SOAH DOCKET NO. 473-04-1033
PUC DOCKET NO. 28840

APPLICATION OF AEP TEXAS	§	**BEFORE THE STATE OFFICE**
CENTRAL COMPANY FOR	§	**OF**
AUTHORITY TO CHANGE RATES	§	**ADMINISTRATIVE HEARINGS**

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AEP TEXAS CENTRAL COMPANY'S RESPONSE TO CITIES' SEVENTEENTH REQUEST FOR INFORMATION

JANUARY 5, 2004

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AUTHORITY TO CHANGE RATES	§	ADMINISTRATIVE HEARINGS

AEP TEXAS CENTRAL COMPANY'S RESPONSE TO CITIES' SEVENTEENTH REQUEST FOR INFORMATION

Question No. 1:

Provide a copy of AEP Texas Central Company's ("AEP/TCC") internal monthly operating reports (i.e., balance sheets, income statements, plant, revenues, customers, O&M expenses, etc.) for the months June 2002 to date.

Response No. 1:

Please see the attached documents for the monthly accounting trial balance reports of income statements, balance sheets and a listing of all account balances which includes revenues, plant balances, and O&M expenses. The information responsive to this request is voluminous and is available for review at the Austin offices of American Electric Power Company (AEP), 400 West 15th Street, Suite 610, Austin, Texas, 78701, (512) 481-4561, during normal business hours.

Prepared By:	Gary W. Moore	Title:	Senior Accounting Consultant
Sponsored By:	Randall W. Hamlett	Title:	Manager, Regulatory Accounting Services

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AEP TEXAS CENTRAL COMPANY'S RESPONSE TO CITIES' SEVENTEENTH REQUEST FOR INFORMATION

Question No. 2:

Provide copies of AEP and AEP/TCC's Board of Director's reports and minutes, executive committee reports and minutes, executive management reports, etc. from 2001 to date.

Response No. 2:

Pursuant to agreement with the Cities, the Company has received an extension of the deadline to answer this question.

Prepared By:	Sandra S. Bennett	Title:	Assistant Controller, Regulatory Accounting
Sponsored By:	Sandra S. Bennett	Title:	Assistant Controller, Regulatory Accounting

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APPLICATION OF AEP TEXAS	§	BEFORE THE STATE OFFICE
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AEP TEXAS CENTRAL COMPANY'S RESPONSE TO CITIES' SEVENTEENTH REQUEST FOR INFORMATION

Question No. 3:

Provide a description of the accounting (e.g., software, etc.) system currently used by AEP/TCC. Include a copy of the current chart of accounts showing all accounts and subaccounts numbers, titles and a brief description of each subaccount.

Response No. 3:

The accounting system currently used at AEP is a fully integrated system consisting of various vendor supplied applications. The applications include PeopleSoft General Ledger (GL), Accounts-Payable (AP) and Accounts-Receivable/Billing (AR/BI) and PowerPlant Asset Management (AM).

The GL application delivers business processes and functionality for maintaining charts of accounts, maintaining ledgers, posting journal entries, performing combination editing (both within GL and other feeder applications), performing allocations, performing corporate consolidations and reporting from the journal transaction table and the ledger tables. In addition to the integrated functionality, the GL application provides for the batch input of journals from various feeder systems, such as AP, AR/BI, AM, Payroll, Customer Information System, Materials Management, AEP Service Corp. Billing, and Cash Management.

The AP application delivers business processes and functionality for maintaining vendor information; entering, maintaining, approving and paying vouchers; performing purchase order matching; editing/updating financial information; creating payment records; and reporting from the vendor and voucher tables.

The AR/BI application delivers business processes and functionality for managing credit, maintaining customer information, generating invoices, processing payments, performing collection activities, editing/updating financial information, and reporting from the customer and billing tables. This system is used for miscellaneous billings only and not used for the billing of electric customers.

The AM application delivers business processes and functionality for project cost tracking, depreciation calculation and reporting of project and depreciation information.

The attachments to the response to Cities Seventeenth Request for Information, Question No.1, includes the chart of accounts showing all accounts and subaccounts with a description.

Prepared By:	Gary W. Moore	Title:	Senior Accounting Consultant
Sponsored By:	Randall W. Hamlett	Title:	Manager, Regulatory Accounting Services

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Question No. 4:

Regarding AEP/TCC's current accounting software, provide (1) the in-service date; (2) the original cost; (3) the expected life of the software; (4) the annual amortization expense of the software for the year ended June 30, 2003; (5) the allocation of the software costs for the year ended June 30, 2003 to the various entities; and (6) the derivation of the allocation factors used to allocate the software costs during the year ended June 30, 2003.

Response No. 4:

The Company does not track its software costs by system. The company does have data on the entire Enterprise Applications Solution (EAS). The answers to this question will show the total cost of EAS, which does include the company's current accounting software.

