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

2019 MAY 15 PM 2:29

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

May 15, 2019

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-01

QUESTION:

Provide the compensation expense for executives and key employees employed by Service Company and charged to CEHE pursuant to employment agreements by type or category separated into base salaries, other compensation (other than STI and LTI), and benefits, including, but not limited to: compensation tied to total shareholder return, EPS, and CNP stock price, and/or other financial and other performance metrics; and other benefits not available to all other exempt and/or non-exempt employees, such as SERP. Provide these amounts in total incurred by the Service Company and the amounts charged to CEHE. Provide all amounts by FERC account (including, but not limited to, O&M and A&G expense accounts and balance sheet accounts, including, but not limited to, plant accounts) for each calendar year 2016, 2017, and 2018.

ANSWER:

CenterPoint Energy Service Company does not have any executives and key employees employed pursuant to employment agreements. GCCC 02-01 Attachment 1.xlsx includes Service Company executive and key employee compensation and benefits paid by category for each calendar year 2016, 2017, and 2018. The information provided is not available by FERC account and has not been provided.

SPONSOR (PREPARER):
Michelle Townsend (Michelle Townsend)

RESPONSIVE DOCUMENTS:
GCCC02-01 Attachment 1.xlsx

Service Company Executive/Key Employee Compensation
For the Year Ended 12/31/2016

Pay Type	Employee Group	Total	% to CenterPoint Energy Houston Electric *	Amount to CenterPoint Energy Houston Electric
Base Pay	Non-Union	9,643,279	45.88%	4,424,181
Bonus	Non-Union	5,065,956	45.88%	2,324,179
BRP FICA Taxable Income	Non-Union	152,514	45.88%	69,971
Chg in FMV (Vest vs Grant)	Non-Union	(325,464)	45.88%	(149,317)
DCP FICA Excess Earnings	Non-Union	34,976	45.88%	16,047
Def Comp Dist - W4	Non-Union	37,782	45.88%	17,334
Dividend Equivalents	Non-Union	405,991	45.88%	186,262
Ex Life Imp Inc NFS Supp	Non-Union	1,656	45.88%	760
Executive Life Ins Gross Up	Non-Union	1,130	45.88%	518
Fin Planning	Non-Union	28,423	45.88%	13,040
FMV at Grant Date	Non-Union	3,253,699	45.88%	1,492,744
Fractional Shares	Non-Union	470	45.88%	216
Misc Unpd Supp Tax (PA)	Non-Union	115,141	45.88%	52,825
SRP FICA Taxable Income	Non-Union	351,355	45.88%	161,196
Grand Total		**18,766,908**		**8,609,954**

*Portion allocated to CenterPoint Energy Houston Electric is estimated based on Service Company billings

Service Company Executive/Key Employee Compensation
For the Year Ended 12/31/2017

Pay Type	Employee Group	Total	% to CenterPoint Energy Houston Electric *	Amount to CenterPoint Energy Houston Electric
Base Pay	Non-Union	9,454,511	46.55%	4,400,638
Ben Restoration Plan - Supp	Non-Union	1,414,844	46.55%	658,545
Bonus	Non-Union	5,557,674	46.55%	2,586,840
BRP FICA Taxable Income	Non-Union	1,657,212	46.55%	771,356
Chg in FMV (Vest vs Grant)	Non-Union	943,915	46.55%	439,349
Def Comp Dist - Supp	Non-Union	80,851	46.55%	37,632
Def Comp Dist - W4	Non-Union	5,646	46.55%	2,628
Dividend Equivalents	Non-Union	817,261	46.55%	380,397
Ex Life Imp Inc NFS Supp	Non-Union	4,165	46.55%	1,939
Fin Planning	Non-Union	33,075	46.55%	15,395
FMV at Grant Date	Non-Union	6,560,283	46.55%	3,053,509
Fractional Shares	Non-Union	710	46.55%	331
Misc Unpd Supp Tax (PA)	Non-Union	1,633	46.55%	760
	Non-Union	5,904	46.55%	2,748
Ret Elip Tax Supp	Non-Union	2,841	46.55%	1,322
Sav Restoration Plan - Supp	Non-Union	453,995	46.55%	211,313
SRP FICA Taxable Income	Non-Union	420,190	46.55%	195,579
Grand Total		**27,414,709**		**12,760,280**

*Portion allocated to CenterPoint Energy Houston Electric is estimated based on Service Company billings

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Service Company Executive/Key Employee Compensation
For the Year Ended 12/31/2018

	Employee Group	Total	% to CenterPoint Energy Houston Electric *	Amount to CenterPoint Energy Houston Electric
Base Pay	Non-Union	9799146.57	45.71%	4,479,515
Ben Restoration Plan - Supp	Non-Union	16662.68	45.71%	7,617
Bonus	Non-Union	6,361,088.55	45.71%	2,907,864
BRP FICA Taxable Income	Non-Union	360113.49	45.71%	164,620
Chg in FMV (Vest vs Grant)	Non-Union	1827759.47	45.71%	835,529
Dividend Equivalents	Non-Union	1070724.88	45.71%	489,464
Fin Counsel Imln - Supp	Non-Union	93878.39	45.71%	42,915
Fin Planning	Non-Union	22520	45.71%	10,295
FMV at Grant Date	Non-Union	6965844.03	45.71%	3,184,318
Misc Unpd Supp Tax (PA)	Non-Union	2881.79	45.71%	1,317
Sav Restoration Plan - Supp	Non-Union	17689.45	45.71%	8,086
SRP FICA Taxable Income	Non-Union	444240.26	45.71%	203,077
Grand Total		**26,982,550**		**12,334,617**

*Portion allocated to CenterPoint Energy Houston Electric is estimated based on Service Company billings

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-02

QUESTION:

Provide the compensation expense for executives and key employees employed by CEHE pursuant to employment agreements by type or category separated into base salaries, other compensation (other than STI and LTI), and benefits, including, but not limited to: compensation tied to total shareholder return, EPS, and CNP stock price, and/or other financial and other performance metrics; and other benefits not available to all other exempt and/or non-exempt employees, such as SERP. Provide all amounts by FERC account (including, but not limited to, O&M and A&G expense accounts and balance sheet accounts, including, but not limited to, plant accounts) for each calendar year 2016, 2017, and 2018.

ANSWER:

CenterPoint Houston does not have any executives and key employees employed pursuant to employment agreements. GCCC02-02 Attachment 1.xlsx includes CenterPoint Houston executive and key employee compensation and benefits paid by category for each calendar year 2016, 2017, and 2018. The information provided is not available by FERC account and has not been provided.

SPONSOR (PREPARER):
Kristie Colvin (Kristie Colvin)

RESPONSIVE DOCUMENTS:
GCCC02-02 Attachment1.xlsx

CenterPoint Energy Houston Electric, LLC.
Executive/Key Employee Compensation
For the Year Ended 12/31/2016

Pay Type	Employee Group	Total
Base Pay	Non-Union	1,069,817.56
Bonus	Non-Union	464,702.09
BRP FICA Taxable Income	Non-Union	2,444.33
Chg in FMV (Vest vs Grant)	Non-Union	(22,310.80)
Dividend Equivalents	Non-Union	30,324.69
Fin Planning	Non-Union	380.00
FMV at Grant Date	Non-Union	212,280.90
Fractional Shares	Non-Union	89.58
Misc Unpd Supp Tax (PA)	Non-Union	1,293.81
SRP FICA Taxable Income	Non-Union	18,687.71
Grand Total		**1,777,709.87**

CenterPoint Energy Houston Electric, LLC.
Executive/Key Employee Compensation
For the Year Ended 12/31/2017

Pay Type	Employee Group	Total
Base Pay	Non-Union	1,313,271.00
Bonus	Non-Union	576,543.63
BRP FICA Taxable Income	Non-Union	2,395.36
Chg in FMV (Vest vs Grant)	Non-Union	49,341.34
Def Comp Dist - W4	Non-Union	8,428.33
Dividend Equivalents	Non-Union	35,011.36
Fin Planning	Non-Union	5,890.00
FMV at Grant Date	Non-Union	269,882.40
Fractional Shares	Non-Union	137.69
Misc Unpd Supp Tax (PA)	Non-Union	110.48
SRP FICA Taxable Income	Non-Union	23,296.00
Grand Total		**2,284,307.59**

CenterPoint Energy Houston Electric, LLC.
Executive/Key Employee Compensation

Pay Type	Employee Group	Total
Base Pay	Non-Union	1,182,029.85
Ben Restoration Plan - Supp	Non-Union	8,967.69
Bonus	Non-Union	684,723.35
BRP FICA Taxable Income	Non-Union	20,442.40
Chg in FMV (Vest vs Grant)	Non-Union	98,130.33
Dividend Equivalents	Non-Union	61,726.21
Fin Counsel Imln - Supp	Non-Union	11,753.70
Fin Planning	Non-Union	6,690.00
FMV at Grant Date	Non-Union	412,794.39
Sav Restoration Plan - Supp	Non-Union	12,031.22
SRP FICA Taxable Income	Non-Union	29,665.67
Grand Total		**2,528,954.81**

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-03

QUESTION:

Provide the incentive compensation expense incurred by the Service Company and charged to CEHE by program (STI and LTI) and by metric for each program recorded by CEHE. Provide these amounts in total incurred by the Service Company and the amounts charged to CEHE. Provide all amounts by FERC account (including, but not limited to, O&M and A&G expense accounts and balance sheet accounts, including plant accounts) for each calendar year 2016, 2017, and 2018.

ANSWER:

Please refer to PUC03-01 response for the 2018 LTI incentive compensation expense incurred by CenterPoint Energy Service Company and allocated to CenterPoint Houston.

Please refer to COH03-21 response for the estimated 2018 STI incentive compensation expense incurred by CenterPoint Energy Service Company and CERC allocated to CenterPoint Houston.

Please refer to GCCC02-03 Attachment 1 (confidential).xlsx for the 2016 and 2017 incentive compensation expense incurred by CenterPoint Energy Service Company and the estimated amount allocated to CenterPoint Houston, 2018 CERC STI incentive compensation incurred and the estimated amount allocated to CenterPoint Houston, and 2016 through 2018 estimated STI expense amounts by FERC.

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

SPONSOR (PREPARER):
Michelle Townsend (Michelle Townsend)

RESPONSIVE DOCUMENTS:
GCCC02-03 Attachment 1 (confidential).xlsx

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-04

QUESTION:

Provide the incentive compensation expense incurred directly by CEHE by program (STI and LTI) and by metric for each program recorded by CEHE. Provide all amounts by FERC account (including, but not limited to, O&M and A&G expense accounts and balance sheet accounts, including plant accounts) for each calendar year 2016, 2017, and 2018.

ANSWER:

Please refer to PUC03-01 response for the 2018 LTI incentive compensation expense incurred directly by CenterPoint Houston.

Please refer to COH03-21 response for the 2018 STI incentive compensation expense incurred directly by CenterPoint Houston.

Please refer to GCCC02-04 Attachment 1 (confidential).xlsx for the 2016 and 2017 incentive compensation expense incurred directly by CenterPoint Houston by goal, and GCCC02-04 Attachment 2.xlsx 2016 through 2018 for STI and LTI amounts by FERC.

The attachment "GCCC02-04 Attachment 1 (confidential).xlsx" is confidential and is being provided pursuant to the Protective Order issued in Docket No. 49421.

SPONSOR (PREPARER):
Kristie Colvin/Lynne Harkel-Rumford (Kristie Colvin/Lynne Harkel-Rumford)

RESPONSIVE DOCUMENTS:
GCCC02-04 Attachment 1 (confidential).xlsx
GCCC02-04 Attachment 2.xlsx

CenterPoint Energy Houston Electric
Short-Term Incentive Compensation (STI) Expense
For the Twelve Months Ended December 31

FERC	2016	2017	2018
5600	188,955	183,689	249,078
5611	6,326	6,552	4,860
5612	212,778	204,537	184,548
5613	22,108	22,784	17,355
5614	54,514	51,326	
5615	74,248	66,715	65,936
5617	17,933	16,057	24,529
5620	40,308	43,226	57,159
5630	77,532	77,495	78,401
5640	30,279	31,383	29,474
5660	137,097	131,853	154,842
5690	36,121	37,177	62,245
5700	129,633	134,512	215,188
5710	169,318	168,967	172,380
5720	30,279	31,383	29,474
5730	12,779	12,810	11,169
5800	977,393	955,307	802,531
5810	187,768	157,503	135,777
5820	178,668	199,853	145,377
5830	327,547	345,443	350,179
5840	454,399	486,365	441,885
5850	68,666	72,082	65,619
5860	504,044	529,994	495,638
5870	149,030	153,980	146,382
5880	411,314	428,165	405,389
5900	386,466	366,067	279,562
5910	29,046	27,361	23,609
5920	362,605	373,450	285,391
5930	600,283	633,286	631,267
5940	218,653	225,311	245,531
5960	48,406	56,015	45,527
5970	30,279	31,383	29,474
5980	624	614	598
9020	15,165	13,305	11,005
9030	351,846	339,799	321,138
9070	1,560	1,510	1,454
9080	168,403	155,170	170,889
9090	6,236	6,188	5,466
9200	54,352	47,053	52,241
9250	-	-	75,951
9302	1,009,869	2,343,258	1,101,503
Total	7,782,831	9,168,925	7,671,711
9302-True Up	(27,786)	274,131	577,350
Total	7,755,045	9,443,056	8,249,061

CenterPoint Energy Houston Electric
Long-Term Incentive Compensation (LTI) Expense
For the Twelve Months Ended December 31

Long-term incentive goals are all financially-based.
Total amount of direct LTI included in FERC 9260:

GL		2016	2017
518164	Performance Shares and Units	$ 1,005,284	$ 105,752
518165	Other Equity Awards	497,925	591,887
		$ 1,503,209	$ 697,640

Source: SAP GL 518164 and 518165, FERC 9200

FERC Trial Balance (ZFAT)
Company:0003 CNP Houston Electric, LLC
Profit Center Group: * Name: *
Fiscal Year:2016 Period: 12

Lead column	YTD
[redacted]	1,005,284.09
	497,925.21
* 9260 Empl Pensions&Ben	1,503,209.30
** Functional area	1,503,209.30

FERC Trial Balance (ZFAT)
Company:0003 CNP Houston Electric, LLC
Profit Center Group: * Name: *
Fiscal Year:2017 Period: 12

Lead column	YTD
[redacted]	1,057,552.24
	591,887.36
* 9260 Empl Pensions&Ben	1,649,439.60
** Functional area	1,649,439.60

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-05

QUESTION:

Describe the Company's change in revenue accounting to accrue unbilled revenues, which it adopted in 1992.

a. Confirm that this change in accounting resulted in a one-time increase in revenues compared to the prior billed revenue accounting. Provide the journal entries recorded to implement this change in accounting, including the related income tax effects.

b. Provide a copy of the descriptions of this change in accounting reported in the Company's I992 I0-K and I992 Form 1.

c. Confirm that the Company recorded this one-time increase in revenues of $142.697 million as an increase to income in I992 ($94.180 million after income taxes) and did not defer this amount as a regulatory liability.

d. Identify the docket(s) and describe the ratemaking treatment sought by the Company and approved by the Commission to address the one-time increase in revenues due to this change in accounting, if any. If the Company did not seek to defer and/or refund this one-time increase in revenues as a reduction in the revenue requirement for ratemaking purposes, then explain why it did not do so.

ANSWER:

a. Based on the information found in the Houston Lighting & Power 1992 Federal Energy Regulatory Commission (FERC) Form 1 as shown below confirm. The requested journal entries fall outside of the CenterPoint Energy, Inc.'s record retention period and are not available.

b. The requested information is outside of the CenterPoint Energy, Inc.'s record retention period. However, the following was extracted from the 1992 Houston Lighting & Power Company FERC Form 1 located on the FERC website at https://ferc.gov/. The language is included in the Houston Industries Inc 1994 10-K located on the SEC website at https.//www.sec.gov/.

   (d) Revenues. Effective January 1, 1992, HL&P changed its method of recording electricity sales from cycle billing to a full accrual method, whereby unbilled electricity sales are estimated and recorded each month in order to better match revenues with expenses. Prior to January 1, 1992, electric revenues were recognized as bills were rendered.

   (18) Change In Accounting Method For Revenues

   During the fourth quarter of 1992, HL&P adopted a change in accounting method for revenue from a cycle billing to a full accrual method, effective January 1, 1992. Unbilled revenues represent the estimated amount customers will be charged for service received, but not yet billed, as of the end of each month. The accrual of unbilled revenues results in a better matching of revenues and expenses. This change impacts the pattern of revenue recognition, which had the effect of increasing revenues and earnings in the second and third quarters (periods of higher usage) and decreasing revenues and earnings in the first and fourth quarters (periods of lower usage). The cumulative effect of this accounting change, less income taxes of $48.5 million, amounted to $94.2 million, and was included in 1992 income. If this change in accounting method were applied retroactively, the effect on consolidated net income in 1991 and 1990 would not have been material.

c. Page 113 of the 1992 Houston Lighting & Power Company FERC Form 1 (GCCC02-05 Attachment 1.pdf) contains the Balance Sheet that does not include a balance in FERC account 254 Other Regulatory Liability. The absence of a regulatory liability confirms the transition balance was not deferred to the normal regulatory liability account. In addition, the extracted information in b above notes the cumulative effect to income. If the transition was fully deferred for rate making treatment the impact to income would have been zero.

d. CenterPoint Houston did not seek to defer the unbilled revenue as this amount reverses and is not used in the calculation of a revenue requirement nor is it cash collected from ratepayers. Therefore, there is no docket number to reference.

SPONSOR (PREPARER):
Kristie Colvin (Kristie Colvin)

RESPONSIVE DOCUMENTS:
GCCC02-05 Attachment 1.pdf

HOUSTON LIGHTING & POWER COMPANY — An Original — Dec. 31, 1992

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS) (CONTINUED)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
46	DEFERRED CREDITS			
47	Customer Advances for Construction (252)		$7,186,263	$3,608,676
48	Accumulated Deferred Investment Tax Credits (255)	266-267	451,964,652	433,117,985
49	Deferred Gains from Disposition of Utility Plant (256)			
50	Other Deferred Credits (253)	269	126,553,943	263,600,999
51	Unamortized Gain on Reacquired Debt (257)			
52	Accumulated Deferred Income Taxes (281-283)	272-277	1,613,990,417	1,703,840,200
53	TOTAL Deferred Credits (Enter Total of lines 47 thru 52)		2,199,695,275	2,404,167,860
54	TOTAL Liabilities and Other Credits (Enter Total of lines 14, 22, 30, 45 and 53)		$10,450,493,107	$10,639,190,141

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-06

QUESTION:

Refer to the Direct Testimony of Charles Pringle at 14 wherein he states: "The EDIT balance represents the amount of previously-recorded deferred income tax expense to be returned to customers." Confirm that the deferred income tax expense accumulated as ADIT, and now considered as EDIT, was recovered from customers in prior years, but not yet remitted to the federal government due to temporary differences between GAAP and the IRC in the recognition of revenues (income) and expenses (deductions). Explain your response.

ANSWER:

Ratemaking is designed to recover the authorized Revenue Requirement. Federal income tax expense, including both current and deferred income taxes, adjusted for known and measurable changes, is a component of the Commission approved Revenue Requirement. Once rates are set, based on the adjusted historic Cost of Service, actual expenses are not compared backward to the authorized amount on a line item by line item basis. Some expenses may increase while others decrease from the levels reflected in the historic test-year. So, the Company cannot confirm or deny that all deferred income tax expense accumulated as ADIT and now considered EDIT was recovered from customers in prior years as this calculation is not tracked.

SPONSOR (PREPARER):
Charles Pringle (Charles Pringle)

RESPONSIVE DOCUMENTS:
None

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-07

QUESTION:

Refer to the Direct Testimony of Charles Pringle at 17:19 through 18:4.

a. Identify and describe all sources reviewed and/or relied on by Mr. Pringle to inform his "understanding," including, but not limited to, research prepared by or for the Company internally or by external advisors.

b. Provide a copy of all sources and all other materials reviewed and/or relied on by Mr. Pringle to inform his understanding, including, but not limited to, research prepared by or for the Company internally or by external advisors.

c. Confirm that the budgeted 2019 amortization is based on a known and certain scheduled "runout" of the EDIT at 12/31/17, except for potential adjustments such as future IRS audit adjustments, IRS rulings and/or clarifications to normalization rules.

d. Describe any known or pending potential adjustments due to future IRS audit adjustments, IRS rulings and/or clarifications to normalization rules.

ANSWER:

a. The referenced testimony discusses how the amortization of protected EDIT is reflected in the current filing. Mr. Pringle's understanding of how to correctly calculate and incorporate EDIT into this filing has been formulated by his review of GAAP accounting standards, Internal Revenue Code. Treasury regulations, the Tax Reform Act of 1986, applicable PLR and the TCJA as they pertain to a normalized method of accounting. Specifically, Mr. Pringle has relied upon:

   IRC Section 168(i)(9) – Normalization Rules
   TRA of 1986 – Section 203(e)
   TCJA Section 13001(d)
   Treasury Reg. Section 1.167(l)-1(h) – Normalized Method of Accounting
   ASC 980-740-25 – Income Taxes Applicable to Regulated Entities
   PLR 8920025 – Depreciation. Property of certain utilities

b. Please see attachments:

   GCCC02-07 Attachment 1 IRC 168(i)(9).pdf
   GCCC02-07 Attachment 2 Treas Reg 1.167(l)-1(h).pdf
   GCCC02-07 Attachment 3 ASC 980-740-25.pdf
   GCCC02-07 Attachment 4 PLR 8920025.pdf

   In addition, the following information is publicly available at the links below:

   TCJA: https://www.congress.gov/115/bills/hr1/BILLS-115hr1enr.pdf.

   TRA of 1986: https://www.govinfo.gov/content/pkg/STATUTE-100/pdf/STATUTE-100-Pg2085.pdf

c. Budgeted 2019 ARAM amortization is not included in the filing. The estimated ARAM for protected EDIT referenced is the 2018 ARAM amortization that is based on the runout of the 12/31/2017 EDIT balance. The referenced $18.7 million of protected ARAM is being re-classified as unprotected because it can be refunded after rates are set in this case without violating the normalization rules promulgated in the TCJA.

d. Mr. Pringle is currently not aware of any potential adjustments.

SPONSOR (PREPARER):
Charles Pringle (Charles Pringle)

RESPONSIVE DOCUMENTS:
GCCC02-07 Attachment 1 IRC 168(i)(9).pdf
GCCC02-07 Attachment 2 Treas Reg 1.167(l)-1(h).pdf
GCCC02-07 Attachment 3 ASC 980-740-25.pdf
GCCC02-07 Attachment 4 PLR 8920025.pdf

168(i)(9)NORMALIZATION RULES.—

168(i)(9)(A)IN GENERAL.—

In order to use a normalization method of accounting with respect to any public utility property for purposes of subsection (f)(2)—

168(i)(9)(A)(i)

the taxpayer must, in computing its tax expense for purposes of establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, use a method of depreciation with respect to such property that is the same as, and a depreciation period for such property that is no shorter than, the method and period used to compute its depreciation expense for such purposes; and

168(i)(9)(A)(ii)

if the amount allowable as a deduction under this section with respect to such property (respecting all elections made by the taxpayer under this section) differs from the amount that would be allowable as a deduction under section 167 using the method (including the period, first and last year convention, and salvage value) used to compute regulated tax expense under clause (i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

168(i)(9)(B)USE OF INCONSISTENT ESTIMATES AND PROJECTIONS, ETC.—

168(i)(9)(B)(i)IN GENERAL.—

One way in which the requirements of subparagraph (A) are not met is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with the requirements of subparagraph (A).

168(i)(9)(B)(ii)USE OF INCONSISTENT ESTIMATES AND PROJECTIONS.—

The procedures and adjustments which are to be treated as inconsistent for purposes of clause (i) shall include any procedure or adjustment for ratemaking purposes which uses an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under subparagraph (A)(ii) unless such estimate or projection is also used, for ratemaking purposes, with respect to the other 2 such items and with respect to the rate base.

168(i)(9)(B)(iii)REGULATORY AUTHORITY.—

The Secretary may by regulations prescribe procedures and adjustments (in addition to those specified in clause (ii)) which are to be treated as inconsistent for purposes of clause (i).

168(i)(9)(C)PUBLIC UTILITY PROPERTY WHICH DOES NOT MEET NORMALIZATION RULES.—

In the case of any public utility property to which this section does not apply by reason of subsection (f)(2), the allowance for depreciation under section 167(a) shall be an amount computed using the method and period referred to in subparagraph (A)(i).

(h) *Normalization method of accounting*

(1) *In general*

(i)

Under section 167(l), a taxpayer uses a normalization method of regulated accounting with respect to public utility property—

(a)

If the same method of depreciation (whether or not a subsection (l) method) is used to compute both its tax expense and its depreciation expense for purposes of establishing cost of service for ratemaking purposes and for reflecting operating results in its regulated books of account, and

(b)

If to compute its allowance for depreciation under section 167 it uses a method of depreciation other than the method it used for purposes described in (*a*) of this subdivision, the taxpayer makes adjustments consistent with subparagraph (2) of this paragraph to a reserve to reflect the total amount of the deferral of Federal income tax liability resulting from the use with respect to all of its public utility property of such different methods of depreciation.

(ii)

In the case of a taxpayer described in section 167(l) (1)(B) or (2)(C), the reference in subdivision (i) of this subparagraph shall be a reference only to such taxpayer's "qualified public utility property." See § 1.167(l)-2(b) for definition of "qualified public utility property."

(iii)

Except as provided in this subparagraph, the amount of Federal income tax liability deferred as a result of the use of different method of depreciation under subdivision (i) of this subparagraph is the excess (computed without regard to credits) of the amount the tax liability would have been had a subsection (l) method been used over the amount of the actual tax liability. Such amount shall be taken into account for the taxable year in which such different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (l) method for purposes of determining the taxpayer's reasonable allowance under section 167(a) results in a net operating loss carryover (as determined under section 172) to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under section167(a) using a subsection (l) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

(2)*Adjustments to reserve*

(i)

The taxpayer must credit the amount of deferred Federal income tax determined under subparagraph (l)(i) of this paragraph for any taxable year to a reserve for deferred taxes, a depreciation reserve, or other reserve account. The taxpayer need not establish a separate reserve account for such amount but the amount of deferred tax determined under subparagraph (l)(i) of this paragraph must be accounted for in such a manner so as to be readily identifiable. With respect to any account, the aggregate amount allocable to deferred tax under section 167(l) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation under subparagraph (l)(i) of this paragraph. An additional exception is that the aggregate amount allocable to deferred tax under section 167(l) may be properly adjusted to reflect asset retirements or the expiration of the period for depreciation used in determining the allowance for depreciation under section 167(a).

(ii)

The provisions of this subparagraph may be illustrated by the following examples:

Example (1). Corporation X is exclusively engaged in the transportation of gas by pipeline subject to the jurisdiction of the Federal Power Commission. With respect to its post-1969 public utility property, X is entitled under section 167(l)(2)(B) to use a method of depreciation other than a subsection (l) method if it uses a normalization method of regulated accounting. With respect to such property, X has not made any election under § 1.167(a)-11 (relating to depreciation based on class lives and asset depreciation ranges). In 1972, X places in service public utility property with an unadjusted basis of $2 million, and an estimated useful life of 20 years. X uses the declining-balance method of depreciation with a rate twice the straight line rate. If X uses a normalization method of regulated accounting, the amount of depreciation allowable under section 167(a) with respect to such property for 1972 computed under the double declining balance method would be $200,000. X computes its tax expense and depreciation expense for purposes of determining its cost of service for ratemaking purposes and for reflecting operating results in its regulated books of account using the straight line method of depreciation (a subsection (l) method). A depreciation allowance computed in this manner is $100,000. The excess of the depreciation allowance determined under the double declining balance method ($200,000) over the depreciation expense computed using the straight line method ($100,000) is $100,000. Thus, assuming a tax rate of 48 percent, X used a normalization method of regulated accounting for 1972 with respect to property placed in service that year if for 1972 it added to a reserve $48,000 as taxes deferred as a result of the use by X of a method of depreciation for Federal income tax purposes different from that used for establishing its cost of service for ratemaking purposes and for reflecting operating results in its regulated books of account.

Example (2). Assume the same facts as in example (l), except that X elects to apply § 1.167(a)-11 with respect to all eligible property placed in service in 1972. Assume further that all property X placed in service in 1972 is eligible property. One hundred percent of the asset guideline period for such property is 22 years and the asset depreciation range is from 17.5 years to 26.5 years. X uses the double declining balance method of depreciation, selects an asset depreciation period of 17.5 years, and applies the half-year convention (described in § 1.167(a)-11(c)(2)(iii)). In 1972, the depreciation allowable under section 167(a) with respect to property placed in service in 1972 is $114,285 (determined without regard to the normalization requirements in § 1.167(a)-11(b)(6) and in section 167(l)). X computes its tax expense for purposes of determining its cost of service for ratemaking purposes and for reflecting operating results in its regulated books of account using the straight-line method of depreciation (a subsection (l) method), an estimated useful life of 22 years (that is, 100 percent of the asset guideline period), and the half-year convention. A depreciation allowance computed in this manner is $45,454. Assuming a tax rate of 48 percent, the amount that X must add to a reserve for 1972 with respect to property placed in service that year in order to qualify as using a normalization method of regulated accounting under section 167(l)(3)(G) is $27,429 and the amount in order to satisfy the normalization requirements of proposed § 1.167(a)-11(b)(6) is $5,610. X determined such amounts as follows:

(1) Depreciation allowance on tax return (determined without regard to section 167(l) and § 1.167(a)-11(b)(6))	$114,285
(2) Line (1), recomputed using a straight line method	57,142
(3) Difference in depreciation allowance attributable to different methods (line (1) minus line (2))	$57,143
(4) Amount to add to reserve under this paragraph (48 percent of line (3))	$27,429
(5) Amount in line (2)	$57,142

(6)	Line (5), recomputed by using an estimated useful life of 22 years and the half-year convention	45,454
(7)	Difference in depreciation allowance attributable to difference in depreciation periods	$11,688
(8)	Amount to add to reserve under § 1.167(a)-11(b)(6)(ii) (48 percent of line (7))	5,610

If, for its depreciation expense for purposes of determining its cost of service for ratemaking purposes and for reflecting operating results in its regulated books of account, X had used a period in excess of the asset guideline period of 22 years, the total amount in lines (4) and (8) in this example would not be changed.

