulatory asset.

Q. WHAT IS THE RESULT OF APPLYING A SIMPLE INTEREST FORMULA TO THE COMPANY'S HURRICANE HARVEY REGULATORY ASSET?

A. The resulting amount of carrying charges is $8.616 million, which is $0.126 million less than the Company's request of $8.742 million. This calculation is shown on Attachment KJN-1.

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[47] Response to PUC RFI 8-14e, Attachment 1.

Q. WHAT IS THE FINANCIAL IMPACT ON CARRYING CHARGES AFTER INCORPORATING ALL OF YOUR RECOMMENDED ADJUSTMENTS TO THE COMPANY'S HURRICANE HARVEY REGULATORY ASSET?

A. Attachment KJN-2 shows the impact on carrying charges of applying a simple interest formula after incorporating all of the adjustments to the Hurricane Harvey regulatory asset that I discussed above. My recommended adjustments reduced the regulatory asset by $9.525 million, and consequently, reduced the carrying charges by $1.148 million. The total financial impact of using a simple interest formula is a reduction to carrying charges of $1.275 million.

D. Storm Loss Reserves

Q. HOW DOES CENTERPOINT HOUSTON ADDRESS INSURANCE FOR STORM-RELATED PROPERTY LOSSES?

A. CenterPoint Houston self-insures against storm-related property losses impacting its transmission and distribution assets, rather than obtaining property insurance from a third-party. Under 16 TAC § 25.231(b)(1)(G), a utility's self-insurance plan provides for accruals to be credited to reserve accounts. The reserve accounts are to be charged with certain property and liability losses that occur and that are not paid or reimbursed by commercial insurance.[48]

Q. WHAT IS THE COMPANY REQUESTING REGARDING ITS STORM LOSS RESERVES?

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[48] Direct Testimony of Kristie Colvin at 27.

A. In this proceeding, CenterPoint Houston is requesting an annual accrual of $7.685 million and a new target property insurance reserve of $6.55 million. The accrual consists of two elements: (1) $3.575 million to provide for average annual O&M expense losses from storm events where the O&M expense loss is greater than $100,000 and the total event loss does not exceed $100 million; and (2) $4.110 million accrued annually for three years to achieve the target reserve of $6.55 million from the current reserve deficit level of ($5.791 million).[49]

Q. HOW WERE THE RESERVE AMOUNTS DETERMINED?

A. The $3.575 million annual accrual was calculated using a Monte Carlo simulation run on the loss history of the Company.[50] The remaining $4.110 million represents the Company's target reserve of $6.55 million, plus the current reserve deficit level of ($5.791 million), amortized over three years.[51]

Q. HOW WAS THE TARGET RESERVE DETERMINED?

A. The target reserve of $6.55 million represents the largest annual expected impact on the self-insurance reserve in any 25-year period, based on the Monte Carlo simulation run on the loss history of the Company.

Q. DO YOU AGREE WITH THE COMPANY'S REQUEST?

A. I do not have an issue with the calculation of the target reserve. However, I recommend that the target reserve be amortized over five years rather than three years, consistent with the recommendations of OPUC witness Ms. Dively.

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[49] Direct Testimony of Gregory Wilson at 5.

[50] A Monte Carlo simulation is a statistical technique that uses a computer program to simulate loss experience over a longer period of time than the period captured in the available loss history. *Id.*

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

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. Under my recommendation, the storm loss reserve would be calculated as:

$3.575 million + ($6.55 million + $5.791 million) / 5 = $6.043 million

This reserve amount is $1.642 million less than the Company's calculation.

Q. HOW WOULD YOUR ADJUSTMENT BE REFLECTED IN CENTERPOINT HOUSTON'S SCHEDULES?

A. The adjustment would be made to Schedule II-D-2, which in CenterPoint Houston's application reflects a known and measurable adjustment of $3.535 million in column 3. This value was derived by subtracting the current uninsured property loss reserve accrual of $4.150 million from the Company's proposed $7.685 million accrual.[52] Using my revised accrual amount, the adjustment in column 3 of Schedule II-D-2 should be $1.893 million.

E. Loss on Sale of Land

Q. PLEASE DESCRIBE THE LOSS ON SALE OF LAND THAT CENTERPOINT HOUSTON INCLUDED IN ITS APPLICATION.

A. The Company's testimony does not describe how the loss on sale of land occurred. However, based on a workpaper to the Company's application schedules, the loss relates to the sale of approximately 105 acres across 14 tracts of land associated with the Brazos Valley Connection transmission project.[53] The total book value of the tracts was

[52] WP/II-D-2 Adj 9.

[53] WP/II-B-13.

$2.294 million, but the tracts sold for a total of $0.830 million, for a total loss of $1.464 million.[54]

Q. WHAT IS THE COMPANY REQUESTING REGARDING RECOGNITION OF ITS LOSS ON SALE OF LAND?

A. The Company is requesting that its loss of $1,464,113 on the sale of these tracts of land be shared 50%/50% between its shareholders and customers.[55]

Q. WHAT IS THE COMPANY'S BASIS FOR SHARING THE LOSS WITH CUSTOMERS?

A. The Company contends that in Docket No. 38339 the Commission found that customers should share in any gain or loss resulting from the sale of land during the test year.[56] In particular, the Company cites Finding of Fact No. 137 from the Order on Rehearing, which states that: "Land is not a depreciable asset, and customers have not paid any depreciation expense associated with the land. This does not mean ratepayers have no claim on any gain or loss resulting from the sale of land."[57]

Q. DO YOU AGREE WITH CENTERPOINT HOUSTON'S INTERPRETATION APPLYING THE ORDER TO A LOSS ON THE SALE OF LAND?

A. No. Finding of Fact No. 139B in the same Commission order found that it was reasonable for CenterPoint Houston to return 50% of the $187,000 gain on the sale of

[54] *Id.*

[55] Direct Testimony of Kristie Colvin at 50 and WP/II-E-5.1.

[56] *Id.* at 50

[57] Docket No. 38339, Order on Rehearing, FoF 137 (June 23, 2011).

land that occurred within the test year.[58] The decision to share equally between shareholders and customers was limited to a **gain** on the sale of land. Additionally, in its order, the Commission noted that ratepayers pay a return on the investment and expenses associated with land, such as taxes, and that customers should benefit through a 50% share of the gain on any land sold during the test year.[59]

Q. WHY WOULD IT BE DIFFERENT FOR A LOSS ON A SALE OF LAND?

A. The utility controls if and when a parcel of land is sold. If there is a loss on the sale, the utility should be expected to document its actions to show that the original purchase price was reasonable and the subsequent sale was reasonable. In this case, CenterPoint Houston took a 64% hit on the value of the land. The Company purchased the land for almost $22,000 per acre,[60] but sold the land for less than $8,000 per acre.[61] The Company's testimony does not provide any detailed documentation about why it sold the tracts of land or the why it was necessary to sell the land when it did. The Company, therefore, has failed to provide any evidence that the sale for a loss was reasonable and necessary, yet expects customers to pick up half the difference. Further, if a utility is allowed to share losses on the sale of land, the utility may have a reduced incentive to obtain the best purchase and sales prices because the utility would not fully bear the consequences of its decisions.

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[58] *Id.*, FoF 139B.

[59] *Id.* at 5.

[60] $2,294,559 / 105 acres = $21,853/acre.

[61] $830,446 / 105 acres = $7,909/acre.

Q. WHAT IS YOUR RECOMMENDATION REGARDING SHARING THE LOSS ON THE SALE OF LAND?

A. I recommend that customers not be assigned any of the$732,057 loss on the sale of land. The Company has not shown that the sale was reasonable and necessary, and the Commission's Order on Rehearing in Docket 38339 only addresses a gain on the sale of land.

VI. RATE BASE

A. CenterPoint Houston's Change in Capitalization Policy

Q. HAS CENTERPOINT HOUSTON CHANGED ITS CAPITALIZATION POLICY SINCE ITS LAST RATE CASE?

A. Yes. Since Docket No. 38339, the Company has made changes to its capitalization policy for luminaires, microprocessor control devices, certain construction overhead costs, and program assessment costs (underground cable life extension).[62]

Q. WHAT WAS THE COMPANY'S BASIS FOR THE CHANGE TO LUMINAIRES?

A. CenterPoint Houston asserts it had always capitalized luminaires installed with the pole and bracket as one unit, but expensed replacements of luminaires only. But in 2013, the Company began to recognize a change in luminaire technology and related increases in material costs that no longer qualified luminaires alone as a minor material. As a result, the Company began treating luminaire replacements as a separate retirement unit on January 1, 2014.[63]

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[62] Direct Testimony of Kristie Colvin at 92-93.

[63] *Id.* at 93-94.

Q. WHAT WAS THE COMPANY'S BASIS FOR THE CHANGE TO MICROPROCESSOR CONTROL DEVICES?

A. Microprocessor control devices are a component of the substation control panel. CenterPoint Houston claims that prior to 2017, replacing only a microprocessor control device in a substation was expensed. However, changing technology has led to more prevalent use of microprocessor control devices across the Company's system. Thus, effective January 1, 2017, the Company changed its capitalization policy to make the microprocessor control device a separate retirement unit from the control panel.[64]

Q. WHAT WAS THE COMPANY'S BASIS FOR THE CHANGE TO OVERHEAD CONSTRUCTION COSTS?

A. In 2013, consistent with the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USOA"), CenterPoint Houston claims it began to analyze whether an accounting change related to certain overhead construction costs, such as general office salaries and expenses, was warranted. In 2014, the Company began to include a portion of its costs associated with the Property Accounting and Accounts Payable departments in overhead construction cost.

Furthermore, the Company stated that it researched whether call center calls related to new construction projects could be separately identified and capitalized to those projects. In 2015, the Company determined that it could separately identify the call center activities related to new construction, and consequently, it began to include in

[64] *Id.* at 95-96.

overhead construction cost a portion of its Call Center department that interfaces directly with new construction and new meter calls.[65]

Q. WHAT WAS THE COMPANY'S BASIS FOR THE CHANGE TO PROGRAM ASSESSMENT COSTS?

A. CenterPoint Houston asserts that FERC issued guidance in 1996 that permits utilities to capitalize certain pipeline assessment costs related to a one-time major rehabilitation project of the utility's system if the project would extend the useful life of the system. The Company notes that FERC later clarified that underground cable assessment costs could also be capitalized if certain criteria were met by the utility. In 2013, the Company updated its capitalization policy due to the FERC guidance and implemented an underground cable assessment program to determine the specific location of cables needing to be repaired or replaced. The Company maintains that the underground cable assessment program was not a routine maintenance program that should be expensed, but rather, a program implemented specifically as part of a large capital project that met the FERC criteria for capitalization.[66]

Q. HAS THE COMMISSION ADDRESSED THE COMPANY'S CAPITALIZATION POLICY IN PREVIOUS DOCKETS?

A. Yes. The Company's change in capitalization policy was addressed in each of its prior Distribution Cost Recovery Factor ("DCRF") filings since 2015.[67] Intervenors in each of those DCRF cases opposed the Company's policy change. The DCRF cases all resulted

[65] *Id.* at 96-97.

[66] *Id.* at 103-105.

[67] Docket Nos. 44572, 45747, 47032 and 48226 (CenterPoint Houston DCRF proceedings from 2015 to 2018).

in settlements that deferred consideration of the Company's change in capitalization policy to this base rate proceeding.

Q. WHAT WAS THE BASIS FOR THE INTERVENORS' OPPOSITION TO THE COMPANY'S CHANGE IN POLICY IN THE DCRF PROCEEDINGS?

A. The primary basis for the intervenors' opposition was that a change in capitalization policy would result in potential double counting of costs that were expensed in the Company's last rate case but then capitalized since that rate case.

Q. CAN YOU PROVIDE EXAMPLES OF DOUBLE COUNTING?

A. Yes. In Docket No. 44572, State Agencies witness Kit Pevoto testified:[68]

> *Q. Why would CEHE's proposal result in double recovery of lighting luminaire replacement costs?*
>
> *A. CEHE's existing rates already include lighting luminaire replacement costs. According to its updated response to State Agencies' First RFI Question TSA 01-12 02U (attached as State Attachment KP-7), CEHE's existing rates reflect a recovery of a total of $939,000 lighting luminaire replacement costs as an operation and maintenance expense. Therefore, the capitalization of any lighting luminaire replacement costs would allow CEHE to recover costs it already receives through its current rates.*

Similarly, in Docket No. 45747, TCUC witness Constance Cannady testified:[69]

> *Q. Are the proposed capitalized corporate overhead costs already recovered under a separate rate? Please explain.*
>
> *A. In PUC Docket No. 38339, the approved rates included $194.7 million in affiliated costs, including $513,000 allocated from Property Accounting, $279,000 allocated from Accounts Payable and $6,667,000 included in FERC Account 903, which included the Call Center costs requested in this filing. All of these costs were identified as an expense in that case. CEHE's proposal to capitalize a portion of the costs that were included as expense in the PUC Docket No. 38339 will force ratepayers to pay for the* ***same expense twice****: once as an expense item and once as a capital cost.*

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[68] Docket No. 44572, Direct Testimony of Kit Pevoto at 10.

[69] Docket No. 45747, Direct Testimony of Constance Cannady at 10-11.

Q. DID THE INTERVENORS PROVIDE ANY OTHER BASIS FOR OPPOSING THE COMPANY'S CHANGE IN CAPITALIZATION POLICY?

A. Yes. Regarding the program assessment costs, I argued in Docket No. 44572 that CenterPoint Houston improperly applied the FERC guidance with regard to capitalizing the program assessment costs. FERC did not advocate capitalizing 100% of the program assessment costs, but only the costs that are associated with specific rehabilitation projects. And in fact, the Company established separate projects when major rehabilitation work was necessary. In addition, the program assessment was planned to be an 18-year project, not a "one-time major rehabilitation project" as asserted by the Company. I concluded that the program was much more like an ongoing assessment program which FERC has confirmed should be expensed.[70]

Q. WHAT IS YOUR POSITION ON THE COMPANY'S PROPOSED CHANGE OF CAPITALIZATION POLICY IN THIS PROCEEDING?

A. I do not oppose the change in capitalization policy for the rates set in this rate case proceeding on a going-forward basis. However, I conclude that many of the expenses that CenterPoint Houston began to capitalize since its last rate case filing were reflected in the rates set in that case. Therefore, the Company's capitalized expenses duplicated costs that were already being recovered in its rates. Furthermore, the Company has not shown that all of the underground program assessment costs should be capitalized. Thus, I recommend that any costs capitalized under the Company's change in capitalization policy since its last rate case be disallowed from plant in service.

[70] Docket No. 44572, Direct Testimony of Karl Nalepa at 18-24 (filed on behalf of Gulf Coast Coalition of Cities).

Q. WHAT EXPENSES WERE CAPITALIZED SINCE CENTERPOINT HOUSTON'S LAST RATE CASE?

A. The total amount capitalized was $51.418 million. Table 2 summarizes the costs by program:[71]

Table 2

Capitalized Expenses Due to Change in Policy ($)

	Accounts Payable	Property Accounting	Call Center	Micro processor	Luminaries	Program Assessment	Total
2009	-	-	-	-	-	-	-
2010	-	-	-	-	-	-	-
2011	-	-	-	-	-	-	-
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	2,662,605	2,662,605
2014	292,581	356,210	-	-	868,478	13,821,869	15,339,138
2015	267,939	367,141	210,013	-	683,172	12,184,931	13,713,196
2016	288,288	286,851	328,916	-	1,327,026	3,641,713	5,872,794
2017	295,303	383,424	388,523	143,964	-	6,000,571	7,211,785
2018	312,569	261,922	514,260	115,933	2,510,007	2,903,545	6,618,236
Total	1,456,680	1,655,548	1,441,712	259,897	5,388,683	41,215,234	51,417,754

For the reasons discussed above, the entire amount should be removed from the Company's rate base.

Q. DOES YOUR RECOMMENDED ADJUSTMENT HAVE ANY ASSOCIATED ATTENDANT IMPACTS?

A. Yes. This change to plant accounts will have attendant impacts associated with the adjustment. These impacts include changes to depreciation expense, accumulated depreciation, accumulated deferred federal income taxes ("ADFIT"), federal income taxes, Texas gross margin tax, and return. To the extent my recommendation is adopted,

[71] WP RMP-2 and response to PUC RFI 2-33, Attachment 6.

these impacts should be included in the final calculation of the Company's cost of service.

B. Prudence of Plant Additions Since 2009

Q. IS CENTERPOINT HOUSTON REQUESTING A PRUDENCE DETERMINATION IN THIS PROCEEDING?

A. Yes. CenterPoint Houston is requesting a prudency determination on all capital investments made to its system from December 31, 2009 (i.e., the end of the test year in the Company's last rate case) to December 31, 2018 (i.e., the end of the test year in this rate case). During that nine-year period, the Company has added $2,344.7 million of distribution plant[72] and $3,036.4 million of transmission plant.[73]

Q. WHAT ARE CENTERPOINT HOUSTON'S MAJOR CATEGORIES OF PLANT ADDITIONS?

A. CenterPoint Houston's major categories of plant additions are summarized in Table 3:

[72] Direct Testimony of Randal Pryor at 16.

[73] Direct Testimony of Martin Narendorf at 15.

Table 3

Capital Investments by Category ($Millions)

Distribution	
Customer Growth	$ 1,095
Reliability Improvement	$ 866
Service Restoration	$ 392
Operations and Support	$ (9)
Total	$ 2,345
High Voltage	
Interconnections	$ 461
Load Growth	$ 1,507
System Improvements	$ 755
Restoration	$ 94
Operations and Support	$ 221
Total	$ 3,036

As shown above, the Company's capital investments in customer load growth make up nearly 50% of the total distribution and high-voltage transmission plant investments. This capital investment was followed in amount by the Company's system and reliability improvements. Together, customer load growth, reliability, and system improvements comprise nearly 80% of the Company's total plant investments.

Q. HAVE YOU REVIEWED THE COMPANY'S PLANT INVESTMENT SCHEDULES AND RELATED RESPONSES TO DATA REQUESTS?

A. Yes.

Q. BY WHAT STANDARD SHOULD CENTERPOINT HOUSTON'S PLANT INVESTMENTS BE EVALUATED?

A. Pursuant to 16 TAC § 25.231(c)(2), plant investments must be used and useful in providing service to the public.[74] In addition, expenses included in a utility's cost of service must be reasonable and necessary,[75] thus plant investments that yield expenses reflected in the cost of service must be reasonable and necessary as well.