1. The in-service date for EAS was April 1, 2002.
2. The original cost for AEP/TCC for EAS was $13,270,393.
3. The expected life of this software is 5 years.
4. The annual amortization for AEP/TCC's portion of EAS is $2,654,079.
5. The allocation of the software costs to the various AEP entities at 12/31/2002 is shown on attachment 1.
6. The factors used to allocate the software costs are shown on attachment 2. Attachment 3 shows the various EAS software projects and their corresponding attribution basis. The attribution basis was assigned based upon how the system was used. For example, all HR system costs were allocated according to employee count. General ledger systems costs were allocated based upon each entity's number of ledger transactions. Stores system costs were allocated using the number of stores system transactions.

Prepared By: Gary W. Moore — Title: Senior Accounting Consultant
Sponsored By: Gary W. Moore — Title: Senior Accounting Consultant

AEPSC
Allocation of EAS Costs
As of December 31, 2003

CO. NO.	COMPANY	TOTAL COST
100	American Electric Power Company, Inc.	735,316.41
101	AEP Utilities, Inc.	55,781.17
104	Cardinal Operating Company	1,757,403.42
109	C3 Communications, Inc.	142,768.58
110	Kentucky Power Company - Distribution	2,269,407.95
114	Public Service Of Oklahoma - Transmission	1,278,658.74
116	AEP Texas POLR, LLC	873.35
117	Kentucky Power Company - Generation	1,693,734.47
119	AEP Texas North Company - Dist	2,417,498.14
120	Indiana Michigan Power Co. - Transmission	1,672,828.26
123	AEP Ohio Commercial & Industrial Retail Company, LLC	1,201.13
126	AEP Communications, LLC	855,098.63
127	AEP Energy Services Gas holding Company	1,128,577.63
128	AEP Communications, Inc.	3,798.01
130	Columbus Southern Power - Transmission	1,016,522.47
132	Indiana Michigan Power Co. - Generation	4,062,197.35
138	Mutual Energy Service Company, L.L.C.	99,253.20
140	Appalachian Power Company - Distribution	10,973,178.40
143	AEP Pro Serv, Inc.	1,335,745.60
144	Columbus Southern Power - Generation	2,755,455.75
147	AEP Texas Central Company - Gen	2,649,121.61
149	AEP EmTech LLC	66,024.08
150	Appalachian Power Company - Transmission	2,145,691.01
153	AEP Generating Company	51,561.40
154	AEP Credit, Inc.	88,354.46
157	AEP Ohio Retail Energy, LLC	4,323.79
158	AEP Resource Services LLC	955.33
159	Southwestern Electric Power Co. - Distribution	3,348,742.11
160	Ohio Power Company - Transmission	2,387,581.16
161	Southwestern Electric Power - Texas Distribution	2,247,513.88
165	EnerShop Inc.	12,530.74
166	AEP Texas North Company - Gen	1,373,373.91

AEPSC
Allocation of EAS Costs
As of December 31, 2003

CO. NO.	COMPANY	TOTAL COST
167	Public Service of Oklahoma - Distribution	5,296,113.63
168	Southwestern Electric Power - Generation	3,528,315.72
169	AEP Texas Central Company - Tran	1,954,300.82
170	Indiana Michigan Power Co. - Distribution	6,283,986.81
171	CSW Energy, Inc.	617,312.60
172	AEP Resources, Inc.	505,565.92
173	AEP Gas Power GP, LLC	19,488.93
174	Rep Holdco Inc.	158,168.58
175	CSW Power Marketing, Inc.	33.06
176	CSW Energy Services, Inc.	127,675.34
180	Kentucky Power Company - Transmission	502,431.83
181	Ohio Power Company - Generation	7,324,503.50
185	AEPES General and Administrative	4,960,210.17
187	CSW Leasing, Inc.	6,042.83
190	Indiana Michigan Power Co. - Nuclear	4,370,349.12
192	AEP Texas North Company - Tran	1,230,823.76
194	Southwestern Electric Power - Transmission	1,504,222.49
196	AEP Investments, Inc.	18,794.59
198	Public Service of Oklahoma - Generation	2,251,719.21
200	Wheeling Power Company - Transmission	155,186.77
203	AEP C & I Company LLC	1,834.51
204	AEP T & D Services, LLC	22,153.58
207	AEP Delaware Investment Company	1,231.61
210	Wheeling Power Company - Distribution	940,797.81
211	AEP Texas Central Company - Dist	8,660,965.30
215	Appalachian Power Company - Generation	9,698,136.47
216	AEP Texas Commercial & Industrial Retail GP, LLC	9,142.92
220	Columbus Southern Power - Distribution	7,126,333.78
223	Mutual Energy L.L.C.	1,129.55
230	Kingport Power Company - Distribution	473,077.07
232	AEP Delaware Investment Company II	6,340.36
234	AEP Energy Services Limited	64,959.96

SOAH 473-04-1033
PUC Docket No 28840
Cities 17th Q #4
Attachment 1

AEPSC
Allocation of EAS Costs
As of December 31, 2003

CO. NO.	COMPANY	TOTAL COST
245	Dolet Hills Lignite Company, LLC	43,426.79
250	Ohio Power Company - Distribution	9,434,550.69
260	Kingsport Power company - Transmission	67,412.97
270	Cook Coal Terminal	333,037.95
280	Ind Mich River Transp Lakin	866,591.74
290	Conesville Coal Preparation Company	192,526.40
308	POLR Power, L. P.	7,933.80
314	AEP Desert Sky LP, LLC	13,517.08
315	AEP Desert Sky GP, LLC	96.52
319	United Sciences Testing, Inc.	3,390.72
322	AEPR Ohio, LLC	750.01
		127,415,655.41