Example (3). Corporation Y, a calendar-year taxpayer which is engaged in furnishing electrical energy, made the election provided by section 167(l)(4)(a) with respect to

service qualified public utility property which had an adjusted basis of $2 million, estimated useful life of 20 years, and no salvage value. With respect to property of the same kind most recently placed in service, Y used a flow-through method of regulated accounting for its July 1969 regulated accounting period and the applicable 1968 method is the declining balance method of depreciation using 200 percent of the straight line rate. The amount of depreciation allowable under the double declining balance method with respect to the qualified public utility property would be $200,000. Y computes its tax expense and depreciation expense for purposes of determining its cost of service for ratemaking purposes and for reflecting operating results in its regulated books of account using the straight line method of depreciation. A depreciation allowance with respect to the qualified public utility property determined in this manner is $100,000. The excess of the depreciation allowance determined under the double declining balance method ($200,000) over the depreciation expense computed using the straight line method ($100,000) is $100,000. Thus, assuming a tax rate of 48 percent, Y used a normalization method of regulated accounting for 1971 if for 1971 it added to a reserve $48,000 as tax deferred as a result of the use by Y of a method of depreciation for Federal income tax purposes with respect to its qualified public utility property which method was different from that used for establishing its cost of service for ratemaking purposes and for reflecting operating results in its regulated books of account for such property.

Example (4). Corporation Z, exclusively engaged in a public utility activity did not use a flow-through method of regulated accounting for its July 1969 regulated accounting period. In 1971, a regulatory body having jurisdiction over all of Z's property issued an order applicable to all years beginning with 1968 which provided, in effect, that Z use an accelerated method of depreciation for purposes of section 167 and for determining its tax expenses for purposes of reflecting operating results in its regulated books of account. The order further provided that Z normalize 50 percent of the tax deferral resulting from the use of the accelerated method of depreciation and that Z flow-through 50 percent of the tax deferral resulting therefrom. Under section 167(l), the method of accounting provided in the order would not be a normalization method of regulated accounting because Z would not be permitted to normalize 100 percent of the tax deferral resulting from the use of an accelerated method of depreciation. Thus, with respect to its public utility property for purposes of section 167, Z may only use a subsection (l) method of depreciation.

Example (5). Assume the same facts as in example (4) except that the order of the regulatory body provided, in effect, that Z normalize 100 percent of the tax deferral with respect to 50 percent of its public utility property and flow-through the tax savings with respect to the other 50 percent of its property. Because the effect of such an order would allow Z to flow-through a portion of the tax savings resulting from the use of an accelerated method of depreciation, Z would not be using a normalization method of regulated accounting with respect to any of its properties. Thus, with respect to its public utility property for purposes of section 167, Z may only use a subsection (l) method of

(3)***Establishing compliance with normalization requirements in respect of operating books of account.—***

The taxpayer may establish compliance with the requirement in subparagraph (l)(i) of this paragraph in respect of reflecting operating results, and adjustments to a reserve, in its operating books of account by reference to the following:

(i)

The most recent periodic report for a period beginning before the end of the taxable year, required by a regulatory body described in section 167(l)(3)(A) having jurisdiction over the taxpayer's regulated operating books of account which was filed with such body before the due date (determined with regard to extensions) of the taxpayer's Federal income tax return for such taxable year (whether or not such body has jurisdiction over rates).

(ii)

If subdivision (i) of this subparagraph does not apply, the taxpayer's most recent report to its shareholders for the taxable year but only if (*a*) such report was distributed to the shareholders before the due date (determined with regard to extensions) of the taxpayer's Federal income tax return for the taxable year and (*b*) the taxpayer's stocks or securities are traded in an established securities market during such taxable year. For purposes of this subdivision, the term "established securities market" has the meaning assigned to such term in § 1.453-3(d)(4).

(iii)

If neither subdivision (i) nor (ii) of this subparagraph applies, entries made to the satisfaction of the district director before the due date (determined with regard to extensions) of the taxpayer's Federal income tax return for the taxable year in its regulated books of account for its most recent period beginning before the end of such taxable year.

(4)***Establishing compliance with normalization requirements in computing cost of service for ratemaking purposes***

(i)

In the case of a taxpayer which used a flow-through method of regulated accounting for its July 1969 regulated accounting period or thereafter, with respect to all or a portion if its pre-1970 public utility property, if a regulatory body having jurisdiction to establish the rates of such taxpayer as to such property (or a court which has jurisdiction over such body) issues an order of general application (or an order of specific application to the taxpayer) which states that such regulatory body (or court) will permit a class of taxpayers of which such taxpayer is a member (or such taxpayer) to use the normalization method of regulated accounting to establish cost of service for ratemaking purposes with respect to all or a portion of its public utility property, the taxpayer will be presumed to be using the same method of depreciation to compute both its tax expense and its depreciation expense for purposes of establishing its cost of service for ratemaking purposes with respect to the public utility property to which such order applies. In the event that such order is in any way conditional, the preceding sentence shall not apply until all of the conditions contained in such order which are applicable to the taxpayer have been fulfilled. The taxpayer shall establish to the satisfaction of the Commissioner or his delegate that such conditions have been fulfilled.

(ii)

In the case of a taxpayer which did not use the flow-through method of regulated accounting for its July 1969 regulated accounting period or thereafter (including a taxpayer which used a subsection (l) method of depreciation to compute its allowance for depreciation under section 167(a) and to compute its tax expense for purposes of reflecting operating results in its regulated books of account), with respect to any of its public utility property, it will be presumed that such taxpayer is using the same method of depreciation to compute both its tax expense and its depreciation expense for purposes of establishing its cost of service for ratemaking purposes with respect to its post-1969 public utility property. The presumption described in the preceding sentence shall not apply in any case where there is (*a*) an expression of intent (regardless of the manner in which such expression of intent is indicated) by the regulatory body (or bodies), having jurisdiction to establish the rates of such taxpayer, which indicates that the policy of such regulatory body is in any way inconsistent with the use of the normalization method of regulated accounting by such taxpayer or by a class of taxpayers of which such taxpayer is a member, or (*b*) a decision by a court having jurisdiction over such regulatory body which decision is any way inconsistent with the use of the normalization method of regulated accounting by such taxpayer or a class of taxpayers of which such taxpayer is a member. The presumption shall be applicable on January 1, 1970, and shall, unless rebutted, be effective until an inconsistent expression of intent is indicated by such regulatory body or by such court. An example of such an inconsistent expression of intent is the case of a regulatory body which has, after the July 1969 regulated accounting period and before January 1, 1970, directed public utilities subject to its ratemaking jurisdiction to use a flow-through method of regulated accounting, or has issued an order of general application which states that such agency will direct a class of public utilities of which the taxpayer is a member to use a flow-through method of regulated accounting. The presumption described in this subdivision may be rebutted by evidence that the flow-through method of regulated accounting is being used by the taxpayer with respect to such property.

(iii)

The provisions of this subparagraph may be illustrated by the following examples:

Example (1). Corporation X is a calendar-year taxpayer and its "applicable 1968 method" is a straight line method of depreciation. Effective January 1, 1970, X began collecting rates which were based on a sum of the years-digits method of depreciation and a normalization method of regulated accounting which rates had been approved by a regulatory body having jurisdiction over X. On October 1, 1971, a court of proper jurisdiction annulled the rate order prospectively, which annulment was not appealed, on the basis that the regulatory body had abused its discretion by determining the rates on the basis of a normalization method of regulated accounting. As there was no inconsistent expression of intent during 1970 or prior to the due date of X's return for

1970, X's use of the sum of the years-digits method of depreciation for purposes of section 167 on such return was proper. For 1971, the presumption is in effect through September 30. During 1971, X may use the sum of the years-digits method of depreciation for purposes of section 167 from January 1 through September 30, 1971. After September 30, 1971, and for taxable years after 1971, X must use a straight line method of depreciation until the inconsistent court decision is on longer in effect.

Example (2). Assume the same facts as in example (1), except that pursuant to the order of annulment, X was required to refund the portion of the rates attributable to the use of the normalization method of regulated accounting. As there was no inconsistent expression of intent during 1970 or prior to the due date of X's return for 1970, X has the benefit of the presumption with respect to its use of the sum of the years-digits method of depreciation for purposes of section 167, but because of the retroactive nature of the rate order X must file an amended return for 1970 using a straight line method of depreciation. As the inconsistent decision by the court was handed down prior to the due date of X's Federal income tax return for 1971, for 1971 and thereafter the presumption of subdivision (ii) of this subparagraph does not apply. X must file its Federal income tax returns for such years using a straight line method of depreciation.

Example (3). Assume the same facts as in example (2), except that the annulment order was stayed pending appeal of the decision to a court of proper appellate jurisdiction. X has the benefit of the presumption as described in example (2) for the year 1970, but for 1971 and thereafter the presumption of subdivision (ii) of this subparagraph does not apply. Further, X must file an amended return for 1970 using a straight line method of depreciation and for 1971 and thereafter X must file its returns using a straight line method of depreciation unless X and the district director have consented in writing to extend the time for assessment of tax for 1970 and thereafter with respect to the issue of normalization method of regulated accounting for as long as may be necessary to allow for resolution of the appeal with respect to the annulment of the rate order.

The taxpayer shall notify the district director of a change in its method of regulated accounting, an order by a regulatory body or court that such method be changed, or an interim or final rate determination by a regulatory body which determination is inconsistent with the method of regulated accounting used by the taxpayer immediately prior to the effective date of such rate determination. Such notification shall be made within 90 days of the date that the change in method, the order, or the determination is effective. In the case of a change in the method of regulated accounting, the taxpayer shall recompute its tax liability for any affected taxable year and such recomputation shall be made in the form of an amended return where necessary unless the taxpayer and the district director have consented in writing to extend the time for assessment of tax with respect to the issue of normalization method of regulated accounting.

(6)*Exclusion of normalization reserve from rate base*

(i)

Notwithstanding the provisions of subparagraph (1) of this paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's tax expense in computing cost of service in such ratemaking.

(ii)

For the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i) of this subparagraph, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for the period is the amount of the reserve (determined under subparagraph (2) of this paragraph) at the end of the historical period. If solely a future period is used for such determination, the amount of the reserve account for the period is the amount of the reserve at the beginning of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during such period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period. The pro rata portion of any increase to be credited or decrease to be charged during a future period (or the future portion of a part-historical and part-future period) shall be determined by multiplying any such increase or decrease by a fraction, the numerator of which is the number of days remaining in the period at the time such increase or decrease is to be accrued, and the denominator of which is the total number of days in the period (or future portion).

(iii)

The provisions of subdivision (i) of this subparagraph shall not apply in the case of a final determination of a rate case entered on or before May 31, 1973. For this purpose, a determination is final if all rights to request a review, a rehearing, or a redetermination by the regulatory body which makes such determination have been exhausted or have lapsed. The provisions of subdivision (ii) of this subparagraph shall not apply in the case of a rate case filed prior to June 7, 1974, for which a rate order is entered by a regulatory body having jurisdiction to establish the rates of the taxpayer prior to September 5, 1974, whether or not such order is final, appealable, or subject to further review or reconsideration.

(iv)

The provisions of this subparagraph may be illustrated by the following examples:

Example (1). Corporation X is exclusively engaged in the transportation of gas by pipeline subject to the jurisdiction of the Z Power Commission. With respect to its post-1969 public utility property, X is entitled under section 167(l)(2)(B) to use a method of depreciation other than a subsection (l) method if it uses a normalization method of regulated accounting. With respect to X the Z Power Commission for purposes of establishing cost of service uses a recent consecutive 12-month period ending not more than 4 months prior to the date of filing a rate case adjusted for certain known changes occurring within a 9-month period subsequent to the base period. X's rate case is filed on January 1, 1975. The year 1974 is the recorded test period for X's rate case and is the period used in determining X's tax expense in computing cost of service. The rates are contemplated to be in effect for the years 1975, 1976, and 1977. The adjustments for known changes relate only to wages and salaries. X's rate base at the end of 1974 is $145,000,000. The amount of the reserve for deferred taxes under section 167(l) at the end of 1974 is $1,300,000, and the reserve is projected to be $4,400,000 at the end of 1975, $6,500,000 at the end of 1976, and $9,800,000 at the end of 1977. X does not use a normalization method of regulated accounting if the Z Power Commission excludes more than $1,300,000 from the rate base to which X's rate of return is applied. Similarly, X does not use a normalization method of regulated accounting if, instead of the above, the Z Power Commission, in determining X's rate of return which is applied to the rate base, assigns to no-cost capital an amount that represents the reserve account for deferred tax that is greater than $1,300,000.

Example (2). Assume the same facts as in example (1) except that the adjustments for known changes in cost of service made by the Z Power Commission include an additional depreciation expense that reflects the installation of new equipment put into service on January 1, 1975. Assume further that the reserve for deferred taxes under section 167(l) at the end of 1974 is $1,300,000 and that the monthly net increases for the first 9 months of 1975 are projected to be

January	1-31	$310,000
February	1-28	300,000
March	1-31	300,000
April	1-30	280,000
May	1-30	260,000

July	1-31	260,000
August	1-31	250,000
Sept.	1-30	240,000
		$2,470,000

For its regulated books of account X accrues such increases as of the last day of the month but as a matter of convenience credits increases or charges decreases to the reserve account on the 15th day of the month following the whole month for which such increase or decrease is accrued. The maximum amount that may be excluded from the rate base is $2,470,879 (the amount in the reserve at the end of the historical portion of the period ($1,300,000) and a pro rata portion of the amount of any projected increase for the future portion of the period to be credited to the reserve ($1,170,879)). Such pro rata portion is computed (without regard to the date such increase will actually be posted to the account) as follows:

$310,000	×	243/273	=	$275,934
300,000	×	215/273	=	236,264
300,000	×	184/273	=	202,198
280,000	×	154/273	=	157,949
270,000	×	123/273	=	121,648
260,000	×	93/273	=	88,571
260,000	×	62/273	=	59,048
250,000	×	31/273	=	28,388
240,000	×	1/273	=	879
				$1,170,879

Example (3). Assume the same facts as in example (1) except that for purposes of establishing cost of service the Z Power Commission uses a future test year (1975). The rates are contemplated to be in effect for 1975, 1976, and 1977. Assume further that plant additions, depreciation expense, and taxes are projected to the end of 1975 and that the reserve for deferred taxes under section167(l) is $1,300,000 for 1974 and is projected to be $4,400,000 at the end of 1975. Assume also that the Z Power

Commission applies the rate of return to X's 1974 rate base of $145,000,000. X and the Z Power Commission through negotiation arrive at the level of approved rates. X uses a normalization method of regulated accounting only if the settlement agreement, the rate order, or record of the proceedings of the Z Power Commission indicates that the Z Power Commission did not exclude an amount representing the reserve for deferred taxes from X's rate base ($145,000,000) greater than $1,300,000 plus a pro rata portion of the projected increases and decreases that are to be credited or charged to the reserve account for 1975. Assume that for 1975 quarterly net increases are projected to be

1st quarter	$910,000
2nd quarter	810,000
3rd quarter	750,000
4th quarte	630,000
Total	$3,100,000

For its regulated books of account X will accrue such increases as of the last day of the quarter but as a matter of convenience will credit increases or charge decreases to the reserve account on the 15th day of the month following the last month of the quarter for which suce reserve account on the 15th day of the month following the last month of the quarter for which such increase or decrease will be accrued. The maximum amount that may be excluded from the rate base is $2,591,480 (the amount of the reserve at the beginning of the period ($1,300,000) plus a pro rata portion ($1,291,480) of the $3,100,000 projected increase to be credited to the reserve during the period). Such portion is computed (without regard to the date such increase will actually be posted to the account) as follows:

$910,000	×	276/365	=	$688,110
810,000	×	185/365	=	410,548
750,000	×	93/365	=	191,096
630,000	×	1/365	=	1,726

$1,291,480

(i) ***Flow-through method of regulated accounting.—***

Under section 167(l)(3)(H), a taxpayer uses a flow-through method of regulated accounting with respect to public utility property if it uses the same method of depreciation (other than a subsection (l) method) to compute its allowance for depreciation under section 167 and to compute its tax expense for purposes of reflecting operating results in its regulated books of account unless such method is the same method used by the taxpayer to determine its depreciation expense for purposes of reflecting operating results in its regulated books of account. Except as provided in the preceding sentence, the method of depreciation used by a taxpayer with respect to public utility property for purposes of determining cost of service for ratemaking purposes or rate base for ratemaking purposes shall not be considered in determining whether the taxpayer used a flow-through method of regulated accounting. A taxpayer may establish use of a flow-through method of regulated accounting in the same manner that compliance with normalization requirements in respect of operating books of account may be established under paragraph (h)(4) of this section. [Reg. §1.167(l)-1.]

May 02, 2019

980 Regulated Operations
740 Income Taxes
25 Recognition

General Note: The Recognition Section provides guidance on the required criteria, timing, and location (within the financial statements) for recording a particular item in the financial statements. Disclosure is not recognition.

General

> Income Taxes Applicable to Regulated Entities

980-740-25-1 For regulated entities that meet the criteria for application of paragraph 980-10-15-2, this Subtopic specifically:

a. Prohibits net-of-tax accounting and reporting

b. Requires recognition of a deferred tax liability for tax benefits that are flowed through to customers when temporary differences originate and for the equity component of the **allowance for funds used during construction**

c. Requires adjustment of a deferred tax liability or asset for an enacted change in tax laws or rates.

980-740-25-2 If, as a result of an action by a regulator, it is probable that the future increase or decrease in taxes payable for (b) and (c) in the preceding paragraph will be recovered from or returned to customers through future rates, an asset or liability shall be recognized for that probable future revenue or reduction in future revenue pursuant to paragraphs 980-340-25-1 and 980-405-25-1. That asset or liability also shall be a temporary difference for which a deferred tax liability or asset shall be recognized.

980-740-25-3 Example 1 (see paragraph 980-740-55-8) illustrates recognition of an asset for the probable revenue to recover future income taxes.

980-740-25-4 Example 2 (see paragraph 980-740-55-13) illustrates adjustment of a deferred tax liability when the liability represents amounts already collected from customers.

IRS Letter Rulings and TAMs (1954-1997), UIL No. 167.23-00 Depreciation, Property of certain utilities; UIL No. 168.00-00 Accelerated cost recovery system, Letter Ruling 8920025, (Feb. 15, 1989), Internal Revenue Service, (Feb. 15, 1989)

Letter Ruling 8920025, February 15, 1989

CCH IRS Letter Rulings Report No. 639, 05-30-89

IRS REF: Symbol: CC:P&SI:6-TR-31-3411-88

Uniform Issue List Information:

UIL No. 0167.23-00

Depreciation

- Property of certain utilities

UIL No. 0168.00-00

Accelerated cost recovery system

[Code Secs. 167 and 168]

We received your private letter ruling request dated May 10, 1988, and all subsequently forwarded data. You have asked us to determine whether the proposed rate-making treatment of certain deferred income taxes meets the normalization requirements of sections 167 and 168 of the Internal Revenue Code. Specifically, you have asked us to rule as follows:

Whether Commission's proposed treatment of customer premises equipment (CPE) related excess deferred tax reserves for ratemaking purposes complies with the normalization requirements of sections 167(1) and 168(i)(9) of the Code, or whether the entire deferred tax balance should follow the property which was removed from regulation.

You have made the following representations:

Company is incorporated under the laws of State X and has its principal place of business in State Y. Company is a member of a group of affiliated corporations which files a consolidated federal income tax return on a calendar year basis. Parent of the group provides telephone and other forms of communications services, and manufactures telephone, communications, lighting and other electronic equipment and products. Company provides telephone and other communications services, and is subject to the jurisdiction of the Federal Communications Commission, and other commissions.

Company computes depreciation expense for federal income tax purposes utilizing an accelerated method of depreciation as permitted by section 167 or section 168 of the Code and utilizes a straight line method of deprecation for financial reporting and ratemaking purposes. Therefore, as required by section 167(1)(3)(G)(ii) and section 168(i)(9)(A)(ii) , Company makes adjustments to a reserve for deferred income taxes to reflect the deferral of taxes resulting from the use of different depreciation methods. These adjustments to the deferred tax reserve have been computed based upon the prevailing tax rate at the time of deferral and the weighted average rate at the time of reversal.

Intrastate telephone service rates in State Y are regulated by Commission. These rates are based upon the sum of a cost of service component and a return on rate base component. The cost of service component essentially represents the ongoing cost of providing service (the costs of operating and maintaining the system) including depreciation and tax expense. Rate base is the original cost of Company's property used and useful in providing telephone service. This property is composed of telephone plant in service, cash working capital, and materials and supplies inventory, less accumulated depreciation and deferred tax reserves. Commission allows Company to earn a return on this rate base. Cost of service and rate base used for establishing telephone rates in State

Y are based upon historical test period data, adjusted for know and measurable changes which affect the test period data.

Company records deferred tax reserves based on the difference between accelerated depreciation for tax purposes and a straight-line depreciation computation applied to the tax basis of plant. Originating differences are recorded in the early years of an asset's life, when accelerated depreciation exceeds straight-line depreciation, based on the corporate income tax rate in effect during the originating period. Reversals or terminating differences are recorded in the late years when straight-line depreciation exceeds accelerated depreciation. The amount of the reversal is computed based on a weighted average of the tax rates in effect when the corresponding originating differences relating to each vintage account were recorded. Any reductions or increases in corporate income tax rates do not directly result in an immediate reduction or increase in Company's previously recorded deferred tax reserves.

On October 22, 1986, with the enactment of the Tax Reform Act of 1986 (the "Act"), corporate income tax rates were reduced form 46 percent to 34 percent effective for tax years beginning on or after July 1, 1987. This reduction in corporate income tax rates by the Act resulted in an "excess" amount in the deferred tax reserves that were established as a result of normalizing the income tax effect of the difference between regulatory and tax depreciation of public utility property. Generally, the excess deferred tax reserves are defined as the reserves for deferred taxes computed under prior law, less what the reserves for deferred tax would be if the tax rate in effect under the Act had been in effect for all the prior periods.

Technological advances and increases in competition have rendered the regulation of certain services provided by Company as inappropriate. Among the services permitted to be deregulated was the leasing of embedded CPE to its subscribers by telephone companies. CPE consists of such items as telephone instruments, radio paging/mobile equipment, data sets, dialers and other supplemental equipment.

On a

Sections 167(1)(3)(G) and 168(i)(9) of the Code contemplate the creation of a reserve for deferred income taxes when depreciation for tax purposes is greater than depreciation for book purposes, and a reduction of the reserve when depreciation for tax purposes is less than depreciation for book purposes. Section 1.167(1)-1(h)(2)(i) of the regulations requires that the deferred tax reserve shall not be reduced except to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation, and that the aggregate amount allocable to deferred tax under section 167(1) may be properly adjusted to reflect asset retirements or the expiration of the period for depreciation used in determining the allowance for depreciation under section 167(a) .

Section 203(e) of the Act sets forth a transitional rule for normalization excess deferred tax reserves resulting from the reduction of corporate income tax rates with respect to depreciation on assets placed in service before 1986. Under this rule, a taxpayer is not considered to be using a normalization method of accounting with respect to any of its assets if the excess deferred tax reserve is reduced more quickly or to a greater extent than the reserve would be reduced under the average rate assumption method.

Section 203(e)(1) of the Act provides that:

In General - A normalization method of accounting shall not be treated as being used with respect to any public utility property for purposes of section 167 or 168 of the Internal Revenue Code of 1986 if the taxpayer, in computing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, reduces the excess tax reserve more rapidly or to a greater extent than such reserve would be reduced under the average rate assumption method.

The average rate assumption method was defined in section 203(e)(2)(B) of the Act as "the method under which the excess in the reserve for deferred taxes is reduced over the remaining lives of the property as used in its regulated books of account which gave rise to the reserve for deferred taxes."

In this case, most of Company's deferred tax reserve was established during a period when the federal tax rate was at 46 percent. The federal income tax rate has now been reduced to 34 percent; therefore, the amount of the reserve with respect to the assets in question is larger than required at the current prevailing tax rate.

Commission concluded that their proposed treatment of CPE related excess deferred tax reserves will not reduce the reserve for deferred taxes below the amount that is necessary to accommodate the adjustments required by an acceptable normalization method of accounting during the period when the tax depreciation on the assets in question is less than the straight-line depreciation calculation by which deferred taxes are measured. Commission concluded furthermore that since the cost of service used in setting regulated rates reflected use of the normalization method of accounting for income taxes, the income tax expense component of cost of service included higher taxes than were actually incurred by Company.

The primary basis for including the higher income tax expense was, among other reasons, to allow Company the cost-free source of capital advantages associated with accelerated tax depreciation. Commission contends that the implicit assumption in using the higher tax expense in determining cost of service was that the tax savings accumulated in the deferred tax reserve account would be reversed later, when book depreciation exceeded tax depreciation. for these years this would result in a lower income tax expense for cost of service purposes than the income tax expense actually incurred. If the excess deferred tax reserves are transferred to the nonregulated accounts, rather than remaining in the regulated accounts, ratepayers will never receive the benefit of the reversal of these tax deferrals which no longer constitute a tax liability for Company. In contrast, shareholders will obtain from regulated operations higher deferred taxes reserves than required to pay CPE related federal tax liability. Commission, along with Commission's Staff and the State Y Attorney General, believe that the proposed treatment would meet the normalization requirements of the Code.

In addition, Commission Staff and State Y Attorney General did not find section 168(i)(9)(B) of the Code applicable to the situation in question. Section 168(i)(9)(B) deals with inconsistent estimates and projections of income tax expense, depreciation and the reserve for deferred taxes for ratemaking purposes. Section 203(e) of the Act clearly distinguishes "excess deferred tax reserves" from the reserve for deferred taxes and sets forth special regulatory treatment for the "excess deferred tax reserves". They believed that since the "excess deferred tax reserves" were not addressed in section 168(i)(9)(B) , any references to this section were irrelevant to the instant case.

On the contrary, we believe that where property is removed from regulation, all taxes previously deferred in compliance with sections 167(1) and 168(i)(9) of the Code attributable to such property must also be removed from regulation. We also believe that section 203(e) of the Act does not override the consistency requirements of sections 167(1) and 168(i)(9) . Indeed, Sec. 2.04 of Revenue Procedure 88-12 (1988-8 I.R.B. 15) provides that "section 203(e) of the Act does not modify the normalization requirements of section 167(1) or section 168(i) of the Code".

A violation of the normalization requirements of the Code will occur if the excess deferred taxes remain in regulation either as an immediate flow through to ratepayers or as a deferred tax which reduces rate base and cost of service, when the property which gave rise to the excess is no longer subject to regulation. This interpretation is supported by the consistency requirements of section 168(i)(9)(B) of the Code.

Section 203(e) of the Act does not redefine a normalization method of accounting. It does, however, provide that amounts which were originally deferred pursuant to a normalization method of accounting remain subject to the normalization rules of sections 167(1) and 168(i)(9) of the Code.[1] Accordingly, all amounts previously deferred under corporate tax rates at 46 percent are part of a "reserve to reflect the deferral of taxes" as described in sections 167(1)(2)(G)(ii) and 168(i)(9)(A)(ii) , and become inseparable from the assets which initially gave rise to the deferral.

When property is removed from regulation in a nontaxable transfer, taxes previously normalized pursuant to sections 167(1) and 168(i)(9) of the Code must also be removed from regulation in order to carry out the intent of normalization. This is supported by the consistency requirements of section 168(i)(9)(B) and the regulations under section 167(1) . A transfer of property from regulation, as ordered by Commission, without a transfer of all taxes deferred under statutory normalization, would result in an inconsistency; being that regulated cost of service and/or rate base would be reduced by a portion of the associated tax deferral while the asset is no longer subject to regulation, thereby not generating regulated depreciation expense.

The same conclusion can also be drawn if property is subject to more than one regulatory jurisdiction. As percentages of use shift between regulatory jurisdictions (or shift in or out of regulation), amounts subject to normalization follow those percentages proportionately. Section 1.167(1)-3(a)(2) of the regulations, and the example contained therein, makes the same connection between normalization of taxes and the underlying asset giving rise to the deferral. The aforementioned example clearly points out that in instances of multiple regulation of an asset (including a portion of an asset not subject to regulation), the percentage of an asset subject to a particular regulatory jurisdiction determines the extent to which a normalization violation is applicable.

Therefore, based on your representations and our legal analysis, we rule that:

Commission's proposed treatment of CPE related excess deferred tax reserves for ratemaking purposes does not comply with the normalization requirements of sections 167(1) and 168(i)(9) of the Code; the entire deferred tax balance should follow the property which was removed from regulation.

This ruling is directed only to the taxpayer who requested it. Section 6110(j)(3) of the Internal Revenue Code provides that it may not be use or cited as precedent. Temporary or final regulations pertaining to one or more of the issues addressed in this ruling have not yet been adopted. Therefore, this ruling will be modified or revoked by adoption of temporary or final regulations, to the extent the regulations are inconsistent with any conclusions in the ruling. See section 16.04 of Rev. Proc. 89-1 , 1989-1 I.R.B. 8, 19. However, when the criteria in section 16.05 of Rev. Proc. 89-1 are satisfied, a ruling is not revoked or modified retroactively, except in rare or unusual circumstances.

A copy of this ruling letter should be filed with the income tax return for the taxable year or years in which the transaction covered by this ruling are consummated.

[1] Revenue Procedure 88-12 provides relief for those taxpayers who cannot comply with the average rate assumption method due to the absence of vintage records. Company maintains a deferred tax reserve through the use of vintage records, and, therefore, is required to use the average rate assumption method.

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-08

QUESTION:

Refer to the Direct Testimony of Charles Pringle at 24:14-17 wherein he describes his "understanding that this approach appropriately allocates FIT among members of the consolidated group."

a. Identify and describe all sources reviewed and/or relied on by Mr. Pringle to inform his "understanding," including, but not limited to, research prepared by or for the Company internally or by external advisors.
b. Provide a copy of all sources and all other materials reviewed and/or relied on by Mr. Pringle to inform his understanding, including, but not limited to, research prepared by or for the Company internally or by external advisors.

ANSWER:

a. Mr. Pringle relied on FERC Order 173 to reach his conclusion.

b. Please see attachment GCCC02-08 Attachment 1 FERC Opinion 173.