Furthermore, the Commission has applied a prudence standard which was affirmed by the Austin Court of Appeals in *Gulf States Utilities Co. v. Public Utility Commission of Texas*. The Court recognized the following definition of "prudence":[76]

> *Prudence is the exercise of that judgment and the choosing of that select range of options which a reasonable utility manager would exercise or choose in the same or similar circumstances given the information or alternatives at the point in time such judgment is exercised or option is chosen.*

Q. WHAT HAVE YOU CONCLUDED REGARDING THE COMPANY'S PLANT ADDITIONS?

A. I have identified several instances where the Company is seeking to capitalize project costs that should be expensed and not included in plant accounts. In addition, the Company is seeking to recover certain plant costs that were excessive or were imprudently incurred. These plant costs do not meet the *Gulf States* prudence standard described above. Based on my review, I recommend five adjustments, which are discussed below.

[74] 16 TAC § 25.231(c)(2).

[75] 16 TAC § 25.231(b).

[76] *Gulf States Utils. Co. v. Pub. Util. Comm'n of Tex.*, 841 S.W.2d 459, 475-76 (Tex. App.—Austin 1992, writ denied).

Q. WHY IS IT IMPORTANT TO EXCLUDE IMPROPERLY CAPITALIZED EXPENSES OR IMPRUDENT COSTS FROM CENTERPOINT HOUSTON'S PLANT ACCOUNTS?

A. Capital costs are generally associated with major assets that will be used over time or extend the productive life of a previously purchased asset. Conversely, operating expenses are costs incurred to run the day-to-day operations of a utility. These costs are recurring in nature and are used to maintain a capital asset.

A utility earns a return on its capital assets and recovers depreciation expense that represents the reduction in the value of the asset due to wear and tear over the life of the asset. It would be inappropriate to allow a utility to recover in rates a return or depreciation expense on costs that should not be capitalized by the utility.

Q. PLEASE EXPLAIN YOUR FIRST ADJUSTMENT.

A. The Company characterizes the following projects as routine or corrective:[77]

AB1Z.[78] *Proactive routine capital replacements to the overhead distribution system.*

HLP/00/0011. Unscheduled substation corrective projects. Small, unscheduled corrective type projects and unforeseen equipment failures. These projects involve replacement of equipment and/or structures.

HLP/00/0012. Scheduled substation corrective projects. Small, scheduled corrective projects. These projects involve replacement of equipment and/or structures.

Given that these projects are routine or corrective in nature, and are intended to maintain a capital asset, these projects more appropriately meet the criteria for expense items. These projects should have been expensed, rather than capitalized, and thus, the

[77] WP RMP-2, 2010 – 2018 Capital Project Lists.

[78] This project is identified as AB1X in the 2018 Capital Project List.

project should be removed from plant in service. Accordingly, I recommend a reduction to plant in service of $13,850,004 as shown below:

	AB1Z	HLP/00/0011	HLP/00/0012
2010	$ 6,341,735	$ 1,191,445	$ -
2011	$ 6,341,595	$ 1,298,293	$ -
2012	$ 7,904,953	$ 6,754,115	$ 2,940,965
2013	$ 11,167,517	$ 10,983,346	$ 1,097,412
2014	$ 11,278,636	$ 3,193,386	$ -
2015	$ 10,635,772	$ 3,547,907	$ 3,271,455
2016	$ 11,414,103	$ 3,454,006	$ 1,241,538
2017	$ 35,117,023	$ 3,582,621	$ 3,342,573
2018	$ 3,737,635	$ 2,566,221	$ 1,956,061
Total	$ 103,938,969	$ 36,571,340	$ 13,850,004

Q. PLEASE EXPLAIN YOUR SECOND ADJUSTMENT.

A. The following project is for a corporate website redesign:[79]

ENTD086. Corporate website redesign.

While computers and computer software can be capitalized by a utility, there is no basis for capitalizing a website redesign. This web design service is more properly recorded as an expense account, such as FERC Account No. 923, Outside Services. Thus, the following website redesign costs should have been expensed and should be removed from plant in service:

2014	ENTD086	$7,086,684

Q. PLEASE EXPLAIN YOUR THIRD ADJUSTMENT.

A. The following project is to purchase tools for a substation:[80]

[79] WP RMP-2, 2014 Capital Project List.

[80] *Id.*

S/101318/CG/TOOLS. *Purchase of substation tools that meet the capital criteria per CenterPoint Energy capitalization policy.*

Tools are used to maintain capital assets and are typically expensed under FERC rules, not capitalized. While the Company asserts that the tools were capitalized pursuant to its capitalization policy, the Company is not entitled to capitalize the tools under FERC's rules. Furthermore, the Company did not explain why it believes it is appropriate to depart from the typical FERC treatment for tools in this instance. Thus, these tool costs should have been expensed and should be removed from plant in service:

2014	S/101318/CG/TOOLS	$2,127,089

Q. PLEASE EXPLAIN YOUR FOURTH ADJUSTMENT.

A. The following project costs were incurred due to a faulty foundation installation:[81]

HLP/00/0801. Foundation replacements due to Alkali-Silica Reaction (ASR) in the foundation causing large cracks in the piers/foundations. The reaction cannot be stabilized and is not reversable.

These project costs were incurred because of apparent errors in laying the original foundation installation. These costs were incurred to replace the foundation and would not have been incurred, but for the error. The costs are unreasonable and customers should not be responsible for them. Thus, the project costs should be removed from plant in service:

2015	HLP/00/0801	$1,190,140

Q. PLEASE EXPLAIN YOUR FIFTH ADJUSTMENT.

A. The following transmission projects incurred cost overruns due to construction errors:[82]

[81] WP RMP-2, 2015 Capital Project List.

Alexander Island Substation. *138 kV transmission line. Foundations were staked with the wrong line pull orientation which wasn't discovered until after the foundations were built. Foundations were removed and reconstructed. Structures had to be modified and some additional material had to be ordered.*

La Marque Substation. *Partial rebuild and partial reconductor of 138kV transmission line. Tower design and location changed during detailed engineering phase which led to some material errors. One angle structure had to be removed and replaced.*

These project costs exceeded budgets because of errors in the original construction activities. The resulting cost overruns would not have been incurred, but for the errors. The costs are unreasonable and customers should not be responsible for them. Thus, the amount of project costs over the budgeted amount should be removed from plant in service:

	Project	Budgeted Cost	Final Cost	Excess Cost
2015	Alexander Island Substation	$358,000	$732,052	$374,052
2016	La Marque Substation	$1,446,000	$2,773,369	$1,327,369

Q. WHAT IS THE TOTAL IMPACT OF YOUR RECOMMENDED ADJUSTMENTS ON CENTERPOINT HOUSTON?

A. The total impact of my recommended adjustments would reduce CenterPoint Houston's rate base by $166.466 million.

Q. DO YOUR RECOMMENDED ADJUSTMENTS HAVE ANY ASSOCIATED ATTENDANT IMPACTS ON CENTERPOINT HOUSTON?

[82] Response to PUC RFIs 1-38 and 6-24.

A. Yes. These recommended changes to plant accounts will have attendant impacts associated with the adjustments. These impacts include changes to depreciation expense, accumulated depreciation, ADFIT, federal income taxes, Texas gross margin tax, and return. To the extent my recommendations are adopted by the Commission, these impacts should be included in the final calculation of the Company's cost of service.

VII. BILLING DETERMINANTS

A. Weather Normalization Adjustment

Q. WHAT IS THE PURPOSE OF WEATHER NORMALIZATION?

A. Utilities make weather adjustments to normalize energy usage patterns in the test year. By looking at weather data from recent years, a test year weather pattern can be constructed that is representative of normal conditions. This approach ensures that rates are not based upon the specific and possibly uncharacteristic weather pattern that occurred in one particular year. CenterPoint Houston witness J. Stuart McMenamin noted that this is especially important in a year like 2018 which had weather that was much colder than normal in some winter months and weather that was warmer than normal in the summer months.[83] Colder than normal weather in the winter and warmer than normal weather in the summer will both increase energy usage above what it would otherwise be under normal conditions.

Q. HOW IS CENTERPOINT HOUSTON PROPOSING TO NORMALIZE TEST YEAR CUSTOMER ENERGY USAGE DATA?

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[83] Direct Testimony of J. Stuart McMenamin at 4.

A. The Company developed detailed regressions (i.e., mathematical models) to model how weather affects customer energy usage.[84] The Company then incorporated normal weather conditions into these models based on 20 years of weather data to adjust the test year data to reflect expected usage under normal conditions.[85]

The weather adjustment is based on "degree days" or the difference between actual temperatures and a 65° baseline. "Cooling Degree Days," or "CDDs", measure temperatures above 65° and reflect the need for cooling. Conversely, "Heating Degree Days," or "HDDs", measure temperatures below 65° and reflect the need for heating. Normal weather is based on historic average HDDs and CDDs.

Q. DO YOU AGREE WITH THE COMPANY'S APPROACH TO NORMALIZE TEST YEAR CUSTOMER ENERGY USAGE DATA?

A. The Company's regression models are quite detailed and rely on data obtained from its fully deployed advanced meter systems that have provided actual customer demand for every 15-minute interval in every day of every month. Mr. McMenamin claims that this data supports exact calculation of daily energy, daily peaks, and daily coincident loads at the time of system peaks, eliminating the statistical uncertainty from previously used sample data.

I do not object to the Company's models. However, I disagree with the Company's use of a 20-year weather normalization period, and instead, I recommend using a 10-year weather normalization period to determine weather-adjusted test year usage data.

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

[85] *Id.* at 36-37.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. Using the most recent 10 years of weather data is more representative of recent weather trends, and thus, a 10-year weather normalization period is more likely to be representative of expected weather conditions during the test year than a longer weather normalization period. Furthermore, the Commission has shown a preference for using a 10-year weather normalization period in recent rate case proceedings and other regulatory proceedings.

Q. PLEASE EXPLAIN.

A. The Commission considered the appropriate weather normalization period in Docket No. 40443, Southwestern Electric Power Company's ("SWEPCO") 2012 rate case. In that rate case, SWEPCO proposed a 30-year weather normalization period, but the Commission adopted a 10-year weather normalization period. The State Office of Administrative Hearings ("SOAH") Administrative Law Judges ("ALJs") in that proceeding found that:

> *SWEPCO's post-test-year adjustment for weather normalization for the residential and commercial classes is not known and measurable based on its use of a 30-year period. The 30-year period is too lengthy, understates the number of expected normal cooling degree days, and would not be an accurate representation of the expected weather conditions during SWEPCO's test year.*[86]

The SOAH ALJs further concluded that:

> *a weather normalization adjustment using data from a 10-year period is consistent with Commission precedent and sound public policy and more accurately reflects the weather conditions during the test year.*[87]

[86] Docket No. 40443, Proposal for Decision at 243.

[87] *Id.* at 244.

The Commission adopted the SOAH ALJs' recommendation, finding that:[88]

- *Weather data is not randomly distributed by year. There can be weather trends.*
- *The use of a 30-year period for normalizing weather is not a reasonable means of capturing such trends.*
- *The use of 10 years of data is a reasonable means of capturing such weather trends.*

Q. HAS THE COMMISSION ADDRESSED WEATHER NORMALIZATION IN ANY SUBSEQUENT PROCEEDINGS?

A. Yes. In two subsequent rate cases before the Commission, the issue of weather normalization was litigated by the parties, and the Commission again concluded that a 10-year weather normalization period was appropriate. In particular, in Docket No. 43695, which was Southwestern Public Service Company's ("SPS") 2014 rate case, the Commission found that:[89]

> *It is reasonable for SPS (Southwestern Public Service) to calculate its normal weather based on a 10-year period in order to be consistent with the Commission's decision to use a 10-year period in the most recent SWEPCO base rate case...*

In addition, in SWEPCO's 2016 rate case in Docket No. 46449, SWEPCO again proposed a 30-year weather normalization period, and the Commission again adopted a 10-year weather normalization period, finding that:[90]

- *Weather data are not randomly distributed by year. There can be weather trends, including both warming and cooling trends.*

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[88] Docket No. 40443, Order on Rehearing, FoFs 256-258 (Mar. 6, 2014).

[89] Docket No. 43695, Order on Rehearing, FoF 238 (Feb. 23, 2016).

[90] Docket No. 46449, Order on Rehearing, FoFs 271-274 (March 19, 2018).

- *The use of a 30-year period for normalizing weather is not a reasonable means of capturing such trends.*
- *The use of 10 years of data is a reasonable means of capturing such weather trends.*
- *The use of 10 years of data is more sensitive to weather patterns during the test year.*

Furthermore, in El Paso Electric Company's ("EPE") 2017 settled rate case in Docket No. 46831, EPE proposed using a 10-year weather normalization period.[91]

Q. HAS THE COMMISSION ADOPTED A 10-YEAR WEATHER NORMALIZATION PERIOD IN ANY OTHER PROCEEDINGS?

A. Yes. The Commission requires utilities to use a 10-year weather normalization period in their DCRF applications,[92] Energy Efficiency Cost Recovery Factor ("EECRF") applications,[93] and Earnings Monitoring Reports ("EMR").[94]

Q. HOW DOES A 10-YEAR WEATHER NORMALIZATION PERIOD COMPARE TO A 20-YEAR WEATHER NORMALIZATION PERIOD IN THIS RATE CASE?

A. In this rate case, a 10-year weather normalization period increases CDDs and slightly decreases HDDs compared to a 20-year weather normalization period, as summarized in Table 4:

[91] Docket No. 46831, Direct Testimony of George Novela at 34.

[92] 16 TAC § 25.243(b)(5).

[93] 16 TAC § 25.181(e)(3)(A).

[94] Instructions for EMR Schedule X, referring to 16 TAC § 25.243(b)(5).

Table 4

Test Year vs. Normal CDDs and HDDs

	Test Year	20-Year Normal[95]	10-Year Normal[96]	Difference
CDDs	3,351	3,097	3,181	84
HDDs	1,271	1,227	1,220	(7)

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON BILLING DETERMINANTS?

A. Using a 10-year weather normalization period increases the billing determinants used to calculate test year revenues and proposed rates, relative to using a 20-year weather normalization period. Table 5 compares the results of the Company's proposed 20-year weather adjusted billing determinants and my recommended 10-year adjusted billing determinants:

Table 5

Adjusted Billing Determinants

	20-Year Normal[97]	10-Year Normal[98]	Difference
Adjusted kWh	89,702,145,359	90,297,499,787	595,354,428
Adjusted Dist. kVA	164,318,553	164,361,539	42,986
Adjusted Trans. kVA	141,996,680	142,481,061	484,381

Q. WHAT IS THE IMPACT OF USING A 10-YEAR WEATHER NORMALIZATION PERIOD ON TEST YEAR REVENUES?

A. CenterPoint Houston's adjusted test year base revenues are $1,660 million using a 20-year weather normalization period.[99] Adjusted test year base revenues using a 10-year

[95] WP/H-5.1.

[96] Response to OPUC RFI 1-20, H Schedule w/ 10 yr norm.

[97] Schedule II-H-4.1.9.

[98] Response to OPUC RFI 1-20, H Schedule w/ 10 yr norm.

[99] Schedule II-H-4.1.9.

weather normalization period are $1,672 million.[100] Thus, using a 10-year weather normalization period increases test year revenues by $11.902 million,[101] and correspondingly, reduces the Company's requested increase by the same amount.[102]

B. Energy Efficiency Program ("EEP") Adjustment

Q. WHAT IS CENTERPOINT HOUSTON'S PROPOSED EEP ADJUSTMENT?

A. CenterPoint Houston states that its proposed EEP adjustment is intended to adjust test year billing determinants to account for energy efficiency measures that were installed throughout the test year. The Company contends that the energy reductions associated with these programs were not fully captured in the test year data. The Company claims that its proposed change to the billing determinants is a known and measurable adjustment.[103]

Q. WHAT IS THE MAGNITUDE OF THE COMPANY'S PROPOSED EEP ADJUSTMENT?

A. The Company's proposed EEP adjustment would increase present revenues by $1.205 million.[104]

Q. HOW DOES THE COMPANY PROPOSE TO CALCULATE THIS ADJUSTMENT?

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[100] Response to OPUC RFI 1-20, H Schedule w/ 10 yr norm.

[101] $1,672.281 million - $1,660.379 million = $11.902 million.

[102] The Company's requested increase is reduced because it is determined by taking the difference between the Company's proposed cost of service and its adjusted test year revenues. To the extent that the Company's adjusted test year revenues are increased, the amount of the Company's requested increase is reduced.

[103] Direct Testimony of Matthew Troxle at 11.

[104] Schedule II-H-4.1.7.

A. Company witness Matthew Troxle explained that the Company calculated its energy savings resulting from its 2018 energy efficiency programs by using data from the Commission's Technical Reference Manual for energy efficiency programs. The Company's energy savings were then broken down by month for each month that a particular energy efficiency program was in effect.[105]

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED ADJUSTMENT?

A. No. This adjustment is not known and measurable. The adjustment is more like a lost revenue adjustment, which the Commission has previously rejected.

Q. WHY IS THE COMPANY'S PROPOSED ADJUSTMENT NOT A KNOWN AND MEASURABLE ADJUSTMENT?

A. CenterPoint Houston proposes to apply the "deemed savings" obtained from the Commission's Technical Reference Manual to quantify its proposed adjustment. However, the deemed savings are estimated savings based on engineering algorithms and common practice, rather than actual measured energy and demand savings. The deemed savings are used instead of actual measurement and verification activities.[106] Thus, to the extent that there were actual energy reductions as a result of the energy efficiency programs, these energy reductions are not reflected in the Company's EEP adjustment.

Q. WHEN DID THE COMMISSION CONSIDER A LOST REVENUE ADJUSTMENT?

A. In Project No. 37623, the Commission amended its energy efficiency rule. In its filed comments on the Commission's proposed rule, CenterPoint Houston supported the

[105] *Id.* at 12.