AEPSC
Attribution Basis Factors Used for Billing

Number	Description
8	Number of Customers
9	Number of Employees
11	Number of G/L Transactions
17	Number of Purchase Orders
26	Number of Storeroom transactions
28	Number of Trans. Pole Miles
32	Number of Vendor Payments
48	Generating Capacity in MW
58	Total Assets
60	Service Corp. Bill Less Loadings
61	Total Fixed Assets
70	Number of Non Electric Other A/R Invoices

EAS ATTRIBUTION BASIS

DESCRIPTION	TO ATTRIB BASIS
EAS WMS Distribution	08
Non EAS WM Distribution Integration	08
Non EAS MACCS Integration Inter	08
EAS WMS Training	09
EAS WMS Infrastructure	09
EAS WMS Change Management	09
EAS WMS Technical Development	09
EAS WMS Shared Services	09
EAS FCM Training	09
EAS HRM Payroll	09
EAS HRM Human Resources	09
EAS HRM Technical Development	09
EAS HRM Learning & Development	09
EAS HRM Change Management	09
EAS HRM Conversion & Interface	09
EAS HRM Benefits	09
EAS HRM Reporting	09
EAS HRM Infrastructure	09
EAS HRM Shared Services	09
EAS HRM Training	09
Non EAS HRM General Integration	09
Non EAS HRM Human Resources Integration	09
Non EAS HRM Learning & Development	09
Non EAS HRM Payroll Integration	09
EAS HRM - General	09
EAS FCM GL	11
Non EAS FCM GL Integration	11
EAS SCM General	17
EAS SCM Infrastructure	17
Non EAS SCM General Integration	17
EAS WMS - General	26
EAS WMS Transmission	28
EAS FCM AP	32
EAS WMS Fossil & Hydro	48
Non EAS WM Fossil & Hydro	48
EAS FCM Budgeting	58
EAS Global Design	60
EAS FCM Tech Development	60
EAS FCM Projects	60
EAS FCM Reporting / EMP	60
EAS FCM Change Management	60
EAS FCM Infrastructure	60
EAS FCM Conversion & Interface	60
EAS FCM Shared Services	60
EAS Implementation	60

EAS ATTRIBUTION BASIS

DESCRIPTION	TO ATTRIB BASIS
Non EAS FCM Projects Integration	60
EAS FCM General Integration	60
Non EAS WMS General Intergration	60
EAS - Project Management	60
EAS FCM - General	60
EAS FCM AM - Lease	61
EAS FCM AR / Billing	70

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AEP TEXAS CENTRAL COMPANY'S RESPONSE TO CITIES' SEVENTEENTH REQUEST FOR INFORMATION

Question No. 5:

Provide a copy of AEP and AEP/TCC's audit reports and workpapers for the years 2002 and 2003.

Response No. 5:

Pursuant to agreement with the cities, the Company is coordinating with Deloitte & Touche (D&T) and interested parties to make available the 2002 D&T voluminous workpapers in Columbus Ohio. The 2003 audit has not been completed and thus the D&T workpapers for that audit are not available from D&T for review.

Prepared By:	Randall W. Hamlett	Title:	Manager, Regulatory Accounting Services
Sponsored By:	Randall W. Hamlett	Title:	Manager, Regulatory Accounting Services

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AEP TEXAS CENTRAL COMPANY'S RESPONSE TO CITIES' SEVENTEENTH REQUEST FOR INFORMATION

Question No. 6:

Provide a breakdown (e.g., per FERC Form No. 1, page 335.1) of AEP/TCC's FERC Account 930.2 expenses for the year ended June 30, 2003. Include a brief description of expense categories in excess of $100,000.

Response No. 6:

See the attached spreadsheet for a breakdown of account 930.2 and descriptions of expense catagories > $100,000

Prepared By:	Randall W. Hamlett	Title:	Mgr. Regulatory Accounting Services
Sponsored By:	Gary W. Moore	Title:	Sr. Accounting Consultant

AEP TEXAS CENTRAL CO
CITIES' SEVENTEENTH, QUESTION 6
ACCOUNT 9302
MISCELLANEOUS GENERAL EXPENSES
RATE CASE FOR YEAR ENDED 6/30/03