SPONSOR (PREPARER):
Charles Pringle (Charles Pringle)

RESPONSIVE DOCUMENTS:
GCCC02-08 Attachment 1 FERC Opinion 173.pdf

James T. McManus and *Dale A. Wright* for the Interstate Natural Gas Association of America

Hodges B Childs and *James A. Biddison* for Baltimore Gas & Electric Company

Rose T. Lennon for Washington Gas Light Company

Frederick L. Jaffe , [**2] *William A Thielen* , and *Demetrios G Pulas* for the Staff of the Federal Energy Regulatory Commission

JUDGES:

Before Commissioners: C. M. Butler III, Chairman; Georgiana Sheldon and Oliver G. Richard III.

OPINION:
[*61,847]

I.

Columbia Gas Transmission Corporation owns and operates an extensive pipeline system in the Appalachian and Atlantic coast regions. It sells natural gas at wholesale to a number of distribution systems. The company has much of its gas transported to it by Columbia Gulf Transmission Company, which owns and operates a pipeline extending from the Gulf Coast to Appalachia. In May 1975 each pipeline company tendered for filing increased rates. n1 As part of the justification for the increased rates, each pipeline included in its cost of service and allowance for federal income tax expense. Each pipeline determined its tax allowance as would any other company seeking an increase in rates from this Commission--by applying the applicable statutory tax rate to, essentially, the allowed return on equity. n2

n1 The pipelines' proposed rates were accepted for filing and suspended on July 14, 1975, and became effective, subject to refund, on December 15, 1975. The rates remained in effect through November 1, 1976, when they were superseded by the pipelines' proposed rates filed in Docket Nos. RP76-94 and RP76-95.
[**3]

n2 For a fuller discussion of how the pipelines calculated their tax allowances, see *infra* p. 11.

The City of Charlottesville, Virginia, a customer of Columbia Gas Transmission, contends that, because the pipelines are not like most other rate applicants, this method of determining the tax allowance produces excessive rates. Hence the question [*61,848] before us is whether the method the pipelines have used produces a just and reasonable tax allowance. We hold that it does.

II.

The facts that give rise to the controversy are straight-forward. They are as follows: Columbia Gas Transmission and Columbia Gulf Transmission are wholly owned subsidiaries of Columbia Gas System, Inc. Besides owning all the stock and debt securities of the pipelines, the parent owned during the time in question all the stock and debt securities of 14 other companies. Because the parent is the sole owner of each of its subsidiaries, the group has a choice as to how it will report its income to the Internal Revenue Service. The group may have each company file a return for itself and pay a tax on its own taxable income. Alternatively, the group may have the parent file a consolidated return [**4] and pay a tax on the group's consolidated taxable income. n3 Since 1947 the Columbia group has elected to have the parent file a consolidated return.

n3 Permission to file a consolidated return is granted in *Section 1501 of the Internal Revenue Code of 1954, 26 U.S.C. § 1501* (1982) [hereinafter cited as I.R.C.].

The rules governing the calculation of consolidated taxable income are quite complex and detailed But the basic conception underlying them is simple. It is that:

> [T]he consolidated group constitutes, in substance, a single taxable enterprise, despite the existence of technically distinct entities; as such, its tax liability ought to be based on its dealings with "outsiders," rather than on intra-group transactions. This "single taxpayer" concept lies at the heart of the treatment, both past and present, of intercompany transactions which, in general, are eliminated in computing the group's consolidated taxable income. In effect, the results are not unlike the "joint return" treatment of husband and wife. n4

n4 Bittker & Eustice, *Federal Income Taxation of Corporations and Shareholders*, § 15.23 (3rd ed. 1971).

[**5]

Once these adjustments are made, each member's various items of income and deductions are combined on the standard corporate income tax return. The taxable income shown there is the consolidated taxable income. The statutory rate is then applied to derive the group's consolidated tax liability

The principal advantage of filing a consolidated return over filing separate returns occurs when one member of the group has deductions that exceed its income, that is, when it has a tax loss. If separate returns were filed, the deductions would eliminate the company's income, and the company would pay no income tax. But the excess deductions would have no further tax reducing effect for the company or the group in that year. On a consolidated return, however, those excess deductions can be used to reduce the taxable income of other members of the group. Hence in a year when one member of the group has deductions in excess of its income, the tax liability of the group will be less if a consolidated return is filed than if each member filed a separate return. The difference between the tax liability the group reports on the consolidated return and the tax liability the group would have reported [**6] had each member filed separately is often called a "tax savings."

During the test year, 1974, six members of the Columbia group had deductions that exceeded their income. So the group realized a tax savings by filing a consolidated tax return. The losses of five of these companies--the parent and four companies engaged in developing new gas supplies for the system--are relevant here. n5

n5 The four gas development companies are: Columbia Gas Development, Columbia Gas Development of Canada, Columbia Coal Gasification, and Columbia LNG.

The sixth loss company was Columbia Gas of West Virginia, which distributes gas at retail. No issue concerning this company is now before us. For an explanation, see *infra* notes 8 and 26.

III

The City of Charlottesville contends that the tax savings created by offsetting the excess deductions of the five companies against the income of the other members of the [*61,849] Columbia group, including the pipelines, must be shared with, or flowed through, to the pipelines' ratepayers. This is so, Charlottesville argues, because the tax allowance for a utility is limited by established regulatory principle to the taxes it actually pays. According [**7] to Charlottesville, the pipelines' actual tax responsibility is a *pro rata* share of the consolidated tax liability Since the consolidated tax liability reflects the tax reducing effects of using the excess deductions of the loss companies to reduce the taxable income of other members of the group, a tax allowance based on a *pro rata* share of the consolidated tax liability flows an equal share of the savings through to the pipelines' ratepayers. n6 Because the pipelines' tax allowances are greater than their *pro rata* share of the consolidated tax liability, Charlottesville argues that the tax allowances are excessive.

n6 We will explain how Charlottesville proposes to implement its recommendation below *See infra* p. 15.

The Public Service Commission of the State of New York supports Charlottesville's position.

The pipelines, who are supported by our staff, a group of electric utilities, and the Interstate Natural Gas Association of America, take a different view. The pipelines concede that their tax allowances do not reflect any of the tax savings produced by the excess deductions of the four gas development companies. But they argue that, as [**8] a matter of proper ratemaking policy, those tax savings should not be reflected in the tax allowances. The pipelines contend that this is the correct policy because the ratepayers have not been charged with the responsibility of paying the expenses that gave rise to the excess deductions.

With respect to the parent, the pipelines and their supporters agree with Charlottesville that the savings produced by this company's excess deductions should be flowed through to the pipelines' ratepayers. This is so because the ratepayers have been charged with the responsibility of paying the expenses that gave rise to the parent's excess deductions. But it is the position of these parties that the method the pipelines used to calculate their tax allowances already reflects those savings Hence, it is argued, no reduction in the tax allowances is justified.

IV.

There are thus two issues before us. One concerns the parent's loss. It is very technical--indeed, it is arithmetical. Does the pipelines' method of calculating their tax allowances flow the tax savings created by the parent's loss through to ratepayers?

The other issue concerns our policy towards utilities that join in filing a consolidated [**9] tax return. The precise question before us, though, is not so easily stated The issue has had a long history at this Commission and at others. The terms of the debate--"actual taxes paid," "phantom taxes," "stand alone," "separate entity"--have acquired many meanings Their use here suggests the division between the parties is stark and the question before us simple. Are the tax savings to be shared or are they not? Should the tax allowance be based on the consolidated return or should the filing of that return be ignored and the pipelines treated as though they filed separate returns?

These, however, are not the questions before us. The pipelines join in filing a consolidated tax return. And the Columbia group realizes a tax savings by filing such a return. There is no justification for ignoring that reality. And no one contends that we should. [*61,850]

But saying that resolves nothing. It only creates the problem that must be resolved here. The consolidated tax liability is the liability of a single entity. No amount can be specifically identified as the liability of one member of the group. n7 The same is true of the tax savings. So we must allocate some portion of the [**10] liability or of the tax savings to the members of the group. The question we have before us, then, is really the very pragmatic one of how we should do that. Should we, as Charlottesville urges, adopt a method that automatically shares a portion of all the tax savings with the ratepayers? Or should we, as the pipelines urge, adopt a method that shares the tax savings with the ratepayers only when there has been a commensurate sharing of the burdens? Which of these methods is just and reasonable? n8

n7 Indeed, each member is severally liable for the consolidated tax liability of the entire group. *26 C.F.R. § 1.1502-6(a) (1982).*

n8 This is not the first time these issues have been before the *Commission In Opinion No. 47, 8 FERC P61,002 (1979)*, and *Opinion No 47-A, 9 FERC P61,355 (1979)*, the Commission held that as a matter of policy the tax losses of the gas supply companies should not be used to reduce the pipelines' tax allowances. Among the reasons the Commission gave for this policy was that it was needed to encourage gas exploration and development. The Commission also held that the pipelines' tax allowances already reflected the tax savings produced by the parent's tax loss. Finally, the Commission held that the tax savings produced by the tax loss of the retail distribution subsidiary should not be used to reduce the pipelines' tax allowances because of the particular circumstances of that company.

The City of Charlottesville then sought review of Opinion No. 47 and Opinion No. 47-A in the Court of Appeals for the District of Columbia Circuit. The Court affirmed the Commission's decision with respect to the tax loss of the retail distribution subsidiary. *City of Charlottesville v. F E.R.C ., 661 F.2d 945, 952 (1981)* But the Court held that there was insufficient evidence to support the Commission's incentive rationale. *661 F.2d at 954*. The Court also found the record incomplete on the treatment of the parent's tax loss. *661 F.2d at 952* Accordingly, the Court returned the case to us.

We then directed that a hearing be held on the issues the Court remanded to us and that the record be certified to us for decision. *20 FERC P61,036 (1982)*. That hearing has held, and a voluminous record has been made.

In reviewing this record we have reconsidered the policy question from the ground up Though we reach the same result on that question as did the Commission in Opinion No. 47 and Opinion No. 47-A, we do so for considerably different reasons. Specifically, we place no reliance on what has come to be called the "incentive rationale" that the Commission relied on in those Opinions. We do so because the policy the Commission applied is broader and more fundamental than one needed to encourage gas supplies. The policy involves a basic decision about the proper way to set cost-based rates. As such, the policy applies not only when a pipeline joins with an exploration affiliate in filing a consolidated return but also when any jurisdictional company, be it a pipeline or an electric utility, joins with other businesses in filing a consolidated return.

[**11]

We consider the policy issue first.

V.

For us, a rate for a gas pipeline or an electric utility is "just and reasonable" when it is cost-justified. That is, the rate should be set so as to allow the company the opportunity to recover the expenses it incurs in providing service and earn, after paying taxes, the allowed rate of return.

That is easy enough to say. But the cost-based standard is difficult to apply. Among the problems is simply the determination of the costs incurred in providing service.

The amounts the company records in its books for the year are the starting point. But they are a starting point only. These amounts often do not reflect the costs incurred in providing service during the test year. The amounts may reflect payments for services that were performed earlier or that will be performed later or that benefit other services separately regulated by us, by other regulatory commissions, or that are not regulated at all. And where the company is part of an affiliated group, the amounts recorded on the company's books may reflect payment for services performed for its siblings. Or the company's books may not reflect the expenses its siblings have incurred for [**12] the benefit of the ratepayers.

In all these cases the "problem is to allocate to each class of the business [and to each time period and each company] its fair share of the costs." n9 We have developed a number of methods for doing that. These methods vary with the expense at issue and the problem presented. Some are simple and straight-forward. Others are complex and subtle.

n9 *Colorado Interstate Gas Co. v. F P.C , 324 U.S. 581, 591 (1945)*

Despite the profusion of allocation methods we employ, there is a common thread that ties them together. That thread is the concept of cost responsibility or cost incurrence. n10 Each of the methods attempts to allocate costs to the group of ratepayers in question on the basis of a causal link between the service the company provides them and the expenses the company reports. That this is a fair method of allocation is self-evident. And it limits the allowance for expenses to the costs associated with the goods and services provided in the period.

n10 *See e .g ., Utah Power & Light Company , Opinion No. 113, 14 FERC P61,162, at p. 61,298 (1981),* where the Commission said that it "must allocate costs in a manner which reflects cost incurrence."

[**13]

Taxes are no different from other expenses included in the cost of service. So there should be no difference between the principles used to determine the tax allowance and the allowances for other expenses. And we make no distinction In both cases we limit the allowance charged to ratepayers to an amount equal to the costs the company incurs in serving them. But the application of these principles is a little different in the case of taxes. [*61,851]

The need for a different application of the principles stems from the fact that the income tax is not simply a tax on income It is a tax on profits, which is gross income less the expenses incurred in producing income. So the tax allowance should be equal to the tax on the profit the ratepayers will contribute to the company. In short, the tax allowance should be equal to the tax on the company's allowed return on equity. n11 This is so because the allowed return on equity is the amount of profit the company should receive for providing service to the ratepayers.

n11 This is somewhat of an oversimplification The calculation is slightly more complicated. *See infra* p. 11 But we need not address these refinements here.

[**14]

There are, however, vast differences between our assessment of the profit the company is due and the calculation of the amount by which the company is considered to have been enriched by the Internal Revenue Service. Some of these differences stem from the differences in the revenue that is used in calculating the company's profit. The most obvious difference is that we base our determination of the company's profit on projections of revenue. The Internal Revenue Service uses, of course, the revenues the company either actually receives or accrues the right to receive during the tax year. There are even greater differences in the expenses that are recognized.

Because these differences are so vast, the Commission has found that the taxes the company pays to the Internal Revenue Service are not a reliable guide, even as a starting point, for determining a company's tax allowance. Instead, the Commission has always made its own assessment of the tax cost the company incurs in providing service.

We make that independent assessment by considering the two elements that go into the calculation of taxes--income and expenses--separately. We start by determining the income we expect the company [**15] to receive from the particular service in question. There is usually no problem with this. We then consider the deductions from income. This requires an allocation, for just as the expenses recorded in the company's books may be for services performed for different periods or different classes, so also with the deductions reported on the tax return. Here again we allocate on the basis of the customers' responsibility for the deductions.

Because deductions are given for expenses incurred in producing income, the necessary causal link between the ratepayers and the deductions is the expenses the company incurs in providing service. Accordingly, the proper way to allocate deductions is to match the deductions with the expenses included in the cost of service. Thus, when an expense is included in the cost of service, the corresponding tax deduction is also allocated to the ratepayers. In this way any tax reducing benefits, or savings, the company realizes in providing the service are recognized in calculating the tax allowance for the benefit of the ratepayers.

The corollary to this is that when an expense is not included in the cost of service (because the company did not incur that [**16] expense in providing service), the deduction created by that expense is not allocated to the ratepayers. To do otherwise would result in the tax savings the company realizes from expenses incurred in providing services to other groups and periods or for its own benefit being used to reduce rates for a particular group of ratepayers. The tax allowance would then be lower or higher than is warranted by the profit each group provides the company. Since the amount of profit to be provided is the measure of the tax cost the company will incur in providing service, none of the rates for the groups would be cost-justified. Subsidization would inevitably result. One group would bear the burden, but another group would gain the benefit. [*61,852]

VI

So much for theory. What of its application to the case? How does the method the pipelines have used stack up against this standard?

The short answer to these questions is that the method the pipelines have used stacks up very well. It produces an allocation of the consolidated tax liability that is cost-justified and just and reasonable.

The method the pipelines have used, and the method the Commission has followed since 1972, is one [**17] in which "a utility [is] considered as nearly as possible on its own merits and not on those of its affiliates." n12 This method is called the stand-alone method, for "a stand-alone income tax allowance is one that takes into account the revenues and costs entering into the regulated cost of service without increase or decrease for tax gains or losses related to other activities . . . " n13 The stand-alone method results in the tax allowance being equal to the tax the utility would pay on the basis of its projected revenues less deductions for all operating, maintenance, and interest expenses included in the cost of service. In short, it results in a tax allowance equal to the tax on the allowed return on equity.

n12 *Florida Gas Transmission Company, Opinion No 611, 47 FPC 341, 363 (1972).*

n13 Exh. 11 at 4.

The mechanics of calculating a stand-alone tax allowance are as follows. From the total return allowed on rate base are deducted interest expenses (computed by multiplying the rate base by the weighted cost of long-term debt used in determining the rate of return), permanent tax differences, and the effect of the surtax exemption to arrive at the [**18] tax base. The tax base is then multiplied by the factor of 48% over 52% (now 46% over 54%) to produce the tax allowance, which includes recognition of the fact that the tax allowance itself is subject to tax when received by the utility and is not deductible. The amount so calculated is the tax allowance.

That the mechanics of calculating a stand-alone tax allowance do not take into account the revenue received and deductions for operating and maintenance expenses is not important. In calculating the tax allowance our policy is that a legitimate expense for cost of service purposes is to be considered to be a legitimate deductible expense in calculating a company's cost of service tax allowance. n14 Accordingly, we can safely ignore the utility's operating and maintenance expenses and the revenues needed to recover those expenses. The only area for concern is the return on rate base.

n14 This policy is most familiar from our rulemaking on tax normalization. *Tax Normalization for Certain Items Reflecting Timing Differences in the Recognition of Expenses or Revenues for Ratemaking and Income Tax Purposes*, Order No. 144, *FERC Statutes and Regulations* P30,254 (1981), *reh. denied*, Order No. 144-A, *FERC Statutes and Regulations* P30,340 (1982), *aff'd sub nom.*, *Public Systems v F.E.R.C.*, Nos. 82-1183 *et al* . (D.C. Cir. May 31, 1983).

[**19]

This may not look like an allocation of the consolidated tax liability Indeed, it looks like a policy that willfully ignores the consolidated tax liability. At least, this is the way Charlottesville views our stand-alone policy. It says that our stand-alone policy is nothing but a policy that calculates the tax allowance on the false assumption that the pipelines file separate returns and thus ignores the tax savings the group realizes by filing a consolidated return. n15 This is incorrect.

n15 Brief for Charlottesville at 12; Exh. 13 at 11.

A separate return policy assumes that the tax allowance should be equal to the tax the jurisdictional service would pay if it filed a separate return. Under a separate return policy the tax allowance would equal the tax the jurisdictional service would pay on its projected revenues less the deductions that would be shown on its return. A separate return policy thus ignores the consolidated tax return and reflects in the tax allowance none of the tax reducing benefits the group realizes from filing a consolidated return n16

n16 It is doubtful whether a separate return policy could ever be put into operation. The problem is, of course, that the company does not file a separate return. So we would have no way of really knowing what its taxable income would be if it filed such a return To be sure, appended to the consolidated return is a calculation of each member's "separate taxable income." But the separate taxable income used in preparing the consolidated return "differs sharply from the separate taxable income of the members that would be reported on separate returns." Peel, *A Treatise on the Law of Consolidated Federal Income Tax Returns* § 5.03 (2d ed. 1973). *See also supra* p. 2. Even if these differences were ignored, there would be other problems. Many deductions permitted by the Code are elective. For example, certain interest during construction and intangible drilling costs may be deducted when incurred or capitalized and depreciated later Hence a separate return policy requires an assumption about the deductions the jurisdictional service would report if it filed a separate return. Presumably, the assumption would be that the jurisdictional service would report deductions in exactly the same manner as the group does on the consolidated return. Whether the service would do so if it in fact filed a separate return is open to question. *See* Exh. 5 at 12; Tr 247, 425.

[**20]

Our stand-alone method is different. It does not ignore the consolidated return or the tax reducing benefits the group realizes by filing such a return. Unlike a separate [*61,853] return policy, our stand-alone policy in effect looks beneath the single consolidated tax liability and analyzes each of the deductions used to reduce the group's tax liability to determine the deductions for which each service is responsible. It then allocates to the jurisdictional service those deductions which were generated by expenses incurred in providing that service. In making this allocation it is irrelevant on which member's return the deductions would be reported if the group filed separate returns. Instead, the test is whether the expenses that generate the deduction are used to determine the jurisdictional service's rates. n17 Put more simply, the test is whether the expenses are included in the relevant cost of service. If they are, the associated deductions and their tax reducing benefits will be taken into account in calculating the tax allowance for that cost of service. If the expenses are not, the deductions will not be taken into account. In this way the tax allowance will reflect [**21] the profit the ratepayers contribute to the group's consolidated taxable income.

n17 *Louisiana Power & Light Company, Opinion No 110, 14 FERC P61,075, at p. 61,124 (1981)* ("The test [for determining when the consolidated tax savings should be flowed through to the jurisdictional customers] is whether the expenses which created the deductions used to achieve the tax savings were paid by the jurisdictional customers "); *Southern California Edison Company, Opinion No. 821, 59 FPC 2167, 2174*

(1977)

Application of our stand-alone policy to the facts of this case results in some of the tax reducing benefits the Columbia group realizes from filing a consolidated return being used to reduce the pipelines' tax allowances. Specifically, the benefits the group realizes from including the parent are used to reduce the pipelines' tax allowance, the tax benefits realized by including the four supply companies are not

The parent reports a tax loss because its deduction for the interest expense it incurs in servicing its debt exceeds its income. n18 By filing a consolidated return this loss is used to reduce the taxable incomes of the pipelines and other [**22] members of the group. Hence the parent's interest expense creates a consolidated tax savings.

n18 The parent also incurs some expenses in serving stockholder accounts and paying its directors. These expenses are deductible. But there is no issue here that these deductions should be used to reduce the pipelines' tax allowances.

In setting the return for the pipelines we used the parent's interest expense as the pipelines' cost of debt. Thus, the ratepayers bear the burden of paying the parent's interest expense. That being so, an equal portion of the parent's interest expense deduction must be allocated to the pipelines' ratepayers. Our stand-alone policy does just this. n19 In this way it reflects in the tax allowances a portion of the consolidated tax savings created by the parent's loss. n20

n19 We will explain in more detail how this is done. *See infra* pp. 50-57.

n20 Under a separate return policy the result would be different The tax allowance for the pipelines would be calculated by using the pipelines' lower interest expense deductions because those are the deductions the pipelines would report if they filed separate returns Under a separate return policy none of the tax reducing benefits the Columbia group realizes by offsetting the parent's loss against the income of the group would be reflected in the pipelines' rates.

[**23]

In 1974 the four supply companies were in various stages of starting their operations. So they had little or no revenue. n21 But because of certain provisions of the Internal Revenue Code they had large tax deductions. Hence each company contributed more deductions than income to the group's consolidated taxable income

n21 Columbia LNG began operating a plant for the manufacture of synthetic gas in 1974. The company was also constructing a plant to store and regasify imported liquefied natural gas. Columbia Coal was engaged in the development of methods of converting coal to gas. But it did not produce any gas. Nor did it produce any revenue Columbia Gas Development of Canada was exploring for gas in Canada and the Arctic Like Columbia Coal, this company produced neither gas nor revenue Columbia Gas Development was exploring for gas in the Southwest. This company also produced some gas. So this company produced some revenue, but not enough to offset its deductions.

These companies have undertaken their projects to provide additional gas supplies for the system, including the pipelines. But the expenses these companies have incurred were not incurred in providing transmission [**24] service. So the requisite causal link between the pipelines' ratepayers and the expenses incurred is missing The ratepayers were therefore not responsible for these expenses. Accordingly, none of the expenses of the gas development companies were included in the pipelines' cost of services Because this is so, none of the deductions of the gas development companies should be allocated to the pipelines' ratepayers And they are not under our stand-alone policy To hold otherwise would result in tax allowances for the pipelines lower than are called for by the amount of profit the pipelines' ratepayers will contribute. The rates would then not be cost-justified or just and reasonable.

VII.

The method for determining the tax allowance Charlottesville advocates is considerably different. Charlottesville starts with each pipeline's *pro rata* share of the consolidated tax liability. Charlottesville calculates that amount by multiplying the [*61,854] consolidated tax liability by the ratio the pipeline's taxable income bears to the total taxable income of all members of the group having taxable income. Charlottesville then derives an effective tax rate by dividing the pipeline's [**25] taxable income into the pipeline's share of the consolidated tax liability. Charlottesville uses the effective tax rate instead of the statutory rate in calculating the pipelines' tax allowances n22

n22 See Exh. 22B for the calculations

Charlottesville suggested an alternative method that reaches the same result. Under this method the total losses of the group are multiplied by each pipeline's allocation ratio. The pipeline's share of the losses are then taken as an additional deduction in calculating the pipeline's tax base for the cost of service. The statutory rate is applied to the tax base so calculated *See* Exh. 23B.

We do not find this to be a reasonable method for determining the pipelines' tax allowances. The method focuses solely on the total tax liability and the aggregate reduction. It is oblivious to how that liability and reduction came about It ignores each member's income and deductions that were combined to produce that liability. But consideration of what each member has contributed is essential. Without knowing that we cannot properly assess each member's and the ratepayers' responsibility for the single tax liability. So the method need not produce--and [**26] in this case does not produce--tax allowances that reflect the tax costs the pipelines incur in providing jurisdictional service.

If this were the first case in which this method had been presented to us, this might be a sufficient response. But this is not the first case. Indeed, in a number of cases in the 1940's and 1950's the Federal Power Commission's method for calculating the tax allowance when the regulated entity joined in filing a consolidated return was identical in all essential respects to the method Charlottesville advocates. n23 Hence we need to explain why we no longer follow this method.

n23 *Michigan-Wisconsin Pipeline Company , Opinion No 275, 13 FPC 326, 373 (1954); Ohio Fuel Gas Company , 13 FPC 281, 286 (1954), Home Gas Company , Opinion No. 272, 13 FPC 241, 246 (1954), Hope Natural Gas Company , Opinion No 262, 12 FPC 342, 347 (1953), United Fuel Gas Company , Opinion No 258, 12 FPC 251, 264-65 (1953); Atlantic Seaboard Corporation , Initial Decision, 11 FPC 486, 515, aff'd , Opinion No 225, 11 FPC 43 (1952); Hope Natural Gas Company , Initial Decision, 10 FPC 583, 612 (1950), aff'd , 10 FPC 625 (1951); Penn-York Natural Gas Corporation , 5 FPC 33, 38-39 (1946).*

[**27]

We have no quarrel with the results of those cases or the method used to calculate the tax allowances. For the most part the only loss company was the parent. n24 These companies reported a tax loss because they were capitalized like Columbia, and hence, also like Columbia, had interest expense deductions in excess of their income. The Commission held that the tax savings produced by these losses should be shared with the pipelines' ratepayers. We think that is correct. We reach the same result here. And the use of the method Charlottesville advocates here was, given the way rates were determined in those cases, perfectly sensible. n25

n24 This fact does not appear in the Opinions. But the records establish that in all but one instance the parent was the primary, if not only, reason the group realized a tax savings by filing a consolidated tax savings. The one exception was the first consolidated tax case, *Penn-York Natural Gas* . The record in that case does not reveal the source of the tax savings.

In three cases, *United Fuel Gas* , *Ohio Fuel Gas* , and *Home Gas* , which all involved the Columbia group for the same time period, some of the tax savings were created by losses incurred by the pipelines' retail distribution affiliates. The Commission flowed those savings through to ratepayers. Since the amounts at issue were very small, we can appreciate why the Commission made no distinction between these tax savings and the much larger tax savings created by the parent's loss. Nevertheless, we have our doubts about this aspect of the Commission's decisions. *See infra* p. 26

[**28]

n25 Rates are now determined somewhat differently. Hence a different method must be used to reach the same result. *See infra* p 57 and note 115.

The reason we can no longer follow this method is that the facts we now have to deal with, not only in this case but also in others, are no longer so simple. There are now many other loss companies besides the parent In most cases there is no justification for reducing a pipeline's tax allowance because of these losses. Hence to continue to use the method the Commission used in the past, we would have to make exceptions for these losses But the exceptions that would have to be made are so numerous that this would be an enormously complicated and administratively impractical way to proceed. Moreover, the method would be so riddled with exceptions that there would not be much of a method left

That exceptions have to be made to the Commission's prior method to reflect the particular circumstances of a loss company has long been recognized. In the cases where Charlottesville's method was used, the Commission nevertheless excluded tax savings resulting from a non-recurring or atypical loss. n26

n26 *Michigan Wisconsin Pipeline Company , 13 FPC at 373; Home Gas Company , 13 FPC at 246*

This same reasoning was followed by the Commission in Opinion No 47 with respect to the loss of Columbia's retail distribution subsidiary in West Virginia. That company lost money from 1970 through 1974 because the state public utility commission had imposed a rate moratorium. The moratorium was lifted late in 1974 so the company was expected to have in place rates that would enable it to report taxable income in the future. Because of that, the Commission held that this loss should be ignored in calculating the tax allowances for the pipelines. 8 FERC at p. 61,009. The Court of Appeals affirmed. *661 F.2d at 952.*

(We note that this rationale would be equally applicable to the loss of Columbia LNG. Although this company reported a tax loss in 1974, the test year, the company has since reported taxable income in every year but one. *See* Exh. 2, Schedule 3; Exh. 5 at 12-13, Exh 14, Schedule 16)

[**29]

But instances of such losses were rare then. And they are probably rare now These losses would not by themselves justify a change in method. n27

n27 This is, however, an area we would prefer to avoid. Many of the instances where there is an allegedly non-recurring loss have involved and will involve a retail subsidiary that has a tax loss. Since we do not regulate retail subsidiaries, it is very hard for us to form a reliable judgment, absent special circumstances as were present in the case of Columbia's West Virginia retail subsidiary, about when these companies will report taxable income.

What does justify a change are two other factors. One of these is the structure of the industry. Since the 1950's pipelines have diversified. They have integrated upstream into production and pipe and compressor manufacturing and downstream into chemicals, fertilizer, and appliances. More importantly, pipelines have moved into [*61,855] other businesses that have nothing to do with the gas business. Pipelines have become involved in such businesses as real estate, financing, packaging, wire manufacturing, textiles, shipbuilding, mining, and even vocational training and employment [**30] services. n28

n28 To be sure, pipelines have always been involved in businesses other than pipelining. But what is important here is that since the 1950's it has become increasingly likely that a pipeline has moved into other businesses and that those businesses have little or nothing to do with the gas business. That this is so is obvious. But we need not rely on general knowledge. Statistics tell the story. In 1959 the nine companies that make up Moody's Natural Gas Transmission Index (El Paso Natural Gas Company, Northern Natural Gas Company. Sonat, Inc., Tenneco Inc., Texas Eastern Transmission Corporation. Transco Companies Inc., United Energy Resources, Inc., and Panhandle Eastern Pipe Line Company) derived 81% of their gross revenue from their gas pipeline operations. By 1978 these companies derived only 55% of their gross revenues from their pipelines. In terms of net revenue the decline was even greater, from 78% in 1959 to 37% in 1978. *See Moody's Public Utility Manual, 1960-1979* and *Statistics of Interstate Natural Gas Pipeline Companies. 1960-1978* . (All figures are weighted averages.) For a chart showing the businesses some natural gas pipelines had moved into by 1973, *see* Federal Power Commission, *Natural Gas Survey* , I-3-65 (1975).