[106] 16 TAC § 25.181(c)(7) and (8).

adoption of a lost revenue adjustment mechanism ("LRAM") for an electric utility's programs that are administered pursuant to the energy efficiency rule. The Company supported a LRAM because it contended that energy efficiency programs harm the ability of utilities to recover Commission-authorized costs.[107] A LRAM is a rate adjustment mechanism that allows a utility to recover revenues that are specifically reduced as a result of the utility's energy efficiency programs.

Q. WHAT DID THE COMMISSION CONCLUDE?

A. The Commission referenced its decision in Docket No. 38213 in which it determined that lost revenues are not energy-efficiency costs that may be recovered through an EECRF under PURA § 39.905. Consistent with that prior decision, the Commission declined to adopt a LRAM mechanism in the energy efficiency rule.[108]

Q. WHAT WERE THE CIRCUMSTANCES IN DOCKET NO. 38213?

A. Docket No. 38213 was an application by CenterPoint Houston to adjust its EECRF. In its application, the Company requested a LRAM to collect lost revenues based on "verified and reported 2009 energy savings."[109] In the Commission's Supplemental Preliminary Order in that docket, the Commission found that:[110]

> *P.U.C. SUBST. R. 25.181 and PURA §§ 36.204 and 39.905 do not permit a utility to recover the amount of decrease in revenues that result from energy-efficiency programs through an EECRF.*

Q. WHAT IS YOUR RECOMMENDATION?

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[107] Project No. 37623, Initial Comments of CenterPoint Energy Houston Electric, LLC at 7.

[108] Project No. 37623, Order Adopting Amendment to §25.181 at 16-17.

[109] Docket No. 38213, Application at 3-4.

[110] *Id.*, Supplemental Preliminary Order at 6.

A. CenterPoint Houston's proposed EEP adjustment is not known and measurable and should be rejected by the Commission. Furthermore, this case is the Company's "third bite at the apple" at requesting a LRAM, and the Commission should deny the Company's request based on the prior case precedent. My recommendation would increase test year revenues by $1.205 million, and correspondingly, reduce the Company's requested increase by the same amount.[111]

VIII. COST ALLOCATION

A. Allocation of Hurricane Harvey Costs

Q. HOW DOES CENTERPOINT HOUSTON PROPOSE TO RECOVER ITS HURRICANE HARVEY REGULATORY ASSET?

A. As discussed above, CenterPoint Houston is requesting to recover certain Hurricane Harvey restoration costs through a regulatory asset. However, the Company is inconsistent in explaining its functionalization of the regulatory asset. CenterPoint Houston witness Kristie Colvin testifies that the regulatory asset was functionalized 100% to distribution.[112] However, the Company's schedules show that the regulatory asset was functionalized to both distribution and transmission.[113]

Q. DO YOU AGREE WITH THE COMPANY'S FUNCTIONALIZATION PROPOSAL?

[111] As with my recommended weather normalization adjustment, the Company's requested increase is reduced because it is determined by taking the difference between the Company's proposed cost of service and its adjusted test year revenues. To the extent that the Company's adjusted test year revenues are increased, the amount of the Company's requested increase is reduced.

[112] Direct Testimony of Kristie Colvin at 36.

[113] WP/II-I-1.1.

A. No, not if it is functionalized all to distribution. The Hurricane Harvey regulatory asset contains both distribution- and transmission-related costs. I recommend that the recovery of the regulatory asset be functionalized to both distribution and transmission customers based on the relative amount of each type of cost in the asset.

Q. WHAT ARE THE RELATIVE AMOUNTS?

A. The regulatory asset contains $63,587,086 of distribution costs and $819,057 of transmission costs.[114] This means 98.7% should be functionalized to distribution and 1.3% functionalized to transmission.

B. Allocation of Transmission Key Accounts

Q. WHERE IS THE TRANSMISSION AND KEY ACCOUNTS DEPARTMENT WITHIN THE CENTERPOINT HOUSTON ORGANIZATION?

A. The Company's Power Delivery Solutions ("PDS") Division is responsible for facilitating the interconnection process for customers and generators on both the transmission and distribution system. Within the PDS are the Power Quality Solutions Department, the Service Consultants North Department, the Service Consultants South Department, and the Transmission and Key Accounts Department.[115]

Q. WHAT ARE THE RESPONSIBILITIES OF THE COMPANY'S TRANSMISSION AND KEY ACCOUNTS DEPARTMENT?

A. The Transmission and Key Accounts Department is comprised of three groups: Transmission Accounts and Support, Key Accounts, and Street Lighting Design. The Transmission Accounts and Support group is responsible for the interconnection of large

[114] WP/II-B-12b.

[115] Direct Testimony of Julienne Sugarek at 4-5.

industrial customers and generators to the transmission system, approval and payment of Transmission Cost of Service payments to other Transmission Service Providers, and coordination of regulatory filings for CenterPoint Houston's transmission projects, including the monthly construction reports, final cost reports, and Certificate of Convenience and Necessity ("CCN") applications.

The Key Accounts group is responsible for maintaining relationships with major distribution customers and coordinating special service arrangements with identified key accounts and major customers. The Street Lighting Design group designs lighting systems for roadways, bridges, walkways, hike and bike trails, and parks at the request of municipal governments and residential and commercial customers.[116]

Q. WHAT IS THE TOTAL COST OF THIS DEPARTMENT?

A. The total O&M expense of the Transmission and Key Accounts Department during the test year was $2,034,463.[117]

Q. HOW SHOULD THESE EXPENSES BE RECOVERED FROM CUSTOMERS?

A. A portion of these expenses should be directly assigned to the transmission function, as the Transmission Accounts and Support group is 100% dedicated to serving transmission customers.

Q. WHAT AMOUNT SHOULD BE ALLOCATED TO TRANSMISSION?

A. A reasonable amount would be one third of the annual expense. This assumes an equal allocation of expenses across the three groups that make up the department. Thus, $678,154 should be directly assigned to the Company's transmission customers.[118]

[116] *Id.* at 7-8.

[117] *Id.* at 9.

Q. HOW MUCH CUSTOMER SERVICE EXPENSE DOES THE COMPANY ALLOCATE TO THE TRANSMISSION CLASS?

A. The Company has allocated $267,000 to the transmission voltage class.[119] This amount should be increased by $411,154.[120]

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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[118] $2,034,463 / 3 = $678,154.

[119] Schedule II-I-TDCS.

[120] $678,154 - $267,000 = $411,154.

ATTACHMENTS

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
HURRICANE HARVEY WITH CARRYING CHARGES

Adjustment to remove Compounding

Cumulative Total Costs	Additions with Half Year Convention	Rate	CC on Change	CC on Beginning Balance	Total Carrying Costs
12,029,774.27	6,014,887.13	0.88584%	23,088.98		23,088.98
39,834,253.37	13,902,239.55	0.88584%	123,151.56	106,564.52	229,716.08
79,407,216.63	19,786,481.63	0.88584%	175,276.52	352,867.65	528,144.17
90,712,913.63	5,652,848.50	0.88584%	50,075.18	703,420.68	753,495.86
69,265,382.16	(10,723,765.73)	0.88584%	(94,995.38)	803,571.04	708,575.66
69,722,086.42	228,352.13	0.78360%	1,789.37	542,763.68	544,553.05
69,912,452.38	95,182.98	0.78360%	745.85	546,342.42	547,088.27
69,779,143.30	(66,654.54)	0.78360%	(522.31)	547,834.12	547,311.82
70,219,456.20	220,156.45	0.78360%	1,725.15	546,789.51	548,514.66
68,942,042.90	(638,706.65)	0.78360%	(5,004.91)	550,239.81	545,234.90
67,464,409.48	(738,816.71)	0.78360%	(5,789.37)	540,229.99	534,440.62
67,494,880.94	15,235.73	0.78360%	119.39	528,651.25	528,770.64
67,775,536.58	140,327.82	0.78360%	1,099.61	528,890.03	529,989.64
67,796,510.00	10,486.71	0.78360%	82.17	531,089.25	531,171.42
64,603,245.26	(1,596,632.37)	0.78360%	(12,511.21)	531,253.60	518,742.38
62,750,371.72	(926,436.77)	0.78360%	(7,259.56)	506,231.17	498,971.61
64,406,142.55	827,885.41	0.78360%	6,487.31	491,712.05	498,199.36
	32,203,071.28				8,616,009.12
	-			Requested	8,742,496.50
				Adjustment	(126,487.37)

Note: August 2017 is calculated for 13 days.

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
HURRICANE HARVEY WITH CARRYING CHARGES

Adjustment for Regulatory Asset Disallowances

Requested Additions	Recommended Adjustments	Adjusted Additions	Cumulative Total Costs	Additions with Half Year Convention	Rate	CC on Change	CC on Beginning Balance	Total Carrying Costs
12,029,774.27		12,029,774.27	12,029,774.27	6,014,887.13	0.88584%	23,088.98		23,088.98
27,804,479.10	(4,752,500)	23,051,979.10	35,081,753.37	11,525,989.55	0.88584%	102,101.80	106,564.52	208,666.32
39,572,963.26	(4,752,500)	34,820,463.26	69,902,216.63	17,410,231.63	0.88584%	154,226.75	310,768.11	464,994.87
11,305,697.00	(6,492)	11,299,205.00	81,201,421.63	5,649,602.50	0.88584%	50,046.42	619,221.62	669,268.04
(21,447,531.46)	(12,220)	(21,459,751.46)	59,741,670.16	(10,729,875.73)	0.88584%	(95,049.50)	719,314.47	624,264.96
456,704.26		456,704.26	60,198,374.42	228,352.13	0.78360%	1,789.37	468,135.85	469,925.22
190,365.96		190,365.96	60,388,740.38	95,182.98	0.78360%	745.85	471,714.59	472,460.44
(133,309.08)		(133,309.08)	60,255,431.30	(66,654.54)	0.78360%	(522.31)	473,206.30	472,683.99
440,312.90		440,312.90	60,695,744.20	220,156.45	0.78360%	1,725.15	472,161.69	473,886.83
(1,277,413.30)		(1,277,413.30)	59,418,330.90	(638,706.65)	0.78360%	(5,004.91)	475,611.98	470,607.07
(1,477,633.42)		(1,477,633.42)	57,940,697.48	(738,816.71)	0.78360%	(5,789.37)	465,602.17	459,812.80
30,471.46		30,471.46	57,971,168.94	15,235.73	0.78360%	119.39	454,023.43	454,142.81
280,655.64		280,655.64	58,251,824.58	140,327.82	0.78360%	1,099.61	454,262.20	455,361.81
20,973.42		20,973.42	58,272,798.00	10,486.71	0.78360%	82.17	456,461.42	456,543.59
(3,193,264.74)		(3,193,264.74)	55,079,533.26	(1,596,632.37)	0.78360%	(12,511.21)	456,625.77	444,114.55
(1,852,873.54)		(1,852,873.54)	53,226,659.72	(926,436.77)	0.78360%	(7,259.56)	431,603.34	424,343.78
1,655,770.83		1,655,770.83	54,882,430.55	827,885.41	0.78360%	6,487.31	417,084.22	423,571.53
64,406,142.55	(9,523,712)	54,882,430.55		27,441,215.28				7,467,737.61
-				-		After Adj for Compounding		8,616,009.12
							Adjustment	(1,148,271.52)

Note: August 2017 is calculated for 13 days.

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
2019 CEHE RATE CASE
DOCKET 49421-SOAH DOCKET NO. 473-19-3864

CITY OF HOUSTON
REQUEST NO.: COH01-13

QUESTION:

Provide CEHE's SAIDI, excluding major storm events, for each year since 2009

a. *For distribution system outages only;*
b. For transmission system outages only;
c. For distribution plus transmission outages.

ANSWER:

CEHE provides system-wide SAIDI values to the PUCT on an annual basis. The categories for SAIDI values are: 1) major storm events, 2) forced interruptions (on the distribution system), 3) scheduled interruptions (outages that result when a component is deliberately taken out of service at a selected time for purposes of construction, preventative maintenance, or repair), and 4) outside causes (outages that are caused by influences arising outside of the distribution system, such as generation, transmission, or substation outages). See WP DB (PUCT Subst Rule 25.52) regarding the PUCT rules regarding reliability reporting. SAIDI values for each year since 2009 are provided by these categories. The SAIDI values for outside causes are also broken down by substation and transmission related outages. See attached chart.

SPONSOR (PREPARER):
Dale Bodden (Dale Bodden)

RESPONSIVE DOCUMENTS:
COH01-13 Attachment 1.xlsx

SAIDI	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Major Event	2.37	9.32	51.06	32.36	14.2	0.23	59.65	63.46	312.17	4.85
Forced Interruptions	112.25	81.67	94.36	102.54	92.59	85.71	154.61	119.81	102.73	116.46
Scheduled Interruptions	16.05	15.24	18.6	17.92	29.09	32.04	36.8	34.12	36.84	50.05
Outside Causes	4.83	4.49	5.76	4.3	4.57	2.5	8.22	8.45	2.62	7.23
Outside Causes - Substation	4.56	4.48	3.92	4.3	4.54	2.39	7.72	8.28	2.2	4.25
Outside Causes - Transmission	0.27	0	1.84	0	0.03	0.11	0.5	0.16	0.42	2.98

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
2019 CEHE RATE CASE
DOCKET 49421-SOAH DOCKET NO. 473-19-3864

CITY OF HOUSTON
REQUEST NO.: COH01-15

QUESTION:

Provide CEHE's SAIFI, excluding major storm events, for each year since 2009

a. For distribution system outages only;
b. For transmission system outages only;
c. For distribution plus transmission outages.

ANSWER:

CEHE provides system-wide SAIFI values to the PUCT on an annual basis. The categories for SAIFI values are: 1) major storm events, 2) forced interruptions (on the distribution system), 3) scheduled interruptions (outages that result when a component is deliberately taken out of service at a selected time for purposes of construction, preventative maintenance, or repair), and 4) outside causes (an outage that are caused by influences arising outside of the distribution system, such as generation, transmission, or substation outages). See WP DB (PUCT Subst Rule 25.52). SAIFI values for each year since 2009 are provided by these categories. The SAIFI values for outside causes are also broken down by substation and transmission related outages. See attached chart.

SPONSOR (PREPARER):
Dale Bodden (Dale Bodden)

RESPONSIVE DOCUMENTS:
COH01-15 Attachment 1.xlsx

SAIFI	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Major Event	0.02	0.05	1.45	0.2	0.06	0	0.27	0.26	0.45	0.03
Forced Interr.	1.44	1.08	1.22	1.36	1.16	1.1	1.46	1.22	1.04	1.16
Scheduled Interr.	0.28	0.28	0.3	0.27	0.32	0.3	0.31	0.3	0.29	0.34
Outside Causes	0.14	0.11	0.13	0.14	0.14	0.1	0.12	0.13	0.09	0.14
Outside Causes - Substation	0.12	0.11	0.12	0.14	0.14	0.1	0.12	0.13	0.08	0.13
Outside Causes - Transmission	0.02	0	0.01	0	0	0	0.01	0.01	0	0.01

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
2019 CEHE RATE CASE
DOCKET 49421-SOAH DOCKET NO. 473-19-3864

CITY OF HOUSTON
REQUEST NO.: COH01-17

QUESTION:

Provide CEHE's corporate goals for SAIDI and SAIFI performance for each of the last five years and for the next three years.

ANSWER:

See attached chart for the corporate goals for SAIDI and SAIFI performance for each of the last five years and for the next three years.

SPONSOR (PREPARER):
Dale Bodden (Dale Bodden)

RESPONSIVE DOCUMENTS:
COH01-17 Attachment 1.xlsx

SOAH DOCKET NO. 473-19-3864
PUC Docket No. 49421
COH01-17 Attachment 1.xlsx
Page 1 of 1

COH01-17

	2014	2015	2016	2017	2018	2019	2020	2021
SAIDI Goal	107.5	107.5	107.5	107.5	125.72	125.72	125.72	125.72
SAIFI Goal	1.37	1.37	1.37	1.37	1.24	1.24	1.24	1.24

*2020 and 2021 are subject to change

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
2019 CEHE RATE CASE
DOCKET 49421-SOAH DOCKET NO. 473-19-3864

CITY OF HOUSTON
REQUEST NO.: COH01-20

QUESTION:

Explain any factors unique to CEHE's system that contribute to higher SAIDI or SAIFI performance when compared to SAIDI or SAIFI performance of other utilities.

ANSWER:

There are a number of factors that make every utility system different related to reliability performance. In fact, the PUCT recognizes this fact in that for every utility under their jurisdiction, they base the utility's reliability standard for system-wide SAIDI and SAIFI on the utility's own historical record. See WP DB (PUCT Subst Rule 25.52).
Some of the factors that impact the CEHE distribution system include:

- Being located in a geographic area with significant storm activity adjacent to the Gulf of Mexico.
- Significant equipment corrosion issues with facilities located along the coastal environment.
- Lightning strike levels that are the second highest in the United States, just behind Florida.
- Being located in a livable forest with a large number of trees and associated operational issues caused by vegetation.
- Utilizing a one-minute definition for a sustained outage, as opposed to a five-minute definition that is utilized by many other utilities. This makes outages between 1 and 5 minutes a sustained interruption instead of a momentary interruption, which can negatively impact reliability metrics.
- Utilizing 35KV distribution circuits which have approximately three times as many customers on each circuit as a 12KV circuit. This will increase the number of customers impacted by a feeder fault.
- Response times can be impacted by the heavy traffic in the dense urban parts of Houston.

Additionally, CEHE's SAIDI scores were impacted beginning in the spring of 2015 with the migration to a new Advanced Distribution Management System and the adoption of new safety rules that limited the approach distance for one-man crews. As a result of these two developments, CEHE requested and received an adjustment to its system-wide SAIDI and SAIFI standard from the PUC in 2018.

SPONSOR:
Dale Bodden/Randal Pryor (Dale Bodden/Randal Pryor)

RESPONSIVE DOCUMENTS:

None

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
2019 CEHE RATE CASE
DOCKET 49421-SOAH DOCKET NO. 473-19-3864

CITY OF HOUSTON
REQUEST NO.: COH01-27

QUESTION:

Provide the amount expended on CEHE's existing tree-trimming programs for each of the last five years and as forecasted for the next three years.

ANSWER:

Attached please find the requested historical data and the Company's forecast for 2019. The Company has not conducted an analysis to forecast future 2020 and 2021 expense related to tree-trimming.