Line No.	DESCRIPTION	AMOUNT	Desc of line items > 100,000
1	INDUSTRY ASSOCIATION DUES	$ 415,378.48	Industry Assoc. Dues for company memberships. In addition, this may include expenses for conventions and meetings of the industry.
2	OTHER EXPERIMENTAL AND GENERAL RESEARCH EXP	257,981.48	Research, development and demonstration expenses not charged to other operation and maintenance expense accounts.
3	PUBLISHING AND DISTRIBUTING INFORMATION EXP	82,386.19	
4	ASSOCIATED BUSINESS DEVELOPMENT	1,336,839.15	Misc. Associated Business Development expenses.
5	OTHER EXPENSES:		
6	MISC. GENERAL SERVICE BILLING	65,231.09	
7	ADJUSTMENTS	255,451.93	Deregulation Implementation Related Expenses
8	DIRECTORS' FEES AND EXPENSES	6,307.90	
9	BUSINESS PROCESS IMPROVEMENT	134,093.72	Operations Improvements
10	RELOCATION EXPENSES	85.17	
12	MISCELLANEOUS MINOR ITEMS UNDER $5,000	58,654.40	
46	**TOTAL**	$ 2,612,409.51	

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AEP TEXAS CENTRAL COMPANY'S RESPONSE TO CITIES' SEVENTEENTH REQUEST FOR INFORMATION

Question No. 7:

Provide a description of all of AEP/TCC regulatory assets (i.e., SFAS 71). For each regulatory asset, provide (1) date the regulatory asset was established; (2) a copy of the excerpts from the regulatory order establishing the regulatory asset; (3) the beginning balance of the regulatory asset; (4) the annual amortization expense; (5) the amortization period; (6) the basis for the amortization period used; (7) the unamortized balances as of June 30, 2002, and June 30, 2003; (8) the annual amortization expense for the year ended June 30, 2002; and (9) the completion date of the amortization period. Identify FERC accounts used to record the original regulatory assets balances, the accumulated amortization and the expenses.

Response No. 7:

Attachment 1 is a table containing the requested information (note- the FERC does not provide for an account to be used for accumulated amortization for regulatory assets). Attachment 2 includes PUC dockets supporting the recognition of regulatory assets related to T&D operations, including Docket 19265 for merger assets and Docket 22352 for debt refinancing costs-restructuring. The other regulatory assets referenced in the attachment were properly established as a result of the application of GAAP, in light of the standards governing and/or the outcome of the referenced PUC proceedings.

Prepared By:	Gary W. Moore	Title:	Senior Accounting Consultant
Sponsored By:	Randall W. Hamlett	Title:	Manager, Regulatory Accounting Services

AEP TEXAS CENTRAL COMPANY
RESPONSE TO CITIES QUESTION NO. 17-7

FERC Account to Record Reg Asset	Description	AUTHORIZATION	(1) Date Established	(3) Original Amt. Deferred	(4) Annual Amort.	(5) Amort. Period
1823000	Other Regulatory Assets-Plant impairment	PURA true-up	4th qtr 2002	122,703,116	n/a	n/a
1823000	Other Regulatory Assets-merger asset	19265	Jun-00	15,684,672	2,614,112	6-years
1823050, 90	Uranium Decommissioning	12820,15900,20290	Sep-93	8,064,630	n/a PURA true-up	n/a
1823083	ECOM - assets unsecuritized-PURA true-up	21528	various	various	n/a PURA true-up	n/a
1823085	REG ASSET-SECURITZTN(PUCT SB7)	21528	Feb-02	184,575,704		14-years
1823097, 98	Debt Refinancing - Restructuring	22352	Jul-02	12,925,676	861,712	15-years
1823099	Asset Retirement Obligations	(a)	Mar-03	63,771,524	n/a	Decomm Trust life
1823101	Capacity Auction True-Up	PURA true-up	Dec-02	262,000,000	n/a	n/a
1823301	SFAS 109 Flow Thru Defd FIT	12820, 14965, 22352	Mar-93	527,128,000	n/a	life of plant
1823302	SFAS 109 Flow Thru Defrd SIT	22352	Dec-97	77,913,289	n/a	life of plant

Note: Amounts established prior to 09-30-1999 are total company amounts
The Company went off SFAS 71 for generation purposes in Sept. 1999.

(a) The PUCT approval to collect nuclear decommissioning costs from customers provides tha authorization to record the regulatory asset to reflect the requirements of GAAP and the PUCT for asset retirement obligations.

AEP TEXAS CENTRAL COMPANY
RESPONSE TO CITIES QUESTION NO. 17-7

FERC Account to Record Reg Asset	Description	AUTHORIZATION	(6) Basis for Amort. Period	(7) Unamortized Balance Jun-02	Jun-03	(8) Test Yr Amort.
1823000	Other Regulatory Assets-Plant impairment	PURA true-up	n/a	0	126,392,331	0
1823000	Other Regulatory Assets-merger asset	19265	merger settlement	10,456,148	7,842,036	2,614,112
1823050, 90	Uranium Decommissioning	12820,15900,20290	n/a	3,445,269	3,219,343	0
1823083	ECOM - assets unsecuritized-PURA true-up	21528	n/a		194,502,091	0
1823085	REG ASSET-SECURITZTN(PUCT SB7)	21528	Recovery of Assets	170,354,369	136,407,279	33,947,090
1823097, 98	Debt Refinancing - Restructuring	22352	PUCT Docket 22352	0	12,457,136	468,540
1823099	Asset Retirement Obligations	(a)	n/a	0	56,675,670	0
1823101	Capacity Auction True-Up	PURA true-up	n/a	0	370,400,000	0
1823301	SFAS 109 Flow Thru Defd FIT	12820, 14965, 22352	SFAS 109	7,899,717	7,583,714	316,003
1823302	SFAS 109 Flow Thru Defrd SIT	22352	SFAS 109	35,166,527	35,166,527	0
					950,646,127	

Note: Amounts established prior to 09-30-1999 are total company amounts
The Company went off SFAS 71 for generation purposes in Sept. 1999.