[**31]

That diversification causes problems for our regulation is obvious. It may expose the pipeline's ratepayers to a variety of burdens. The diversified activities may incur losses or costs that the company may attempt to pass on to the pipeline's ratepayers. And the riskiness of the activities may impair the company's credit, thereby raising the cost of capital. The universal response of regulators (at least at this Commission) has been to try to isolate the ratepayers from these burdens. The Commission's allocation methods, which are designed to segregate the costs of jurisdictional and non-jurisdictional businesses, solve many of the problems. But the Commission has gone beyond that to require that the costs of different jurisdictional services, such as gas production, be segregated from the costs of providing transmission service. n29 The Commission has also attempted to limit the capitalization and cost of capital used in setting rates to the capitalization and cost associated with the pipeline business. n30 In short, the response has been to try to regulate the pipeline as an "independent entity" so that it is "considered as nearly as possible on its own merits and not on those [**32] of its affiliates." n31

n29 *See Pipeline Production Area Rate Proceeding (Phase I), 42 FPC 738 (1969), aff'd sub. nom. , City of Chicago v. F.P.C , 458 F.2d 731 (D.C Cir. 1971), cert. denied , 405 U S. 1074 (1972).*

n30 *See e .g ., El Paso Natural Gas Company , Opinion No 582, 44 FPC 73, 77, reh . denied , 44 FPC 753 (1970), aff'd 449 F.2d 1245 (5th Cir 1971); Pacific Gas Transmission Company , Opinion No 579, 43 FPC 837, 842-43 (1970).*

Charlottesville and New York contend that we have not done that here. We disagree. We discuss the question below, pp. 41-45.

n31 *Florida Gas Transmission Company , 47 FPC at 363.*

That too was the Commission's ultimate response to the consolidated tax problem. But that took a while. There were several false starts. n32

n32 This is not surprising. The issue is a difficult one. Even a jurist as insightful as Justice Harlan found the issue "elusive " *See F.P.C. v. United Gas Pipeline Co ., 386 U.S. 237, 248 (1967)* (Harlan, J , dissenting).

[**33]

The first consolidated tax case dealing with a diversified company was *Olin Gas Transmission Company* in 1957 n33 Olin explored, produced, and transported gas. The group to which Olin belonged reported a tax loss on the consolidated return because the losses of Olin's parent on its independent gas exploration and development program exceeded the income from Olin and its other subsidiaries.

n33 *17 FPC 695 (1957).*

The Commission staff, following the established method, argued that because the group paid no taxes, no tax allowance should be included in Olin's cost of service. The judge and the Commission disagreed and allowed a tax allowance based on the company's return on equity. The Commission did so because the losses arose "from unregulated [*i.e* , non-jurisdictional] business activities unrelated to Olin's natural gas operation." n34

n34 *17 FPC at 703*

The Commission's holding seems sound in theory. As a panel of the Court of Appeals for the District of Columbia Circuit said in a famous *dictum* :

> [W]e are not aware of any principled basis for saying that natural gas consumers should pay less for gas simply because [**34] the unlikely hypothesis materializes and, say, Mobil Oil loses money in its Montgomery Ward investment. n35

n35 *American Public Gas Ass'n v. F.P C , 567 F.2d 1016, 1040 n. 33 (D.C Cir 1977)*

But as an administratively practical method, the Commission's holding leaves much to be desired. In many cases it would be easy to tell that the diversified activity is "unrelated" to the pipeline's gas operations. n36 But in other cases the task would not be so easy. The question of what makes an activity related can be answered in many ways. So there would be many questions and many close cases. n37

n36 Such activities as financing, real estate, merchandising, wire manufacturing, textiles, and vocational training seem to be so obviously unrelated to the gas business that no discussion would seem to be needed to establish the point.

n37 For example, would gas operations that are downstream from the pipeline, such as retail gas distribution, chemicals, fertilizer, and gas appliance manufacture and distribution, be related? Because these activities are involved in the gas business, they are related in a way. But they provide nothing to the pipeline. So maybe they are not. Gas operations that are upstream from the pipeline, such as exploration and development, seem more clearly related to the pipeline's business. But how is "relatedness" to be determined? Would the production company be related if it intended to produce gas for the pipeline but had not done so at the time the loss was incurred and would not do so at anytime in the foreseeable future? For example, Columbia Coal Gasification's purpose is to produce gas from coal. But this company's activity since its formation has been mainly to buy and sell coal fields and to mine coal for sale. The company has not produced any gas. Nor does it appear that it will anytime soon. *See* Exh. 48 at 1, 7; Exh 20 at 7.

Columbia Gas Development of Canada had drilled for gas. But it had not found any by the end of 1975. Since then, this subsidiary has found gas in commercial quantities. Exh. 15 at 30. And it wants to sell that gas to

Columbia Gas Transmission. But to date the pipeline has not been granted authority to import the gas. Whether it will ever be granted that authority is uncertain *See* Exh. 48 at 9-10; Exh. 12B at 8; Exh 20 at 6-7.

Can the activities of these two companies then be described as related to the pipelines' activities?
[**35]

These questions were never answered, however. The diversification movement was just beginning. So cases presenting the question were rare. And in the next case that did present the question the Commission changed policies again. [*61,856]

This occurred in the *Cities Service Gas Company* case. n38 Cities Service Gas Company was a member of a truly diversified company. Besides the gas pipeline company, the parent owned, directly or indirectly, companies that produced oil in the United States, South America, Africa, Canada, the Middle East; that refined oil; that transported oil through a pipeline in the United States and by means of a fleet of tankers; and that owned office buildings. Many of these companies, especially the foreign oil production companies, reported losses On the consolidated return filed by the parent these losses were used to reduce the taxable income produced by the gas pipeline company and others.

n38 *Opinion No. 396, 30 FPC 158, reh. denied , 30 FPC 676 (1963), rev'd , Cities Service Gas Co v F.P.C , 337 F.2d 97 (10th Cir 1964) But see F.P.C. v. United Gas Pipeline Co , 386 U.S. at 248,* where the Supreme Court rejected the Court of Appeals' reasoning and affirmed the Commission's position in the *Cities Service* case.
[**36]

The Commission's staff argued that the Commission should adhere to its traditional "actual taxes paid" principle. Following that traditional principle the staff would have allocated the consolidated tax liability the way the Commission had done in the cases from the 1940's and 1950's and as Charlottesville urges here.

The administrative law judge rejected the Staff's argument. He did so because the losses were incurred in activities that were unrelated to the pipeline's business. n39 The Commission also rejected the staff's argument. It found the staff's method artificial and unstable. The Commission did not think the method was satisfactory for ratemaking purposes. n40

n39 *30 FPC at 185.*

n40 *Id . at 162*

The Commission, however, did not affirm the judge. It developed yet another method. The Commission pointed out that its task was "to determine the proportion of the consolidated tax [liability] which is reasonably attributable to the Gas Company *vis-a-vis* the other Cities Service affiliates." n41 That being so, the Commission said, the principles controlling the allocation of other costs should control the allocation of the consolidated [**37] tax liability. n42 In the Commission's view these principles required the "separation between regulated and unregulated costs and revenues." n43

n41 *Id*

n42 *Id*

n43 *Id .*

Following these principles the Commission developed this method of allocating the consolidated tax liability (1) separate the companies into regulated (whether by this Commission or some other commission) and unregulated groups;

(2) determine the net aggregate taxable income of each group; and (3) allocate the consolidated tax liability between the groups and among the companies of each group on the basis of their respective taxable incomes n44 The effect of this method was to apply the losses of unregulated companies as an offset first to the taxable income of unregulated companies. If the unregulated group had taxable income after being reduced by unregulated losses, the regulated companies would not share in the tax savings. Only if the unregulated group as a whole incurred a tax loss, would the regulated group share in the consolidated tax savings.

n44 *Id . at 164.*

We agree with the Commission's starting point in *Cities Service* . As we have said, the question [**38] before us is simply an allocation question. The allocation principles used here should not differ from those used to allocate other costs. We also appreciate what the Commission was trying to accomplish with its distinction between regulated and unregulated companies. Most companies that are unregulated are probably unrelated to the activity of a regulated gas pipeline. So the distinction would exclude most of the losses that should not be used to reduce the tax allowance of the pipeline And the question of whether the company is regulated or not certainly appears to be more easily answered than the question of whether the company's activities are related or unrelated to the pipeline's business. [*61,857]

But beyond this, we cannot agree with this approach. The distinction between regulated and unregulated and the allocation method the Commission developed to reflect this distinction faces insurmountable problems.

Some of these problems are practical. The method is, or at least can be, difficult to apply. n45

n45 The practical problems are two-fold. First, it is not at all that clear what makes a company regulated. Is rate regulation required? The Court of Appeals for the Fifth Circuit thought so. *United Gas Pipe Line Co. v. F P C ., 388 F 2d 385, 388, rev'd on other grounds , 390 U S 71 (1968).* But a plausible case can be made that certificate authority or even import authority is sufficient.

The other problem concerns companies that engage in both regulated and unregulated activities. It is clear that the taxable income must be allocated to these activities. *F P C v United Gas Pipe Line Co ., 386 U S. at 247.* That task presents many nice questions of fact and methodology. There is no easy way to resolve those questions short of preparing a full cost of service. Where the company is jurisdictional and before us seeking a change in rates that would present no additional burdens. We would have prepared the cost of service anyway. But where the company is either not before us seeking a change in rates or is non-jurisdictional, these questions would significantly add to our burden. For example, to follow the *Cities Service* method in this case would require us to allocate the loss of Columbia LNG to its unregulated synthetic gas operations and its jurisdictional liquefied gas operations. But the company was still building the liquefied gas terminal during the test year of this case. So we had no need to inquire into that company's costs. Yet that is what we would have to do to arrive at the tax allowance for the pipelines That seems to us to be a little bit wasteful of the Commission's resources.
[**39]

Other problems are more fundamental. One is that the distinction between regulated and unregulated is inconsistent with the principles this Commission uses to allocate costs. Instead, we allocate costs between jurisdictional and non-jurisdictional operations, and, where there are two or more jurisdictional operations, the costs incurred in providing the service whose rates are being determined and costs incurred in providing other services. The simple fact that a company's operations are regulated is quite irrelevant. So the *Cities Service* method does not conform to its own starting point.

Viewing the question more broadly we do not see why the absence of regulation makes a company's loss less significant to the task of determining a pipeline's tax costs Adherence to that view could produce absurd results n46 n46 Hypotheticals are easy enough to think of. For example, in the Columbia system the operations of the parent, Columbia Coal Gasification, the synthetic gas operations of Columbia LNG, and (probably) Columbia Gas Development of Canada are unregulated. Suppose that in the future the unregulated operating subsidiaries made bundles of money and had more than enough taxable income to absorb the parent's loss Under the *Cities Service* method the tax savings produced by the parent's loss would not be used to reduce the pipelines' tax allowances. But these tax savings should be shared with the pipelines' ratepayers.

[**40]

A third problem concerns the loss of a regulated company. Under the *Cities Service* method such a loss is automatically used to reduce the taxable income of regulated companies. n47 Thus, the *Cities Service* method (or, for that matter, the method Charlottesville advocates) permanently assigns the tax savings generated in providing service to one group of ratepayers to an entirely different group of ratepayers, based solely on the fortuity of common ownership. We see no justification for that If the tax savings are to be shared with any group of ratepayers, they should be shared with the ratepayers of the company that incurred the loss. n48

n47 In *Cities Service* the regulated company with the loss was a company that transported oil by pipeline. The company was then regulated by the Interstate Commerce Commission.

n48 The point can be put a little more bluntly. The method may look fair to ratepayers of a company with taxable income. But we doubt it looks fair to the ratepayers of the company with a loss.

Problems like these led the Commission to reassess the whole question and to start afresh in its *Florida Gas* decision. n49 This reassessment rested on two [**41] facts. One was that the complicated set of facts presented in the *Cities Service* case was not unique. Instead, as the Commission noted, "there has been an increasing tendency for pipeline affiliates to diversify and to engage in activities completely unrelated to gas pipeline operations or the gas business at all, so that determining a tax allowance for the pipelines' jurisdictional business on the basis of the activities of a far-flung conglomerate bears less and less relationship to the operations in which we are properly interested." n50 The second fact was that with other ratemaking questions the Commission had endeavored to isolate the pipeline business from the consequences of that diversification. n51

n49 *47 FPC at 362-63, supra* p. 10. The Commission noted the problem of using the tax loss of one regulated company to reduce the tax allowance of another regulated company.

n50 *Id . at 362*

n51 *Id* The Commission cited its decision in *El Paso Natural Gas Company , 44 FPC at 77, supra* note 30, to exclude the company's investment in its manufacturing affiliate from the pipeline's capitalization

In light [**42] of these facts the Commission concluded that a pipeline's tax allowance should not be based on the "activities of others in the affiliated group" but instead, like other costs, should be based on the activities of the pipeline itself. n52 Thus, the Commission rejected methods of determining the tax allowance by allocating a pro rata share of the consolidated tax liability and then adjusting that amount by excluding the losses of certain affiliates. In place of these methods the Commission installed the stand-alone method which determines the tax allowance on the basis of the pipeline's own revenue and expenses. n53

n52 *Id* . at 363.

n53 In *dicta* the Commission also expressed its view that a change to the stand-alone method was needed to avoid "discouraging" gas exploration. *Id* . at 362. In Opinion No. 47 the Commission applied the stand-alone method in this case largely for this reason.

We, however, do not rely on this rationale. *See supra* note 8.

We adhere to that judgement of the Commission. We do so for three reasons. First, the facts the Commission relied on have not changed Pipelines are still diversified. We have no reason to believe that the diversity [**43] in the natural gas industry the Commission [*61,858] observed in 1972 will decrease in any significant way. n54 So the problems diversification poses for our regulation remain.

n54 The Commission decided *Florida Gas* at the height of the trend towards diversification. In 1972 pipeline operations of the companies in Moody's Natural Gas Transmission Index contributed only 54% of the companies' gross revenues. Since then, pipeline operations have contributed about the same percentages of their companies' gross revenues. *See supra* note 28.

Second, the stand-alone method is consistent with the principles used to allocate other costs and produces a tax allowance that is rigorously cost based.

Third, though stand-alone is not the only method the Commission could have adopted to resolve the problems posed by diversification and the *Cities Service* method, we think it was the administratively proper one to adopt. The only alternative would have been to return to the method the Commission followed in the 1950's and adjust the results to reflect the facts of diversification by excluding the losses from unrelated and regulated activities as well as non-recurring losses [**44] As we have seen, that can be complicated. And because the exceptions would be numerous, doing so would be time-consuming and administratively burdensome. Like the Commission in 1972, we do not think that burden is warranted. Our conviction on this point is made all the stronger by the other change that has occurred since the 1950's, a change the Commission did not consider in 1972. This change is in the tax laws.

When the Commission articulated the method Charlottesville advocates here, there was little difference between the time expenses were recognized in the cost of service and the time the same expenses were recognized as deductions on the company's tax return. This changed in 1954 with the passage of the Internal Revenue Code of 1954. That Act allowed companies to deduct depreciation, a significant expense, at an accelerated rate. The Commission, however, continued to require that depreciation be included in the cost of service at a straight-line rate

Thus was born the question of how to treat timing differences in the recognition of expenses for cost of service and income tax purposes. That question is quite simple. The same amount of depreciation expense is recognized in [**45] the cost of service and on the company's tax return over the life of the plant. But most of that expense is recognized in the early years on the income tax return while the expense is recognized evenly throughout the life of the plant in the cost of service. The ratemaking question is how to calculate the tax allowance in this situation. Should the tax allowance reflect the recognition of expenses on the tax return, which is called "flow-through"? Or should the tax allowance reflect the recognition of expenses in the cost of service, which is called "normalization"?

The Commission's answer to that question has been to follow a normalization policy. The Commission had done so because a flow-through policy mismatches burdens and benefits. Under flow-through earlier ratepayers receive credit for tax deductions greater than the depreciation expense they pay; later ratepayers receive credit for tax deductions that are less than the depreciation expenses they pay. Under a normalization policy the tax benefits and expense burdens are matched. This does not mean that tax deductions are being ignored. Quite the contrary. The tax reducing effects of the deductions that are not used to reduce [**46] the cost of service in the early years are accumulated in a deferred account, deducted from rate base, and used to reduce the cost of service in the later years.

Once a normalization policy is adopted for dealing with tax and ratemaking timing differences, a policy on consolidated taxes that ignores the source of the loss makes no sense. n55 A hypothetical makes this clear.

n55 Charlottesville moves that all evidence concerning normalization be struck from the record. Charlottesville contends that any consideration of the impact the Commission's normalization policy may have on the proper policy to follow with respect to consolidated taxes is beyond the scope of the Court's mandate remanding this case to us. We disagree. We do not think we are so constrained. *See S.E.C v. Chenery Corp , 332 U S. 194,* (1947) Accordingly, the motion is denied.

Assume that H, a holding company owns two subsidiaries: A, a gas pipeline, and B, an electric utility. In 1982 B puts into service a new generating unit. Because that [*61,859] new unit generates not only electricity but also a large amount of accelerated depreciation deductions, B's deductions exceed its income [**47] by $100. A, on the other hand, has taxable income of $100. A, B, and H file a consolidated return. The consolidated income is zero, so there is no consolidated tax liability. Because A would have had a $50 tax liability if separate returns had been filed, the filing of a consolidated return produces a tax savings of $50.

In setting rates for B we would, following our normalization policy, calculate B's tax allowance on the assumption that tax deductions were taken on the basis of straight-line depreciation. And we would require B to accumulate in a deferred account the tax reducing effects of its excess deductions so that they will be available to reduce its rate base now and its tax allowance later.

What then should we do in setting rates for A? According to Charlottesville, we should flow the consolidated tax savings through to A's ratepayers. This we think is simply wrong. The tax savings produced by B's excess deductions belong to B's future ratepayers, not A's current ratepayers. After all, it is B's future ratepayers who will pay the expense associated with the deductions. So here there should be no flow-through of the consolidated tax savings to A's ratepayers n56 Hence to [**48] follow Charlottesville's method we would have to exclude B's losses from consideration.

n56 Note that since the hypothetical concerns 1982, B's depreciation expense deduction for tax purposes would be governed by the new Accelerated Cost Recovery System. which was enacted by Congress in the Economic Recovery Tax Act of 1981. Pub. L. No. 97-34, §§ 201-209, 95 Stat. (1981). If the utility is to use that method, its rates must be set on a normalized basis. Having done that for B, a question has been raised whether flowing the savings through to A's ratepayers would violate the statutory mandate. *See* Exh. 1 at 5; Exh. 11 at 21 For a contrary view, see Exh. 13 at 54-55; Tr. 534.

Without a definitive ruling from the Internal Revenue Service, we cannot resolve this question.

Though this is a hypothetical, it is by no means atypical. This case presents several examples. During the test year Columbia LNG was building a terminal to receive and regasify imported liquefied natural gas This portion of the company's business reported a tax loss because of typical timing difference expenses. That is, the company's construction expenses, such as interest during construction, were deducted [**49] for tax purposes n57 But for ratemaking purposes these expenses were capitalized. The company will recover them over the life of plant through depreciation expense. Hence the deductions should be used to reduce the rates of that operation's future customers.

n57 Exh. 3. These timing difference expenses were the only source of the loss. Thus, if this operation's expenses were reported on the tax return in the same way that we recognized expenses in the cost of service, the LNG operation would not have reported a tax loss.

And that is what we did. When we set rates for this operation, we required that the tax reducing effects of the deductions for the construction period be accumulated in a deferred account so that they could be used to reduce the tax allowance over the life of the plant. n58 n58 *See Columbia Gas Transmission Corporation, 8 FERC P62,005 (1979)*

The company also began to operate a synthetic natural gas plant in the test year. This operation also reported a tax loss solely because of timing difference expenses. n59 Though we have no jurisdiction over this operation and its rates, the company and customers have agreed to price the synthetic [**50] gas on a cost of service basis. So the company capitalized its construction expenditures, charged depreciation at a straight-line rate, and accumulated the tax effects related to those expenditures and its excess depreciation deductions in a deferred tax account. n60

n59 Exh. 3.

n60 Exh. 1 at 5-6.

These results are proper. The rates Columbia LNG charges flow the tax benefits created by its deductions through to the ratepayers who pay the associated expenses when those expenses are recognized in rates. n61 Hence, if we were to follow Charlottesville's method, we would have to exclude from consideration Columbia LNG's losses. To do otherwise would result in the tax savings being flowed through twice. n62 There are many similar cases. n63

n61 It might be argued that whatever the merits of normalization in other cases, it is irrelevant here. This is so, it might be argued, because the ratepayers of Columbia LNG are the ratepayers of the pipeline. Since that is so, normalization is not needed to preserve the tax benefits for ratepayers. The tax benefits should therefore be flowed through to the pipelines' ratepayers immediately.

We reject this argument. Columbia LNG's rates are normalized. It would be extremely hard to undo that now.

But even if those decisions had not already been made, we would reject this argument. The liquefied natural gas the company produces is sold to Columbia Gas Transmission and flows to all the ratepayers of the pipeline. But still the ratepayers are not identical. The ratepayers who should receive the tax benefits are those customers who will pay the expenses over the life of the plant. But under Charlotteville's method the ratepayers who receive the benefits are the ratepayers of 1976. Those two groups of ratepayers can never be exactly the same So Charlottesville's method would create an intergenerational subsidy.

The situation is slightly different with respect to the synthetic gas this company produces. This gas is sold directly to customers of Columbia Gas Transmission. The pipeline performs only a transmission function. Tr. 390. Not all of the pipeline's customers decided to purchase synthetic gas. Exh. 15 at 18. So Charlottesville's method would not only create an intergenerational subsidy here but would also result in the synthetic gas customers subsidizing the pipeline's customers who did not purchase synthetic gas.

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n62 Conceivably, we could flow the tax savings created by Columbia LNG's deductions through to the pipeline's ratepayers and still normalize Columbia LNG's rates. To do this, however, we would need to establish a mechanism whereby the pipelines would repay Columbia LNG for the use of its losses as the expenses are recognized in Columbia LNG's rates. This we decline to do. Setting up the required accounting would be complicated. And doing so would cause the pipelines' rates to fluctuate on the basis of events having nothing to do with their own operations.

n63 Many of the cases involve a group of corporations that form a partnership to build a pipeline. The deductions for construction expenditures are used by the partners to reduce their taxes. We ignore the partners' use of the deductions and require the project to accumulate the tax benefits in a deferred tax account as if it were a separate corporation *See e g ., Trailblazer Pipeline Company , Initial Decision, 15 FERC P63,046, at p 65,175 (1981), aff'd , Opinion No 138, 18 FERC P61,244 (1982).* If we did not do this, the tax benefits would be lost not only to the customers of the project but also, because some of the partners are not regulated, to any group of customers.

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This does not end the significance of normalization, however. Normalization is simply a method of allocating tax deductions over time. It tells us when a tax deduction should be recognized for ratemaking purposes. So before we could even apply Charlottesville's method, we would have to normalize the timing differences shown on [*61,860] the group's consolidated return and eliminate the losses those differences create, whether the losses be reported by a company subject to our rate regulation or not.

Charlottesville takes a different view It argues that we should follow the Commission's traditional method of using the tax losses that appear on the consolidated return. n64

n64 Charlottesville, of course, recognizes that the pipelines' tax allowances must be normalized to eliminate the timing differences reported by those companies. Thus, Charlottesville has added the pipelines' deferred taxes to the pipelines' allocable share of the consolidated tax liability. *See* Exh. 22B The question here is whether the same should be done for the other members of the Columbia group.

This, however, was not the Commission's traditional policy. The question was decided long ago in [**53] the *Cities Service* case.

In that case the Cities Service group deducted depreciation expense at an accelerated rate on its consolidated tax return. The Commission's policy at that time was to normalize those deductions. n65 Following that policy the Commission eliminated the timing differences caused by the group's use of accelerated depreciation. n66 We think this was correct. As with any other item to be included in the cost of service, we must allocate the item to the proper time period before we allocate the items among groups. Normalization performs that task for tax deductions.

n65 *Order No. 171, 13 FPC 968 (1954).*

n66 *See 30 FPC at 166*

At the time this case was filed the Commission did not require that all timing differences be normalized. So under the Commission's holding in *Cities Service* some timing differences would remain. What is significant to us in adopting a policy for dealing with consolidated taxes, though, is that we now do require that all timing differences be normalized. n67 In the future all timing differences will be eliminated. Doing that will eliminate most, if not all, the losses shown on the consolidated [**54] return. That is true of the development companies here, n68 and also true of the losses reported by the members with whom Southern Natural Gas Company joins in filing a consolidated return. n69

n67 *See* Order No. 144, *Tax Normalization for Certain Items Reflecting Timing Differences in the Recognition of Expenses or Revenues for Ratemaking and Income Tax Purposes , supra* n. 14; *see also* Order No. 404, *Calculation of Taxes for Property of Public Utilities, Licensees and Natural Gas Companies Constructed or Acquired after January 1, 1970 , 43 FPC 740, reh. denied , Order No. 404-A, 44 FPC 16 (1970), aff'd sub nom , Memphis Light, Gas & Water Division v F.P.C , 462 F.2d 853* (D.C. Cir), *cert. denied , 409 U S. 941 (1972); Texas Gas Transmission Corporation , Opinion No. 578, 43 FPC 824, reh . denied , Opinion No. 578-A, 44 FPC 140 (1970), aff'd , Memphis Light, Gas & Water Division v. F P.C , 500 F.2d 798 (D.C. Cir. 1974)* n68 These companies reported tax losses because they could deduct intangible drilling cost and construction expenditures that are capitalized for ratemaking purposes or because they deducted depreciation at an accelerated rate. When those timing differences are eliminated, the development companies did not have losses in the test year. *See* Exh. 2, Schedule 2. The timing differences of these companies are explained in considerable detail in Exh. 1 at 2-6.

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n69 *See Southern Natural Gas Company, Opinion No 174, 23 FERC P61,397* (June 22, 1983).

Thus, we are left with the following situation. To make Charlottesville's method responsive to changes that have occurred since the method was formulated over a quarter of a century ago and to therefore make it reasonable, we would have to make exceptions for non-recurring losses, losses incurred in unrelated activities, losses caused by timing differences, and losses incurred by a regulated company. That pretty much covers the field. What is left are losses that are permanent, not caused by timing differences, and that are incurred in an activity related to the pipeline's operations but that is not itself regulated. There are not many losses like that. The only example we have here is the parent's loss. The tax savings produced by that loss are flowed through to ratepayers by our stand-alone method.

So our stand-alone method reaches much the same result that would be reached by a proper application of Charlottesville's method. n70 But our stand-alone policy does that quite simply. It requires the answer to only one question. have the expenses that generated the tax [**56] deduction been included in the cost of service? That question can be answered readily by examining the cost of service. Charlottesville's method, however, requires the answer to many questions. The answers to those questions are not readily available In some instances they can only be answered after a detailed examination of the business activities or accounts of companies that are not before us or that might not even be regulated by us. The time needed to answer these questions is unwarranted. Only one element of the cost of service is at stake. And there is another method at hand that is easily applied yet produces just and reasonable results--the stand-alone method. Hence we adhere to that method here

n70 To be sure, there might be some differences. But we expect them to be small

[*61,861]

VIII.

Charlottesville and the Public Service Commission of the State of New York advance a number of arguments against our stand-alone policy. n71 Most of these arguments have been addressed previously. But two arguments warrant further comment.

n71 Charlottesville also advances one policy argument in favor of its position. Charlottesville points out that the Columbia pipelines have a "market ordering" problem By this Charlottesville means that the price the pipelines charge for gas is too high when compared to alternative fuels Charlottesville argues that as a step towards solving this problem we should flow the consolidated tax savings through to ratepayers in order to lower the delivered price of gas.

Little time need be spent on this argument. That the Columbia pipelines, like many other pipelines, face stiff competition from alternative fuels is obvious. The causes for this are numerous and far-reaching. They include management decisions as well as the statutory basis for pricing natural gas at the well-head and changes in the world-wide demand and supply of oil. If the problems are to be solved, they must be solved through measures that address the causes directly and in a comprehensive way. They will not be solved by making *ad hoc* adjustments to the tax allowance, which is a minor part of the cost of transporting gas, which is itself a minor

part of the cost of gas sold to consumers.
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A.

Both Charlottesville and the New York Public Service Commission contend that our stand-alone method is not supportable on the facts of this case. Though the parties express this contention somewhat differently, their point comes down to essentially this: "In instances where the jurisdictional ratepayers of a pipeline are fully insulated from the risks and increased costs associated with the investment activities of non-jurisdictional companies, . . . there may be some basis for reducing the ratepayers' share of the consolidated tax savings generated solely by such non-jurisdictional investments. The situation of the Columbia system, however, is not one of those instances." n72 That is so, the parties contend, because the activities of the pipelines' sister companies, especially the development companies, have imposed numerous burdens on the pipelines' ratepayers. Accordingly, the parties argue that in fairness the tax benefits created by the pipelines' sister companies ought to be shared with the ratepayers.

n72 Brief for the Public Service Commission of the State of New York at 7. *See also* Brief for Charlottesville at 48.

We disagree To be sure, we agree with [**58] the principle that benefits should follow burdens. That is implicit in our stand-alone policy. What we disagree with is the parties' application of that principle The task we have before us is to allocate the tax reducing benefits created by the system's deductions to the system's members. That must be done on the basis of some factor that is reasonably closely related to the benefits to be allocated. But the burdens Charlottesville and New York point to (to the extent they are burdens at all) are simply too far removed from the tax benefits to justify allocating the benefits to the ratepayers.