SPONSOR (PREPARER):
Randal Pryor (Randal Pryor)

RESPONSIVE DOCUMENTS:
COH01-27 Attachment 1.xlsx

COH 1-27

Year	PROACTIVE CIRCUIT TRIMMING				PROACTIVE HAZARD TREE REMOVALS			REACTIVE WORK	Total
	Circuit Trimming	Circuit Beneficial Removals	Circuit Related Dead Tree Removals	Sub Total	CSO/DMR Dead Tree Removals	Hazard Tree Program	Sub Total	CSO/DMR Trimming	
2014	$ 15,596,969	$ 1,914,241	$ 1,473,016	$ 18,984,226	$ 582,424	$ 616,510	$ 1,198,935	$ 2,761,378	$ 22,944,539
2015	$ 19,942,686	$ 1,363,255	$ 839,832	$ 22,145,773	$ 420,240	$ 508,309	$ 928,549	$ 3,949,542	$ 27,023,864
2016	$ 22,554,336	$ 1,377,446	$ 243,536	$ 24,175,318	$ 424,485	$ 339,213	$ 763,699	$ 4,512,693	$ 29,451,710
2017	$ 20,004,203	$ 1,512,801	$ 217,517	$ 21,734,521	$ 297,072	$ 311,401	$ 608,473	$ 5,559,209	$ 27,902,203
2018	$ 26,356,991	$ 1,540,581	$ 125,482	$ 28,023,054	$ 317,428	$ 299,033	$ 616,462	$ 6,382,524	$ 35,022,040
2019	$ 24,636,000	$ 1,602,000	$ 862,000	$ 27,100,000	$ 325,000	$ 425,000	$ 750,000	$ 6,382,524	$ 34,232,524
2020	No Forecast for 2020								
2021	No Forecast for 2021								

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
2019 CEHE RATE CASE
DOCKET 49421-SOAH DOCKET NO. 473-19-3864

CITY OF HOUSTON
REQUEST NO.: COH08-04

QUESTION:

Vegetation Management:
Please refer to the table on WP RMP-1, page 2 of 3, and provide the miles of transmission and distribution lines trimmed each year from 2011 through 2018.

ANSWER:

The miles of distribution lines trimmed each year from 2011 through 2018 is shown below. Consistent with a clarification received by counsel for the City of Houston, this response includes data only for distribution.

Year	2011	2012	2013	2014	2015	2016	2017	2018
Miles	5,606	4,328	5,074	5,139	4,662	4,437	3,922	5,357

SPONSOR (PREPARER):
Randal Pryor (Randal Pryor)

RESPONSIVE DOCUMENTS:
None

**CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
2019 CEHE RATE CASE
DOCKET 49421-SOAH DOCKET NO. 473-19-3864**

**OFFICE OF PUBLIC UTILITY COUNSEL
REQUEST NO.: OPC01-20**

QUESTION:

Refer to the Direct Testimony of Stuart McMenamin at 5. Please provide the results of Dr. McMenamin's weather normalization analysis using 30 year average temperatures and 10 year average temperatures.

ANSWER:

In the preparation of the data and schedules for the rate filing, no additional analysis was done using 30 year average temperatures. However, a comparison of weather impacts at the meter was conducted using the 10 year average temperatures. Please see attachment OPC01-20 CompareImpacts.xlsx.

In response to this RFI, these results have been used to populate forms H-1.1, H-1.2, H-1.3.1, and H-1.4 for energy and demand and H-5.1 and H-5.2 for monthly weather. Schedule H-4.1 reflects revenue impacts using the 10 year average temperatures. Energy and demand results at the meter are adjusted to results at the source using the same loss factor multipliers that were used in the initial filing.

Please see the revised H schedules with 10 year normal weather in the attachment "OPC01-20 H Schedule w 10 yr norm.xlsx" and the workpapers "OPC01-20 H Schedule Wkpr 10 yr norm.xlsx".

The requested information is voluminous and will be provided to the propounding party only in electronic format on CD. Please contact Alice Hart at (713) 207-5322 to request a copy of the CD. Please see index of voluminous material below.

Filename	Preparer	Pages
OPC01-20 CompareImpacts.xlsx	McMenamin	CD
OPC01-20 H Schedule w 10yr norm.xlsx	McMenamin	CD
OPC01-20 H Schedule Wkpr 10 yr norm.xlsx	McMenamin	CD

SPONSOR (PREPARER):
Stuart McMenamin (Stuart McMenamin)

RESPONSIVE DOCUMENTS:
OPC01-20 CompareImpacts.xlsx
OPC01-20 H Schedule w 10yr norm.xlsx
OPC01-20 H Schedule Wkpr 10 yr norm.xlsx

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
2019 CEHE RATE CASE
DOCKET NO. 49421-SOAH DOCKET NO. 473-19-3864

PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC01-38

QUESTION:

MCPR - Monthly Construction Progress Reports filed with the Commission

For any new transmission lines that did not require a CCN, complete the following:

a. Explain the need for the new facility.

b. If the need was to connect a new single-point load customer or generation source, was a cost in aid of construction charged? If not, why not? If so,

  i. What was the amount?

  ii. How was the amount of the contribution calculated?

c. The first MCPR on which the project was reported (control number, item number, project numbers)

d. The final MCPR on which the project was reported (control number, item number, project numbers)

e. The initial estimated project cost from internal utility project approval, the percent of contingency cost included in the estimate, the final project cost, and the percent difference from the estimated cost

f. A breakdown by FERC account (and subaccount) for the total project costs booked to each account that were associated with the project.

ANSWER:

Please see PUC01-38 Attachment 1.

SPONSOR (PREPARER):
Martin Narendorf (Martin Narendorf)

RESPONSIVE DOCUMENTS:
PUC01-38 Attachment 1.xls

PUC01-38 Attachment 1

	a) explain the need for the project		b) If the need was to connect a single point load customer or genera		
Project Name	Description	Type of Project (New Customer Service, Network Improvement, Relocation)	Y/N	If not, why not?	If so, what was the amount?
Kirby Substation	138 kV service to Kirby Substation within one mile of Ckt. 90A	Network Improvement	No	The project carried system wide benefit and was not specific to a single customer	n/a
W.A. Parish Substation	345 kV service to W.A. Parish Substation within one mile of Ckt. 64A and 72A	Network Improvement	No	The project carried system wide benefit and was not specific to a single customer	n/a
Fry Road Substation	138 kV service to Fry Road Substation within one mile of Ckts. 09J and 76A	Network Improvement	No	The project carried system wide benefit and was not specific to a single customer	n/a
Fort Bend Substation	69 kV service to Fort Bend Substation within one mile of Ckt. 49B	Network Improvement	No	The project carried system wide benefit and was not specific to a single customer	n/a
Fort Bend-Rosenberg	Partial Upgrade of 69 kV Ckt. 49B to 138 kV; Partial Rebuild and Partial Reconductor of 69 kV Ckt. 49A; 138 kV service to Fort Bend Substation within one mile of Ckt. 49B	Network Improvement	No	The project carried system wide benefit and was not specific to a single customer	n/a
Flewellen-Fort Bend	Partial Upgrade of 69 kV Ckt. 49A to 138 kV; Partial Reconductor of 69 kV Ckt. 49A; Installation, on an existing transmission line, of an additional 138 kV circuit not previously certificated 138 kV service to Fort Bend Substation within one mile of Ckts. 49A and 09G	Network Improvement	No	The project carried system wide benefit and was not specific to a single customer	n/a
TEXAS_ Substation	138 kV service to TEXAS_ Substation within one mile of Ckt. 87E	New Customer Service	No	This service extension was part of a 69kV to 138kV conversion project.	n/a
CRSBAY Substation	138 kV service to CRSBAY substation within one mile of Ckt. 84A	New Customer Service	Yes	n/a	$1,357,000
DUNCAN Substation	138 kV service to DUNCAN substation within one mile of Ckt. 86D	New Customer Service	Yes	n/a	$2,950,000
SCRDLE Substation	138 kV service to SCRDLE substation within one mile of Ckt. 92A	New Customer Service	Yes	n/a	$5,885,000
DEPOT Substation	138 kV service to DEPOT Substation within one mile of Ckt. 84A	New Customer Service	Yes	n/a	$1,794,000
WINFRE Substation	138 kV service to WINFRE Substation within one mile of Ckt. 86C	New Customer Service	Yes	n/a	$1,848,500
BARNES Substation	138 kV service to BARNES Substation within one mile of Ckt. 88B	New Customer Service	Yes	n/a	$1,263,000
NORTON Substation	138 kV service to NORTON Substation within one mile of Ckt. 86C	New Customer Service	Yes	n/a	$5,698,898

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	a) explain the need for the project		b) If the need was to connect a single point load customer or genera		
Project Name	Description	Type of Project (New Customer Service, Network Improvement, Relocation)	Y/N	If not, why not?	If so, what was the amount?
TANKER Substation	138 kV service to TANKER Substation within one mile of Ckt. 94K	New Customer Service	Yes	n/a	$805,000
MILLER Substation	138 kV service to MILLER Substation within one mile of Ckt. 88Z	New Customer Service	Yes	n/a	$2,100,000
RALYND Substation	138 kV service to RALYND Substation within one mile of Ckt. 86C and 86F	New Customer Service	Yes	n/a	$2,380,000
SEADOC Substation	138 kV service to SEADOC Substation within one mile of Ckt. 02F; Installation, on an existing transmission line, of an additional 138 kV circuit not previously certificated	New Customer Service	Yes	n/a	$4,050,000
LNGSTN Substation	138 kV service to LNGSTN Substation within one mile of Ckts. 86C and 86K	New Customer Service	Yes	n/a	$4,207,000
CONNER Substation	138 kV service to CONNER Substation within one mile of Ckts. 86D and 86J	New Customer Service	Yes	n/a	$3,855,000
MCCABE Substation	138 kV service to MCCABE Substation within one mile of Ckt. 96B	New Customer Service	Yes	n/a	$951,000
RANGER Substation	138 kV service to RANGER Substation within one mile of Ckt. 84G	New Customer Service	Yes	n/a	$12,780
ALKANE Substation	138 kV service to ALKANE Substation within one mile of Ckt. 96D	New Customer Service	Yes	n/a	$1,827,000
MARINE Substation	138 kV Service to MARINE Substation within one mile of Ckt. 47C	New Customer Service	Yes	n/a	$3,974,600
MOORE_ Substation	138 kV Service to MOORE_ Substation within one mile of Ckt. 08F	New Customer Service	Yes	n/a	$3,747,255
FOSTER Substation	138 kV Service to FOSTER Substation within one mile of Ckt. 25E	New Customer Service	Yes	n/a	$230,000
CAMDEN Substation	138 kV Service to CAMDEN Substation within one mile of Ckt. 26E	New Customer Service	Yes	n/a	$1,778,435
BUNKER Substation	138 kV Service to BUNKER Substation within one mile of Ckt. 08B	New Customer Service	Yes	n/a	$2,648,765
COPPER Substation	138 kV Service to COPPER Substation within one mile of Ckt. 02E	New Customer Service	Yes	n/a	$2,206,000
MIRAGE Substation	138 kV Service to MIRAGE Substation within one mile of Ckt. 96B; Partial Rebuild of 38 kV Ckts. 96B and 96F	New Customer Service	Yes	n/a	$1,469,000
CORTEZ Substation	138 kV Service to CORTEZ Substation within one mile of Ckts. 59I and 59K	New Customer Service	Yes	n/a	$2,266,485
TEXWAL Substation	69 kV Service to TEXWAL Substation within one mile of Ckt. 10A	New Customer Service	Yes	n/a	$1,655,000
HUDSON Substation	138 kV Service to HUDSON Substation within one mile of Ckts. 04A	New Customer Service	Yes	n/a	$907,500

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	a) explain the need for the project		b) If the need was to connect a single point load customer or genera		
Project Name	Description	Type of Project (New Customer Service, Network Improvement, Relocation)	Y/N	If not, why not?	If so, what was the amount?
PATRIK Substation	138 kV Service to PATRIK Substation within one mile of Ckt. 06J; Partial Rebuild of 69 kV Ckts. 16A and 23A	New Customer Service	Yes	n/a	$1,850,000
RUSSEL Substation	138 kV Service to RUSSEL Substation within one mile of Ckt. 84F	New Customer Service	Yes	n/a	$2,099,000
GLOBAL Substation	138 kV Service to GLOBAL Substation within one mile of Ckt. 82D	New Customer Service	Yes	n/a	$4,385,000
WINMIL Substation	138 kV Service to WINMIL Substation within one mile of Ckt. 26B	New Customer Service	Yes	n/a	$1,725,000
DALTON Substation	138 kV Service to DALTON Substation within one mile of Ckt. 86I; Modification of 138 kV Ckt. 86I for fiber optics cable.	New Customer Service	Yes	n/a	$3,760,000
Rothwood Substation	138 kV and 345 kV service to Rothwood Substation within one mile of Ckts. 66C and 74B	Service to a Substation	No	The project carried system wide benefit and was not specific to a single customer	n/a
Meadow Substation	345 kV service to Meadow Substation within one mile of Ckt. 99A	Service to a Substation	No	The project carried system wide benefit and was not specific to a single customer	n/a
Dow Substation	345 kV service to Dow Substation within one mile of Ckt. 18A	Service to a Substation	No	The project carried system wide benefit and was not specific to a single customer	n/a
Atascocita Substation	138 kV service to Atascocita Substation within one mile of Ckt. 66E	Service to a Substation	No	The project carried system wide benefit and was not specific to a single customer	n/a
Crabb River Substation	138 kV service to Crabb River Substation within one mile of Ckt. 80B	Service to a Substation	No	The project carried system wide benefit and was not specific to a single customer	n/a
Jordan Substation	138 kV and 345 kV service to Jordan Substation within one mile of Ckts. 86C, 86D, and 99G	Service to a Substation	No	The project carried system wide benefit and was not specific to a single customer	n/a
Alexander Island Substation	138 kV service to Alexander Island Substation within one mile of Ckts. 84B and 87D	Service to a Substation	No	The project carried system wide benefit and was not specific to a single customer	n/a
Rothwood Substation	345 kV service to Rothwood Substation within one mile of Ckts. 74H and 75B	Service to a Substation	No	The project carried system wide benefit and was not specific to a single customer	n/a
Fort Bend Substation	69 kV service to Fort Bend Substation within one mile of Ckt. 49B	Service to a Substation	No	The project carried system wide benefit and was not specific to a single customer	n/a
Ellington Substation	138 kV service to Ellington Substation within one mile of Ckts. 06K, 07A, and 91A	Service to a Substation	No	The project carried system wide benefit and was not specific to a single customer	n/a

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Project Name	a) explain the need for the project: Description	Type of Project (New Customer Service, Network Improvement, Relocation)	b) If the need was to connect a single point load customer or genera: Y/N	If not, why not?	If so, what was the amount?
Lyondell Substation	138 kV Service to Lyondell Substation within one mile of Ckt. 03G	Service to a Substation	No	The project carried system wide benefit and was not specific to a single customer	n/a
Rothwood Substation (Phase 2)	138 kV Service to Rothwood Substation within one mile of Ckts. 66C and 66I	Service to a Substation	No	The project carried system wide benefit and was not specific to a single customer	n/a
Tanner Substation	138 kV Service to Tanner Substation within one mile of Ckts. 24A and 76A	Service to a Substation	No	The project carried system wide benefit and was not specific to a single customer	n/a
Orchard Substation	138 kV Service to Orchard Substation within one mile of Ckt. 60A	Service to a Substation	No	The project carried system wide benefit and was not specific to a single customer	n/a
Tiki Island Substation	138 kV Service to Tiki Island Substation within one mile of Ckt. 01B	Service to a Substation	No	The project carried system wide benefit and was not specific to a single customer	n/a
La Marque Substation	Partial Rebuild and Partial Reconductor of 138 kV Ckt. 01B; 138 kV Service to La Marque Substation within one mile of Ckts. 63D, 63E, and 93B	Service to a Substation	No	The project carried system wide benefit and was not specific to a single customer	n/a
Bailey Substation	345 kV Service to Bailey Substation within one mile of Ckt. 72C	Service to a Substation	No	The project carried system wide benefit and was not specific to a single customer	n/a
Franz Substation	138 kV Service to Franz Substation within one mile of Ckts. 09H and 66A; Partial Rebuild of 345 kV Ckts. 71D and 99F	Service to a Substation	No	The project carried system wide benefit and was not specific to a single customer	n/a
Jones Creek Substation	138 kV Service to Jones Creek Substation within one mile of Ckts. 02F, 48F, and 59K; 345 kV Service to Jones Creek Substation within one mile of Ckt. 18A	Service to a Substation	No	The project carried system wide benefit and was not specific to a single customer	n/a
Sandy Point Substation	138 kV Service to Sandy Point Substation within one mile of Ckt. 96F	Service to a Substation	No	The project carried system wide benefit and was not specific to a single customer	n/a
Bringhurst Substation	69 kV Service to Bringhurst Substation within one mile of Ckt. 12A; Partial Rebuild of 69 kV Ckt. 12A	Service to a Substation	No	The project carried system wide benefit and was not specific to a single customer	n/a

PUC01-38 Attachment 1

	a) explain the need for the project		b) If the need was to connect a single point load customer or genera		
Project Name	Description	Type of Project (New Customer Service, Network Improvement, Relocation)	Y/N	If not, why not?	If so, what was the amount?
Southwyck Substation	138 kV Service to Southwyck Substation within one mile of of Ckt. 26A; Installation, on an existing transmission line, of an additional 138 kV circuit not previously certificated	Service to a Substation	No	The project carried system wide benefit and was not specific to a single customer	n/a
FOSTER Loop	Installation, on an existing transmission line, of an additional 138 kV circuit not previously certified.	Service to a Substation	No	The project carried system wide benefit and was not specific to a single customer	n/a