(a) The PUCT approval to collect nuclear decommissioning costs from customers provides tha authorization to record the regulatory asset to reflect the requirements of GAAP and the PUCT for asset retirement obligations.

AEP TEXAS CENTRAL COMPANY
RESPONSE TO CITIES QUESTION NO. 17-7

FERC Account to Record Reg Asset	Description	AUTHORIZATION	(9) Date Amort. Ends	FERC A/C To Record Amortization
1823000	Other Regulatory Assets-Plant impairment	PURA true-up	n/a	n/a
1823000	Other Regulatory Assets-merger asset	19265	Jun-06	407
1823050, 90	Uranium Decommissioning	12820,15900,20290	2004 PURA true-up	n/a
1823083	ECOM - assets unsecuritized-PURA true-up	21528	2004 PURA true-up	n/a
1823085	REG ASSET-SECURITZTN(PUCT SB7)	21528	2015	407
1823097, 98	Debt Refinancing - Restructuring	22352	2017	407
1823099	Asset Retirement Obligations	(a)	Decomm Trust life	234
1823101	Capacity Auction True-Up	PURA true-up	2004 PURA true-up	n/a
1823301	SFAS 109 Flow Thru Defd FIT	12820, 14965, 22352	plant life	282
1823302	SFAS 109 Flow Thru Defrd SIT	22352	plant life	282

Note: Amounts established prior to 09-30-1999 are total company amounts
The Company went off SFAS 71 for generation purposes in Sept. 1999.

(a) The PUCT approval to collect nuclear decommissioning costs from customers provides tha authorization to record the regulatory asset to reflect the requirements of GAAP and the PUCT for asset retirement obligations.

(2) The Merged Company and Texas operating companies will defer and amortize their merger related costs-to-achieve over a six year period following the effective date of the merger. Costs to achieve the merger are those costs incurred to consummate the merger and combine the operations of AEP and CSW. These costs include, but are not limited to, investment banking fees; consulting and legal services incurred in connection with obtaining regulatory and shareholder approvals; transition planning and development costs; employee separation costs including severance costs, change-in-control payments and retraining costs; and facilities consolidation costs. Subject to Subparagraph F.(3), in any proceeding to change base rates of a Texas operating company to become effective prior to the end of the six year period after the effective date of the merger and that is not initiated to implement electric industry restructuring legislation, the annual amount of amortization of costs to achieve the merger included in Attachment C will be reflected as a reasonable and necessary expense included in the calculation of cost of service.

(3) In any proceeding initiated by a Texas operating company requesting an increase to overall base rate revenues to become effective prior to end of the six year period after the effective date of the merger:

(a) The net merger savings expense item and annual amount of amortization of costs to achieve the merger will not be included in the calculation of the cost of service unless the Texas operating company demonstrates:

(i) that the proposed rate increase results from circumstances not directly or indirectly related to the merger; and

(ii) that the full level of achieved merger savings for the applicable year as reflected in Attachment D have been achieved; and

(b) the revenue requirements otherwise determined to be reasonable and necessary will be reduced by the annual amounts included in Attachment E.

(4) The Merged Company and the Texas operating companies, subject to the following force majeure provisions, agree not to initiate a base rate proceeding seeking an overall base rate revenue increase to be effective prior to January 1, 2003 or three years from the effective date of the merger, whichever is later (the "rate moratorium"):

AEP/CSW Merger
Example of Application of Rate Treatment of Merger Savings and Expense
Central Power and Light Company

Attachment F to
Integrated Stipulation and Agreement
Page 1 of 3

Rate Case Initiated By The Company

Year	Net Merger Savings Rate Rider (Attach. A) (1)	Achieved Savings (a) (2)	Net Merger Savings Expense Adj. (Attach. B) (3)	Amortization of Costs to Achieve (Attach. C) (4)	Revenue Requirements Impact: Net Revenue Requirements (2)-(3)-(4) (5)	Revenue Requirements Impact: Revenue Requirements Credit (Attach. E) (6)	Revenue Requirements Impact: Net Base Rate Impact (5)-(6) (7)	Rate Reduction Rider (Table H-1) (8)	Rate Reduction Rider (Table H-2) (9)	Total Rate Impact (1)+(7)+(8)+(9) (10)
Year 1	$ (3,663)							$ (15,337)	$ (4,807)	$ (23,807)
Year 2	(6,999)	Not applicable due to rate cap unless a force majeure proceeding is initiated under Sec. 3. F.						(12,001)	(4,807)	(23,807)
Year 3	(8,841)							(10,159)	(4,807)	(23,807)
Year 4	(10,212)	(25,256)	19,080	6,176	-	2,554	(2,554)	-	(4,807)	(17,573)
Year 5	(11,180)	(27,193)	21,016	6,176	-	3,038	(3,038)	-	(4,807)	(19,025)
Year 6	(11,827)	(28,486)	22,309	6,176	-	3,361	(3,361)	-	(4,807)	(19,995)
Total	$ (52,722)	$ (80,934)	$ 62,405	$ 18,529	$ -	$ 8,952	$ (8,952)	$ (37,497)	$ (28,842)	$ (128,014)