For example, it is argued that the ratepayers are burdened because the pipelines' internally generated funds are used to finance the system's gas supply efforts. Internally generated funds consist of net income (or profits), depreciation, and deferred income taxes. Since a pipeline would not have these funds but for the revenue provided by the ratepayers, the ratepayers can be said to be bearing a burden here. But this is not a burden imposed by the system's gas development activities. Pipelines are not eleemosynary institutions. Their shareholders are entitled to a return on, and a return [**59] of, their capital. Pipelines are also entitled to the use of the money ratepayers have paid for taxes that have not yet been paid to the government. The ratepayers have paid no more in rates because of the gas supply efforts. Moreover, what the pipelines' shareholders do with this cash is largely their own business. They may reinvest it in the pipelines or they may invest it in other business ventures. So we do not see how the particular investment decisions the pipelines' shareholders have made, namely, to invest a large part of the cash they derive from the pipelines in gas supply efforts, justify allocating any of the tax benefits created by those efforts to the ratepayers n73

n73 Charlottesville and New York advance a somewhat similar argument concerning taxable income. They argue that because the taxable income generated by the pipelines is needed to give value to the tax losses of the gas supply companies, the pipelines ratepayers should receive the tax savings. But, as with the pipelines' internally generated funds, this is not a burden the system's gas supply companies have imposed on the ratepayers. The pipelines' rates are no higher than they would be if the taxable income generated by the pipelines were not used to give value to the tax losses.
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We reach the same conclusion with respect to the argument that because the pipelines are "funneling" hypothetical taxes to the gas supply companies, the ratepayers have been burdened n74 While the ratepayers are paying a tax allowance and are to that extent burdened, this is not a burden imposed by the gas supply companies. The tax allowances reflect the costs of providing service. Nothing has been [*61,862] added to the tax allowances to help finance the gas supply companies. n75 And what the pipelines do with the revenue they receive for the service they provide is, again, largely their own business.

n74 The "funneling" takes place pursuant to an order of the Securities and Exchange Commission exempting the pipelines from the SEC's rule for allocating the consolidated tax liability, *17 C.F.R. § 250.45(b)(6) (1977)*. Following this order the consolidated tax liability is allocated to the members' of the Columbia group for financial reporting purposes in a way that three of the gas supply companies are given credit for the tax savings produced by their tax losses. *See* Exh. 5 at 13. What this means is that the amounts the pipelines pay to their parent to help discharge the consolidated tax liability do not reflect any reduction for the tax savings produced by the gas supply companies' losses. Consequently, the parent pays a part of these amounts to the Internal Revenue Service to discharge the tax liability and the remainder to the gas supply companies. Tr. 155.

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n75 To be sure, when this case was first here, the Commission held that the tax allowance should be increased to spur additional gas exploration and development. But we place no reliance on that rationale. *See supra* notes 8 & 53. Equally immaterial to us is what the pipelines forward to their parent pursuant to the SEC's allocation rules and orders. That would occur no matter how we treated the consolidated tax liability for ratemaking purposes.

Other burdens mentioned are more significant. At least here the parties contend that the pipelines' rates are higher because of the system's gas supply efforts. There is some merit to the points the parties make. But there is not enough to justify allocating any of the tax benefits to the ratepayers.

It is pointed out that one of the pipelines, Columbia Gas Transmission, made advance payments to one of the gas supply companies, Columbia Gas Development. n76 Because ratepayers pay the pipeline a return on these advances, ratepayers are here unquestionably bearing a burden

n76 Exh. 13 at 25. Charlottesville's witness listed advance payments by both pipelines to all producers. Exh. 14, Schedule 12. These amounts are quite large. Columbia's evidence reveals, however, that only Columbia Gas Transmission made advance payments to an affiliate. These advances are quite small. At the end of the test year, 1974, the outstanding advances totalled only about $3,000,000. Exh. 15 at 13-15; Exh. 17

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The primary reason we do not find this to be sufficient is that advance payments did not create any tax benefits for either the pipeline or the gas supply company. So there is no relationship between this burden and the tax benefits to be allocated. We do not see how this burden justifies allocating any of the tax benefits to the pipelines, let alone the tax benefits created by loss companies that did not receive advance payments. Moreover, the burden imposed here is balanced by its own benefit--the prospect of future gas supplies.

Charlottesville and New York also point out that in setting the pipelines' rates of return we have used the parent's capitalization The parties contend that by doing so we have inflated the pipelines' rates of return and forced ratepayers to finance the system's gas supply efforts. This argument is without merit

The reason we used the parent's capitalization and cost of capital are fairly obvious. The pipelines issue bonds and common stock to their parent. They issue no securities to the public. So the pipelines' capital structure and cost of capital can be manipulated by the parent "to maximize the profits of the integrated corporate enterprise and [**63] maximize the benefits to the parent company's stockholders." n77 n77 *Kentucky West Virginia Gas Company , Opinion No 7, 2 FERC P61,139, at p 61,326, reh . denied , 3 FERC P61,225 (1978).*

Consequently, to avoid setting rates on the basis of such contrived facts, we must use either the parent's capital structure and costs or hypotheticals. n78 With the Columbia pipelines we have traditionally used, as here, the parent's capital structure and costs n79

n78 *Id.*

n79 *Manufacturers Light and Heat Company , Opinion No. 583, 44 FPC 314, 326, reh denied , 44 FPC 1138 (1970); Manufacturers Light and Heat Company , 23 FPC 446, 448 (1960).*

Charlottesville's witness thought this was preferable to using hypotheticals Exh. 13 at 21.

Using the parent's capitalization solves one problem. But it may create others. Though the use of parent's capital structure and capital costs presupposes that the parent's risks are essentially comparable to those of the pipeline, its risks may not be exactly comparable. n80 Because of investments in other companies, the parent may have more equity [**64] than the pipeline would have, a higher cost of debt, or a higher cost of equity. Charlottesville and New York contend that this is so here. They make two points.

n80 *See Kentucky West Virginia Gas Company* , 2 FERC at p. 61,326.

First, they argue that the parent's cost of debt has been increased by financing the system's gas supply operations. This is so because much of the system's financing during the relevant period of time was to raise capital for the gas supply companies. The debt raised during this time was more expensive than the debt the parent had previously issued. So the parent's embedded debt costs were raised, and accordingly, so were the pipelines' rates of return. n81

n81 Exh. 13 at 22-24.

Second, they argue that the parent's cost of equity has been increased. This is so, they say, because the stock market views gas exploration operations as riskier than [*61,863] pipeline operations. This perception has entered into the market's calculation of Columbia's stock and would be reflected in a higher cost of equity. So the pipelines' rates of return reflect a "risk premium" for the system's exploration and development activities. n82

n82 *Id* . at 21-22.

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The evidence shows that the system's exploration and development activities have had some impact on the cost of debt used in setting the pipelines' rates of return, though less than Charlottesville claims and far less than the tax benefits at issue. n83 This evidence might justify, on purely equitable grounds, some sharing of the consolidated tax savings if there were no other way to protect the ratepayers from this increased cost of capital.

n83 Charlottesville says that the cost of debt was raised from 6.60% to 7.29% and that the pipelines' revenue requirement was increased by $5.2 million. Exh. 13 at 23-24; Exh. 14, Schedules 4-8.

Columbia does not dispute that the pipelines' revenue requirements have been increased. But it argues that the increase is only $2 6 million Exh. 15 at 8-10; Exh. 16. We think Columbia is correct

We find no evidence that the system's gas supply efforts have caused investors to add a risk premium to

Columbia's stock. While it is no doubt true that investors view gas exploration activities as riskier than the pipeline business, that is not enough to establish the existence of a risk premium. An investor's required return is based on the consolidated earnings power of the Columbia system. That system is large and operates in all the major areas of the gas business. Hence before we could conclude that the system's gas supply activities have raised the investor's required return, we would need evidence on the system's other business activities and how those activities interact with the gas supply efforts. But no such evidence was offered. Moreover, the only evidence in the record that remotely bears on this question is the credit rating for the system. Throughout the 1970's Columbia maintained an A credit rating. Exh. 15 at 7. This suggests to us that investors' perceptions of the riskiness of the system were not greatly affected by the existence of the gas supply companies.

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But this is not the case.

Our stand-alone policy applies not only to the determination of a utility's tax allowance but also to the determination of the utility's rate of return. n84 Hence, when we use the parent's capital structure and costs, adjustments, where necessary, can be made to both elements to insure that the return reflects only the risks and costs of providing the specific service at issue And where the question has been raised the Commission has done so. It has eliminated equity from the capital structure when the equity was used to finance non-utility business or operations that were separately regulated by the Commission, n85 it has eliminated the risks imposed on the system by operations other than the pipeline; n86 and it has endorsed in principle excluding from the rate of return the cost of debt that was not used to finance the pipeline business. n87

n84 *Kentucky West Virginia Gas Company*, 2 FERC at p. 61,325.

n85 *El Paso Natural Gas Company, 44 FPC at 77; Southern Natural Gas Company, Opinion No. 585, 44 FPC 567, 571-73 (1970).*

n86 *See e .g ., Arkansas Louisiana Gas Company, Opinion No 71, 10 FERC P61,027, at p 61,046, 10 FERC P62,195 (1979), rev'd on other grounds, 654 F.2d 435 (5th Cir. 1981); Consolidated Gas Supply Corporation, Opinion No 70, 10 FERC P61,029, at p 61,053 reh denied, 10 FERC P62,224 (1979), aff'd 653 F 2d 129 (4th Cir 1981); Natural Fuel Gas Supply Corporation, Initial Decision, 5 FERC P63,018, at pp 65,143-45 (1978), aff'd, Opinion No. 58, 8 FERC P61,135 (1979), Pacific Gas Transmission Company, 43 FPC at 842-43.*

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n87 *Florida Gas Transmission Company, Opinion No 561, 42 FPC 74, 79. reh. denied, 42 FPC 649 (1969), rev'd on other grounds sub nom. Sun Oil Co. v F P C , 445 F.2d 764 (D.C. Cir. 1971)* (cost of debt should in theory be lowered, but no adjustment made because the difference was trivial).

So nothing prevented the parties from raising their concerns that the return was too high when that issue was presented to the Commission for decision. But they did not. Instead, they settled n88 Hence what the parties' argument here amounts to is a plea that we use consolidated tax savings to relieve them of a bargain with which they are no longer happy. This we decline to do The plea is too late.

n88 *See* the order issued in these dockets on September 13, 1976. *56 FPC 1651.*

B

Charlottesville contends that our stand-alone method consistently produces tax allowances for the pipelines far larger than the pipelines' "actual tax responsibility." Charlottesville supports this argument with a table comparing the pipelines' stand-alone tax allowances with various amounts reported to the Internal [**68] Revenue Service on the group's consolidated returns. n89 This table shows, for example, that the rates in this docket, which were in effect for most of 1976, assumed that the pipelines' tax costs totalled $78.4 million. Charlottesville says that the pipelines' share of the group's actual tax liability was $60.6 million before investment tax credits and $52.8 million after investment tax credits. Moreover, Charlottesville says, in some years the pipelines' stand-alone tax allowances exceed the actual tax liability of the entire group. Charlottesville therefore argues that our stand-alone policy violates the statutory mandate that "requires that ratepayers reimburse a regulated pipeline only for actual costs, including federal income taxes" and is thus unlawful. n90

n89 *See* Table II on page 28 of Charlottesville's Initial Brief.

n90 Initial Brief for Charlottesville at 31.

We disagree. We do so not because we disagree with the principle that only actual costs should be included in the cost of service. Everything we have heretofore said in this Opinion shows that we are in complete agreement with that principle. Rather, we do so because we cannot agree that the amounts [**69] reported to the Internal Revenue Service represent the actual tax costs the pipelines incur in providing service. [*61,864]

There are a number of reasons the pipelines' tax allowances exceed what Charlottesville says is the pipelines' "actual tax responsibility" and even exceed the group's actual tax liability as shown on the group's tax return. Most of these involve policies and ratemaking methodologies that have nothing to do with the treatment of the consolidated tax savings. These policies and methods are not in dispute. So even if we were to follow Charlottesville on the consolidated tax issue here, we would not use the "actual tax responsibility" it has calculated as the pipelines' tax allowances. n91

n91 The basic differences are described in the pipelines' Reply Brief at 4, 9-10.

Nevertheless, our stand-alone policy produces tax allowances for the pipelines that will be somewhat larger than the amounts Charlottesville calculates as their "actual tax responsibility." This difference stems from the method used to allocate the consolidated tax liability. Charlottesville has allocated to the pipelines a portion of the consolidated tax liability, and therefore a portion [**70] of all the tax savings, according to the method it advocates here. n92 The stand-alone tax allowance allocates only a portion of the tax savings generated by the parent's excess interest deductions.

n92 *See supra* p. 15.

Charlottesville's comparisons and argument on this point suggest that the portions of the consolidated tax liability it has allocated to the pipelines reflect the pipelines' actual tax liabilities, the taxes they actually pay to the Internal Revenue Service There is some merit to this suggestion even though, as we previously said, no amount can be identified from the face of the return as the actual tax liability of a member of the consolidated group. The reason is that the Internal Revenue Code and the regulations require the group to allocate the consolidated tax liability to the members n93 One of the methods permitted is identical to the method Charlottesville uses. n94 And this is the method the Columbia group uses to allocate its consolidated tax liability for tax purposes. n95

n93 *I R C § 1552(a); 26 C F R §§ 1 1502-33(d)* and *1 1552-1(a).*

n94 *I.R.C. § 1552(a)(1); 26 C.F.R § 1.1552-1(a)(1)(ii).*

[**71]

n95 Tr. 165.

There are, however, two reasons we cannot treat the allocation used for tax purposes as the pipelines' actual tax costs for cost of service purposes. First, the Code and regulations require an allocation of the consolidated tax liability to determine each member's "earnings and profits " n96 This, in turn, is necessary to determine whether a distribution is a taxable dividend or a tax-free return of capital n97 So the allocation is required to administer the revenue laws It has no other effect. It does not determine what each member pays to the parent to help discharge the liability. n98 Nor does the allocation attempt to ascertain the tax costs of a member for ratemaking, or any other, purpose. n99 Hence, we think the allocation a consolidated group reports for tax purposes is simply too far removed from the issues before us to warrant its adoption as the allocation to be used for cost of service purposes.

n96 *I.R.C. § 1552(a)*; *26 C F.R. §§ 1.1502-33(d)* and *1.1552-1(a).*

n97 *I.R.C. § 316(a).*

n98 That is determined either by an agreement among the members of the group or, where the group is a public utility holding company like Columbia. by the rules and orders of the Securities and Exchange Commission. *See supra* n. 74.

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n99 *See* Technical Information Release 878, 1967 Stand. Fed. Tax Rep. , P6396, where it is said:

The alternative methods of allocating the Federal income tax liability provided under section 1552 of the Code, as well as the methods provided under the proposed regulations [codified at *26 C.F.R. § 1.1502-33*] may be elected even though the Federal income tax liability may be allocated in a different manner for purposes other than the Internal Revenue Code, which are not intended to be affected.

Secondly, the allocation method used by the Columbia group is only one of many the Code and regulations permit a group to use n100 The amounts allocated to the members under these various methods can be quite different. For example, one method allocates to the loss members the tax reducing benefits attributable to the use of their losses on the consolidated return. n101 Put differently, this method produces an allocation of the consolidated tax liability almost exactly opposite the one produced by the method Columbia uses

n100 *See I R.C. § 1552(a)(2)*-(4) and *26 C.F.R. §§ 1.1502-33(d)(2)(i)*-(iii) and 1 1552-1(a)(2)-(4).

[**73]

n101 *See 26 C.F.R § 1.1502-33(d)(2)(ii).*

The important thing about these alternative methods of allocating the consolidated tax liability is that they are elective. A group can choose any one of them. n102 Hence to treat the amounts allocated to members for tax purposes as the member's actual tax costs for ratemaking purposes would mean the tax allowance of a regulated member of an affiliated group would be determined by the election of the group. Thus, the rates charged to ratepayers of different companies could vary [*61,865] considerably because of the way the members of the groups have chosen to adjust their earnings and profits As a policy matter, we think that is unacceptable The differences in rates would not be based on differences in the cost of providing service. n103 Accordingly. we see no alternative but to disregard the allocation the Columbia group uses for tax purposes and make our determination of the amount of the consolidated tax liability that should be allocated to the pipelines.

n102 *See 26 C.F.R. §§ 1 1552-1(c)(1)* and *1 1502-33(d)(3).*

n103 For example, the Southern Natural Gas Company has, since 1967, joined with its parent, Sonat Inc., and its affiliates in filing a consolidated tax return. For tax purposes the Sonat group allocates its consolidated tax liability in a way that the members' reporting a tax loss are credited with the "tax savings"--just the opposite of the method the Columbia group uses. *See* Exh. 1(j) at 4, *Southern Natural Gas Company, Opinion No. 174, 23 FERC P61,397.* Thus, if we were to follow the allocation method the group uses for tax purposes, the ratepayers of the Columbia pipelines would receive the tax saving the group derives from filing a consolidated return but the ratepayers of the Southern pipeline would not. We can perceive no justification for that.

[**74]

IX.

The other issue before us concerns the tax savings created by the parent's loss This issue involves no question of policy. Everyone agrees that under our stand-alone method, these tax savings must be shared with the pipelines' ratepayers. Instead, the question here is the technical--though complicated--one of whether those savings have been used to reduce the pipelines' tax allowances.

These are the facts:

(1) The subsidiaries of the Columbia group issue no securities to the public The parent secures all the capital for the system by issuing debt and equity securities to the public. The subsidiaries obtain their capital by issuing debt and equity to the parent.

(2) So the parent receives dividends and interest from its subsidiaries. And it pays interest to its bondholders.

(3) In calculating the consolidated taxable income on the consolidated return the parent's dividend income is excluded n104 The parent therefore reports only its interest income and interest expense. Because the parent's interest expense is greater than its interest income, the parent reports a tax loss. This loss is used to reduce the taxable incomes of other members of the group. Thus, the parent's [**75] excess interest expense deductions create a tax savings.

n104 26 C.F.R. § 1 1502-14(a)

(4) There are two reasons the parent's interest expense is greater than its interest income One is that the interest rate on the bonds the parent issues to the public is slightly higher than the interest rate on the bonds the subsidiaries have issued to the parent. This difference in interest rates is minimal. n105 It accounts for only a small portion of the difference between the parent's interest expense and interest income. n106 The other reason for the difference is that the parent has more debt in its capital structure than do the subsidiaries. In 1974 the capital structures of the parent and the subsidiaries were as follows: n107

n105 What happens is this: The parent will, for example, issue 30 year bonds to the public paying a coupon rate of 9.83%. When the parent lends money to one of its subsidiaries, the maturity and interest rates on the subsidiary's bonds are tied to those of the parent's most recent borrowing. The interest rate, however, is rounded down to the next lower 1/10th of one percent. Thus, the subsidiary would issue to the parent 30 year bonds with a coupon rate of 9.80%. *See* Exh. 5 at 7.

[**76]

n106 *Id* . at 8.

n107 Exh. 8, Schedule 2.

	Parent	*All Subsidiaries*
Debt ...	57.8%	48%
Preferred Stock ...	2.1%	--
Common Equity ...	40.1%	52%
	100.0%	100%

(5) In settling most other issues in this case the parties agreed to use the parent's capital structure and cost of capital to establish the pipelines' rates of return. Thus, the rate of return is based on the parent's, not the pipelines', interest expense. Because this is so, our stand-alone policy requires that the tax savings created by the parent's excess interest deductions be used to reduce the pipelines' tax allowances. [*61,866]

(6) In a normal case the tax allowance is simply the tax factor derived from statutory tax rate applied to the tax base. The tax base is derived, essentially, by multiplying the rate base by the overall rate of return and then subtracting the company's interest expense used in determining the return. n108 In calculating their tax allowances the pipelines followed this method exactly. The only point worth noting is that the interest expense the pipelines deducted was their parent's interest expense since the overall return [**77] was based on the parent's capital structure and costs.

n108 For a fuller description of how the tax base is calculated, see *supra* p. 11.

None of these points is in dispute. What is in dispute is the significance of using the parent's interest expense as the interest deduction in calculating their tax allowances. The pipelines contend that by using the parent's interest expense they have flowed the savings created by the parent's loss through to the ratepayers Charlottesville contends that the pipelines are wrong. Using the parent's interest expense, Charlottesville argues, does not flow the tax savings through to ratepayers. To do that, Charlottesville says, an effective tax rate, not the statutory rate, must be used. The pipelines contend that using an effective tax rate would result in giving their ratepayers the tax savings twice. We hold that the pipelines are correct.

Charlottesville argues that the pipelines are wrong because by using the parent's interest expense as a deduction the pipelines have done nothing but follow the Commission policy mandating interest synchronization, which is simply the fancy name for the idea that the interest expense taken as a deduction [**78] in calculating the tax allowance should be the same as the interest expense used in calculating the return n109 Charlottesville contends that interest synchronization does not flow the tax savings through to ratepayers. Charlottesville's reasoning here appears to be that because interest synchronization would be used even if there were no consolidated tax savings to be flowed through, the use of that policy has no effect on the tax savings.

n109 *Sierra Pacific Power Company , Opinion No. 730, 53 FPC 1975, 1806-7 (1975),* states the general rule. But there can be exceptions. *See e .g , East Tennessee Natural Gas Company , Opinion No. 106, 13 FERC P61,227 (1980).*

We agree with Charlottesville that all the pipelines have done is to follow our policy requiring interest synchronization. We also agree that interest synchronization would be used whether or not there is a tax savings to be shared with ratepayers. But to say this does not answer the question, which is, what is the effect of using interest synchronization here?

That effect we think is obvious. As we have discussed previously, the task before us is to allocate deductions [**79] among members of the group In this case the pipelines' ratepayers are charged with the responsibility of paying the parent's interest expense. Therefore, the parent's interest expense deduction should be allocated to the pipelines and used to reduce their tax allowances. This is just what the pipelines have done by deducting the same interest expense in calculating their tax allowances.

There is another reason the pipelines are correct. The effect of using the parent's capital structure and costs in setting the return is to treat the pipelines and their parent as one business. Viewed in this way the pipelines and parent have income (what the pipelines receive from ratepayers) and an interest deduction (what the parent pays its bondholders). Their tax allowances should be based on those elements And that is what the pipelines have done by deducting the parent's interest. The effect of filing a consolidated tax return is also to treat the pipelines and their parent as a "single entity." n110 The consolidated tax liability is therefore based on this entity's dealings with outsiders--ratepayers and bondholders. So the tax allowance is based on the same elements as is the tax liability [**80] on the consolidated return. Accordingly, the tax allowance will equal the tax liability that would be produced on the consolidated return [*61,867] by deducting the parent's interest expense against the pipelines' income Since the consolidated tax liability reflects the tax savings, the tax allowance will, too.

n110 *See supra* p. 2.

This point can be demonstrated. Since the question is really one of arithmetic, we, like the parties, will do so by means of an example using simple numbers.

Suppose that P Company (P) sells $10,000 of securities to the public: $6,000 of bonds paying 10% and $4,000 of common stock on which P will pay 12%. P does not carry on any business. Instead, it forms a subsidiary, S Company (S), to transport natural gas. P invests all of its capital in S. For its $10,000 P receives $5,000 in bonds paying 8% and $5,000 of common stock on which S will pay 12%. S has no other capital. With its $10,000 S builds a pipeline.

Suppose further that at the beginning of the year S puts into effect rates that yield revenue of $1,560. At the end of the year S and P file a consolidated tax return. A customer then complains to the Federal Energy Regulatory Commission [**81] that S's rates are excessive.

To justify its rates S files a rate of return study and a cost of service The rate of return study is based on P's capital structure and cost of capital Those are as follows:

	Ratio	*Cost*	*Weighted Cost*
Debt ...	60%	10%	6.0%
Equity ...	40%	12%	4.8%
	100%		10.8%

Using this capitalization, S's cost of service study shows return, tax allowance, and revenue requirement as follows.

Debt .	S 600

Equity ...	480
Total Return ...	$1080
Less: Interest ...	(600)
Tax Base ...	$ 480
Tax Allowance (at 50%) n111 . .	$ 480
Revenue Requirement ...	$1560

n111 The tax allowance includes an amount to compensate for the fact that the tax allowance is subject to taxation when received. When the tax rate is 50%, the additional amount is exactly equal to the tax on the tax base. *See supra* p 11.

Proof:

Gross Income ...	$1560
Less: Interest ...	(600)
Taxable Income	$ 960
Tax (at 50%)	$ 480

The customer does not contend that using the parent's capital structure and cost of capital is wrong. What the customer argues is that the [**82] tax allowance is too high This is so, the customer argues, because the tax savings produced by filing a consolidated return are not reflected in the rates To do that an effective tax rate must be used. S takes the opposite position. It argues that the tax allowance already reflects the tax savings.

If S is correct, the tax allowance should be equal to the consolidated tax liability. That is in fact the case. [*61,868]

The first step in preparing the consolidated return is to calculate the taxable income of each member. S will report gross income of $1,560, which is what it received from ratepayers. From this S will deduct the interest it paid P--its book interest. S's interest expense is $400. n112 Taxable income for S is therefore $1,160.

n112 S has issued $5,000 of bonds at 8%

P received during the year $600 in dividends and $400 in interest from S. But for purposes of calculating taxable income on the consolidated return P's dividend income is excluded. P's gross income is therefore $400. From this P will deduct the interest it paid to its bondholders. That amount is $600. P therefore reports a tax loss of $200.

The calculations of the taxable incomes of S and [**83] P would look like this:

S		*P*	
Gross Income:		Gross Income:	
Operations ...	$1560	Interest from S ...	$400
Deductions:		Deductions:	
Interest to P ...	(400)	Interest ...	(600)
Taxable Income ...	$1160	Taxable Income ...	$ (200)

The next step is to consolidate each member's taxable income. That calculation would look like this:

Gross Income:	
S's operations ..	$1560
P's interest ...	400
Total ...	$1960
Deductions:	
S's interest ...	(400)
P's interest ...	(600)
Total ...	(1000)
Consolidated taxable income .	$ 960

The tax on the consolidated taxable income is $480--just what the tax allowance included in the cost of service is. n113

n113 The calculation of the consolidated tax liability looks a little different from the calculation of the tax allowance. But this difference is without significance. Unlike the calculation of the tax allowance, the consolidated return continues to respect corporate form. Because that is so, there is an intermediate step in calculating the consolidated tax liability. That step is to allow S to report a deduction for the interest of $400 it pays to P and to require P to include its interest income from S Because those amounts are equal, the intermediate step is a wash. This leaves only income of $1,560, which is offset by $600 of interest expense. The tax allowance is calculated in the same way

[**84]

If S and P had filed separate returns, the tax liability S would have incurred on its own taxable income is $580. So the filing of the consolidated return produces a tax savings of $100 ($580-480). Put differently, S had an effective tax rate of 41.4%. n114 But there is no need to reduce S's tax allowance by $100 or to use an effective tax rate. The consolidated tax liability, which is used in the tax allowance, already reflects the effects of using P's interest expense to reduce S's taxable income.

n114 The effective tax rate is derived by dividing the consolidated tax liability of $480 by S's own taxable income, $1160, as shown on the consolidated return.

Of course, the tax savings could be reflected in the tax allowance by using an effective tax. But if that were done, then S's own interest expense, not the parent's, would have to be used as the interest deduction in calculating the tax allowance. n115 This is so because using an effective tax rate or the parent's interest expense reduces the tax allowance by the tax savings. But they do so in different parts of the formula Hence the one thing that cannot be done is, as Charlottesville would have us do, to deduct the parent's [**85] interest expense and use an effective tax rate. To do that would be to flow the tax savings through to ratepayers twice. The company would then not recover its tax costs or earn its allowed return. This can be seen in the following comparison:

n115 This is what the Commission did in the old consolidated tax cases where the parent reported a tax loss because of its interest deduction and an effective tax rate was used. *See supra* p 17 This was also what the Columbia pipelines did in rate cases prior to the change in the Commission's policy in *Florida Gas* . Tr 428.

[*61,869]

	P's Interest/ Statutory Rate	S's Interest/ Effective Rate	P's Interest/ Effective Rate
Debt ...	$ 600	$ 600	$ 600
Equity ...	480	480	480
Return	$1080	$1080	$1080
Less: Interest ...	(600)	(400)	(600)
Tax Base ..	$ 480	$ 680	$ 480
Tax Allowance ...	$ 480 n116	$ 480 n117	$ 339 n118
Revenue Requirement ...	$1560	$1560	$1419

n116 The tax rate is 50%

n117 The tax rate is the effective tax rate of 41.4%.

n118 *Id*.

Charlottesville thinks all this is irrelevant. According to [**86] Charlottesville, what is significant is that the parent's cost of debt is higher than the costs the pipelines incur on the debt they have issued to the parent. Since the parent's cost of debt was used in setting the rate of return for the pipelines, Charlottesville argues that the ratepayers are reimbursing the pipelines for costs not incurred.

It is difficult to know what to make of this argument. It sounds as though Charlottesville's complaint is with the use of the parent's cost of debt in setting the rate of return rather than with the use of the parent's interest expense as a deduction in calculating the tax allowance. But Charlottesville says that this is not its position. Charlottesville recognizes that in settling other parts of the case it has agreed to use the parent's capital structure and costs for the pipelines' return Charlottesville says that it is not contending that the settlement's rate of return should be changed. n119 Instead, Charlottesville says that its position is that, because the return is inflated, deducting the parent's interest expense does not flow the tax savings through.

n119 Tr. 548, 586

This argument is without merit. The issue here is whether [**87] the tax savings created by the parent's interest expense have been flowed through by deducting those expenses in calculating the pipelines' tax allowances. To answer that we must look at the tax consequences of our order. Those consequences are unaffected by the interest expense we use in setting the return. Companies do not report income on the basis of what revenues recover their equity return and what recovers their debt costs. Instead, they simply report gross income and deductions. So whether the pipelines' or the parent's cost of debt is used in the setting, the return tells us nothing about the tax consequences. That must be determined by considering the interest expense deductions taken on the consolidated return. n120

n120 Charlottesville has attempted to prove its argument by comparing the tax base when the pipelines' cost of debt is used in setting rates and when the parent's cost of debt is used. *See* Exh. 13 at 39-41; Exh. 14, and Schedules 14-15; Exh. 49; *see also* Petitioner's Reply Brief, *City of Charlottesville v F.E.R.C*., *661 F.2d 945*. This comparison shows that the tax base is the same. This should not be, Charlottesville implies, if deducting the parent's interest expense had the effect the pipelines claim it does.

The problem with this comparison is that it rests on contrived facts. What Charlottesville has done is to substitute the pipelines' cost of debt for the parent's cost of debt in the parent's capital structure Everything else remains the same, including the equity component. Because the equity component is the basic measure of the tax base, the tax base will of course be the same whether the parent's or the pipelines' cost of debt is used.