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	tion source, was a CIAC charged?	c) The first MCPR on which the project was reported and the project number		d) The final MCPR on which the project was reported and the project number		e) The initial estimated project cost from inter contingency cost included in the estimate, the fi from the estim	
Project Name	How was it Calculated?	Initial MCPR Date	Utility's Project Number	Final MCPR Date	Utility's Project Number	Filed Initial Estimated Project Cost	% Contingency Cost
Kirby Substation	n/a	November 15, 2011	770.0	07/15/12	770.0	$565,000	0%
W.A. Parish Substation	n/a	July 15, 2012	805.0	11/15/13	805.0	$380,000	0%
Fry Road Substation	n/a	June 15, 2014	614.0	06/15/15	614.0	$191,000	0%
Fort Bend Substation	n/a	March 14, 2014	853.2	04/15/16	853.2	$488,000	0%
Fort Bend-Rosenberg	n/a	July 15, 2014	853.3	11/15/15	853.3	$1,913,000	0%
Flewellen-Fort Bend	n/a	November 15, 2014	853.5	11/15/15	853.5	$509,000	0%
TEXAS_ Substation	n/a	October 15, 2010	718.0	05/15/12	718.0	$1,034,000	0%
CRSBAY Substation	The CIAC is the estimated cost for the facility extension	January 7, 2011	763.0	10/15/11	763.0	$1,357,000	0%
DUNCAN Substation	The CIAC is the estimated cost for the facility extension	January 17, 2011	781.0	09/15/11	781.0	$2,950,000	0%
SCRDLE Substation	The CIAC is the estimated cost for the facility extension	September 15, 2011	793.0	08/15/12	793.0	$5,885,000	0%
DEPOT Substation	The CIAC is the estimated cost for the facility extension	February 15, 2012	799.0	12/14/12	799.0	$1,794,000	0%
WINFRE Substation	The CIAC is the estimated cost for the facility extension	June 15, 2012	812.0	08/15/13	812.0	$1,848,500	0%
BARNES Substation	The CIAC is the estimated cost for the facility extension	May 15, 2012	792.0	08/15/13	792.0	$1,263,000	0%
NORTON Substation	The CIAC is the estimated cost for the facility extension	September 15, 2012	813.0	04/15/14	813.0	$5,698,898	0%

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	tion source, was a CIAC charged?	c) The first MCPR on which the project was reported and the project number		d) The final MCPR on which the project was reported and the project number		e) The initial estimated project cost from inter contingency cost included in the estimate, the fi from the estim	
Project Name	How was it Calculated?	Initial MCPR Date	Utility's Project Number	Final MCPR Date	Utility's Project Number	Filed Initial Estimated Project Cost	% Contingency Cost
TANKER Substation	The CIAC is the estimated cost for the facility extension	January 15, 2013	844.0	12/15/13	844.0	$805,000	0%
MILLER Substation	The CIAC is the estimated cost for the facility extension	December 15, 2012	833.0	02/14/14	833.0	$2,100,000	0%
RALYND Substation	The CIAC is the estimated cost for the facility extension	March 15, 2013	846.0	04/15/14	846.0	$2,380,000	0%
SEADOC Substation	The CIAC is the estimated cost for the facility extension	June 15, 2013	850.0	05/15/15	850.0	$4,050,000	0%
LNGSTN Substation	The CIAC is the estimated cost for the facility extension	July 15, 2013	852.0	05/15/15	852.0	$4,207,000	0%
CONNER Substation	The CIAC is the estimated cost for the facility extension	September 15, 2013	849.0	05/15/15	849.0	$3,855,000	0%
MCCABE Substation	The CIAC is the estimated cost for the facility extension	March 14, 2014	848.0	05/15/15	848.0	$951,000	0%
RANGER Substation	The CIAC is the estimated cost for the facility extension	December 15, 2014	895.0	10/15/15	895.0	$12,780	0%
ALKANE Substation	The CIAC is the estimated cost for the facility extension	December 15, 2014	917.0	07/14/17	917.0	$1,827,000	0%
MARINE Substation	The CIAC is the estimated cost for the facility extension	February 15, 2015	904.0	02/15/17	904.0	$3,974,600	0%
MOORE_ Substation	The CIAC is the estimated cost for the facility extension	May 15, 2015	855.0	11/15/16	855.0	$3,747,255	0%
FOSTER Substation	The CIAC is the estimated cost for the facility extension	November 15, 2015	853.8	08/15/16	853.8	$230,000	0%
CAMDEN Substation	The CIAC is the estimated cost for the facility extension	November 15, 2015	937.0	11/15/16	937.0	$1,778,435	0%
BUNKER Substation	The CIAC is the estimated cost for the facility extension	January 15, 2016	965.0	03/15/17	965.0	$2,648,765	0%
COPPER Substation	The CIAC is the estimated cost for the facility extension	November 15, 2015	960.0	04/16/17	960.0	$2,206,000	0%
MIRAGE Substation	The CIAC is the estimated cost for the facility extension	August 15, 2016	978.0	06/15/17	978.0	$1,469,000	0%
CORTEZ Substation	The CIAC is the estimated cost for the facility extension	September 15, 2016	865.0	07/15/18	865.0	$2,266,485	0%
TEXWAL Substation	The CIAC is the estimated cost for the facility extension	June 15, 2017	993.0	02/15/19	993.0	$1,655,000	0%
HUDSON Substation	The CIAC is the estimated cost for the facility extension	October 13, 2017	1005.0		1005.0	$907,500	0%

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	tion source, was a CIAC charged?	c) The first MCPR on which the project was reported and the project number		d) The final MCPR on which the project was reported and the project number		e) The initial estimated project cost from inter contingency cost included in the estimate, the fi from the estim	
Project Name	How was it Calculated?	Initial MCPR Date	Utility's Project Number	Final MCPR Date	Utility's Project Number	Filed Initial Estimated Project Cost	% Contingency Cost
PATRIK Substation	The CIAC is the estimated cost for the facility extension	November 15, 2017	991.0		991.0	$1,650,000	0%
RUSSEL Substation	The CIAC is the estimated cost for the facility extension	March 15, 2018	1001.0		1001.0	$2,099,000	0%
GLOBAL Substation	The CIAC is the estimated cost for the facility extension	May 15, 2018	981.2		981.2	$4,385,000	0%
WINMIL Substation	The CIAC is the estimated cost for the facility extension	May 15, 2018	996.0		996.0	$1,725,000	0%
DALTON Substation	The CIAC is the estimated cost for the facility extension	January 15, 2018	1132.0		1132.0	$3,760,000	0%
Rothwood Substation	n/a	April 15, 2009	707.0	09/15/10	707.0	$2,366,000	0%
Meadow Substation	n/a	September 15, 2009	665.0	11/15/10	665.0	$2,250,000	0%
Dow Substation	n/a	February 15, 2012	764.0	07/15/12	764.0	$48,000	0%
Atascocita Substation	n/a	January 15, 2013	836.0	09/16/13	836.0	$153,000	0%
Crabb River Substation	n/a	January 15, 2013	842.0	04/15/14	842.0	$267,000	0%
Jordan Substation	n/a	June 15, 2013	811.1	01/15/15	811.1	$7,367,000	0%
Alexander Island Substation	n/a	November 15, 2014	903.0	05/15/16	903.0	$358,000	0%
Rothwood Substation	n/a	November 15, 2014	900.0	01/15/16	900.0	$2,186,000	0%
Fort Bend Substation	n/a	December 15, 2014	853.6	11/15/15	853.6	$430,000	0%
Ellington Substation	n/a	October 15, 2014	902.0	09/15/15	902.0	$345,000	0%

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	tion source, was a CIAC charged?	c) The first MCPR on which the project was reported and the project number		d) The final MCPR on which the project was reported and the project number		e) The initial estimated project cost from inter contingency cost included in the estimate, the fi from the estim	
Project Name	How was it Calculated?	Initial MCPR Date	Utility's Project Number	Final MCPR Date	Utility's Project Number	Filed Initial Estimated Project Cost	% Contingency Cost
Lyondell Substation	n/a	August 15, 2015	948.0	07/14/17	948.0	$295,000	0%
Rothwood Substation (Phase 2)	n/a	January 15, 2016	900.1	09/15/16	900.1	$834,000	0%
Tanner Substation	n/a	April 15, 2015	894.0	02/15/17	894.0	$7,417,000	0%
Orchard Substation	n/a	November 15, 2015	952.0	08/15/16	952.0	$204,000	0%
Tiki Island Substation	n/a	November 15, 2015	912.1	11/15/16	912.1	$197,000	0%
La Marque Substation	n/a	November 15, 2015	912.0	01/16/17	912.0	$1,446,000	0%
Bailey Substation	n/a	November 15, 2015	949.0	01/16/17	949.0	$2,115,000	0%
Franz Substation	n/a	September 15, 2016	1183.0	11/15/17	1183.0	$2,867,000	0%
Jones Creek Substation	n/a	April 15, 2016	840.0	10/13/17	840.0	$15,021,000	0%
Sandy Point Substation	n/a	October 15, 2016	857.0	09/15/17	857.0	$2,619,000	0%
Bringhurst Substation	n/a	February 15, 2017	1157.0	06/15/18	1157.0	$1,395,000	0%

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	ion source, was a CIAC charged?	c) The first MCPR on which the project was *reported and the project number*		d) The final MCPR on which the project was reported and the project number		e) The initial estimated project cost from inter contingency cost included in the estimate, the fi from the estim	
Project Name	How was it Calculated?	Initial MCPR Date	Utility's Project Number	Final MCPR Date	Utility's Project Number	Filed Initial Estimated Project Cost	% Contingency Cost
Southwyck Substation	n/a	January 15, 2018	954.3	9/27/2018	954.3	$1,635,000	0%
FOSTER Loop	n/a	April 15, 2015	853.7		853.7	$396,000	0%

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	nal utility project approval, the percent of nal project cost, and the percent difference ated cost		f) A breakdown by FERC account (and suba			
Project Name	Final Actual Project Cost	% Difference	E35001	E35101	E35201	E35401
Kirby Substation	$247,331.00	-56.2%				
W.A. Parish Substation	$420,531.00	10.7%				254,440.44
Fry Road Substation	$77,428.35	-59.5%				
Fort Bend Substation	$449,400.23	-7.9%				
Fort Bend-Rosenberg	$2,680,262.08	40.1%			3,600.44	2,205,071.14
Flewellen-Fort Bend	$758,533.95	49.0%				80,638.35
TEXAS_ Substation	$961,482.94	-7.0%				218,114.76
CRSBAY Substation	$321,000.00	-76.3%				106.41
DUNCAN Substation	$1,128,123.00	-61.8%				138,168.89
SCRDLE Substation	$3,078,895.78	-47.7%				186,858.04
DEPOT Substation	$448,646.00	-75.0%				39,387.81
WINFRE Substation	$486,137.13	-73.7%				(31,461.62)
BARNES Substation	$445,587.60	-64.7%				14,513.59
NORTON Substation	$4,250,800.00	-25.4%				1,928,087.98

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	hal utility project approval, the percent of hal project cost, and the percent difference ated cost		f) A breakdown by FERC account (and suba			
Project Name	Final Actual Project Cost	% Difference	E35001	E35101	E35201	E35401
TANKER Substation	$224,246.01	-72.1%				
MILLER Substation	$1,387,645.00	-33.9%				(432,660.31)
RALYND Substation	$367,322.00	-84.6%				0.00
SEADOC Substation	$3,308,263.77	-18.3%				165,785.60
LNGSTN Substation	$2,715,905.82	-35.4%				(113,855.68)
CONNER Substation	$1,557,730.57	-59.6%				(42,285.42)
MCCABE Substation	$576,239.01	-39.4%				(27,447.38)
RANGER Substation	$972,364.33	7508.5%				(181,873.59)
ALKANE Substation	$741,359.97	-59.4%				(158,005.80)
MARINE Substation	$5,130,533.00	29.1%				(313,488.06)
MOORE_ Substation	$2,445,679.00	-34.7%				(306,555.96)
FOSTER Substation	$127,036.00	-44.8%				
CAMDEN Substation	$1,051,627.00	-40.9%				(175,508.22)
BUNKER Substation	$1,440,768.00	-45.6%				(262,408.16)
COPPER Substation	$1,465,769.00	-33.6%				(314,719.64)
MIRAGE Substation	$1,061,200.00	-27.8%				(6,684.24)
CORTEZ Substation	$1,394,853.92	-38.5%				(284,755.92)
TEXWAL Substation	$892,402.66	-46.1%			(280,098.19)	662,599.57
HUDSON Substation		-100.0%			462,357.11	

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	nal utility project approval, the percent of nal project cost, and the percent difference ated cost		f) A breakdown by FERC account (and suba			
Project Name	Final Actual Project Cost	% Difference	E35001	E35101	E35201	E35401
PATRIK Substation		-100.0%			132,338.19	
RUSSEL Substation		-100.0%			209,518.82	
GLOBAL Substation		-100.0%			796,238.98	
WINMIL Substation		-100.0%			495,932.65	
DALTON Substation		-100.0%			658,350.95	
Rothwood Substation	$1,342,765.00	-43.2%				1,256,217.30
Meadow Substation	$1,142,247.00	-49.2%				1,122,337.00
Dow Substation	$72,463.00	51.0%				
Atascocita Substation	$78,505.00	-48.7%				
Crabb River Substation	$250,283.00	-6.3%				
Jordan Substation	$7,577,677.00	2.9%			916.10	6,757,403.04
Alexander Island Substation	$732,051.52	104.5%				606,549.38
Rothwood Substation	$862,079.84	-60.6%				779,194.93
Fort Bend Substation	$330,462.11	-23.1%				
Ellington Substation	$310,042.01	-10.1%				236,804.12

PUC01-38 Attachment 1

	nal utility project approval, the percent of nal project cost, and the percent difference ated cost		f) A breakdown by FERC account (and suba			
Project Name	Final Actual Project Cost	% Difference	E35001	E35101	E35201	E35401
Lyondell Substation	$104,906.26	-64.4%				
Rothwood Substation (Phase 2)	$675,744.00	-19.0%			0.05	588,447.16
Tanner Substation	$6,641,378.00	-10.5%				5,697,300.17
Orchard Substation	$71,858.00	-64.8%				
Tiki Island Substation	$100,761.00	-48.9%				
La Marque Substation	$2,773,369.00	91.8%				2,344,308.16
Bailey Substation	$2,154,166.00	1.9%				1,676,498.43
Franz Substation	$1,831,542.84	-36.1%			8,003.53	1,745,905.75
Jones Creek Substation	$13,320,426.60	-11.3%			(7,814.61)	12,320,836.41
Sandy Point Substation	$4,957,564.92	89.3%				3,897,366.56
Bringhurst Substation	$1,115,337.24	-20.0%				956,746.89

PUC01-38 Attachment 1

	nal utility project approval, the percent of nal project cost, and the percent difference ated cost		f) A breakdown by FERC account (and suba			
Project Name	Final Actual Project Cost	% Difference	E35001	E35101	E35201	E35401
Southwyck Substation	$934,026.50	-42.9%				
FOSTER Loop	$376,104	-5.0%				

PUC01-38 Attachment 1

ccount) for the total project costs booked to each account that were associated with the project.

Project Name	E35501	E35601	E35901	E36201	RWIP
Kirby Substation	179,507.01	67,824.23			
W.A. Parish Substation	1,324.39	22,967.73	141,798.00		
Fry Road Substation	49,902.56	27,525.79			
Fort Bend Substation	369,489.95	79,696.84			
Fort Bend-Rosenberg	136,748.75	338,442.19			
Flewellen-Fort Bend	177,629.68	500,265.92			
TEXAS_ Substation	426,703.26	445,887.30			
CRSBAY Substation		30.59			
DUNCAN Substation		(138,168.89)			
SCRDLE Substation	(24,795.70)	(61,167.22)		(100,895.12)	
DEPOT Substation		(39,387.81)			
WINFRE Substation		(6,845.99)			
BARNES Substation	2,804.47	11,124.15			
NORTON Substation	227,082.10	602,826.56			

PUC01-38 Attachment 1

	ccount) for the total project costs booked to each account that were associated with the project.				
Project Name	E35501	E35601	E35901	E36201	RWIP
TANKER Substation	(2,265.99)	(15,404.60)			
MILLER Substation		331,300.98			
RALYND Substation	(19,098.10)	(7,732.62)			
SEADOC Substation	(13,954.47)	(393,480.36)			
LNGSTN Substation	(8,163.42)	(76,361.86)			
CONNER Substation	(15,406.94)	(56,090.70)			
MCCABE Substation		(14,643.49)			
RANGER Substation	20,563.50	25,532.12			
ALKANE Substation	19,792.69	34,691.88			
MARINE Substation	(309,911.12)	(93,014.69)			
MOORE_ Substation	35,339.93	92,573.56			
FOSTER Substation		127,035.74			
CAMDEN Substation		15,120.04			
BUNKER Substation	3,124.73	58,099.05			135,445.83
COPPER Substation		110,044.23			
MIRAGE Substation	(31,953.07)	(37,141.54)			81,506.24
CORTEZ Substation		58,371.13			
TEXWAL Substation	30,777.99	94,900.57			
HUDSON Substation					

PUC01-38 Attachment 1

ccount) for the total project costs booked to each account that were associated with the project.

Project Name	E35501	E35601	E35901	E36201	RWIP
PATRIK Substation					
RUSSEL Substation					
GLOBAL Substation					
WINMIL Substation					
DALTON Substation					
Rothwood Substation		86,394.47	35,076.90		
Meadow Substation		43,477.00			
Dow Substation		72,453.00			
Atascocita Substation	41,524.77	36,979.89			
Crabb River Substation	167,875.19	82,506.85			
Jordan Substation	138,271.81	681,085.99			
Alexander Island Substation	53,730.50	72,269.62			
Rothwood Substation		82,884.91			
Fort Bend Substation	181,395.39	95,354.26			53,712.46
Ellington Substation	19,870.81	53,367.08			

PUC01-38 Attachment 1

	ccount) for the total project costs booked to each account that were associated with the project.				
Project Name	E35501	E35601	E35901	E36201	RWIP
Lyondell Substation	77,275.85	27,630.41			
Rothwood Substation (Phase 2)		87,297.12			
Tanner Substation	36,578.43	708,394.75			
Orchard Substation	58,040.58	13,816.91			
Tiki Island Substation	32,881.90	67,878.96			
La Marque Substation	91,819.80	337,241.11			
Bailey Substation	477,667.30				
Franz Substation	32,256.90	116,094.01			
Jones Creek Substation	999,590.19				
Sandy Point Substation	451,229.19	608,969.17			
Bringhurst Substation	52,103.48	106,486.87			

PUC01-38 Attachment 1

	ccount) for the total project costs booked to each account that were associated with the project.				
Project Name	E35501	E35601	E35901	E36201	RWIP
Southwyck Substation	43,312.42	778,232.70			112,481.38
FOSTER Loop		376,104.34			

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
2019 CEHE RATE CASE
DOCKET 49421-SOAH DOCKET NO. 473-19-3864

PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC02-33

QUESTION:

Accounting Changes
Please identify all changes in accounting policy since the Company's last rate case in Texas in which the Company has changed from expensing certain costs to capitalizing them or *vice versa*. Provide internal documentation of such policy changes. For each change, identify the number of dollars in each year since the change in accounting policy took place.