Rate Case Initiated By A Signatory Other Than The Company

Year	Merger Savings Rate Rider (Attach. A) (1)	Achieved Savings (a) (2)	Net Merger Savings Expense Adj. (Attach. B) (3)	Amortization of Costs to Achieve (Attach. C) (4)	Revenue Requirements Impact: Net Revenue Requirements (2)-(3)-(4) (5)	Revenue Requirements Impact: Revenue Requirements Credit (Attach. E) (6)	Revenue Requirements Impact: Net Base Rate Impact (5)-(6) (7)	Rate Reduction Rider (Table H-1) (8)	Rate Reduction Rider (Table H-2) (9)	Total Rate Impact (1)+(7)+(8)+(9) (10)
Year 1	$ (3,663)							$ (15,337)	$ (4,807)	$ (23,807)
Year 2	(6,999)	Not applicable due to rate freeze.						(12,001)	(4,807)	(23,807)
Year 3	(8,841)	(22,514)	18,337	6,176	-	-	-	(10,159)	(4,807)	(23,807)
Year 4	(10,212)	(25,256)	19,080	6,176	-	-	-	(8,788)	(4,807)	(23,807)
Year 5	(11,180)	(27,193)	21,016	6,176	-	-	-	(7,820)	(4,807)	(23,807)
Year 6	(11,827)	(28,486)	22,309	6,176	-	-	-	(7,173)	(4,807)	(23,807)
Total	$ (52,722)	$ (103,448)	$ 78,742	$ 24,705	$ -	$ -	$ -	$ (61,278)	$ (28,842)	$ (142,842)

Note (a) Achieved savings are the reduction in cost of service from gross merger savings as shown in Roberson Exhibit MDR-1.

92. The specific allocation approach for Hard-to-Reach customers set forth in Article V of the Stipulation and Agreement is reasonable and should be adopted by the Commission.

f. Rate Case Expenses

93. All rate case expenses incurred by CPL in this docket by December 31, 2000, including expenses of Cities served by CPL, are reasonable and necessary.

94. It is reasonable that all rate case expenses incurred by CPL, including expenses of Cities served by CPL, be deferred and amortized over a three-year period beginning on January 1, 2002.

95. The estimate of Cities' rate case expenses, including appeals, contained in Exhibit DGC-3s of the Stipulation Testimony of David G. Carpenter, is reasonable.

g. Debt Refinancing Costs

96. It is reasonable that $13,100,000 of unamortized loss on reacquired debt and debt discount and issuance expenses as of December 31, 2002, be included in CPL's cost of debt in future ratemaking proceedings.

97. It is reasonable that CPL continue to amortize existing debt costs over the same period as currently amortized, and as reflected in Exhibit WGH-75 of the Supplemental Testimony of Wendy G. Hargus.

98. It is reasonable that the debt refinancing costs incurred to restructure CPL should be deferred and amortized over a 15-year period beginning January 1, 2002, with the unamortized balance included in rate base. Each signatory to the Stipulation and Agreement has expressly retained the right to challenge the reasonableness of the 15-year period and the amounts of the refinancing costs in a future case of CPL. No signatory has waived its right to challenge in future rate cases a decision by the CPL TDU to refinance

its debt as discussed in the direct and rebuttal testimony of CPL witness Wendy G. Hargus in Docket No. 22352.

h. Regulatory Rate of Return on Common Equity and Capital Structure

99. For the reasons stated in *Generic Proceeding* Order No. 42, it is reasonable to adopt a regulatory rate of return on common equity of 11.25% and a capital structure of 60% debt and 40% equity.

i. Transmission Cost of Service

100. It is reasonable to establish the net transmission plant in service for purposes of CPL's transmission cost of service and the establishment of transmission rates in ERCOT for 2002 at $562,209,821, as set forth in Article IX of the Stipulation and Agreement.

101. It is reasonable that CPL shall use the rate of return on common equity and capital structure set out Finding of Fact No. 99, above, for purposes of updates to the transmission cost of service for the CPL TDU. It is reasonable that CPL's cost of debt in such transmission updates be determined pursuant to applicable Commission rules or requirements.

j. Depreciation Rates

102. It is reasonable that the existing depreciation rates of CPL as established in Docket No. 14965 for property transferred to the TDU should be utilized by the TDU, which will succeed CPL.

k. Non-Roadway Lighting

103. The proposed resolution of non-roadway lighting issues detailed in Article XI of the Stipulation and Agreement is reasonable and should be adopted by the Commission.