But the pipelines' cost of debt cannot be used with the parent's capital structure. A company's cost of debt only has significance in relation to its own indebtedness. Hence, if the pipelines' cost of debt is to be used, then their capital structures should also be used. Tr. 545 When that is done, however, Charlottesville's argument falls apart. The pipelines have more equity than their parent. So the equity return will be higher if the pipelines' capital structure and costs are used. The tax base will accordingly be higher than it would be if the parent's capital structure and costs are used. *See* Exh. 53, Schedule 2.
[**88]

What this argument does tell us, then, is that despite its statements to the contrary, Charlottesville's position is that using the parent's capital structure and costs has inflated the return. Is this so? Nothing in the record shows that a return based on the pipelines' own capital structure and costs would be lower n121 But even if there were, we could not conclude that the return is inflated. As we have said previously, where a subsidiary issues no securities to the public, its capital structure and costs should not be used. n122 Those elements have been determined by the parent, not the market. The parent can manipulate those elements for its own advantage. That cannot be permitted. Moreover, in this case the parties, including Charlottesville, have agreed to use the parent's capital structure and costs. That agreement is final So it is too late to complain now that the return is too high.

n121 True, Charlottesville's witness calculated a rate of return based on the pipelines' own capital structure and costs Exh. 53, Schedule 1. The rate of return so calculated is 9.06% while the rate of return included in the settlement, is 9.49%. But the 9.06% rate of return was not based on a test year estimate of interest expense. It was based on amounts recorded on the pipelines' books. So the return is somewhat understated--by how much we do not know. Moreover, the settlement's rate of return was the product of a settlement. It might not be calculated in exactly the same way as the witness did for the pipelines.
[**89]

n122 *See supra* pp. 41-42.
[*61,870]

The Commission orders:

(A) The refund condition imposed by Article IV-D of the Stipulation and Agreement filed in these dockets on June 8, 1976, as modified by Paragraph B of the Commission's order of September 13, 1976, in these dockets *[56 FPC 1651]*, is terminated.

(B) These dockets are terminated.

Legal Topics:

For related research and practice materials, see the following legal topics:
Energy & Utilities LawTaxationEnergy & Utilities LawTransportation & PipelinesNatural Gas TransportationEnergy & Utilities LawTransportation & PipelinesPipelinesRates

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-09

QUESTION:

Refer to the Direct Testimony of Charles Pringle at 25:28-30 wherein he describes his "understanding that it would be neither appropriate nor equitable to increase or reduce cost of service by tax costs or benefits that are not related to the rendering of utility service to customers."

a. Describe all sources relied on by Mr. Pringle to inform his "understanding," including, but not limited to, research prepared by or for the Company internally or by external advisors.

b. Provide a copy of all sources and all other materials reviewed and/or relied on by Mr. Pringle to inform his understanding, including, but not limited to, research prepared by or for the Company internally or by external advisors

c. Confirm that Mr. Pringle is providing subject matter testimony on this issue, and is not providing a legal opinion. If Mr. Pringle is providing a legal opinion, then provide a copy of all research and analyses that he performed and/or that others performed and that he reviewed and/or relied on for this legal opinion.

ANSWER:

a. Mr. Pringle relied on FERC Order No. 173 as well as PURA Section 36.060.

b. Please see the response to GCCC01-08 for FERC Order No. 173. Also see GCCC02-09 Attachment 1 SB01364F for PURA Section 36.060 as amended by S.B. No. 1364.

c. Mr. Pringle is providing subject matter testimony on this issue. Mr. Pringle is not providing a legal opinion.

SPONSOR (PREPARER):
Charles Pringle (Charles Pringle)

RESPONSIVE DOCUMENTS:
GCCC02-09 Attachment 1 SB01364F.pdf

S.B. No. 1364

AN ACT

relating to the computation of an electric utility's income taxes.

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF TEXAS:

SECTION 1. Subsection (a), Section 36.060, Utilities Code, is amended to read as follows:

(a) If an expense is allowed to be included in utility rates or an investment is included in the utility rate base, the related income tax benefit must be included in the computation of income tax expense to reduce the rates. If an expense is not allowed to be included in utility rates or an investment is not included in the utility rate base, the related income tax benefit may not be included in the computation of income tax expense to reduce the rates. The income tax expense shall be computed using the statutory income tax rates. [~~Unless it is shown to the satisfaction of the regulatory authority that it was reasonable to choose not to consolidate returns, an electric utility's income taxes shall be computed as though a consolidated return had been filed and the utility had realized its fair share of the savings resulting from that return, if:~~

[~~(1) the utility is a member of an affiliated group eligible to file a consolidated income tax return; and~~

[~~(2) it is advantageous to the utility to do so.~~]

SECTION 2. This Act takes effect September 1, 2013.

S.B. No. 1364

President of the Senate | Speaker of the House

I hereby certify that S.B. No. 1364 passed the Senate on April 23, 2013, by the following vote: Yeas 24, Nays 7.

Secretary of the Senate

I hereby certify that S.B. No. 1364 passed the House on May 20, 2013, by the following vote: Yeas 137, Nays 8, one present not voting.

Chief Clerk of the House

Approved:

Date

Governor

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-10

QUESTION:

Confirm that CenterPoint Energy Houston Electric, LLC is a pass-through entity and is not a taxpayer itself for federal income tax purposes.

ANSWER:

CenterPoint Energy Houston Electric, LLC is organized as a domestic single member limited liability company whose single member owner is Utility Holding, LLC. Utility Holding, LLC is organized as a domestic single member limited liability company, and its single member owner is a C corporation, CenterPoint Energy, Inc. For U.S. federal income tax purposes both CenterPoint Energy Houston Electric, LLC and Utility Holding, LLC's single member owner is CenterPoint Energy, Inc.

Under Treas. Reg. sec. 301.7701-3, unless an election is made otherwise, a domestic eligible entity (such as a limited liability company) is disregarded as an entity separate from its owner if it has a single owner. (Note that neither the Internal Revenue Code nor the Regulations thereunder generally use the term "pass-through entity" to refer to such disregarded entities.) Neither CenterPoint Energy Houston Electric, LLC nor Utility Holding, LLC have elected otherwise so both entities are treated as disregarded (i.e. treated as non-separate from CenterPoint Energy, Inc.) for federal income tax purposes.

SPONSOR (PREPARER):
Charles Pringle (Charles Pringle)

RESPONSIVE DOCUMENTS:
None

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-11

QUESTION:

Confirm that CenterPoint Energy, Inc. is a traditional C corporation and is a taxpayer itself for federal income tax purposes.

ANSWER:

CenterPoint Energy, Inc. is organized as a C corporation and is a taxpayer for federal income tax purposes.

SPONSOR (PREPARER):
Charles Pringle (Charles Pringle)

RESPONSIVE DOCUMENTS:
None

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-12

QUESTION:

Confirm that the basis for the Company's request for recovery of income tax expense is that CenterPoint Energy, Inc. is subject to federal income tax on the income and deductions passed through from CEHE. If this is not correct, then provide a correct and comprehensive statement of the basis for the Company's request for recovery of income tax expense despite the fact that it is a pass-through entity for federal income tax purposes.

ANSWER:

The basis for including recovery of Federal Income Tax in the current proceeding is that taxes are a reasonable and necessary expense. As required by the RFP instructions, Federal Income Taxes have been calculated using the return method for the test year. Please see the testimony of Mr. Charles Pringle 23:12 to 24:8 for an explanation of how the return method was calculated.

CenterPoint Energy Houston Electric, LLC's taxable income, including its income and deductions, is included in the CenterPoint Energy, Inc. consolidated Federal income tax return. As explained in detail in GCCC02-10, CenterPoint Energy Houston Electric, LLC is disregarded as an entity separate from CenterPoint Energy, Inc. for federal income tax purposes, and neither the Code nor the Treasury Regulations thereunder generally use the term "pass-through entity" to refer to such disregarded entities.

SPONSOR (PREPARER):
Charles Pringle (Charles Pringle)

RESPONSIVE DOCUMENTS:
None

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-13

QUESTION:

Refer to the Direct Testimony of Charles Pringle at 24:14 through 25:18 wherein he addresses FERC Order No. 173, the "benefits/burdens criteria," and the "standalone policy."

a. Provide a copy of all research reviewed and/or relied on related to FERC Order No. 173 and its applicability in this proceeding.

b. Provide a copy of all other research reviewed and/or relied on related to FERC decisions on recovery of income tax expense by pass-through entities.

c. Confirm that Mr. Pringle was aware that the FERC has issued a series of decisions whereby it disallowed income tax expense for pass-through entities. Describe and provide a copy of all research Mr. Pringle has reviewed on this issue.

ANSWER:

a. Mr. Pringle relied on FERC Order No. 173 to come to his conclusions. See GCCC02-08 for a copy of FERC Order No. 173.

b. See response to part c. below.

c. Mr. Pringle is aware of FERC orders limiting Federal income tax recovery for master limited partnerships (MLPs). Since CenterPoint Houston is not organized as an MLP these orders are not applicable to CenterPoint Houston.

SPONSOR (PREPARER):
Charles Pringle (Charles Pringle)

RESPONSIVE DOCUMENTS:
None

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-14

QUESTION:

Refer to the Direct Testimony of Charles Pringle at 33:18 through 34:3 wherein he states that the Company is treating EDIT related to removal costs as protected. Provide a copy of the request for PLR described.

ANSWER:

CenterPoint Houston is not the utility requesting the PLR and, therefore, does not have access to the PLR request. As of the current date, CenterPoint Houston is not aware of any ruling on this PLR request.

SPONSOR (PREPARER):
Charles Pringle (Charles Pringle)

RESPONSIVE DOCUMENTS:
None

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-15

QUESTION:

Refer to Schedule II-E-3.19, which provides ADIT by temporary difference.

a. Indicate which line item includes the EDIT related to removal costs.

b. Provide the EDIT related to removal costs at December 31, 2017 and December 31, 2018. Indicate if the amounts are asset EDIT or liability EDIT amounts.

c. Provide the EDIT amortization related to removal costs before and after the income tax gross-up recorded in 2018.

ANSWER:

a. Removal costs are included in line number 2 – Liberalized Depreciation

b. The Company has not done the analysis necessary to quantify the amount of removal costs included in EDIT so cannot provide the information requested.

c. See response to part b.

SPONSOR (PREPARER):
Charles Pringle (Charles Pringle)

RESPONSIVE DOCUMENTS:
None

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-16

QUESTION:

Refer to the Direct Testimony of Charles Pringle at 40:20-23 regarding the deferred income tax asset recorded on the SFAS 106 gross liability prior to the Health Care Legislation.

a. Provide the SFAS 106 gross liability at December 31, 2018 on the Company's accounting books and the amount subtracted from rate base in this proceeding. Provide a reconciliation and a description of each reconciling difference if the amount on the Company's accounting books and the amount subtracted from rate base are different.

b. Provide the asset ADIT related to the SFAS 106 gross liability at December 31, 2018 on the Company's accounting books and the amount added to rate base in this proceeding. Provide a reconciliation and a description of each reconciling difference if the amount on the Company's accounting books and the amount added to rate base are different.

ANSWER:

a. The SFAS 106 gross liability balance at of December 31, 2018 was $77,392,000 (GL account 259042) of which none was included in rate base in the proceeding, see RFP WP II-E-3.5.1c Excel row 89.

b. The asset ADIT related to SFAS 106 gross liability of $16,252,230 was not included in rate base in the proceeding, see answer GCCC 2-16a above.

SPONSOR (PREPARER):
Charles Pringle (Charles Pringle)

RESPONSIVE DOCUMENTS:
None

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-17

QUESTION:

Refer to Schedule II-D-1 which shows the O&M expense per books amounts for 2018 and to Schedule II-D-1a which shows the O&M expense per books amounts for each of the years 2015, 2016, and 2017. Refer further to the amounts recorded in 2018 compared to 2017 in FERC account 560, Operations Supervision and Engineering. The 2018 expense is $13.074 million compared to the 2017 expense amount of only $11.124 million.

a. Provide a copy of all variance analyses performed during 2018 and subsequently related to the reasons for the large increase in 2018 expense compared to 2017 for FERC account 560.

b. Identify, describe, and quantify all amounts recorded in 2018 in FERC account 560 that should be considered non-recurring in nature and indicate whether they were removed in the filing. If none, please explain all reasons for the large increase in this expense amount in 2018 compared to 2017, 2016, and 2015 and explain why the increase in 2018 should be considered recurring.

ANSWER:

a. Although CenterPoint Energy Houston Electric (CEHE) does not perform O&M variance analysis by FERC account, internal management reporting is performed on a GAAP basis and various approaches ensure that management has proper ongoing control over O&M expenses. When analyzing O&M on a monthly basis, CEHE compares actual expenses to budget and to the prior year. CEHE's annual budgeting exercise includes an assessment of year-over-year cost increases to ensure that the increases are both reasonable, necessary and explainable.

   Every month financial reports similar to the attachments to this response are prepared for use by executives, directors, and managers within CEHE. The reports facilitate discussions about O&M to identify variances and help management make decisions about future spend. In addition to individual review discussions held within each operational area, a collective budget review discussion is held each month with executives, directors, and managers within CEHE.

   Please refer to Dale Bodden, Kristie Colvin, Shachella James, Martin Narendorf, Randy Pryor, John Slanina, Julienne Sugarek, Rebecca Demarr and Michelle Townsend's testimony for additional information about cost controls.

   Please see GCCC02-17 Attachment 1 and GCCC02-17 Attachment 2 for examples of the types of O&M analysis performed on a monthly, quarterly, and/or annual basis.

b. All 2018 costs recorded to FERC 5600 are considered recurring.

   The increase in amounts recorded to FERC 5600 in 2018 is due to a reassignment of FERC accounts. CEHE periodically reviews FERC assignments by cost center for updates and implement changes as required.

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

SPONSOR (PREPARER):
Kristie Colvin (Kristie Colvin)

RESPONSIVE DOCUMENTS:
GCCC02-17 Attachment 1 (confidential).xlsx
GCCC02-17 Attachment 2 (confidential).xlsx

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-18

QUESTION:

Refer to Schedule II-D-1 which shows the O&M expense per books amounts for 2018 and to Schedule II-D-1a which shows the O&M expense per books amounts for each of the years 2015, 2016, and 2017. Refer further to the amounts recorded in 2018 compared to 2017 in FERC account 570, Maintenance of Station Equipment. The 2018 expense is $10.516 million compared to the 2017 expense amount of only $7.818 million.

a. Provide a copy of all variance analyses performed during 2018 and subsequently related to the reasons for the large increase in 2018 expense compared to 2017 for FERC account 570.

b. Refer further to the monthly O&M expense per books reflected for FERC account on Schedule II-D-1.1. Provide a copy of the general ledger detail for FERC account 570 for December 2018 summing to $1.588 million.

c. Identify, describe, and quantify all amounts recorded in 2018 in FERC account 570 that should be considered non-recurring in nature and indicate whether they were removed in the filing. If none, please explain all reasons for the large increase in this expense amount in 2018 compared to 2017, 2016, and 2015 and explain why the increase in 2018 should be considered recurring.

ANSWER:

a. Please see response to GCCC02-17 part a. for a description of O&M variance analyses performed during 2018.

b. See GCCC02-18b Attachment 1 for the general ledger detail for FERC account 5700 for December 2018 summing to $1.588 million.

c. All 2018 costs recorded to FERC 5700 are considered recurring.

   The increase in amounts recorded to FERC 5700 in 2018 was primarily due to corrective and preventive maintenance increases, including transformer oil servicing. As equipment ages, we expect our corrective maintenance levels to continue to increase. Additionally, as the quantity of installed substation equipment grows, more preventive maintenance work is required to keep equipment operating reliably. With growth in the amount of installed transformers, the cost for oil servicing will also continue to increase. The final increase to FERC 5700 was due to cost increases related to North American Electric Reliability Corporation (NERC) and Critical Infrastructure Protection (CIP) compliance.

SPONSOR (PREPARER):
Kristie Colvin / Martin Narendorf (Kristie Colvin / Martin Narendorf)

RESPONSIVE DOCUMENTS:
GCCC02-18b Attachment 1.xlsx

CenterPoint Energy Houston Electric
FERC 5700
For December 2018

Company Code	FERC Account	FERC Description	GL Number	GL Description	012/2018
0003	5700	Maint of Sta Equip	510010	Misc Oper Exp-Assoc	$11 24
0003	5700	Maint of Sta Equip	511010	Misc Oper Exp	$2 99
0003	5700	Maint of Sta Equip	515040	Bonus/Inc-Exempt	$19,215 39
0003	5700	Maint of Sta Equip	515042	Bonus/Inc-Non-Exempt	$943 67
0003	5700	Maint of Sta Equip	515044	Bonus/Inc-Union	$14,382 96
0003	5700	Maint of Sta Equip	515050	Non-prod-Exempt	$81,098 69
0003	5700	Maint of Sta Equip	515052	Non-prod-Non-Exempt	$6,367 23
0003	5700	Maint of Sta Equip	515054	Non-prod-Union	$93,383 78
0003	5700	Maint of Sta Equip	515080	Other Compensation	$0 00
0003	5700	Maint of Sta Equip	517988	Other Comp-Union	$5,271 33
0003	5700	Maint of Sta Equip	517989	OT Union - Double	$63,509 81
0003	5700	Maint of Sta Equip	517990	Overtime Union-1 5X	$101,401 12
0003	5700	Maint of Sta Equip	517991	Regular Union	$354,979 58
0003	5700	Maint of Sta Equip	517992	Oth Comp-Non-Exempt	$4 50
0003	5700	Maint of Sta Equip	517994	OT Non-Exmpt(1 5)	$0 00
0003	5700	Maint of Sta Equip	517995	Regular Non-Exempt	$13,360 46
0003	5700	Maint of Sta Equip	517996	Other Comp-Exempt	$29 00
0003	5700	Maint of Sta Equip	517998	Overtime Exempt	$0 00
0003	5700	Maint of Sta Equip	517999	Regular Exempt	$122,294 02
0003	5700	Maint of Sta Equip	522010	Employee Travel	$1,339 46
0003	5700	Maint of Sta Equip	522020	Training	$679 32
0003	5700	Maint of Sta Equip	522030	Registration	$255 60
0003	5700	Maint of Sta Equip	522040	Dues & Licenses	$97 59
0003	5700	Maint of Sta Equip	522060	Business Meals	$2,988 67
0003	5700	Maint of Sta Equip	522062	Entertainment	$63 00
0003	5700	Maint of Sta Equip	522070	Education Exp	$2,806.50
0003	5700	Maint of Sta Equip	522080	Park/In-town Travel	$2,849 42
0003	5700	Maint of Sta Equip	522090	Awards/Gifts	$0 00
0003	5700	Maint of Sta Equip	522100	Empl Reloc/Moving	$0 00
0003	5700	Maint of Sta Equip	522110	Occ Hlth & Safety	$1,350 19
0003	5700	Maint of Sta Equip	522120	Books & Subscriptons	$1 40
0003	5700	Maint of Sta Equip	522130	Misc Empl Rel Exp	$847 07
0003	5700	Maint of Sta Equip	523000	Empl Reimburs/Deduct	($407 75)
0003	5700	Maint of Sta Equip	530010	M&S - Non Inv	$7,403 75
0003	5700	Maint of Sta Equip	530020	M&S-Stores,Tools	$58 76
0003	5700	Maint of Sta Equip	530050	M&S-Salvage	($3,603 60)
0003	5700	Maint of Sta Equip	530999	M&S-Inventory Issued	$56,865 53
0003	5700	Maint of Sta Equip	531020	Motor-Veh & Plt	$0.00
0003	5700	Maint of Sta Equip	531030	Purch Veh Fuel Exp	$1,379 67
0003	5700	Maint of Sta Equip	532010	Mat & Supplies Exp	$0 00
0003	5700	Maint of Sta Equip	532020	M&S-Equipment	$206,996 50
0003	5700	Maint of Sta Equip	532040	M&S-Misc	$728,945 68
0003	5700	Maint of Sta Equip	533010	Purch-Comp Hdware	$0.00
0003	5700	Maint of Sta Equip	533020	Pur-Comp Sftw & Upgd	$155 43
0003	5700	Maint of Sta Equip	535010	Office Supplies	$2,008 85
0003	5700	Maint of Sta Equip	540010	Maint Services-Other	$0 00
0003	5700	Maint of Sta Equip	540020	Eng & Tech Services	$18,377 94
0003	5700	Maint of Sta Equip	540050	Construction Svcs	$44,145 85
0003	5700	Maint of Sta Equip	540060	Tree Clearing Svcs	$884 86
0003	5700	Maint of Sta Equip	540080	Billable Cntrctd Lbr	$0 00
0003	5700	Maint of Sta Equip	541530	Motor Veh Reg/Lic	$11 00
0003	5700	Maint of Sta Equip	543010	Prof Serv-Ded	$30,619 18
0003	5700	Maint of Sta Equip	543050	Technical Services	$204 59
0003	5700	Maint of Sta Equip	543090	Wireless Services	$1,168 15

Company Code	FERC Account		GL Number	GL Description	012/2018
0003	5700	Maint of Sta Equip	543160	Reimburseable Costs	($499.07)
0003	5700	Maint of Sta Equip	545040	Cont/Sv Add/Alt/Rem	$14,913.10
0003	5700	Maint of Sta Equip	545045	Cont/Sv -Bldg Mnt	$53.82
0003	5700	Maint of Sta Equip	545090	Cont/Sv Sec Elect	$0.00
0003	5700	Maint of Sta Equip	545100	Cont/Sv Sec Owned	$22,900.58
0003	5700	Maint of Sta Equip	545120	Temp Manpower Svc	$0.00
0003	5700	Maint of Sta Equip	545150	Printing Svcs	$0.00
0003	5700	Maint of Sta Equip	545160	Software Maintenance	$33,814.95
0003	5700	Maint of Sta Equip	546010	Other Services	$22,400.81
0003	5700	Maint of Sta Equip	550020	Misc Adm Expenses	$0.70
0003	5700	Maint of Sta Equip	550025	Meeting Exp	$0.00
0003	5700	Maint of Sta Equip	550041	Courier Expense	$62.30
0003	5700	Maint of Sta Equip	550060	Filing Fees	$0.00
0003	5700	Maint of Sta Equip	559994	Cont in Aid of Const	($194,472.83)
0003	5700	Maint of Sta Equip	562170	Uniforms	$1,534.44
0003	5700	Maint of Sta Equip	565010	Repairs & Maintenanc	$0.00
0003	5700	Maint of Sta Equip	565040	Rep & Maint-Vehicles	$3.96
0003	5700	Maint of Sta Equip	566040	Contrib-R & D	$0.00
0003	5700	Maint of Sta Equip	571010	Utilities-Electricit	$934.98
0003	5700	Maint of Sta Equip	571040	Utilities-Water	$2,581.82
0003	5700	Maint of Sta Equip	571050	Utilities-Other	$0.93
0003	5700	Maint of Sta Equip	572025	Rent/Lease-Off Equip	$0.00
0003	5700	Maint of Sta Equip	572027	Rent/Lease-Mot Veh	$0.00
0003	5700	Maint of Sta Equip	583005	Construction OH	$0.00
0003	5700	Maint of Sta Equip	621016	Fleet Maint	$27,673.80
0003	5700	Maint of Sta Equip	621017	Fleet Adj, Damg, Mod	$1,216.77
0003	5700	Maint of Sta Equip	621019	Fleet Services	$289.53
0003	5700	Maint of Sta Equip	621023	Shops	$746.45
0003	5700	Maint of Sta Equip	641002	Stores Overhead	$694.57
0003	5700	Maint of Sta Equip	641003	Transportation OH	$41,181.68
0003	5700	Maint of Sta Equip	642041	Transportation FERC	($91,140.51)
0003	5700	Maint of Sta Equip	642071	Fleet Allocation	$12,182.44
0003	5700	Maint of Sta Equip	642074	Construction OH	($161,823.08)
0003	5700	Maint of Sta Equip	642125	Land & Field Svcs	$1,372.33
0003	5700	Maint of Sta Equip	642129	Overhead Residual	$91.86
0003	5700	Maint of Sta Equip	642142	Fleet GPS	$9,040.36
0003	5700	Maint of Sta Equip	643001	Un labor-ST-IntAlloc	($88,317.74)
0003	5700	Maint of Sta Equip	643002	Un Labor 1 1/2-IntAl	($54,009.67)
0003	5700	Maint of Sta Equip	643003	Un Labor-DBL-Int Act	($39,506.89)
0003	5700	Maint of Sta Equip	643101	Labor-ST-NExmpt	$0.00
0003	5700	Maint of Sta Equip	643102	Labor 1 1/2-NExmpt	($1.40)
0003	5700	Maint of Sta Equip	643201	Labor-ST-Exempt	($1,031.42)
0003	5700	Maint of Sta Equip	643501	Fleet Fuel	$9,321.93
0003	5700	Maint of Sta Equip	643502	Fleet Pool Vehicles	($0.17)
0003	5700	Maint of Sta Equip	702050	Depr-Transportation	$31,415.85
					$1,588,375.56

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GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-19

QUESTION:

Refer to Schedule II-D-1 which shows the O&M expense per books amounts for 2018 and to Schedule II-D-1a which shows the O&M expense per books amounts for each of the years 2015, 2016, and 2017. Refer further to the amounts recorded in 2018 compared to 2017 in FERC account 571, Maintenance of Overhead Lines. The 2018 expense is $15.561 million compared to the 2017 expense amount of only $13.524 million.

a. Provide a copy of all variance analyses performed during 2018 and subsequently related to the reasons for the large increase in 2018 expense compared to 2017 for FERC account 571.

b. Refer further to the monthly O&M expense per books reflected for FERC account on Schedule II-D-1.1. Please provide a copy of the general ledger detail for FERC account 571 for December 2018 summing to $2.410 million.

c. Identify, describe, and quantify all amounts recorded in 2018 in FERC account 571 that should be considered non-recurring in nature and indicate whether they were removed in the filing. If none, please explain all reasons for the large increase in this expense amount in 2018 compared to 2017, 2016, and 2015 and explain why the increase in 2018 should be considered recurring.

ANSWER:

a. Please see response to GCCC02-17 part a. for a description of O&M variance analyses performed during 2018.

b. See GCCC02-19b Attachment 1 for the general ledger detail for FERC account 5710 for December 2018 summing to $2.410 million.

c. All 2018 costs recorded to FERC 5710 are considered recurring.

   The increase in amounts recorded to FERC 5710 in 2018 was primarily due to increases in preventive maintenance and repairs to obstruction lighting on towers. Preventive maintenance activities that contributed to the increase include corrosion mitigation, maintenance of Federal Aviation Administration (FAA) and Navigation lights, upgrade of safety and fall protection equipment, and removal of obsolete equipment.

   Corrosion mitigation spend varies based on site specific environmental corrosion acceleration factors and visual inspection for degree of degradation. Time between repairs varies greatly and can span 15 to 30 years based on severity of corrosion and longevity of available coatings and cathodic protection materials. Replacement versus repair is warranted where service life of hardware has been exhausted due to loss of strength or serviceability. Aging infrastructure in general has an acceleration effect on O&M spend.