ANSWER:

Please refer to Ms. Kristie Colvin's direct testimony on bates page number 927 through 934, for the change in accounting practices from expensing certain costs to capitalizing them or vice versa since the Company's last rate case in Texas and why it is appropriate to include those costs associated with the change.

Please see PUC02-33 Attachments 1 through 5 for documentation of accounting policy changes in which the Company has changed from expensing certain costs to capitalizing them since the Company's last rate case. **The attachments are confidential and are being provided pursuant to the protective order in this docket.**

Please see PUC02-33 Attachment 6 for the capitalized amounts related to the change in accounting policy since the Company's last rate case.

SPONSOR (PREPARER):
Kristie Colvin (Kristie Colvin)

RESPONSIVE DOCUMENTS:
PUC02-33 Attachment 1 (confidential).pdf
PUC02-33 Attachment 2 (confidential).pdf
PUC02-33 Attachment 3 (confidential).pdf
PUC02-33 Attachment 4 (confidential).pdf
PUC02-33 Attachment 5 (confidential).pdf
PUC02-33 Attachment 6.xlsx

CenterPoint Energy Houston Electric
Capitalized Overhead Due to Change in Accounting Policy

	Accounts Payable	Property Accounting	Call Center	Microprocessor	Luminaires	Total
2009	$ -	$ -	$ -	$ -	$ -	$ -
2010	-	-	-	-	-	-
2011	-	-	-	-	-	-
2012	-	-	-	-	-	-
2013	-	-	-	-	-	-
2014	292,581	356,210	-	-	868,478	1,517,269
2015	267,939	367,141	210,013	-	683,172	1,528,265
2016	288,288	286,851	328,916	-	1,327,026	2,231,081
2017	295,303	383,424	388,523	143,964	-	1,211,214
2018	312,569	261,922	514,260	115,933	2,510,007	3,714,691
	$ 1,456,680	$ 1,655,548	$ 1,441,712	$ 259,897	$ 5,388,683	$ 10,202,520

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
2019 CEHE RATE CASE
DOCKET 49421-SOAH DOCKET NO. 473-19-3864

PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC05-01

QUESTION:

Vegetation Management

In regards to WP RMP-1: In the test year, CenterPoint spent a total of $35.02M on tree trimming (total proactive trimming, hazard tress, and reactive).

a. From 2011-2018, the median the Company spent on Tree Trimming was approximately $27.5M annually, and the average was $27.8M annually. Please explain why this amount is greater than the average and the median the Company spent during the years 2011-2017?

b. P. 3 of WP RMP-1 states: "Over the past four years, overhead pole miles (feeder-main and laterals have increased an average of 171 miles per year. With more miles of distribution line to maintain, the Company's costs associated with proactive tree trimming have increased." How many overhead pole miles did CenterPoint add between 2017 and 2018? Is the increase from $21.73M in 2017 to $28.02M in 2018 for Proactive Tree Trimming due to any other factors?

c. To which FERC account(s) were these tree trimming expenses charged?

ANSWER:

In regards to WP RMP-1, see the following responses:

a. The median and average amount spent on tree trimming for 2011-2017 is less than the amount for 2011-2018 because the 2011-2018 amount includes the year 2018 when a larger amount was spent on proactive tree trimming and reactive tree trimming.

b. From 2017 to 2018, the overhead distribution poles miles increased 167 miles (feeder-main and laterals). Other factors that drove the cost increase from 2017 to 2018 were:

1. Ongoing contractor cost increases.
2. The fact that in 2018, the Company trimmed approximately 5,400 miles of line versus approximately 3,900 in 2017. Note, a year's work is not simply a function of our system miles or trim cycles, but will also vary based on the types and location of the circuits prioritized for a given year.
3. In 2017, proactive trimming, reactive trimming and hazard tree removal was halted for a significant time period due to Hurricane Harvey.

c. The O&M expense for distribution tree trimming is charged to FERC account 593 - Maintenance of Overhead Lines. None of the costs identified in WP RHP-1 are capitalized.

SPONSOR (PREPARER):
Randal Pryor (Randal Pryor)

RESPONSIVE DOCUMENTS:
None

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
2019 CEHE RATE CASE
DOCKET 49421-SOAH DOCKET NO. 473-19-3864

PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC06-24

QUESTION:

In CenterPoint's response to the Staffs first RFI, PUC01-38 Attachment 1, pages 12-15, CenterPoint provides a list of projects and the percentages of cost overruns from the original project cost estimates to the actual project cost. Provide a detailed explanation of, and reasons for, the cost overruns that are greater than 10% of the estimated cost of each of the f ollowing projects. Include and break down the estimated and actual costs into the appropriate FERC accounts:

Project	Cost Overrun
a. W. A. Parrish Sub	10.7%
b. Fort Ben- Rosenberg	40.1 %
c. Flewellen- Rosenberg	49%
d. Ranger Sub	7508%
e. Marine Sub	29%
f. Dow Sub	51%
g. Alexander Island Sub	104%
h. La Marque Sub	92%
i. Sandy Point Sub	89%
j. Jones Creek Sub	29%
k. Springwoods Sub	16%
l. Tanner Sub	16%

ANSWER:

CenterPoint Houston's response to PUC01-38 provided, among other things, the percent difference between the Filed Initial Estimated Project Cost and the Final Actual Project Cost for the listed projects. For some of those projects, the cost decreased between the Filed Initial Estimated Project Cost and the Final Actual Project Cost, and for other projects, the cost increased. In addition, the Filed Initial Estimated Project Costs are developed prior to detailed engineering or construction analysis. CenterPoint Houston's final construction reports compare the final actual cost to the final estimate, rather than the initial estimate. For the projects identified in PUC06-24, CenterPoint Houston provides the following responses regarding the differences between the Filed Initial Estimated Project Cost and the Final Actual Project Cost:

a. **W. A. Parrish Sub - 10.7%:** There were no major scope changes to this project, but a variety of small cost differences to labor and materials resulted in a 10.7% cost difference.

b. **Fort Bend - Rosenberg - 40.1 %:** After the Company initially filed this project, the route was significantly modified due to ROW constraints and negotiations with parties such as the Railroad Museum in Rosenberg. While a small amount of bypass work was in included in the initial estimate, additional bypass work was needed. Crews were mobilized and demobilized more than expected due to the scope changes, resulting in increased labor costs.

c. **Flewellen- Rosenberg - 49%:** This project converted 69kV circuits to 138kV while the substation was also being upgraded. The transmission work needed to be done in parallel with substation work ensure continuity of service. Scheduling parallel work required additional mobilization and demobilization that was not planned for in the initial estimates.

d. **Ranger Sub - 7508%:** 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.

e. **Marine Sub - 29%:** 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.

f. **Dow Sub - 51%:** 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.

g. **Alexander Island Sub - 104%:** Foundations were staked with the wrong line pull orientation which wasn't discovered until after the foundations were built. Foundations were removed and reconstructed. Structures had to be modified and some additional material had to be ordered.

h. **La Marque Sub - 92%:** Tower design and location changed during detailed engineering phase which led to some material errors. One angle structure had to be removed and replaced.

i. **Sandy Point Sub - 89%:** The substation site changed after the initial estimate, requiring more temporary work than expected. Crews were mobilized and demobilized more than expected do the schedule changes, resulting in increased labor costs.

j. **Jones Creek Sub – 29%:** The Jones Creek substation project included in the Company's response to PUC 1-38 covered only the transmission work to connect Jones Creek Substation. No substation construction costs were included. The initial filed estimate for the project was $15,021,000 and the final actual project cost was $13,320,426, representing a -11.3% difference.

k. **Springwoods Sub – 16%:** The Springwoods substation project included in the Company's response to PUC 1-37 covered only the transmission work to connect Springwoods Substation. No substation construction costs were included. The initial filed estimate for the project was $9,547,000 and the final actual project cost was $8,593,292, representing a -10% difference.

l. **Tanner Sub – 16%:** The Tanner substation project included in the Company's response to PUC 1-38 covered only the transmission work to connect Tanner Substation. No substation construction costs were included. The initial filed estimate for the project was $7,417,000 and the final actual project cost was $6,641,378, representing a -10.5% difference.

SPONSOR (PREPARER):
Martin Narendorf (Martin Narendorf)

RESPONSIVE DOCUMENTS:
None

**CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
2019 CEHE RATE CASE
DOCKET 49421-SOAH DOCKET NO. 473-19-3864**

**PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC07-06**

QUESTION:

Audits

Refer to Schedule II-C-3, Page 2 of 4. Please provide copies of the audit report and any supporting documentation, including all audit findings, for the internal audit entitled "2018-13 Hurricane Harvey EOP Expense Validation Review."

ANSWER:

Please see *PUC07-06 2018-13 Hurricane Harvey EOP Expense Validation Review Special Project Memo (Confidential).pdf*

The attachment is confidential and is being provided pursuant to the Protective Order issued in Docket No. 49421.

SPONSOR (PREPARER):
Kelly Gauger (Kelly Gauger)

RESPONSIVE DOCUMENTS:
PUC07-06 2018-13 Hurricane Harvey EOP Expense Validation Review Special Project Memo (Confidential).pdf

Attachment KJN-3

Pages 95 – 111 contain

Confidential Material

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
2019 CEHE RATE CASE
DOCKET 49421-SOAH DOCKET NO. 473-19-3864

PUBLIC UTILITY COMMISSION OF TEXAS
REQUEST NO.: PUC08-14

QUESTION:

Miscellaneous

Please reference the Microsoft (MS) Excel workbook *"CEHE RFP Workpapers (redacted)"* filed with CenterPoint Energy Houston Electric, LLC's (CEHE's) April 5, 2019 application. In MS worksheet "WP II-E-4.1.1," CEHE shows The Original Amount to be Amortized amount of $64,406,143 associated with the regulatory asset balance related to the Hurricane Harvey restoration cost (Hurricane Harvey Regulatory Asset). This Hurricane Harvey Regulatory Asset amount of $64,406,143 was derived from MS worksheet "WP II-B-12b Hurricane Harvey" in the same MS workbook "CEHE RFP Workpapers (redacted)".

Please, respond the following questions.

a. Does the Hurricane Harvey Regulatory Asset amount of $64,406,143 include carrying costs?;

b. If the answer to part "a" of this question is "yes," please provide, in electronic spreadsheet format with cell references and formulae intact, the calculation of such carrying costs;

c. If the answer to part "a" of this question is "no," has CEHE included any carrying charges associated with the Hurricane Harvey Regulatory Asset amount of $64,406,143 somewhere in its April 5, 2019 application? If"yes," please indicate where in CEHE's April 5, 2019 application such carrying charges where included and provide in, electronic spreadsheet format with cell references and formula intact, the calculation of such carrying charges;

d. If CEHE has not included anywhere in its April 5, 2019 filing carrying charges associated with the Hurricane Harvey Regulatory Asset amount of $64,406,143, please explain why?; and

e. If CEHE has not included anywhere in its April 5, 2019 filing carrying charges associated with the Hurricane Harvey Regulatory Asset amount of $64,406, 143 and believes that such carrying charges should be included, please provide in electronic spreadsheet format with cell references and formula intact, the amount of carrying charges that the Company believes that should be recovered in rates.

ANSWER:

a. CenterPoint Houston's original filing did not request carrying costs in or on the Hurricane Harvey Regulatory Asset. Therefore, the $64.4 million balance did not include carrying costs. See response to (e) below for additional information.

b. CenterPoint Houston is requesting carrying charges on Hurricane Harvey regulatory asset in its errata filing on May 20, 2019. See response to (e) below.

c. Consistent with CenterPoint Houston's errata filing, CenterPoint Houston is requesting a Hurricane Harvey Regulatory Asset balance of $73,148,639 as of December 31, 2018, which will be reflected on revised Schedule II-B-12, line 7 and on Schedule II-B, line 22 as part of rate base. The carrying charges associated with this regulatory asset will also be reflected in the return on rate base line 30 of Schedule II-B.

d. Please see response to item (c). CenterPoint Houston inadvertently excluded the carrying charges from its initial filing.

e. Please see PUC08-14e Attachment 1 for the amount of carrying charges that is included in the errata filing on May 20, 2019.

SPONSOR (PREPARER):
Kristie Colvin (Kristie Colvin)

RESPONSIVE DOCUMENTS:
PUC08-14e Attachment 1.xlsx

CenterPoint Energy Houston Electric, LLC
Instructions for Hurricane Harvey Carrying Charges Errata

Item			
1	Add in known and measurable change on WP II-B-12b Hurricane Harvey Distribution cell B6886 +8631317 66	$	8,631,317 66
2	Add in known and measurable change on WP II-B-12b Hurricane Harvey Transmission cell C6886 +111178 84	$	111,178 84
3	Add in cell D6886 the sum of B6886 and C6866, on WP II-B-12 in cell F12 link to cell D6886 from WP II-B-12b	formula	
4	On WP II-E-3 5 1a copy amount in cell Q37, replace value in cell D37 from ($14,984,656) to ($16,820,580)	$	(1,835,924 00)
5	On WP II-E-3 5 1a add formula in E37 (+C37-D37) Will change value from ($14,035,331) to ($12,199,407)	$	1,835,924 00

CenterPoint Energy Houston Electric, LLC
Hurricane Harvey Carrying Costs Functionalization

	Functionalization per WP II-B-12b Hurricane Harvey Sum of Distribution $ Func	Sum of Transmission $ Func	Total
Total Costs Net of Insurance Proceeds	63,587,085 87	819,056 68	64,406,142 55
Percentage of Total	98 7282942%	1 2717058%	
Regulatory Asset Functionalized	$ 8,631,317 66	$ 111,178 84	$ 8,742,496 50

CenterPoint Energy Houston Electric, LLC
Hurricane Harvey Carrying Costs - ADIT

	Dist	Trans	Total
Regulatory Asset	8,631,318	111,179	8,742,496
Tax Rate	21 0%	21 0%	21 0%
ADIT Impact	(1,812,577)	(23,348)	(1,835,924)

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
HURRICANE HARVEY WITH CARRYING CHARGES

		[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]
		2017	2018						[C]+[E]+[G]
1	Annual Interest Rate	10 630%	9 403%						
2	Monthly Interest Rate	0 008453961	0 007517123						Cumulative
3				Cumulative	Insurance	Cumulative		Cumulative	Overall
4			Incurred O&M Costs	Incurred O&M Costs	Proceeds	Proceeds	Carrying Costs	Carrying Costs	Balance
5									
6	August-17		$ 12,029,774 27	$ 12,029,774 27		$ -	$ 22,034 84	$ 22,034 84	12,051,809 11
7	September-17		27,804,479 10	39,834,253 37		0 00	219,414 51	241,449 34	40,075,702 71
8	October-17		39,572,963 26	79,407,216 63		0 00	506,072 56	747,521 90	80,154,738 53
9	November-17		15,038,076 36	94,445,292 99	(3,732,379 36)	(3,732,379 36)	725,413 97	1,472,935 88	92,185,849 50
10	December-17		(21,332,097 05)	73,113,195 94	(115,434 41)	(3,847,813 78)	688,677 26	2,161,613 14	71,426,995 30
11	January-18		456,704 26	73,569,900 20		(3,847,813 78)	538,642 08	2,700,255 22	72,422,341 64
12	February-18		190,365 96	73,760,266 16		(3,847,813 78)	545,123 17	3,245,378 39	73,157,830 77
13	March-18		(133,309 08)	73,626,957 08		(3,847,813 78)	549,435 38	3,794,813 77	73,573,957 07
14	April-18		440,312 90	74,067,269 98		(3,847,813 78)	554,719 45	4,349,533 22	74,568,989 42
15	May-18		(58,425 90)	74,008,844 08	(1,218,987 40)	(5,066,801 18)	555,743 05	4,905,276 27	73,847,319 17
16	June-18		73,805 09	74,082,649 17	(1,551,438 51)	(6,618,239 69)	549,565 62	5,454,841 89	72,919,251 37
17	July-18		30,471 46	74,113,120 63		(6,618,239 69)	548,257 53	6,003,099 42	73,497,980 36
18	August-18		280,655 64	74,393,776 27		(6,618,239 69)	553,548 24	6,556,647 66	74,332,184 24
19	September-18		20,973 42	74,414,749 69		(6,618,239 69)	558,843 02	7,115,490 68	74,912,000 68
20	October-18		(462,086 52)	73,952,663 17	(2,731,178 22)	(9,349,417 91)	551,120 66	7,666,611 34	72,269,856 60
21	November-18		84,628 96	74,037,292 13	(1,937,502 50)	(11,286,920 41)	536,297 28	8,202,908 62	70,953,280 34
22	December-18		1,655,770 83	75,693,062 96		(11,286,920 41)	539,587 87	8,742,496 50	73,148,639 05
23									
24									
25		Total		$ 75,693,062 96		$ (11,286,920 41)		$ 8,742,496 50	

to II-B-12 Regulatory Asset - Hurricane Harvey	$	64,406,142 55
Hurricane Harvey carrying costs through 12/31/2018	$	8,742,496 50
Total Hurricane Harvey including carrying costs	$	73,148,639 05

Notes:

[1] Interest for August-2017 calculated using 13 days, which is based on costs incurred beginning August 17th