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AEP TEXAS CENTRAL COMPANY'S RESPONSE TO CITIES' SEVENTEENTH REQUEST FOR INFORMATION

Question No. 8:

Provide descriptions and amounts of any AEP/TCC write-offs (e.g., abandoned projects, etc.) in excess of $100,000 during the year ended June 30, 2003. Identify the FERC accounts charged.

Response No. 8:

TCC has no write-offs/abandoned projects in excess of $100,000 for the test year ended June 30, 2003.

Prepared By:	Gary W. Moore	Title:	Senior Accounting Consultant
Sponsored By:	Randall W. Hamlett	Title:	Manager, Regulatory Accounting Services

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AEP TEXAS CENTRAL COMPANY'S RESPONSE TO CITIES' SEVENTEENTH REQUEST FOR INFORMATION

Question No. 9:

Provide a description of any AEP/TCC amortizations (e.g., severance costs, etc.) included in the test year ended June 30, 2003. For each amortization, provide (1) the date the amortization was established; (2) a copy of the excerpts from the regulatory order establishing the amortization; (3) the beginning unamortized balance of the amortization; (4) the annual amortization expenses; (5) the amortization period; (6) the basis for the amortization period used; (7) the unamortized balances as of June 30, 2002 and June 30, 2003; (8) the annual amortization expense for the year ended June 30, 2003; and (9) the completion date of the amortization period. Identify the FERC accounts used to record the original balances, the accumulated amortization and the expenses.

Response No. 9:

AEP/TCC has included the following amortizations in its requested cost of service: Loss on reacquired debt, excess earnings, merger asset, reserve for catastrophe and rate case expense associated with this proceeding.

1) Loss on reacquired debt: July 2002
Excess earnings: January 2002.
Merger asset: June 2000.
Reserve for catastrophe: Please see the response to Cities 7th Request for Information, Question No.44.
Rate case expense: Not applicable as this only relates to this proceeding.

2) Loss on reacquired debt: Please see the response to Cities 17th Request for Information, Question No. 7.
Excess earnings: Please see Attachment 1.
Merger asset: Please see the response to Cities 17th Request for Information, Question No. 7.

Reserve for catastrophe: Please see the response to Cities 7th Request for Information, Question No. 44.
Rate case expense: Not applicable as this only relates to this proceeding.

3) Loss on reacquired debt: Please see the response to Cities 17th Request for Information, Question No.7.
Excess earnings: Please see the response to Cities 2nd Request for Information, Question No.44. The amount on Cities 2nd Request for Information, Question No.44 included a typo as the actual amount is $42,209,382 versus the $40,209,382 listed on the response to Cities 2nd Request for Information, Question No.44.
Merger asset: Please see the response to Cities 2nd Request for Information, Question No.44.
Reserve for catastrophe: Please see the response to Cities 7th Request for Information, Question No.44.
Rate case expense: Please see the response to Cities 2nd Request for Information, Question No.44.

4) Loss on reacquired debt: Please see the response to Cities 2nd Request for Information, Question No.44.
Excess earnings: Please see the response to Cities 2nd Request for Information, Question No.44.
Merger asset: Please see the response to Cities 2nd Request for Information, Question No.44.
Reserve for catastrophe: Please see the response to Cities 2nd Request for Information, Question No.44.
Rate case expense: Please see the response to Cities 2nd Request for Information, Question No.44.

5) Loss on reacquired debt: Please see the response to Cities 2nd Request for Information, Question No.44.
Excess earnings: Please see the response to Cities 2nd Request for Information, Question No.44.
Merger asset: Please see the response to Cities 2nd Request for Information, Question No.44.
Reserve for catastrophe: Please see the response to Cities 2nd Request for Information, Question No.44.
Rate case expense: Please see the response to Cities 2nd Request for Information, Question No.44.

6) Loss on reacquired debt: Please see the response to Cities 17th Request for Information, Question No.7.
Excess earnings: Please see Attachment 1.
Merger asset: Please see the response to Cities 17th Request for Information, Question No.7.

Reserve for catastrophe: Not applicable. Please see the direct testimony of Mr. Nadel for information on the Company's request.
Rate case expense: Please see the direct testimony of David G. Carpenter, pages 56 - 60.

7) Loss on reacquired debt: Please see the response to Cities 17th Request for Information, Question No.7.
Excess earnings: $38,357,725 as adjusted.
Merger asset: Please see the response to Cities 17th Request for Information, Question No.7.
Reserve for catastrophe: $3,263,925.
Rate case expense: Not applicable.

8) Loss on reacquired debt: Please see the response to Cities 17th Request for Information, Question No.7.
Excess earnings: $27,866,226 as adjusted.
Merger asset: Please see the response to Cities 17th Request for Information, Question No.7.
Reserve for catastrophe: $3,263,925.
Rate case expense: Not applicable.

9) Loss on reacquired debt: Please see the response to Cities 17th Request for Information, Question No.7.
Excess earnings: Please see the response to Cities 2nd Request for Information, Question No.44.
Merger asset: Please see the response to Cities 2nd Request for Information, Question No.44.
Reserve for catastrophe: Not applicable. Please see the direct testimony of Mr. Nadel for information on the Company's request.
Rate case expense: Please see the response to Cities 2nd Request for Information, Question No.44.