SPONSOR (PREPARER):
Kristie Colvin (Kristie Colvin)

RESPONSIVE DOCUMENTS:
GCCC02-19b Attachment 1.xlsx

CenterPoint Energy Houston Electric
FERC 5710
For: December 2018

Company Code	FERC Account	FERC Description	GL Number	GL Description	012/2018
0003	5710	Maint of Ovrhd Lines	511010	Misc Oper Exp	$7.98
0003	5710	Maint of Ovrhd Lines	515040	Bonus/Inc-Exempt	$14,570.63
0003	5710	Maint of Ovrhd Lines	515042	Bonus/Inc-Non-Exempt	$428.50
0003	5710	Maint of Ovrhd Lines	515044	Bonus/Inc-Union	$6,132.27
0003	5710	Maint of Ovrhd Lines	515050	Non-prod-Exempt	$63,537.21
0003	5710	Maint of Ovrhd Lines	515052	Non-prod-Non-Exempt	$4,531.64
0003	5710	Maint of Ovrhd Lines	515054	Non-prod-Union	$47,043.35
0003	5710	Maint of Ovrhd Lines	515080	Other Compensation	$60,990.28
0003	5710	Maint of Ovrhd Lines	517988	Other Comp-Union	$533.91
0003	5710	Maint of Ovrhd Lines	517989	OT Union - Double	$14,078.49
0003	5710	Maint of Ovrhd Lines	517990	Overtime Union-1.5X	$35,177.16
0003	5710	Maint of Ovrhd Lines	517991	Regular Union	$142,638.73
0003	5710	Maint of Ovrhd Lines	517992	Oth Comp-Non-Exempt	$21.86
0003	5710	Maint of Ovrhd Lines	517994	OT Non-Exmpt(1.5)	$349.86
0003	5710	Maint of Ovrhd Lines	517995	Regular Non-Exempt	$6,794.30
0003	5710	Maint of Ovrhd Lines	517996	Other Comp-Exempt	$1,587.11
0003	5710	Maint of Ovrhd Lines	517998	Overtime Exempt	$0.00
0003	5710	Maint of Ovrhd Lines	517999	Regular Exempt	$90,853.40
0003	5710	Maint of Ovrhd Lines	522010	Employee Travel	$1,240.50
0003	5710	Maint of Ovrhd Lines	522020	Training	$706.64
0003	5710	Maint of Ovrhd Lines	522030	Registration	$0.00
0003	5710	Maint of Ovrhd Lines	522040	Dues & Licenses	$86.89
0003	5710	Maint of Ovrhd Lines	522060	Business Meals	$3,980.68
0003	5710	Maint of Ovrhd Lines	522062	Entertainment	$0.00
0003	5710	Maint of Ovrhd Lines	522070	Education Exp	$952.28
0003	5710	Maint of Ovrhd Lines	522080	Park/In-town Travel	$4,523.23
0003	5710	Maint of Ovrhd Lines	522090	Awards/Gifts	$0.00
0003	5710	Maint of Ovrhd Lines	522100	Empl Reloc/Moving	$0.00
0003	5710	Maint of Ovrhd Lines	522110	Occ Hlth & Safety	$643.57
0003	5710	Maint of Ovrhd Lines	522120	Books & Subscriptons	$1.20
0003	5710	Maint of Ovrhd Lines	522130	Misc Empl Rel Exp	$140.81
0003	5710	Maint of Ovrhd Lines	523000	Empl Reimburs/Deduct	$451.83
0003	5710	Maint of Ovrhd Lines	530010	M&S - Non Inv	$9,189.97
0003	5710	Maint of Ovrhd Lines	530020	M&S-Stores,Tools	$0.00
0003	5710	Maint of Ovrhd Lines	530050	M&S-Salvage	$0.00
0003	5710	Maint of Ovrhd Lines	530978	M&S-Land Purchases	$0.00
0003	5710	Maint of Ovrhd Lines	530999	M&S-Inventory Issued	$478,418.80
0003	5710	Maint of Ovrhd Lines	531020	Motor-Veh & Plt	$615.94
0003	5710	Maint of Ovrhd Lines	531030	Purch Veh Fuel Exp	$513.71
0003	5710	Maint of Ovrhd Lines	532010	Mat & Supplies Exp	$0.00
0003	5710	Maint of Ovrhd Lines	532020	M&S-Equipment	$135.87
0003	5710	Maint of Ovrhd Lines	532040	M&S-Misc	$319.23
0003	5710	Maint of Ovrhd Lines	533010	Purch-Comp Hdware	$49.73
0003	5710	Maint of Ovrhd Lines	533020	Pur-Comp Sftw & Upgd	$4,036.90
0003	5710	Maint of Ovrhd Lines	535010	Office Supplies	$762.12
0003	5710	Maint of Ovrhd Lines	540020	Eng & Tech Services	$16,955.26
0003	5710	Maint of Ovrhd Lines	540050	Construction Svcs	$2,184.00
0003	5710	Maint of Ovrhd Lines	540060	Tree Clearing Svcs	$329,453.94
0003	5710	Maint of Ovrhd Lines	540080	Billable Cntrctd Lbr	$955,965.21
0003	5710	Maint of Ovrhd Lines	541530	Motor Veh Reg/Lic	$787.53
0003	5710	Maint of Ovrhd Lines	543010	Prof Serv-Ded	$147,204.27
0003	5710	Maint of Ovrhd Lines	543090	Wireless Services	$1,912.81
0003	5710	Maint of Ovrhd Lines	543140	Site Restoration	$584.00
0003		Maint of Ovrhd Lines	543160	Reimburseable Costs	($3,142.64)

Company Code	FERC Account		GL Number	GL Description	012/2018
0003	5710	Maint of Ovrhd Lines	545040	Cont/Sv Add/Alt/Rem	$1,070 05
0003	5710	Maint of Ovrhd Lines	545100	Cont/Sv Sec Owned	$0 00
0003	5710	Maint of Ovrhd Lines	545120	Temp Manpower Svc	$0 00
0003	5710	Maint of Ovrhd Lines	545150	Printing Svcs	$0 00
0003	5710	Maint of Ovrhd Lines	545160	Software Maintenance	$246 09
0003	5710	Maint of Ovrhd Lines	546010	Other Services	$62,296 37
0003	5710	Maint of Ovrhd Lines	550020	Misc Adm Expenses	$16,040 07
0003	5710	Maint of Ovrhd Lines	550040	Postage/Courier	$0 00
0003	5710	Maint of Ovrhd Lines	550041	Courier Expense	$78 52
0003	5710	Maint of Ovrhd Lines	550086	Member Dues in Orgn	$0 00
0003	5710	Maint of Ovrhd Lines	550100	Freight	$0 00
0003	5710	Maint of Ovrhd Lines	559950	Cap Labor	$0 00
0003	5710	Maint of Ovrhd Lines	559957	Cap Contr Costs	($10,049 60)
0003	5710	Maint of Ovrhd Lines	562170	Uniforms	$1,315.23
0003	5710	Maint of Ovrhd Lines	565010	Repairs & Maintenanc	$37 11
0003	5710	Maint of Ovrhd Lines	565040	Rep & Maint-Vehicles	$0 00
0003	5710	Maint of Ovrhd Lines	566040	Contrib-R & D	$0 00
0003	5710	Maint of Ovrhd Lines	571010	Utilities-Electricit	$270 66
0003	5710	Maint of Ovrhd Lines	571050	Utilities-Other	$0 00
0003	5710	Maint of Ovrhd Lines	572025	Rent/Lease-Off Equip	$5 82
0003	5710	Maint of Ovrhd Lines	621016	Fleet Maint	$40,950 16
0003	5710	Maint of Ovrhd Lines	621017	Fleet Adj, Damg, Mod	$294 67
0003	5710	Maint of Ovrhd Lines	621019	Fleet Services	$924 83
0003	5710	Maint of Ovrhd Lines	621023	Shops	$1,221 16
0003	5710	Maint of Ovrhd Lines	641002	Stores Overhead	$55,106 10
0003	5710	Maint of Ovrhd Lines	641003	Transportation OH	$17,579 37
0003	5710	Maint of Ovrhd Lines	642041	Transportation FERC	($97,876 03)
0003	5710	Maint of Ovrhd Lines	642071	Fleet Allocation	$17,457.65
0003	5710	Maint of Ovrhd Lines	642074	Construction OH	($138,294 80)
0003	5710	Maint of Ovrhd Lines	642094	Internal Allocation	$2,743 73
0003	5710	Maint of Ovrhd Lines	642125	Land & Field Svcs	$7,595 59
0003	5710	Maint of Ovrhd Lines	642129	Overhead Residual	$183 72
0003	5710	Maint of Ovrhd Lines	642142	Fleet GPS	$4,194 42
0003	5710	Maint of Ovrhd Lines	643001	Un labor-ST-IntAlloc	($112,586.55)
0003	5710	Maint of Ovrhd Lines	643002	Un Labor 1 1/2-IntAl	($14,736 48)
0003	5710	Maint of Ovrhd Lines	643003	Un Labor-DBL-Int Act	($8,599 93)
0003	5710	Maint of Ovrhd Lines	643102	Labor 1 1/2-NExmpt	$0 00
0003	5710	Maint of Ovrhd Lines	643112	Labor-DT-NonExempt	$0 00
0003	5710	Maint of Ovrhd Lines	643201	Labor-ST-Exempt	($2,566 54)
0003	5710	Maint of Ovrhd Lines	643202	Labor 1 1/2-Exempt	$0 00
0003	5710	Maint of Ovrhd Lines	643501	Fleet Fuel	$5,774 40
0003	5710	Maint of Ovrhd Lines	643528	Land/Field Serv Bill	$57,274 12
0003	5710	Maint of Ovrhd Lines	702050	Depr-Transportation	$53,660 23
					$2,409,561 10

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2019 CEHE RATE CASE
DOCKET 49421-SOAH DOCKET NO. 473-19-3864

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-20

QUESTION:

Refer to Schedule II-D-1 which shows the O&M expense per books amounts for 2018 and to Schedule II-D-1a which shows the O&M expense per books amounts for each of the years 2015, 2016, and 2017. Refer further to the amounts recorded in 2018 compared to 2017 in FERC account 580, Operations Supervision and Engineering. The 2018 expense is $53.346 million compared to the 2017 expense amount of only $49.265 million.

a. Provide a copy of all variance analyses performed during 2018 and subsequently related to the reasons for the large increase in 2018 expense compared to 2017 for FERC account 580.

b. Identify, describe, and quantify all amounts recorded in 2018 in FERC account 580 that should be considered non-recurring in nature and indicate whether they were removed in the filing. If none, please explain all reasons for the large increase in this expense amount in 2018 compared to 2017, 2016, and 2015 and explain why the increase in 2018 should be considered recurring.

ANSWER:

a. Please see response to GCCC02-17 part a. for a description of O&M variance analyses performed during 2018.

b. All 2018 costs recorded to FERC 5800 are considered recurring.

   The increase in amounts recorded to FERC 5800 in 2018 was primarily due to increases in technology costs. The majority of these cost increases were related to improvements, upgrades and maintenance of system equipment and software, but also included additional costs for cyber security enhancements. CenterPoint Houston expects to continue to incur costs upgrading and maintaining the technology systems in the future and that costs for cyber security will continue to increase.

SPONSOR (PREPARER):
Kristie Colvin / Martin Narendorf / Shachella James (Kristie Colvin / Martin Narendorf / Shachella James)

RESPONSIVE DOCUMENTS:
None

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-21

QUESTION:

Refer to Schedule II-D-1 which shows the O&M expense per books amounts for 2018 and to Schedule II-D-1a which shows the O&M expense per books amounts for each of the years 2015, 2016, and 2017. Refer further to the amounts recorded in 2018 compared to 2017 in FERC account 583, Overhead Line Expense. The 2018 expense is $3.407 million compared to the 2017 expense amount of only $2.655 million.

a. Provide a copy of all variance analyses performed during 2018 and subsequently related to the reasons for the large increase in 2018 expense compared to 2017 for FERC account 583.

b. Identify, describe, and quantify all amounts recorded in 2018 in FERC account 583 that should be considered non-recurring in nature and indicate whether they were removed in the filing. If none, please explain all reasons for the large increase in this expense amount in 2018 compared to 2017, 2016, and 2015 and explain why the increase in 2018 should be considered recurring.

ANSWER:

a. Please see response to GCCC02-17 part a. for a description of O&M variance analyses performed during 2018.

b. All 2018 costs recorded to FERC 5830 are considered recurring.

   The increase in amounts recorded to FERC 5830 in 2018 is primarily due to labor costs for both union and non-union employees working at distribution service centers. These increases are attributable to increased staffing levels, annual wage increases, employee movements that caused a FERC reclassification of their costs, and the deferral of costs related to Hurricane Harvey that depressed the costs in this FERC account in 2017.

SPONSOR (PREPARER):
Kristie Colvin / Randal Pryor / Julienne Sugarek (Kristie Colvin / Randal Pryor / Julienne Sugarek)

RESPONSIVE DOCUMENTS:
None

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-22

QUESTION:

Refer to Schedule II-D-1 which shows the O&M expense per books amounts for 2018 and to Schedule II-D-1a which shows the O&M expense per books amounts for each of the years 2015, 2016, and 2017. Refer further to the amounts recorded in 2018 compared to 2017 in FERC account 584, Underground Line Expense. The 2018 expense is $8 .156 million compared to the 2017 expense amount of only $7.470 million.

a. Provide a copy of all variance analyses performed during 2018 and subsequently related to the reasons for the large increase in 2018 expense compared to 2017 for FERC account 584.

b. Identify, describe, and quantify all amounts recorded in 2018 in FERC account 584 that should be considered non-recurring in nature and indicate whether they were removed in the filing. If none, please explain all reasons for the large increase in this expense amount in 2018 compared to 2017, 2016, and 2015 and explain why the increase in 2018 should be considered recurring.

ANSWER:

a. Please see response to GCCC02-17 part a. for a description of O&M variance analyses performed during 2018.

b. All 2018 costs recorded to FERC 5840 are considered recurring.

   The increase in amounts recorded to FERC 5840 in 2018 is primarily due to increased work performed by the Damage Prevention group for line locating services related to residential and commercial growth in the service territory. In addition to residential and commercial growth, government capital and third-party pipeline infrastructure projects drove the increase in line location requests. Overall, line location requests increased nearly 13% between 2017 and 2018.

SPONSOR (PREPARER):
Kristie Colvin/Randal Pryor (Kristie Colvin/Randal Pryor)

RESPONSIVE DOCUMENTS:
None

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-23

QUESTION:

Refer to Schedule II-D-1 which shows the O&M expense per books amounts for 2018 and to Schedule II-D-1a which shows the O&M expense per books amounts for each of the years 2015, 2016, and 2017. Refer further to the amounts recorded in 2018 compared to 2017 in FERC account 586, Meter Expense. The 2018 expense is $27.262 million compared to the 2017 expense amount of only $22.935 million.

a. Provide a copy of all variance analyses performed during 2018 and subsequently related to the reasons for the large increase in 2018 expense compared to 2017 for FERC account 586.

b. Identify, describe, and quantify all amounts recorded in 2018 in FERC account 586 that should be considered non-recurring in nature and indicate whether they were removed in the filing. If none, please explain all reasons for the large increase in this expense amount in 2018 compared to 2017 and explain why the increase in 2018 should be considered recurring.

ANSWER:

a. Please see response to GCCC02-17 part a. for a description of O&M variance analyses performed during 2018.

b. All 2018 costs recorded to FERC 5860 are considered recurring.

   The increase in amounts recorded to FERC 5860 in 2018 is primarily due to increased labor costs associated with meter maintenance and meter inspections. CenterPoint Houston began a meter inspection program in October 2017, and 2018 was the first full year of the program. This program will continue at the same level as 2018.

SPONSOR (PREPARER):
Kristie Colvin/Randal Pryor (Kristie Colvin/Randal Pryor)

RESPONSIVE DOCUMENTS:
None

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-24

QUESTION:

Refer to Schedule II-D-1 which shows the O&M expense per books amounts for 2018 and to Schedule II-D-1a which shows the O&M expense per books amounts for each of the years 2015, 2016, and 2017. Refer further to the amounts recorded in 2018 compared to 2017 in FERC account 588, Misc. Distribution Expense. The 2018 expense is $35.680 million compared to the 2017 expense amount of only $32.547 million.

a. Provide a copy of all variance analyses performed during 2018 and subsequently related to the reasons for the large increase in 2018 expense compared to 2017 for FERC account 588.

b. Identify, describe, and quantify all amounts recorded in 2018 in FERC account 588 that should be considered non-recurring in nature and indicate whether they were removed in the filing. If none, please explain all reasons for the large increase in this expense amount in 2018 compared to 2017, 2016, and 2015 and explain why the increase in 2018 should be considered recurring.

ANSWER:

a. Please see response to GCCC02-17 part a. for a description of O&M variance analyses performed during 2018.

b. All 2018 costs recorded to FERC 5880 are considered recurring.

   The increase in amounts recorded to FERC 5880 in 2018 is primarily due to environmental costs for disposal and clean-up of transformers. As our system ages, CenterPoint Houston expects this cost to continue to increase. FERC 5880 also saw an increase in 2018 due to Advanced Distribution Management System (ADMS) software maintenance. A new software maintenance agreement went into effect in 2018 and the cost for this agreement is expected to continue. Costs to maintain and repair Heating Ventilation, Air Conditioning (HVAC) equipment at service centers also contributed to the increased amounts in FERC 5880.

SPONSOR (PREPARER):
Kristie Colvin / Randal Pryor / Martin Narendorf (Kristie Colvin / Randal Pryor / Martin Narendorf)

RESPONSIVE DOCUMENTS:
None

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-25

QUESTION:

Refer to Schedule II-D-1 which shows the O&M expense per books amounts for 2018 and to Schedule II-D-1a which shows the O&M expense per books amounts for each of the years 2015, 2016, and 2017. Refer further to the amounts recorded in 2018 compared to 2017 in FERC account 593, Maintenance of Overhead Lines. The 2018 expense is $84.709 million compared to the 2017 expense amount of only $75.173 million.

a. Provide a copy of all variance analyses performed during 2018 and subsequently related to the reasons for the large increase in 2018 expense compared to 2017 for FERC account 593.

b. Identify, describe, and quantify all amounts recorded in 2018 in FERC account 593 that should be considered non-recurring in nature and indicate whether they were removed in the filing. If none, please explain all reasons for the large increase in this expense amount in 2018 compared to 2017, 2016, and 2015 and explain why the increase in 2018 should be considered recurring.

ANSWER:

a. Please see response to GCCC02-17 part a. for a description of O&M variance analyses performed during 2018.

b. All 2018 costs recorded to FERC 5930 are considered recurring.

   The increase in amounts recorded to FERC 5930 in 2018 is primarily due to vegetation management associated with the maintenance of overhead lines. Contract costs to perform vegetation management have increased significantly over recent years. In addition to vegetation management, costs for rotten pole replacement increased in 2018.

SPONSOR (PREPARER):
Kristie Colvin/Randal Pryor (Kristie Colvin/Randal Pryor)

RESPONSIVE DOCUMENTS:
None

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-26

QUESTION:

Refer to Schedule II-D-1 which shows the O&M expense per books amounts for 2018 and to Schedule 11-D-1a which shows the O&M expense per books amounts for each of the years 2015, 2016, and 2017. Refer further to the amounts recorded in 2018 compared to 2017 in FERC account 594, Maintenance of Underground Lines. The 2018 expense is $12.990 million compared to the 2017 expense amount of only $9.811 million.

a. Provide a copy of all variance analyses performed during 2018 and subsequently related to the reasons for the large increase in 2018 expense compared to 2017 for FERC account 594.

b. Identify, describe, and quantify all amounts recorded in 2018 in FERC account 594 that should be considered non-recurring in nature and indicate whether they were removed in the filing. If none, please explain all reasons for the large increase in this expense amount in 2018 compared to 2017, 2016, and 2015 and explain why the increase in 2018 should be considered recurring.

ANSWER:

a. Please see response to GCCC02-17 part a. for a description of O&M variance analyses performed during 2018.

b. All 2018 costs recorded to FERC 5940 are considered recurring.

   The increase in amounts recorded to FERC 5940 in 2018 is due to contractor work related to our preventative maintenance inspection program for single source pad mounted transformer installations. This work was not performed in 2017 because of resource constraints; however, the program was highly successful in 2018 and is expected to continue. It was deemed successful because it identified conditions that required immediate repairs that avoided outages and possible equipment damage, and provided valuable data that allowed other corrective repairs.

SPONSOR (PREPARER):
Kristie Colvin / Randal Pryor / Martin Narendorf (Kristie Colvin / Randal Pryor / Martin Narendorf)

RESPONSIVE DOCUMENTS:
None

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-27

QUESTION:

Refer to Schedule II-D-1 which shows the O&M expense per books amounts for 2018 and to Schedule II-D-la which shows the O&M expense per books amounts for each of the years 2015, 2016, and 2017. Refer further to the amounts recorded in 2018 compared to 201 7 in FERC account 597, Maintenance of Meters. The 2018 expense is $7.758 million compared to the 2017 expense amount of only $6.916 million.

a. Provide a copy of all variance analyses performed during 2018 and subsequently related to the reasons for the large increase in 2018 expense compared to 2017 for FERC account 597.

b. Identify, describe, and quantify all amounts recorded in 2018 in FERC account 597 that should be considered non-recurring in nature and whether they were removed in the filing. If none, please explain all reasons for the large increase in this expense amount in 2018 compared to 2017, 2016, and 2015 and explain why the increase in 2018 should be considered recurring.

ANSWER:

a. Please see response to GCCC02-17 part a. for a description of O&M variance analyses performed during 2018.

b. All 2018 costs recorded to FERC 5970 are considered recurring.

   The increase in amounts recorded to FERC 5970 in 2018 is due to increased labor costs related to the repair and maintenance of high voltage meters. This type of meter will continue to need service at the same or higher levels as 2018.

SPONSOR (PREPARER):
Kristie Colvin/Randal Pryor (Kristie Colvin/Randal Pryor)

RESPONSIVE DOCUMENTS:
None

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-28

QUESTION:

Refer to Schedule II-D-1 which shows the O&M expense per books amounts for 2018 and to Schedule II-D-1a which shows the O&M expense per books amounts for each of the years 2015, 2016, and 2017. Refer further to the amounts recorded in 2018 compared to 2017 in FERC account 909, Information and Instruction Advertising. The 2018 expense is $3.914 million compared to the 2017 expense amount of only $3.338 million.

a. Provide a copy of all variance analyses performed during 2018 and subsequently related to the reasons for the large increase in 2018 expense compared to 2017 for FERC account 909.

b. Identify, describe, and quantify all amounts recorded in 2018 in FERC account 909 that should be considered non-recurring in nature and indicate whether they were removed in the filing. If none, please explain all reasons for the large increase in this expense amount in 2018 compared to 2017, 2016, and 2015 and explain why the increase in 2018 should be considered recurring.

ANSWER:

a. Please see response to GCCC02-17 part a. for a description of O&M variance analyses performed during 2018.

b. All 2018 costs recorded to FERC 9090 are considered recurring.

   The increase in amounts recorded to FERC 9090 in 2018 is primarily due to increased safety communications and external community outreach programs.

SPONSOR (PREPARER):
Kristie Colvin / Rebecca Demarr (Kristie Colvin / Rebecca Demarr)

RESPONSIVE DOCUMENTS:
None

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-29

QUESTION:

Refer to Schedule II-D-2 which shows the A&G expense per books amounts for 2018 and to Schedule II-D-2a which shows the A&G expense per books amounts for each of the years 2015, 2016, and 2017. Refer further to the amounts recorded in 2018 compared to 2017 in FERC account 920, Administrative and General Salaries. The 2018 expense is $2.371 million compared to the 2017 expense amount of only $0.662 million.

a. Provide a copy of all variance analyses performed during 2018 and subsequently related to the reasons for the large increase in 2018 expense compared to 2017 for FERC account 920.

b. Identify, describe, and quantify all amounts recorded in 2018 in FERC account 920 that should be considered non-recurring in nature and indicate whether they were removed in the filing. If none, please explain all reasons for the large per books increase in this expense amount in 2018 compared to 2017, 2016, and 2015 and explain why the increase in 2018 should be considered recurring.

ANSWER:

a. Please see CEHE's response to GCCC02-17 part a. for a description of O&M variance analyses performed during 2018.

b. All 2018 costs recorded to FERC 9200 are considered recurring.

   The increase in amounts recorded to FERC 9200 in 2018 is due to a reassignment of FERC account 9260 to this account. The Company periodically reviews FERC assignments by cost center for updates and implement changes as required.

SPONSOR (PREPARER):
Kristie Colvin / Michelle Townsend (Kristie Colvin / Michelle Townsend)

RESPONSIVE DOCUMENTS:
None

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-30

QUESTION:

Refer to Schedule II-D-2 which shows the A&G expense per books amounts for 2018 and to Schedule II-D-2a which shows the A&G expense per books amounts for each of the years 2015, 2016, and 2017. Refer further to the amounts recorded in 2018 compared to 2017 in FERC account 925, Injuries and Damages. The 2018 expense is $22.845 million compared to the 2017 expense amount of only $16.951 million.

a. Provide a copy of all variance analyses performed during 2018 and subsequently related to the reasons for the large increase in 2018 expense compared to 2017 for FERC account 925.

b. Refer further to the monthly A&G expense per books reflected for FERC account 925 on Schedule II-D-2.1. Provide a copy of the general ledger detail for FERC account 925 for September 2018 summing to $4.257 million and for December 2018 summing to $2.795 million.

c. Identify, describe, and quantify all amounts recorded in 2018 in FERC account 925 that should be considered non-recurring in nature and indicate whether they were removed in the filing. If none, please explain all reasons for the large per books increase in this expense amount in 2018 compared to 2017 and 2016 and explain why the increase in 2018 should be considered recurring.

ANSWER:

a. Please see response to GCCC02-17 part a. for a description of O&M variance analyses performed during 2018.

b. See GCCC02-30b Attachment 1 for the general ledger detail for FERC account 9250 for September 2018 summing to $4.257 million and December 2018 summing to $2.795 million.

c. All 2018 costs recorded to FERC 9250 are considered recurring.

   The increase in amounts recorded to FERC 9250 in 2018 is primarily due to an increase in insurance costs. Insurance reserves are periodically trued-up as a result of studies performed by outside actuarial firms. We expect that all future years will continue to have reserve true-ups to ensure that we have an adequate balance to cover losses related to Auto and General Liability. In addition to insurance reserves, costs for legal representation related to General Liability claims also increased in 2018.

   FERC 9250 also saw an increase in 2018 due to a reassignment of FERC accounts. CenterPoint Houston periodically reviews FERC assignments by cost center for updates and implement changes as required.

SPONSOR (PREPARER):
Kristie Colvin/Robert McRae/Shane Kimzey (Kristie Colvin/Robert McRae/Shane Kimzey)

RESPONSIVE DOCUMENTS:
GCCC02-30b Attachment 1.xlsx

CenterPoint Energy Houston Electric
FERC 9250
For: September and December 2018

Company Code	FERC Account	FERC Description	GL Number	GL Description	009/2018	012/2018
0003	9250	Injuries & Damages	515040	Bonus/Inc-Exempt	$13,487 28	$13,681 45
0003	9250	Injuries & Damages	515042	Bonus/Inc-Non-Exempt	$428 98	$443.27
0003	9250	Injuries & Damages	515044	Bonus/Inc-Union	$4,338 44	$4,956 83
0003	9250	Injuries & Damages	515050	Non-prod-Exempt	$14,399 06	$64,056 73
0003	9250	Injuries & Damages	515052	Non-prod-Non-Exempt	$709 65	$6,645 88
0003	9250	Injuries & Damages	515054	Non-prod-Union	$13,593 53	$39,819 78
0003	9250	Injuries & Damages	517988	Other Comp-Union	$304 00	$58 00
0003	9250	Injuries & Damages	517989	OT Union - Double	$13,035 96	$4,479 42
0003	9250	Injuries & Damages	517990	Overtime Union-1 5X	$14,602 55	$2,517 00
0003	9250	Injuries & Damages	517991	Regular Union	$113,161 17	$111,943 63
0003	9250	Injuries & Damages	517992	Oth Comp-Non-Exempt	$0 00	$0 00
0003	9250	Injuries & Damages	517995	Regular Non-Exempt	$7,828 68	$1,893 23
0003	9250	Injuries & Damages	517996	Other Comp-Exempt	$0 00	$0 00
0003	9250		517999	Regular Exempt	$114,333 42	$74,300 91
0003	9250	Injuries & Damages	518130	Workers Compensation	($74,910 93)	$154,085 83
0003	9250	Injuries & Damages	521989	Non-exempt PRB	($320 52)	($335 56)
0003	9250	Injuries & Damages	521990	Non-exempt OT PRB	($28 08)	($9 50)
0003	9250	Injuries & Damages	521991	Union OT PRB	($145 58)	($297 83)
0003	9250	Injuries & Damages	521992	Union DT PRB	($57 69)	($30 16)
0003	9250	Injuries & Damages	521994	Union	($1,557 37)	($1,646 08)
0003	9250	Injuries & Damages	521999	Payroll Burden	($1,487 23)	($1,498 42)
0003	9250	Injuries & Damages	522010	Employee Travel	$104 69	$281 14
0003	9250	Injuries & Damages	522020	Training	$151 33	$0 00
0003	9250	Injuries & Damages	522030	Registration	$0 00	$0 00
0003	9250	Injuries & Damages	522060	Business Meals	$657 81	$3,596 42
0003	9250	Injuries & Damages	522062	Entertainment	$0.00	$0 00
0003	9250	Injuries & Damages	522080	Park/In-town Travel	$1,652 67	$2,957 87
0003	9250	Injuries & Damages	522110	Occ Hlth & Safety	$279 89	$622 28
0003	9250	Injuries & Damages	522120	Books & Subscriptons	$0 00	$34 99
0003	9250	Injuries & Damages	522130	Misc Empl Rel Exp	$175 32	$144 61
0003	9250	Injuries & Damages	523000	Empl Reimburs/Deduct	($112 17)	($228 47)
0003	9250	Injuries & Damages	530010	M&S - Non Inv	$18,688 02	$6,344 53
0003	9250	Injuries & Damages	530999	M&S-Inventory Issued	$27,072 61	$867 57
0003	9250	Injuries & Damages	533010	Purch-Comp Hdware	$1,737 65	$0.00
0003	9250	Injuries & Damages	533020	Pur-Comp Sftw & Upgd	$75 00	$156 00
0003	9250	Injuries & Damages	535010	Office Supplies	$0.00	$0 00
0003	9250	Injuries & Damages	543010	Prof Serv-Ded	$80 25	$0 00
0003	9250	Injuries & Damages	543090	Wireless Services	$471 85	$374 26
0003	9250	Injuries & Damages	546010	Other Services	$814 52	$2,312 67
0003	9250	Injuries & Damages	550041	Courier Expense	$0 00	$0 00
0003	9250	Injuries & Damages	560020	Claims/Settlements	($3,419 89)	$75,374 85
0003	9250	Injuries & Damages	560070	Ins-Excess Liab	$690,413 73	$770,130.53
0003	9250	Injuries & Damages	560090	Ins-Gen Liab	$3,435,721 00	$1,125,017 33
0003	9250	Injuries & Damages	560100	Ins-Auto Liab	$83,463 58	$346,055 49
0003	9250	Injuries & Damages	560115	Ins-Other	$284 00	$299 00
0003	9250	Injuries & Damages	560120	Ins-Umbrella Liab	$3,499 85	$3,499 85
0003	9250	Injuries & Damages	565010	Repairs & Maintenanc	$0 00	$450 00
0003	9250	Injuries & Damages	566040	Contrib-R & D	$0 00	$0 00
0003	9250	Injuries & Damages	572025	Rent/Lease-Off Equip	$25 41	$352 67
0003	9250	Injuries & Damages	621016	Fleet Maint	$0 00	$839 39
0003	9250	Injuries & Damages	621017	Fleet Adj, Damg, Mod	$427 94	$0 00
0003	9250	Injuries & Damages	642071	Fleet Allocation	$0 00	$0 00
0003	9250	Injuries & Damages	642074	Construction OH	($8,407 08)	($9,283 70)
0003	9250	Injuries & Damages	642137	COA1/642137	($142,185 04)	($152,930 07)
0003	9250	Injuries & Damages	642142	Fleet GPS	$0 00	$0 00
0003	9250	Injuries & Damages	643001	Un labor-ST-IntAlloc	($214,678 43)	($25,611.38)
0003	9250	Injuries & Damages	643002	Un Labor 1 1/2-IntAl	($21,548 66)	($2,031 43)

Company Code	FERC Account		GL Number	GL Description	009/2018	012/2018
0003	9250	Injuries & Damages	643003	Un Labor-DBL-Int Act	($31,050 87)	($11,200 24)
0003	9250	Injuries & Damages	643101	Labor-ST-NExmpt	($0 86)	($15 85)
0003	9250	Injuries & Damages	643102	Labor 1 1/2-NExmpt	($0 34)	($3 50)
0003	9250	Injuries & Damages	643112	Labor-DT-NonExempt	$0.00	$0 00
0003	9250	Injuries & Damages	643201	Labor-ST-Exempt	($12,954 36)	($355 19)
0003	9250	Injuries & Damages	643202	Labor 1 1/2-Exempt	($15 41)	$0 18
0003	9250	Injuries & Damages	643501	Fleet Fuel	$40 22	$19 68
0003	9250	Injuries & Damages	646383	Claims - Reg Ops	$193,392 26	$181,956 98
0003	9250	Injuries & Damages	702050	Depr-Transportation	$0 00	$0 00
					$4,256,571 81	$2,795,092 87

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-31

QUESTION:

Refer to Schedule II-D-2 which shows the A&G expense per books amounts for 2018 and to Schedule II-D-2a which shows the A&G expense per books amounts for each of the years 2015, 2016, and 2017. Refer further to the amounts recorded in 2018 compared to 2017 in FERC account 926, Pensions and Benefits. The 2018 expense is $62.096 million compared to the 2017 expense amount of only $56.979 million.

a. Provide a copy of all variance analyses performed during 2018 and subsequently related to the reasons for the large increase in 2018 expense compared to 2017 for FERC account 926.

b. Refer further to the monthly A&G expense per books reflected for FERC account on Schedule II-D-2.1. Provide a copy of the general ledger detail for FERC account 926 for December 2018 summing to $10.403 million.

c. Identify, describe, and quantify all amounts recorded in 2018 in FERC account 926 that should be considered non-recurring in nature and whether they were removed in the filing. If none, please explain all reasons for the large per books increase in this expense amount in 2018 compared to 2017, 2016, and 2015 and explain why the increase in 2018 should be considered recurring.