[2] Carrying Costs will continue until the amounts are included in base rates

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
HURRICANE HARVEY

		[A]	[B]	[C]	[D]	[E]
		2017	2018			
1	Debt Component of Interest Rate	3 707%	3 707%			
2	Monthly Interest Rate	0 003040309	0 003040309			
3				Cumulative	Insurance	Cumulative
4			Incurred O&M Costs	Incurred O&M Costs	Proceeds	Proceeds
5						
6	August-17		$ 12,029,774 27	$ 12,029,774 27		$ -
7	September-17		27,804,479 10	39,834,253 37		0 00
8	October-17		39,572,963 26	79,407,216 63		0 00
9	November-17		15,038,076 36	94,445,292 99	(3,732,379 36)	(3,732,379 36)
10	December-17		(21,332,097 05)	73,113,195 94	(115,434 41)	(3,847,813 78)
11	January-18		456,704 26	73,569,900 20		(3,847,813 78)
12	February-18		190,365 96	73,760,266 16		(3,847,813 78)
13	March-18		(133,309 08)	73,626,957 08		(3,847,813 78)
14	April-18		440,312 90	74,067,269 98		(3,847,813 78)
15	May-18		(58,425 90)	74,008,844 08	(1,218,987 40)	(5,066,801 18)
16	June-18		73,805 09	74,082,649 17	(1,551,438 51)	(6,618,239 69)
17	July-18		30,471 46	74,113,120 63		(6,618,239 69)
18	August-18		280,655 64	74,393,776 27		(6,618,239 69)
19	September-18		20,973 42	74,414,749 69		(6,618,239 69)
20	October-18		(462,086 52)	73,952,663 17	(2,731,178 22)	(9,349,417 91)
21	November-18		84,628 96	74,037,292 13	(1,937,502.50)	(11,286,920 41)
22	December-18		1,655,770 83	75,693,062 96		(11,286,920 41)
23						
24						
25		Total		$ 75,693,062 96		$ (11,286,920 41)

Equity (

Notes:
[1] Interest for August-2017 calculated using 13 days, which is based on costs incurred beginning August 17th

[F] Carrying Costs	[G] Cumulative Carrying Costs	[H] [C]+[E]+[G] Cumulative Overall Balance
$ 7,924 42	$ 7,924 42	12,037,698 69
78,865 42	86,789 84	39,921,043 21
181,529 31	268,319 15	79,675,535 78
259,424 64	527,743 79	91,240,657 41
244,796 21	772,540 00	70,037,922 16
213,631 17	986,171 17	70,708,257 59
215,264 32	1,201,435 49	71,113,887 87
216,005 53	1,417,441.02	71,196,584 32
217,128 94	1,634,569 96	71,854,026 16
216,516 56	1,851,086 52	70,793,129 42
212,986 74	2,064,073 26	69,528,482 74
211,434 38	2,275,507 64	69,770,388 58
212,550 16	2,488,057 81	70,263,594 38
213,654 91	2,701,712 71	70,498,222 71
209,482 11	2,911,194 82	67,514,440 08
202,448 09	3,113,642 91	65,864,014 63
202,763 97	3,316,406 88	67,722,549 43
	$ 3,316,406 88	
Total Carrying Costs	$ 8,742,496 50	
Component of Carrying Costs	$ 5,426,089 61	

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
HURRICANE HARVEY

		[A]	[B]		[C]	[D]
1					Deferred	Cumulative
2		Carrying Costs	Debt Component		Equity Component	Deferred Equity
3						
4	August-17	22,034 84	7,924 42	$	14,110 42	14,110 42
5	September-17	219,414 51	78,865 42	$	140,549 09	154,659 51
6	October-17	506,072 56	181.529 31	$	324,543 25	479,202 75
7	November-17	725,413 97	259,424 64	$	465,989 34	945,192 09
8	December-17	688,677 26	244,796 21	$	443,881 05	1,389,073 14
9	January-18	538.642 08	213.631 17	$	325,010 91	1,714,084 05
10	February-18	545,123 17	215,264 32	$	329,858 85	2,043,942 90
11	March-18	549,435 38	216,005.53	$	333,429 85	2,377,372 75
12	April-18	554,719 45	217.128 94	$	337,590 50	2,714,963 26
13	May-18	555,743 05	216,516 56	$	339,226 49	3,054,189 74
14	June-18	549,565 62	212,986 74	$	336,578 88	3,390,768 63
15	July-18	548,257 53	211,434 38	$	336,823 15	3,727,591 78
16	August-18	553,548 24	212,550 16	$	340,998 08	4,068,589 85
17	September-18	558,843 02	213,654 91	$	345,188 12	4,413,777 97
18	October-18	551.120 66	209,482 11	$	341,638 55	4,755,416 52
19	November-18	536,297 28	202,448 09	$	333,849 19	5,089,265 71
20	December-18	539,587 87	202,763 97	$	336,823 90	5,426,089 61
21						
22		8,742,496 50	3,316,406 88		5,426,089 61	5,426,089 61

Notes:
Interest for August-2017 calculated using 13 days, which is based on costs incurred beginning August 17th

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
Harvey O&M Incurred

Document type	(All)
Summary Category	O&M Costs

Sum of Val/COArea Crcy	Column Labels				
	2017				
Row Labels	8	9	10	11	12
Distribution O&M	8,987,090 57	26,880,945 47	39,437,368 86	14,710,465 44	(22,144,730 11)
MUG O&M	1,730,845 38	(1,036,721 84)	10,922 14	3,108 70	257,625 45
Substation O&M	1,164,793 28	1,544,012 45	118,828 72	308,914.22	18,412.40
Transmission O&M	147,045 04	416,243 02	5,843 54	15,588 00	536,595 21
Grand Total	12,029,774 27	27,804,479 10	39,572,963 26	15,038,076 36	(21,332,097 05)

CENTERPOINT ENERGY HOUSTON E]
Harvey O&M Incurred

Document type
Summary Category

Sum of Val/COArea Crcy

	2017 Total	2018		
Row Labels		1	2	3
Distribution O&M	67,871,140 23	576,866 41	57,294 92	(146,261 04)
MUG O&M	965,779 83	10,264 63		
Substation O&M	3,154,961 07	(137,013 79)	133,071 04	(4,786 51)
Transmission O&M	1,121,314 81	6,587 01		17,738 47
Grand Total	73,113,195 94	456,704 26	190,365 96	(133,309 08)

CENTERPOINT ENERGY HOUSTON E]
Harvey O&M Incurred

Document type
Summary Category

Sum of Val/COArea Crcy

Row Labels	4	5	6	7	8	9	10	
Distribution O&M		643,379 32	20,869 52	73,805 09	30,471 46	281,196 89	20,973 42	(462,086 52)
MUG O&M			695 00					
Substation O&M		(203,066 42)	(79,990 42)			(541 25)		
Transmission O&M								
Grand Total		440,312 90	(58,425 90)	73,805 09	30,471 46	280,655 64	20,973 42	(462,086 52)

CENTERPOINT ENERGY HOUSTON E
Harvey O&M Incurred

Document type
Summary Category

Sum of Val/COArea Crcy

Row Labels	11	12	2018 Total	Grand Total
Distribution O&M	61,421 33	1,629,919 68	2,787,850 48	70,658,990 71
MUG O&M			10,959 63	976,739 46
Substation O&M	541 25		(291,786 10)	2,863,174 97
Transmission O&M	22,666 38	10,049 60	57,041 46	1,178,356 27
Grand Total	84,628 96	1,639,969 28	2,564,065 47	75,677,261 41

WP II-B-12 Adj 2	15,801 55
Total Harvey O&M	75,693,062 96

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
Hurricane Harvey Insurance Proceeds

Date	Proceeds	Allocated to CEHE
		25 65%
11/7/2017	(5,250,000 00)	(1,346,734 82)
11/9/2017	(1,500,000 00)	(384,781 38)
11/13/2017	(900,000 00)	(230,868 83)
11/14/2017	(435,000 00)	(111,586 60)
11/17/2017	(675,000 00)	(173,151 62)
11/24/2017	(5,790,000 00)	(1,485,256 12)
	(14,550,000 00)	(3,732,379 36)
12/5/2017	(450,000 00)	(115,434 41)
	(450,000 00)	(115,434 41)
05/072018	(3,780,000 00)	(969,649 07)
5/23/2018	(324,000 00)	(83,112 78)
5/25/2018	(648,000 00)	(166,225 56)
	(4,752,000 00)	(1,218,987 40)
6/1/2018	(313,200 00)	(80,342 35)
6/5/2018	(4,168,800 00)	(1,069,384 40)
6/5/2018	(216,000 00)	(55,408 52)
6/12/2018	(270,000 00)	(69,260 65)
6/12/2018	(1,080,000 00)	(277,042 59)
	(6,048,000 00)	(1,551,438 51)
10/26/2018	(546,000 00)	(140,060 42)
10/29/2018	(6,370,000.00)	(1,634,038 25)
10/29/2018	(1,820,000 00)	(466,868 07)
10/29/2018	(1,092,000 00)	(280,120 84)
10/29/2018	(364,000 00)	(93,373 61)
10/30/2018	(455,000 00)	(116,717 02)
	(10,647,000 00)	(2,731,178 22)
11/8/2018	(7,553,000 00)	(1,937,502 50)
	(7,553,000 00)	(1,937,502 50)
Total Insurance Proceeds	(44,000,000 00)	(11,286,920 41)

Total Proceeds	44,000,000 00	
Allocated to CEHE O&M	11,286,920 41	25 65%

G/L Account No. 111999 General Fund Receipt Clearing Account - Chase
Company Code 0299 CenterPoint Energy, Inc

CoCd	Assign.	Reference	G/L	Period	Year	DocumentNo	Type	Pstng Date	PK	Amt in loc.cur.	Profit Ctr	Text
0299	20171107	20171108 070318	111999	11	2017	600014437	SH	11/07/2017	50	5,250,000.00-	1157270	BANK OF AMERICA, N A. SUPE 222 BROADWAY N EW YORK
0299	20171109	20171110 070326	111999	11	2017	600014447	SD	11/09/2017	50	1,500,000.00-	1157270	
0299	20171113	20171114 070326	111999	11	2017	600014467	SH	11/13/2017	50	900,000.00-	1157270	CITIBANK N.A. 399 PARK AVENUE NEW YORK NY 10043-0
0299	20171114	20171115 070334	111999	11	2017	600014477	SH	11/14/2017	50	435,000.00-	1157270	CITIBANK N.A. 399 PARK AVENUE NEW YORK NY 10043-0
0299	20171117	20171120 070404	111999	11	2017	600014496	SH	11/17/2017	50	375,000.00-	1157270	HSBC BANK USA, N.A 452 FIFTH AVENUE NEW YORK NY
0299	20171117	20171120 070404	111999	11	2017	600014496	SH	11/17/2017	50	300,000.00-	1157270	HSBC BANK USA, N.A. 452 FIFTH AVENUE NEW YORK NY
0299	20171124	20171127 070310	111999	11	2017	600014537	SH	11/24/2017	50	5,790,000.00-	1157270	0000000011948742 THE ROYAL BANK OF SCOTLA ND PLC
0299	20171205	20171206 070322	111999	12	2017	600014552	SH	12/05/2017	50	450,000.00-	1157270	0000000910275368 9 PRINCETON EXCESS AND SURPLUS LI
0299	20180507	20180508 070429	111999	5	2018	600014979	SH	05/07/2018	50	3,780,000.00-	1157270	BANK OF AMERICA, N.A. SUPE 222 BROADWAY N EW YORK
0299	20180523	20180524 070404	111999	5	2018	600015067	SH	05/23/2018	50	324,000.00-	1157270	0000000910275368 9 PRINCETON EXCESS AND SURPLUS LI
0299	20180525	20180528 070445	111999	5	2018	600015078	SH	05/25/2018	50	648,000.00-	1157270	CITIBANK N.A. 399 PARK AVENUE NEW YORK NY 10043-0
0299	20180601	20180604 070605	111999	6	2018	600015070	SH	06/01/2018	50	313,200.00-	1157270	CITIBANK N.A. 399 PARK AVENUE NEW YORK NY 10043-0
0299	20180605	20180606 070800	111999	6	2018	600015099	SH	06/05/2018	50	4,168,800.00-	1157270	0000000011948742 THE ROYAL BANK OF SCOTLA ND PLC
0299	20180605	20180606 070800	111999	6	2018	600015099	SH	06/05/2018	50	216,000.00-	1157270	HSBC BANK USA, N.A. 452 FIFTH AVENUE NEW YORK NY
0299	20180612	20180613 070540	111999	6	2018	600015063	SD	06/12/2018	50	270,000.00-	1157270	
0299	20180612	20180613 070540	111999	6	2018	600015063	SD	06/12/2018	50	1,080,000.00-	1157270	
0299	20181026	20181029 070400	111999	10	2018	600015630	SH	10/26/2018	50	546,000.00-	1157270	0000000910275368 9 PRINCETON EXCESS AND SURPLUS LI
0299	20181029	20181030 070351	111999	10	2018	600015572	SH	10/29/2018	50	6,370,000.00-	1157270	BANK OF AMERICA, N.A. SUPE 222 BROADWAY N EW YORK
0299	20181029	20181030 070351	111999	10	2018	600015572	SH	10/29/2018	50	1,820,000.00-	1157270	0000000052829122 7 ZURICH AMERICAN INSURANC E COMPA
0299	20181029	20181030 070351	111999	10	2018	600015572	SH	10/29/2018	50	1,092,000.00-	1157270	CITIBANK N.A. 399 PARK AVENUE NEW YORK NY 10043-0
0299	20181029	20181030 070351	111999	10	2018	600015572	SH	10/29/2018	50	364,000.00-	1157270	HSBC BANK USA, N.A. 452 FIFTH AVENUE NEW YORK NY
0299	20181030	20181031 070732	111999	10	2018	600015617	SD	10/30/2018	50	455,000.00-	1157270	
0299	20181108	20181109 070405	111999	11	2018	600015677	SH	11/08/2018	50	7,553,000.00-	1157270	0000000011948742 THE ROYAL BANK OF SCOTLA ND PLC
•										44,000,000.00-		

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
WEIGHTED AVERAGE COST OF CAPITAL
Per Docket No. 38339

		[A]	[B]	[C]	[D] at 35% Pre-Tax	[E] at 21% Pre-Tax
		Weight	Cost	Weighted Cost	Weighted Cost	Weighted Cost
1	Common Equity	45 00%	10 00%	4 50%	6 92%	5 70%
2	LDT/Preferred Securities	55 00%	6 74%	3 71%	3 71%	3 71%
3	Total	100 00%		8 21%	10 630%	9 403%

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
MONTHLY COMPOUNDING CALCULATION

FORMULA

Pn	=	Po (1 + i)^n
Pn	=	Principal value at the end of n periods
Po	=	Principal, or beginning amount at time 0
i	=	interest rate
n	=	Number of times per year compounding occurs

The above formula is set up to calculate a value to be received by applying compounding Solving for the effective interest rate (i) is simply an algebraic formula which is shown below

at 35%			at 21%		
Pn	=	Po (1 + i)^n	Pn	=	Po (1 + i)^n
11 0750	=	1*((1 + i)^(12))	11 0750	=	1*((1 + i)^(12))
([illegible])^1/12	=	1+i	([illegible])^1/12	=	1+i
[illegible]	=	i	[illegible]	=	i
[illegible]	=	i	[illegible]	=	i

Formula Source Managerial Finance (5th edition) by J Fred Weston and Eugene F Brigham

Proof:

Monthly Interest

	Monthly Interest	Compounded Interest		Monthly Interest	Compounded Interest
1	0 008453961	0 008454	1	0 007517123	0 007517
2	0 00852543	0 016979	2	0 00757363	0 015091
3	0 008597504	0 025577	3	0 007630562	0 022721
4	0 008670187	0 034247	4	0 007687922	0 030409
5	0 008743484	0 042991	5	0 007745713	0 038155
6	0 008817401	0 051808	6	0 007803939	0 045959
7	0 008891943	0 060700	7	0 007862602	0 053821
8	0 008967115	0 069667	8	0 007921706	0 061743
9	0 009042923	0 078710	9	0 007981254	0 069724
10	0 009119372	0 087829	10	0 008041251	0 077766
11	0 009196466	0 097026	11	0 008101698	0 085867
12	0 009274213	0 106300	12	0 008162599	0 094030

APPENDIX A

STATEMENT OF QUALIFICATIONS

KARL J. NALEPA

Mr. Nalepa is an energy economist with more than 35 years of private and public sector experience in the electric and natural gas industries. He has extensive experience analyzing utility rate filings and resource plans with particular focus on fuel and power supply requirements, quality of fuel supply management, and reasonableness of energy costs. Mr. Nalepa developed peak demand and energy forecasts for municipal and electric cooperative utilities and has forecast the price of natural gas in ratemaking and resource plan evaluations. He led a management and performance review of the Texas Public Utility Commission, and has conducted performance reviews and valuation studies of a number of municipal utility systems. Mr. Nalepa previously directed the Railroad Commission of Texas' Regulatory Analysis & Policy Section, with responsibility for preparing timely natural gas industry analysis, managing ratemaking proceedings, mediating informal complaints, and overseeing consumer complaint resolution. He has prepared and defended expert testimony in both administrative and civil proceedings, and has served as a technical examiner in natural gas rate proceedings.

EDUCATION

1998 Certificate of Mediation
Dispute Resolution Center, Austin

1989 NARUC Regulatory Studies Program
Michigan State University

1988 M.S. - Petroleum Engineering
University of Houston

1980 B.S. - Mineral Economics
Pennsylvania State University

PROFESSIONAL HISTORY

2003 - ReSolved Energy Consulting
President and Managing Director

1997 – 2003 Railroad Commission of Texas
Asst. Director, Regulatory Analysis & Policy

1995 – 1997 Karl J. Nalepa Consulting
Principal

1992 – 1995 Resource Management International, Inc.
Supervising Consultant

1988 – 1992 Public Utility Commission of Texas
Fuels Analyst

1980 – 1988 Transco Exploration Company
Reservoir and Evaluation Engineer

AREAS OF EXPERTISE

Regulatory Analysis

Electric Power: Analyzed electric utility rate, certification, and resource forecast filings. Assessed the quality of fuel supply management, and reasonableness of fuel costs recovered from ratepayers. Projected the cost of fuel and purchased power. Estimated the impact of environmental costs on utility resource selection. Participated in regulatory rulemaking activities. Provided expert staff testimony in a number of proceedings before the Texas Public Utility Commission.

As consultant, represent interests of municipal clients intervening in large utility rate proceedings through analysis of filings and presentation of testimony before the Public Utility Commission. Also assist municipal utilities in preparing and defending requests to change rates and other regulatory matters before the Public Utility Commission.

Natural Gas: Directed the economic regulation of gas utilities in Texas for the Railroad Commission of Texas. Responsible for monitoring, analyzing and reporting on conditions and events in the natural gas industry. Managed Commission staff representing the public interest in contested rate proceedings before the Railroad Commission, and acted as technical examiner on behalf of the Commission. Mediated informal disputes between industry participants and directed handling of customer billing and service complaints. Oversaw utility compliance filings and staff rulemaking initiatives. Served as a policy advisor to the Commissioners.

As consultant, represent interests of municipal clients intervening in large utility rate proceedings through analysis of filings and presentation of testimony before the cities and Railroad Commission. Also assist small utilities in preparing and defending requests to change rates and other regulatory matters before the Railroad Commission.

Litigation Support

Retained to support litigation in natural gas contract disputes. Analyzed the results of contract negotiations and competitiveness of gas supply proposals considering gas market conditions contemporaneous with the period reviewed. Supported litigation related to alleged price discrimination related to natural gas sales for regulated customers. Provided analysis of regulatory and accounting issues related to ownership of certain natural gas distribution assets in support of litigation against a natural gas utility. Supported independent power supplier in binding arbitration regarding proper interpretation of a natural gas transportation contract. Provided expert witness testimony in administrative and civil court proceedings.

Utility System Assessment

Led a management and performance review of the Public Utility Commission. Conducted performance reviews and valuation studies of municipal utility systems. Assessed ability to compete in the marketplace, and recommended specific actions to improve the competitive position of the utilities. Provided comprehensive support in the potential sale of a municipal gas system, including preparation of a valuation study and all activities leading to negotiation of contract for sale and franchise agreements.

Energy Supply Analysis

Reviewed system requirements and prepared requests for proposals (RFPs) to obtain natural gas and power supplies for both utility and non-utility clients. Evaluated submittals under alternative demand and market conditions, and recommended cost-effective supply proposals. Assessed supply strategies to determine optimum mix of available resources.

Econometric Forecasting

Prepared econometric forecasts of peak demand and energy for municipal and electric cooperative utilities in support of system planning activities. Developed forecasts at the rate class and substation levels. Projected price of natural gas by individual supplier for Texas electric and natural gas utilities to support review of utility resource plans.

Reservoir Engineering

Managed certain reserves for a petroleum exploration and production company in Texas. Responsible for field surveillance of producing oil and natural gas properties, including reserve estimation, production forecasting, regulatory reporting, and performance optimization. Performed evaluations of oil and natural gas exploration prospects in Texas and Louisiana.

PROFESSIONAL MEMBERSHIPS

Society of Petroleum Engineers
International Association for Energy Economics
United States Association for Energy Economics

SELECT PUBLICATIONS, PRESENTATIONS, AND TESTIMONY

"Summary of the USAEE Central Texas Chapter's Workshop entitled 'EPA's Proposed Clean Power Plan Rules: Economic Modeling and Effects on the Electric Reliability of Texas Region,'" with Dr. Jay Zarnikau and Mr. Neil McAndrews, USAEE Dialogue, May 2015

"Public Utility Ratemaking," EBF 401: Strategic Corporate Finance, The Pennsylvania State University, September 2013

"What You Should Know About Public Utilities," EBF 401: Strategic Corporate Finance, The Pennsylvania State University, October 2011

"Natural Gas Markets and the Impact on Electricity Prices in ERCOT," Texas Coalition of Cities for Fair Utility Issues, Dallas, October 2008

"Natural Gas Regulatory Policy in Texas," Hungarian Oil and Gas Policy Business Colloquium, U.S. Trade and Development Agency, Houston, May 2003

"Railroad Commission Update," Texas Society of Certified Public Accountants, Austin, April 2003

"Gas Utility Update," Railroad Commission Regulatory Expo and Open House, October 2002

"Deregulation: A Work in Progress," Interview by Karen Stidger, *Gas Utility Manager*, October 2002

"Regulatory Overview: An Industry Perspective," Southern Gas Association's Ratemaking Process Seminar, Houston, February 2001

"Natural Gas Prices Could Get Squeezed," with Commissioner Charles R. Matthews, *Natural Gas*, December 2000

"Railroad Commission Update," Texas Society of Certified Public Accountants, Austin, April 2000

"A New Approach to Electronic Tariff Access," Association of Texas Intrastate Natural Gas Pipeline Annual Meeting, Houston, January 1999

"A Texas Natural Gas Model," United States Association for Energy Economics North American Conference, Albuquerque, 1998

"Texas Railroad Commission Aiding Gas Industry by Updated Systems, Regulations," *Natural Gas,* July 1998

"Current Trends in Texas Natural Gas Regulation," Natural Gas Producers Association, Midland, 1998

"An Overview of the American Petroleum Industry," Institute of International Education Training Program, Austin, 1993

Direct testimony in PUC Docket No. 10400 summarized in *Environmental Externality,* Energy Research Group for the Edison Electric Institute, 1992

"God's Fuel - Natural Gas Exploration, Production, Transportation and Regulation," with Danny Bivens, Public Utility Commission of Texas Staff Seminar, 1992

"A Summary of Utilities' Positions Regarding the Clean Air Act Amendments of 1990," Industrial Energy Technology Conference, Houston, 1992

"The Clean Air Act Amendments of 1990," Public Utility Commission of Texas Staff Seminar, 1992

APPENDIX B

PREVIOUSLY FILED TESTIMONY

KARL J. NALEPA
TESTIMONY FILED

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
Before the Public Utility Commission of Texas					
49395	May 19	City of El Paso	El Paso Electric	DCRF	DCRF Methodology
49148	Apr 19	City of El Paso	El Paso Electric	TCRF	TCRF Methodology
49042	Mar 19	Cities	SWEPCO	TCRF	TCRF Methodology
49041	Feb 19	Cities	SWEPCO	DCRF	DCRF Methodology
48973	May 19	Xcel Municipalities	Southwestern Public Service	Fuel Reconciliation	Fuel / Purch Power Costs
48963	Dec 18	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
48420	Aug 18	Gulf Coast Coalition	CenterPoint Energy Houston	EECRF	EECRF Methodology
48404	Jul 18	Cities	Texas-New Mexico Power	EECRF	EECRF Methodology
48371	Aug 18	Cities	Entergy Texas Inc.	Cost of Service	Cost of Service
48231	May 18	Cities	Oncor Electric Delivery	DCRF	DCRF Methodology
48226	May 18	Gulf Coast Coalition	CenterPoint Energy Houston	DCRF	DCRF Methodology
48222	Apr 18	Cities	AEP Texas Inc.	DCRF	DCRF Methodology
47900	Dec 17	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
47527	Apr 18	Xcel Municipalities	Southwestern Public Service	Cost of Service	Cost of Service
47461	Dec 17	Office of Public Counsel	SWEPCO	CCN	Public Interest Review
47236	Jul 17	Cities	AEP Texas	EECRF	EECRF Methodology
47235	Jul 17	Cities	Oncor Electric Delivery	EECRF	EECRF Methodology
47217	Jul 17	Cities	Texas-New Mexico Power	EECRF	EECRF Methodology

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
47032	May 17	Gulf Coast Coalition	CenterPoint Energy Houston	DCRF	DCRF Methodology
46936	Oct 17	Xcel Municipalities	Southwestern Public Service	CCN	Public Interest Review
46449	Apr 17	Cities	SWEPCO	Cost of Service	Cost of Service
46348	Sep 16	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
46238	Jan 17	Office of Public Counsel	Oncor Electric Delivery	STM	Public Interest Review
46076	Dec 16	Cities	Entergy Texas Inc.	Fuel Reconciliation	Fuel Cost
46050	Aug 16	Cities	AEP Texas	STM	Public Interest Review
46014	Jul 16	Gulf Coast Coalition	CenterPoint Energy Houston	EECRF	EECRF Methodology
45788	May 16	Cities	AEP-TNC	DCRF	DCRF Methodology
45787	May 16	Cities	AEP-TCC	DCRF	DCRF Methodology
45747	May 16	Gulf Coast Coalition	CenterPoint Energy Houston	DCRF	DCRF Methodology
45712	Apr 16	Cities	SWEPCO	DCRF	DCRF Methodology
45691	Jun 16	Cities	SWEPCO	TCRF	TCRF Methodology
45414	Feb 17	Office of Public Counsel	Sharyland	Cost of Service	Cost of Service
45248	May 16	City of Fritch	City of Fritch	Cost of Service (water)	Cost of Service
45084	Nov 15	Cities	Entergy Texas Inc.	TCRF	TCRF Methodology
45083	Oct 15	Cities	Entergy Texas Inc.	DCRF	DCRF Methodology
45071	Aug 15	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
44941	Dec 15	City of El Paso	El Paso Electric	Cost of Service	CEP Adjustments
44677	Jul 15	City of El Paso	El Paso Electric	EECRF	EECRF Methodology
44572	May 15	Gulf Coast Coalition	CenterPoint Energy Houston	DCRF	DCRF Methodology

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
44060	May 15	City of Frisco	Brazos Electric Coop	CCN	Transmission Cost Recovery
43695	May 15	Pioneer Natural Resources	Southwestern Public Service	Cost of Service	Cost Allocation
43111	Oct 14	Cities	Entergy Texas Inc.	DCRF	DCRF Methodology
42770	Aug 14	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
42485	Jul 14	Cities	Entergy Texas Inc.	EECRF	EECRF Methodology
42449	Jul 14	City of El Paso	El Paso Electric	EECRF	EECRF Methodology
42448	Jul 14	Cities	SWEPCO	TCRF	Transmission Cost Recovery Factor
42370	Dec 14	Cities	SWEPCO	Rate Case Expenses	Rate Case Expenses
41791	Jan 14	Cities	Entergy Texas Inc.	Cost of Service	Cost of Service/Fuel
41539	Jul 13	Cities	AEP Texas North	EECRF	EECRF Methodology
41538	Jul 13	Cities	AEP Texas Central	EECRF	EECRF Methodology
41444	Jul 13	Cities	Entergy Texas Inc.	EECRF	EECRF Methodology
41223	Apr 13	Cities	Entergy Texas Inc.	ITC Transfer	Public Interest Review
40627	Nov 12	Austin Energy	Austin Energy	Cost of Service	General Fund Transfers
40443	Dec 12	Office of Public Counsel	SWEPCO	Cost of Service	Cost of Service/Fuel
40346	Jul 12	Cities	Entergy Texas Inc.	Join MISO	Public Interest Review
39896	Mar 12	Cities	Entergy Texas Inc.	Cost of Service/ Fuel Reconciliation	Cost of Service/ Nat Gas/ Purch Power
39366	Jul 11	Cities	Entergy Texas Inc.	EECRF	EECRF Methodology
38951	Feb 12	Cities	Entergy Texas Inc.	CGS Tariff	CGS Costs
38815	Sep 10	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
38480	Nov 10	Cities	Texas-New Mexico Power	Cost of Service	Cost of Service/Rate Design
37744	Jun 10	Cities	Entergy Texas Inc.	Cost of Service/ Fuel Reconciliation	Cost of Service/ Nat Gas/ Purch Power/ Gen
37580	Dec 09	Cities	Entergy Texas Inc.	Fuel Refund	Fuel Refund Methodology
36956	Jul 09	Cities	Entergy Texas Inc.	EECRF	EECRF Methodology
36392	Nov 08	Texas Municipal Power	Texas Municipal Power	Interim TCOS	Wholesale Transmission Rate
35717	Nov 08	Cities Steering Committee	Oncor Electric Delivery	Cost of Service	Cost of Service/Rate Design
34800	Apr 08	Cities	Entergy Gulf States	Fuel Reconciliation	Natural Gas/Coal/Nuclear
16705	May 97	North Star Steel	Entergy Gulf States	Fuel Reconciliation	Natural Gas/Fuel Oil
10694	Jan 92	PUC Staff	Midwest Electric Coop	Revenue Requirements	Depreciation/ Quality of Service
10473	Sep 91	PUC Staff	HL&P	Notice of Intent	Environmental Costs
10400	Aug 91	PUC Staff	TU Electric	Notice of Intent	Environmental Costs
10092	Mar 91	PUC Staff	HL&P	Fuel Reconciliation	Natural Gas/Fuel Oil
10035	Jun 91	PUC Staff	West Texas Utilities	Fuel Reconciliation Fuel Factor	Natural Gas Natural Gas/Fuel Oil/Coal
9850	Feb 91	PUC Staff	HL&P	Revenue Req. Fuel Factor	Natural Gas/Fuel Oil/ETSI Natural Gas/Coal/Lignite
9561	Aug 90	PUC Staff	Central Power & Light	Fuel Reconciliation Revenue Requirements Fuel Factor	Natural Gas Natural Gas/Fuel Oil Natural Gas
9427	Jul 90	PUC Staff	LCRA	Fuel Factor	Natural Gas
9165	Feb 90	PUC Staff	El Paso Electric	Revenue Requirements Fuel Factor	Natural Gas/Fuel Oil Natural Gas

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
8900	Jan 90	PUC Staff	SWEPCO	Fuel Reconciliation Fuel Factor	Natural Gas Natural Gas
8702	Sep 89 Jul 89	PUC Staff	Gulf States Utilities	Fuel Reconciliation Revenue Requirements Fuel Factor	Natural Gas/Fuel Oil Natural Gas/Fuel Oil Natural Gas/Fuel Oil
8646	May 89 Jun 89	PUC Staff	Central Power & Light	Fuel Reconciliation Revenue Requirements Fuel Factor	Natural Gas Natural Gas/Fuel Oil Natural Gas
8588	Aug 89	PUC Staff	El Paso Electric	Fuel Reconciliation	Natural Gas

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
Before the Railroad Commission of Texas					
10737	Jun 18	T&L Gas Co.	T&L Gas Co.	Cost of Service	Cost of Service/Rate Design
10622	Apr 17	LDC, LLC	LDC, LLC	Cost of Service	Cost of Service/Rate Design
10617	Mar 17	Onalaska Water & Gas	Onalaska Water & Gas	Cost of Service	Cost of Service/Rate Design
10580	Mar 17	Cities Steering Committee	Atmos Pipeline Texas	Cost of Service	Cost of Service/Rate Design
10567	Feb 17	Gulf Coast Coalition	CenterPoint Energy Entex	Cost of Service	Cost of Service/Rate Design
10506	Jun 16	City of El Paso	Texas Gas Service	Cost of Service	Cost of Service/Energy Efficiency
10498	Feb 16	NatGas, Inc.	NatGas, Inc.	Cost of Service	Cost of Service/Rate Design
10359	Jul 14	Cities Steering Committee	Atmos Energy Mid Tex	Cost of Service	Cost of Service/Rate Design
10295	Oct 13	Cities Steering Committee	Atmos Pipeline Texas	Revenue Rider	Rider Renewal
10242	Jan 13	Onalaska Water & Gas	Onalaska Water & Gas	Cost of Service	Cost of Service/Rate Design
10196	Jul 12	Bluebonnet Natural Gas	Bluebonnet Natural Gas	Cost of Service	Cost of Service/Rate Design
10190	Jan 13	City of Magnolia, Texas	Hughes Natural Gas	Cost of Service	Cost of Service/Rate Design
10174	Aug 12	Steering Committee of Cities	Atmos Energy West Texas	Cost of Service	Cost of Service/Rate Design
10170	Aug 12	Cities Steering Committee	Atmos Energy Mid Tex	Cost of Service	Cost of Service/Rate Design
10106	Oct 11	Gulf Coast Coalition	CenterPoint Energy Entex	Cost of Service	Cost of Service/Rate Design
10083	Aug 11	City of Magnolia, Texas	Hughes Natural Gas	Cost of Service	Cost of Service/Rate Design
10038	Feb 11	Gulf Coast Coalition	CenterPoint Energy Entex	Cost of Service	Cost of Service/Rate Design
10021	Oct 10	AgriTex Gas, Inc.	AgriTex Gas, Inc.	Cost of Service	Cost of Service/Rate Design
10000	Dec 10	Cities Steering Committee	Atmos Pipeline Texas	Cost of Service	Cost of Service/Rate Design

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
9902	Oct 09	Gulf Coast Coalition	CenterPoint Energy Entex	Cost of Service	Cost of Service/Rate Design
9810	Jul 08	Bluebonnet Natural Gas	Bluebonnet Natural Gas	Cost of Service	Cost of Service/Rate Design
9797	Apr 08	Universal Natural Gas	Universal Natural Gas	Cost of Service	Cost of Service/Rate Design
9732	Jul 08	Cities Steering Committee	Atmos Energy Corp.	Gas Cost Review	Natural Gas Costs
9670	Oct 06	Cities Steering Committee	Atmos Energy Corp.	Cost of Service	Affiliate Transactions/ O&M Expenses/GRIP
9667	Nov 06	Oneok Westex Transmission	Oneok Westex Transmission	Abandonment	Abandonment
9598	Sep 05	Cities Steering Committee	Atmos Energy Corp.	GRIP Appeal	GRIP Calculation
9530	Apr 05	Cities Steering Committee	Atmos Energy Corp.	Gas Cost Review	Natural Gas Costs
9400	Dec 03	Cities Steering Committee	TXU Gas Company	Cost of Service	Affiliate Transactions/ O&M Expenses/Capital Costs

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
Before the Louisiana Public Service Commission					
U-34344/ U-34717	Apr 18	PSC Staff	Dixie Electric Member Corporation	Formula Rate Plan	Stipulation
U-34344	Jan 18	PSC Staff	Dixie Electric Member Corporation	Formula Rate Plan	Adjusted Revenues
U-33633	Nov 15	PSC Staff	Entergy Louisiana, LLC/ Entergy Gulf States Louisiana	Resource Certification	Prudence
U-33033	Jul 14	PSC Staff	Entergy Louisiana, LLC/ Entergy Gulf States Louisiana	Resource Certification	Revenue Requirement
U-31971	Nov 11	PSC Staff	Entergy Louisiana, LLC/ Entergy Gulf States Louisiana	Resource Certification	Certification/Cost Recovery
Before the Arkansas Public Service Commission					
O7-105-U	Mar 08	Arkansas Customers	CenterPoint Energy, Inc. & pipelines serving CenterPoint	Gas Cost Complaint	Prudence / Cost Recovery
Before the Colorado Public Utilities Commission					
18A-0791E	Mar 19	Pueblo County	Black Hills Colorado Electric	Economic Development Rate	Tariff Issues