ANSWER:

a. Please see response to GCCC02-17 part a. for a description of O&M variance analyses performed during 2018.

b. See GCCC02-31b Attachment 1 for the general ledger detail for FERC account 9260 for December 2018 summing to $10.403 million.

c. All 2018 costs recorded to FERC 9260 are considered recurring.

   Per books amount of $62m was reduced by a prior period adjustment resulting in an adjusted total that is comparable to the prior years. See WP II-D-2 for adjustment 3 and WP II-E-4.3 and in the 'CEHE RFP Workpapers' file for the prior period adjustment to FERC account 9260. There was a reassignment of FERC account 9260 to 9200 as referenced in GCCC02-29.

SPONSOR (PREPARER):
Kristie Colvin (Kristie Colvin)

RESPONSIVE DOCUMENTS:
GCCC02-31b Attachment 1.xlsx

CenterPoint Energy Houston Electric
Monthly Income Statement

Company Code	FERC Account	FERC Description	GL Number	GL Description	012/2018
0003	9260	Empl Pensions&Ben	518011	Pension - Service Co	$8,607,966 04
0003	9260	Empl Pensions&Ben	518016	Pension NonQualified	$166,322 91
0003	9260	Empl Pensions&Ben	518020	Medical	$1,966,426 86
0003	9260	Empl Pensions&Ben	518032	PostRetirement - Ser	$1,868,518 35
0003	9260	Empl Pensions&Ben	518070	Savings	$1,726,352 07
0003	9260	Empl Pensions&Ben	518090	Long-Term Disability	$329,624 60
0003	9260	Empl Pensions&Ben	518161	Split Doll Life Insu	$0 00
0003	9260	Empl Pensions&Ben	518166	Deferred Comp Plan -	$0 00
0003	9260	Empl Pensions&Ben	521989	Non-exempt PRB	($61,055 82)
0003	9260	Empl Pensions&Ben	521990	Non-exempt OT PRB	($1,731 90)
0003	9260	Empl Pensions&Ben	521991	Union OT PRB	($54,176 90)
0003	9260	Empl Pensions&Ben	521992	Union DT PRB	($5,496 87)
0003	9260	Empl Pensions&Ben	521994	Union	($299,456 15)
0003	9260	Empl Pensions&Ben	521999	Payroll Burden	($272,603 37)
0003	9260	Empl Pensions&Ben	642074	Construction OH	($1,688,795 92)
0003	9260	Empl Pensions&Ben	642080	Cap Labor Alloc	$716,377 32
0003	9260	Empl Pensions&Ben	643001	Un labor-ST-IntAlloc	($981,952 68)
0003	9260	Empl Pensions&Ben	643002	Un Labor 1 1/2-IntAl	($267,774 87)
0003	9260	Empl Pensions&Ben	643003	Un Labor-DBL-Int Act	($433,256 28)
0003	9260	Empl Pensions&Ben	643101	Labor-ST-NExmpt	($2,881 60)
0003	9260	Empl Pensions&Ben	643102	Labor 1 1/2-NExmpt	($639 01)
0003	9260	Empl Pensions&Ben	643112	Labor-DT-NonExempt	$0 00
0003	9260	Empl Pensions&Ben	643201	Labor-ST-Exempt	($64,614 90)
0003	9260	Empl Pensions&Ben	643202	Labor 1 1/2-Exempt	$33 06
0003	9260	Empl Pensions&Ben	718011	Pension - Non-Servic	($1,461,037 54)
0003	9260	Empl Pensions&Ben	718016	Pension NonQualified	$78,381 64
0003	9260	Empl Pensions&Ben	718032	Post Retirement Non	$538,184 82
0003	9260	Empl Pensions&Ben	718033	PostRet Split$ Life	$0.00
0003	9260	Empl Pensions&Ben	718166	Deferred Comp Plan	$0 00
					$10,402,713 86

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

GULF COAST COALITION OF CITIES
REQUEST NO.: GCCC02-32

QUESTION:

Refer to Schedule II-D-2 which shows the A&G expense per books amounts for 2018 and to Schedule II-D-2a which shows the A&G expense per books amounts for each of the years 2015, 2016, and 2017. Refer further to the amounts recorded in 2018 compared to 2017 in FERC account 930.2, Miscellaneous General Expenses. The 2018 expense is $145.091 million compared to the 2017 expense amount of only $136.418 million and the 2016 expense of only $127.568 million.

a. Provide a copy of all variance analyses performed during 2018 and subsequently related to the reasons for the large increase in 2018 expense compared to 2017 for FERC account 930.2.

b. Provide a copy of all variance analyses performed during 2017 and subsequently related to the reasons for the large increase in 2017 expense compared to 2016 for FERC account 930.2

c. Refer further to the monthly A&G expense per books reflected for FERC account on Schedule II-D-2.1. Provide a copy of the general ledger detail for FERC account 930.2 for September 2018 summing to $14.466 million and for December 2018 summing to $19.511 million.

d. Identify, describe, and quantify all amounts recorded in 2018 in FERC account 930.2 that should be considered non-recurring in nature and whether they were removed in the filing. If none, please explain all reasons for the large per books increase in this expense amount in 2018 compared to 2017, 2016, and 2015 and explain why the increase in 2018 should be considered recurring.

ANSWER:

a. Please see response to to GCCC02-17 part a for a description of O&M variance analyses performed during 2018 for CenterPoint Houston. While the Company does not perform variance analyses by FERC account, please see GCCC02-32 Attachment 2.xlsx for drivers of the variances in FERC 9302 comparing 2018 to 2017 for CenterPoint Energy Service Company.

b. Please see response to to GCCC02-17 part a for a description of O&M variance analyses performed during 2018 for CenterPoint Houston. While the Company does not perform variance analyses by FERC account, please see GCCC02-32 Attachment 2.xlsx for drivers of the variances in FERC 9302 comparing 2017 to 2016 for CenterPoint Energy Service Company.

c. See GCCC02-32c Attachment 1 for the general ledger detail for FERC account 9302 for September 2018 summing to $14.466 million and for December 2018 summing to $19.511 million.

d. All 2018 costs recorded to FERC account 9302 are considered recurring.

   The increase in O&M expense directly incurred by CenterPoint Houston recorded to FERC 9302 in 2018 was primarily due to higher work volumes within our Fiber and Wireless group that performs work to support third-party telecommunication companies. While Fiber and Wireless costs increased in 2018, CenterPoint Houston also received higher revenues in 2018 from third-party telecommunication companies that help offset the aforementioned cost increases. The Fiber and Wireless group also saw cost increases due to safety initiatives that were started in 2018, and a higher price for materials. See GCCC02-32 Attachment 2.xlsx for variance explanations for CenterPoint Energy Service Company.

SPONSOR:
Kristie Colvin / Michelle Townsend (Kristie Colvin / Michelle Townsend)

RESPONSIVE DOCUMENTS:

GCCC02-32c Attachment 1.xlsx
GCCC02-32 Attachment 2.xlsx

CenterPoint Energy Houston Electric
FERC 9302
For September and December 2018

Company Code	FERC Account	FERC Description	GL Number	GL Account Description	009/2018	012/2018
0003	9302	Misc General Exps	510010	Misc Oper Exp-Assoc	$101 98	$103 87
0003	9302	Misc General Exps	511010	Misc Oper Exp	$0 00	$0 00
0003	9302	Misc General Exps	515040	Bonus/Inc-Exempt	$3,219,394 67	$542,622 13
0003	9302	Misc General Exps	515042	Bonus/Inc-Non-Exempt	$6,868 45	$7,097 40
0003	9302	Misc General Exps	515044	Bonus/Inc-Union	$0 00	($1,370,000 00)
0003	9302	Misc General Exps	515050	Non-prod-Exempt	$35,718 77	$114,001 65
0003	9302	Misc General Exps	515052	Non-prod-Non-Exempt	$12,304 04	$57,430 75
0003	9302	Misc General Exps	515080	Other Compensation	$364 50	$0 00
0003	9302	Misc General Exps	517992	Oth Comp-Non-Exempt	$333 00	$48 50
0003	9302	Misc General Exps	517994	OT Non-Exmpt(1 5)	$3,247 41	$1,490 62
0003	9302	Misc General Exps	517995	Regular Non-Exempt	$125,793 20	$80,665 88
0003	9302	Misc General Exps	517996	Other Comp-Exempt	$3,412 50	$4,471 82
0003	9302	Misc General Exps	517998	Overtime Exempt	$0 00	$0 00
0003	9302	Misc General Exps	517999	Regular Exempt	$287,604 44	$215,119 85
0003	9302	Misc General Exps	518011	Pension - Service Co	($161,005 50)	$522,607 55
0003	9302	Misc General Exps	518016	Pension NonQualified	($3,515 15)	$168,119 36
0003	9302	Misc General Exps	518032	PostRetirement - Ser	($10,680 37)	($34,495 29)
0003	9302	Misc General Exps	518090	Long-Term Disability	($88,621 21)	$1,111,600.07
0003	9302	Misc General Exps	518166	Deferred Comp Plan -	$26,250.00	$26,250 00
0003	9302	Misc General Exps	522010	Employee Travel	$1,519 15	$7,299 36
0003	9302	Misc General Exps	522020	Training	$0 00	$18,245 60
0003	9302	Misc General Exps	522030	Registration	$0 00	$900 00
0003	9302	Misc General Exps	522040	Dues & Licenses	$2,311 50	$395 00
0003	9302	Misc General Exps	522060	Business Meals	$993 41	$5,420 71
0003	9302	Misc General Exps	522062	Entertainment	$0 00	$27 06
0003	9302	Misc General Exps	522070	Education Exp	$0 00	$0 00
0003	9302	Misc General Exps	522080	Park/In-town Travel	$4,853 25	$6,494 33
0003	9302	Misc General Exps	522090	Awards/Gifts	$11,897 57	$254,899 14
0003	9302	Misc General Exps	522110	Occ Hlth & Safety	$2,763 05	$12,484 54
0003	9302	Misc General Exps	522120	Books & Subscriptons	$63 99	$29 00
0003	9302	Misc General Exps	522130	Misc Empl Rel Exp	($5,755 88)	$162 56
0003	9302	Misc General Exps	522140	Recruit/Empl Agency	$0 00	$8,169 26
0003	9302	Misc General Exps	523000	Empl Reimburs/Deduct	$153 08	$470 59
0003	9302	Misc General Exps	530010	M&S - Non Inv	$4,044 39	$57,317 71
0003	9302	Misc General Exps	530020	M&S-Stores,Tools	$0 00	$0 00
0003	9302	Misc General Exps	530030	M&S-Ofc Furn & Equip	$0 00	$0 00
0003	9302	Misc General Exps	530050	M&S-Salvage	$0 00	$0 00
0003	9302	Misc General Exps	530987	M&S-Inventory Return	($5,759 22)	$0 00
0003	9302	Misc General Exps	530991	M&S - Inv Write-Dns	$20,996 44	$1,134 07
0003	9302	Misc General Exps	530998	M&S-Scrapping/Dest	$1,158 66	$2,308,761 57
0003	9302	Misc General Exps	530999	M&S-Inventory Issued	($14,727 38)	$35,204 94
0003	9302	Misc General Exps	531020	Motor-Veh & Plt	$0 00	$0 00
0003	9302	Misc General Exps	531030	Purch Veh Fuel Exp	$1,192 09	$1,012 63
0003	9302	Misc General Exps	532020	M&S-Equipment	$22 27	$135 81
0003	9302	Misc General Exps	532040	M&S-Misc	$54 11	$20,577 03
0003	9302	Misc General Exps	533010	Purch-Comp Hdware	$482 83	$4,686.60
0003	9302	Misc General Exps	533020	Pur-Comp Sftw & Upgd	$0 00	$0 00
0003	9302	Misc General Exps	534010	Purch-Comm Eq	$437 12	$4,007 54
0003	9302	Misc General Exps	535010	Office Supplies	$1,374 58	$1,641 38
0003	9302	Misc General Exps	535016	One Pay Card	$343,221 45	($191,050.03)
0003	9302	Misc General Exps	540020	Eng & Tech Services	($5,958 16)	$161,518 18
0003	9302	Misc General Exps	540050	Construction Svcs	$351,418 57	$1,692,173 38
0003	9302	Misc General Exps	540060	Tree Clearing Svcs	$32,738.20	$0 00
0003	9302	Misc General Exps	540080	Billable Cntrctd Lbr	$97,112 93	$37,810 83
0003	9302	Misc General Exps	543010	Prof Serv-Ded	($143,735 57)	($158,726 85)

Company Code	FERC Account	FERC Description	GL Number	GL Account Description	009/2018	012/2018
0003	9302	Misc General Exps	543040	Admin Services	$2,250.00	$1,000 00
0003	9302	Misc General Exps	543050	Technical Services	$35,546 48	($150,158 56)
0003	9302	Misc General Exps	543080	Media	$0 00	$0 00
0003	9302	Misc General Exps	543090	Wireless Services	$99,033 87	$146,270 15
0003	9302	Misc General Exps	543150	Legal Services	$0 00	$0 00
0003	9302	Misc General Exps	543160	Reimburseable Costs	($31.02)	($11,026 64)
0003	9302	Misc General Exps	545010	Property Services	$9,325 90	$9,816 89
0003	9302	Misc General Exps	545040	Cont/Sv Add/Alt/Rem	$40,649 87	$5,407 26
0003	9302	Misc General Exps	545045	Cont/Sv -Bldg Mnt	$251 51	$190 26
0003	9302	Misc General Exps	545100	Cont/Sv Sec Owned	$0 00	$8,363 85
0003	9302	Misc General Exps	545120	Temp Manpower Svc	$25,628 44	$46,550 85
0003	9302	Misc General Exps	545150	Printing Svcs	$2,965 25	$0 00
0003	9302	Misc General Exps	545160	Software Maintenance	$169,548 73	$0 00
0003	9302	Misc General Exps	545170	Hardware Maintenance	$4,764 08	$98,709 20
0003	9302	Misc General Exps	545510	IT Services	$0 00	$24,543 75
0003	9302	Misc General Exps	545520	Long Distance/Fax	$44 46	$7,712 52
0003	9302	Misc General Exps	546010	Other Services	$14 67	$25,909 76
0003	9302	Misc General Exps	550020	Misc Adm Expenses	$25,295 09	$28,568 50
0003	9302	Misc General Exps	550025	Meeting Exp	$0 00	$0 00
0003	9302	Misc General Exps	550040	Postage/Courier	$0 00	$0 00
0003	9302	Misc General Exps	550041	Courier Expense	$1,379.10	$1,620 24
0003	9302	Misc General Exps	550050	Bank Charges & Fees	$40 00	$0 00
0003	9302	Misc General Exps	550060	Filing Fees	$0 00	$0 00
0003	9302	Misc General Exps	550080	Club Member & Exp	$1,475 00	$23,444 00
0003	9302	Misc General Exps	550086	Member Dues in Orgn	$0 00	$0 00
0003	9302	Misc General Exps	550087	Dues-Industry	$61,396 42	$73,443 42
0003	9302	Misc General Exps	550100	Freight	$0 00	$0 00
0003	9302	Misc General Exps	559951	Cap Materials	$0 00	$0 00
0003	9302	Misc General Exps	559959	Cap COH	$0.00	$0 00
0003	9302	Misc General Exps	559990	ASC 715 Svc Company	$2,815,105 66	($348,088 11)
0003	9302	Misc General Exps	559994	Cont in Aid of Const	$0 00	$0 00
0003	9302	Misc General Exps	562170	Uniforms	$0 00	$0 00
0003	9302	Misc General Exps	565010	Repairs & Maintenanc	$0 00	$0 00
0003	9302	Misc General Exps	565040	Rep & Maint-Vehicles	$0 00	$0 00
0003	9302	Misc General Exps	566030	Sponsorships/Contrib	$71,700 00	$114,625 18
0003	9302	Misc General Exps	566040	Contrib-R & D	$0 00	$0 00
0003	9302	Misc General Exps	571010	Utilities-Electricit	$7,514 16	$4,577 47
0003	9302	Misc General Exps	571020	Util-Land-Phones Cir	$167,681 93	$259,527 53
0003	9302	Misc General Exps	571050	Utilities-Other	$8 41	$8 58
0003	9302	Misc General Exps	583005	Construction OH	$0 00	$0 00
0003	9302	Misc General Exps	621016	Fleet Maint	$4,975 45	$4,936 00
0003	9302	Misc General Exps	621017	Fleet Adj, Damg, Mod	($1,148 85)	$836 99
0003	9302	Misc General Exps	621023	Shops	$0 00	$0 00
0003	9302	Misc General Exps	641001	Construction OH	$0 00	$0 00
0003	9302	Misc General Exps	641002	Stores Overhead	$7,246 21	$11,311 89
0003	9302	Misc General Exps	641003	Transportation OH	$11,661 94	$6,062 68
0003	9302	Misc General Exps	642071	Fleet Allocation	$742 54	$2,771 09
0003	9302	Misc General Exps	642074	Construction OH	($162,612 03)	($163,181 29)
0003	9302	Misc General Exps	642080	Cap Labor Alloc	($1,281,209.32)	$345,195 34
0003	9302	Misc General Exps	642094	Internal Allocation	$1,580.46	$1,634 38
0003	9302	Misc General Exps	642095	REDG Allocation	($58,667 10)	($61,928 41)
0003	9302	Misc General Exps	642125	Land & Field Svcs	$29,103 51	$53,304 93
0003	9302	Misc General Exps	642142	Fleet GPS	$867 81	$5,063 69
0003	9302	Misc General Exps	642223	Comm Circuit Mgmt	($37,864 28)	($52,711.91)
0003	9302	Misc General Exps	643001	Un labor-ST-IntAlloc	$65,448 93	$41,887 22
0003	9302	Misc General Exps	643002	Un Labor 1 1/2-IntAl	$19,056 33	$11,274 38
0003	9302	Misc General Exps	643003	Un Labor-DBL-Int Act	$9,125 27	$6,121 51
0003	9302	Misc General Exps	643101	Labor-ST-NExmpt	($6,853.40)	($10,836 85)
0003	9302	Misc General Exps	643102	Labor 1 1/2-NExmpt	($59 85)	($1,137 07)
0003	9302	Misc General Exps	643201	Labor-ST-Exempt	$147 85	$10,652 84
0003	9302	Misc General Exps	643202	Labor 1 1/2-Exempt	($2,750 67)	$0 00

Company Code	FERC Account	FERC Description	GL Number	GL Account Description	009/2018	012/2018
0003	9302	Misc General Exps	643501	Fleet Fuel	$2,459 95	$1,696 01
0003	9302	Misc General Exps	643523	Transportation Exp	$0 00	($36 60)
0003	9302	Misc General Exps	643528	Land/Field Serv Bill	$50,573 02	($106,691 67)
0003	9302	Misc General Exps	646101	Governance-Legal	$786,142 96	$887,022 40
0003	9302		646102	Governance-Fin	$1,639,985 49	$1,632,057 98
0003	9302	Misc General Exps	646103	Governance-HR	$900,237 43	$1,326,192 80
0003	9302	Misc General Exps	646104	Governance-Comm	$19,467 43	$58,953 54
0003	9302	Misc General Exps	646106	Governance-ExMgt	$427,031 21	$307,714 75
0003	9302	Misc General Exps	646107	Gov-Regulated Oper	$211,405 25	$135,450 05
0003	9302	Misc General Exps	646109	Gov-Leg Misc Bus Exp	$611 50	$607 02
0003	9302	Misc General Exps	646110	Gov-Fin Misc Bus Exp	$10,843 71	$9,146 79
0003	9302	Misc General Exps	646111	Gov-HR Misc Bus Exp	$420.85	$10,778 39
0003	9302	Misc General Exps	646113	Gov-ExMgt Misc Bus E	$0 00	$428 00
0003	9302	Misc General Exps	646114	Gov-Comm Mis Bus Exp	$5 36	$0 00
0003	9302	Misc General Exps	646116	Gov-Reg Oper Mis Bus	$1,252 32	$245 44
0003	9302	Misc General Exps	646133	BSS Gov Misc Bus Ex	$2,324 62	$1,139 15
0003	9302	Misc General Exps	646136	BSS Governance	$57,307 05	$46,418 21
0003	9302	Misc General Exps	646141	Reg Ops-VP Mktg	$92,889 09	$391,390 52
0003	9302	Misc General Exps	646160	Gov-HR ASC 715 Non S	$315,185 72	$270,189 46
0003	9302	Misc General Exps	646201	Legal Direct	$292,034 66	$255,256 57
0003	9302	Misc General Exps	646204	Finance Direct	$229,663 26	$147,416 39
0003	9302	Misc General Exps	646205	Comm Direct	$7,728 47	$1,976 31
0003	9302	Misc General Exps	646206	Reg Ops Direct	$6,063 03	$11,067 61
0003	9302	Misc General Exps	646207	Direct - HR	$7,933 85	$4,962 90
0003	9302	Misc General Exps	646210	Govt A Direct	$0 00	$82,182 54
0003	9302	Misc General Exps	646211	Dir Leg Misc Bus Exp	$1,203 78	$789.97
0003	9302	Misc General Exps	646212	Dir Fin Misc Bus Exp	$0 00	$0 00
0003	9302	Misc General Exps	646214	Dir Reg Misc Bus Exp	$0 00	$0 00
0003	9302	Misc General Exps	646215	Dir Com Misc Bus Exp	$3,033.60	$25,086 49
0003	9302	Misc General Exps	646216	Dir GA Misc Bus Exp	($573 89)	($114.78)
0003	9302	Misc General Exps	646232	Direct - Regulatory	$75,452 85	$501,608 97
0003	9302	Misc General Exps	646242	Comm Rel Direct	$59,643 12	($1,010,356 18)
0003	9302	Misc General Exps	646301	Support Svcs- Legal	$104,939 89	$120,864 98
0003	9302	Misc General Exps	646302	Support Svcs- Fin	$144,415 47	$118,399 11
0003	9302	Misc General Exps	646303	Support Svcs- HR	$490,286 24	$642,290 71
0003	9302	Misc General Exps	646304	Support Svcs- Comm	$280,582 05	$1,356,217 33
0003	9302	Misc General Exps	646308	Sup Leg Misc Bus Exp	$446 02	$3,497 42
0003	9302	Misc General Exps	646310	Sup- HR Misc Bus Exp	$5,192.42	$9,552 11
0003	9302	Misc General Exps	646312	Sup-Com Misc Bus Exp	$20,222 93	$269,070 29
0003	9302	Misc General Exps	646325	Other-IT Svc	$2,003,866 60	$3,148,169 92
0003	9302	Misc General Exps	646329	IT -Misc Bus Expense	$0 00	$0 00
0003	9302	Misc General Exps	646335	Direct Legal Labor	$150,854 50	$109,965 66
0003	9302	Misc General Exps	646336	Direct Regulatory La	$407,927 04	$367,070 49
0003	9302	Misc General Exps	646340	Direct Finance Labor	$204,320 19	$270,628 30
0003	9302	Misc General Exps	646341	Xchrgs to IT	$202,575 90	$193,945.49
0003	9302	Misc General Exps	646342	Xchrgs to HR	$59,927 44	$69,858 72
0003	9302	Misc General Exps	646343	Xchrgs to Finance	$473,507 54	$389,902 51
0003	9302	Misc General Exps	646344	Xchrgs to Regulatory	$102,301 43	$88,705 88
0003	9302	Misc General Exps	646346	Xchrgs to Reg Ops co	$248,029 64	$358,768 57
0003	9302	Misc General Exps	646347	Xchrgs to Communicat	$42,169 44	$43,700 49
0003	9302	Misc General Exps	646348	Xchrgs to Legal	$46,052 78	$89,131 60
0003	9302	Misc General Exps	646349	Xchrgs to Exec Mgmt	$6,581 06	$7,450 23
0003	9302	Misc General Exps	646350	Xchrgs to Bus Spt Sv	$95,219 73	$126,658 29
0003	9302	Misc General Exps	646352	General Shared Svcs	$150,232 84	$158,089 43
0003	9302	Misc General Exps	646358	Sh Srvs-Misc Bus Exp	$0 00	$0 00
0003	9302	Misc General Exps	646361	Reg Ops Rent	$85,119 77	$68,999 29
0003	9302	Misc General Exps	646386	COA1/646386	$106,969 94	$145,452 19
0003	9302	Misc General Exps	702050	Depr-Transportation	$9,271 62	$7,727.73
0003	9302	Misc General Exps	718011	Pension - Non-Servic	($1,339,679 37)	$0 00
0003	9302	Misc General Exps	718016	Pension NonQualified	($719,479 75)	$0 00
0003	9302	Misc General Exps	718032	Post Retirement Non	($450,913 24)	$0 00

Company Code	FERC Account	FERC Description	GL Number	GL Account Description	009/2018	012/2018
0003	9302	Misc General Exps	718033	PostRet Split$ Life	$4,833 34	$4,833 34
0003	9302	Misc General Exps	718166	Deferred Comp Plan	$29,167 00	$29,167 00
					$14,466,088.12	$19,511,305 72

	FERC 9302 Variance Favorable/ (Unfavorable) 2017 vs 2016	2017 vs 2016 Explanation	FERC 9302 Variance Favorable/ (Unfavorable) 2018 vs 2017	2018 vs 2017 Explanation
Business & Operations Support	$ 1,188,390	Security Operations Center transferred from Service Co to Houston Electric in 2017	$ (194,376)	Increased support costs from Technology Operations cross charges allocated to business units
Communcations/Community Relations	(5,852)	Minor variance	(138,437)	Increased Employee Communications, Media Relations, accelerated Charitable Donation/Sponsorships (Houston Community Outreach) and 2017 Harvey Donations
Environmental/Safety/Training	-	Did not exist as a Service Co function until 2018	(656,349)	Organization change formed Environmental/Safety/Training within Service Co to serve all business units
Executive Management	(1,322,675)	Unfavorable STI True Ups in 2017 for years 2016 and 2017, competitive pay adjustments, offest by favorable employee expenses, depreciation, memberships, and donations/sponsorships	1,321,365	Unfavorable competitive pay adjustments, increased depreciation, fuel, and maintenance exp related to aircraft, offset by favorable STI True Ups in 2017 for years 2016 and 2017 and donations/sponsorships
Finance	1,028	Minor variance	(1,542,220)	Increased Labor, Contract Services (SNL Unlimited, Fin Reporting-Lease Acctg Standard Implementation, Tax-R&D credit analysis, Tax Provision, Mixed Service Cost Analysis,) and TechOps Support (Treasury Process Enhancement), Cyber/Fiduciary Insurance, Tax system, Oracle & SAP maintenance, and Advance Finance.
Government Affairs	15,193	Minor variance	(268,789)	
Human Resources	(838,069)	Increased Learning/Organizational Development (Leadership Academy, Skillsoft service & HMM contracts), Hewitt AON Actuarial services	(3,852,982)	In 2017 the non-service component of pension related benefits was included in the payroll burden and as such, was included across all functions following labor. In 2018 with the implementation of ASC 715 Accounting Standard Change, the non-service component of pension related benefits is no longer included in payroll burden and is recorded in the HR function.
Legal	(994,481)	Increased headcount in 2017 due to reorganization from Regulatory, Increased Outside Legal Services, Internal Time, and Temp Manpower Services relating to Legal Litigation for CenterPoint Houston matters; CenterPoint Houston Regulatory filings and Compliance & Records pertaining to CenterPoint Houston records	(528,729)	Increased Outside Legal Services, Internal Time, and Temp Manpower Services relating to Legal Litigation for CenterPoint Houston matters, CenterPoint Houston Regulatory filings and Compliance & Records pertaining to CenterPoint Houston records

	FERC 9302 Variance Favorable/ (Unfavorable) 2017 vs 2016	2017 vs 2016 *Explanation*	FERC 9302 Favorable/ (Unfavorable) 2018 vs 2017	2018 vs 2017 Explanation
Regulatory	363,356	Favorable variances shown in 2017 vs 2016 are the result of various organizational changes in headcount to Legal and related vendor payments and billable hours	(992,429)	The Regulatory variances are primarily due to 2017 reimbursements related to facility evaluations services and Energy Efficiency, vendor payments transitioning from Regulatory to Legal beginning in 2017, an increase in expenses related to the Bailey to Jones Creek CCN matter and an increase in internal time spent on CenterPoint Houston related matters including RPMO, ERCOT, PUC and the CenterPoint Houston Rate Case.
Regulated Operations Management	110,980	Inreases due to competitive pay adjustments, consulting services, increases in RegOps Marketing Commercial & Industrial (C&I) Relations team growing from 1 employee to 3 employees (2 Key Account Managers were added in 2017), driving an increase in Labor & Benefits. The increase also includes the associated Employee Expenses and Customer Communications managed by this team, offset by reduced Call Center agent headcounts in 2017 vs 2016 resulting in lower TechOps and HR allocations.	(469,561)	Increased headcount to support growing Customer Operatons,additional growth and expansion of commercial & industrial relations programs, competitive pay adjusments, and severance within Reg Ops Marketing.
Technology Operations	(226,657)	Decreased depreciation and labor allocations to Mainframe CPU service and costs related to regulatory mandated activities, offset by increases in Oragcle Fusion software maintenance and services, corporate function billings from Business & Operations Support and Finance, and shfit in treatment of software costs for Service Now	(2,834,003)	Increased Enterprise Infrastructure hardware and software maintenance (IBM, ELA, PCPC hardware), Oracle Fusion software maintenance and services, transfer of Houston Electric employees to Service Company (Tech & Markets), software maintenance for Filenet, additional Cyber Security headcount increases to support enterprise, and increase in corporate support billings primarily from Business & Operations Support.
CenterPoint Houston Direct	(7,151,038)	Please see part c. of this response and GCCC 02-17 (a)	1,483,926	Please see part c. of this response and GCCC 02-17 (a)
Total FERC 9302 Variance Year over Year	$ (8,859,824)		$ (8,672,585)	

CERTIFICATE OF SERVICE

I hereby certify that on this 15th day of May 2019, a true and correct copy of the foregoing document was served on all parties of record in accordance with 16 Tex. Admin. Code § 22.74.

Martin Burns