Prepared By:	Randall W. Hamlett	Title:	Manager, Regulatory Accounting Services
Sponsored By:	Randall W. Hamlett	Title:	Manager, Regulatory Accounting Services

14B. On August 2, 2001, Commission Staff submitted the updated number runs, which have a flow-through effect on transmission rates for other ERCOT utilities.

14C. The August 2, 2001 updated number runs[187] for transmission rates supercede earlier transmission rate determinations.

3. Excess Mitigation

15. Pursuant to a February 8, 2001 order of the Commission in the ECOM phase of this docket, CPL re-ran its ECOM model reflecting the decisions of the Commission made in that order. The ECOM-model run produced a mathematical result of negative $600.716 million.

16. In its Order on Certified Issues in this, and other dockets, issued on November 10, 2000, the Commission found that it had authority to address excess mitigation and identified various tools available in PURA Chapter 39 to do so.

17. In Docket No. 23520, Application of Central Power & Light Company for Authority to Increase Fixed Fuel Factors and to Implement an Interim Surcharge For Fuel Cost Under-Recoveries, the Commission disallowed reduction of fuel charges to address excess mitigation.

18. Assigning CPL's claimed restructuring costs to shareholders is not one of the PURA Chapter 39 tools identified by the Commission for use for excess mitigation.

19. CPL has not redirected transmission and distribution depreciation to generation plant so reversing these amounts is not an available remedy for excess mitigation.

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[187] Commission Staff's Updated Number Runs (the memorandum was dated August 1, but filed on August 2, 2001). Included as Attachment 3 to the Order.

20. Refunding or crediting historical accumulated excess earnings included in CPL's ECOM calculation is an available method to address excess mitigation for CPL.

20A. For the purposes of estimating ECOM, it is appropriate to use excess earnings of the actual amount approved in the revised 1999 Annual Report and the amount in the 2000 filed Annual Report. For the purposes of ECOM, it is appropriate that excess earnings for 2001 be based on an average of the 1999 and 2000 excess earnings, as filed by CPL in the 2000 Annual Report.

20B. At the April 25, 2001 open meeting, the Commission admitted the 1999 revised and approved Annual Report[188] and the Company-filed 2000 Annual Report[189] relating to excess earnings and redirected depreciation into evidence.

20C. Based on the updated Annual Report, excess earnings are $54,788,702 and total mitigation is $54,788,702. The final ECOM estimate, based on a re-run of the model taking excess earnings into account, is negative $615.066 million.

20D. It is appropriate that CPL reverse excess earnings until excess mitigation is zero, as detailed in the Order on Certified Issues. All of CPL's excess earnings are excess mitigation and should be returned to ratepayers through a non-bypassable charge.

21. To address excess mitigation, a credit reflecting excess earnings for 1999, 2000, and 2001, should be instituted as a reduction to TDU rates and thus to non-bypassable charges.

22. Since the price to beat is not discountable for prescribed periods of time or under specific circumstances announced in PURA § 39.202, the excess mitigation credit will not flow through immediately and directly to price-to-beat customers of the affiliated REP.

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[188] *1999 Electric Utilities' Annual Report Pursuant to § 39.257 of PURA*, Docket No. 22276 (Feb. 23, 2001).

[189] *2000 Electric Utilities' Annual Report Pursuant to § 39.257 of PURA*, Docket No. 23806 (pending).

23. The excess mitigation credit will enhance the opportunities for competition in the retail market through an increase in headroom, providing the best overall price protection for residential and small commercial customers.

24. CPL should create a regulatory liability on its books to reflect the excess earnings mitigation obligation.

25. The excess mitigation credit should be instituted beginning January 1, 2002, and should be amortized over five years, from 2002 to 2007, with all principal and interest accounted for and returned at the end of the five years. The five-year amortization period is reasonable since these funds were obtained over a three-year period and because there is no risk that the credit will result in positive stranded costs by the time of the 2004 true-up proceeding.

26. A 7.5% interest rate is reasonable to be applied to excess earnings as an excess mitigation credit.

(a) This is a rate compatible with interest rates on low risk securities and bonds and higher than PUC interest rates on customer-owned funds held by utilities, which range from 5.08% to 7.50%.

(b) The excess mitigation revenue stream carries less risk than a typical regulated revenue stream, because of the shortened recovery period, and because there is a greater assurance of recovery based upon the Commission's order in this proceeding.

27. The 7.5% interest rate should be applied to the total, annual excess earnings at the mid-point of each year (1999, 2000, and 2001) for which the excess earnings were calculated.

28. It is reasonable and necessary to adopt an allocation and tracking method for any excess mitigation credits to prevent any shifting of stranded-cost responsibility among various customer classes, if CPL is found in the 2004 true-up proceeding to have stranded costs.

(a) The excess credit should be allocated to the transition charge (TC) classes approved in CPL's securitization order in P.U.C. Docket No. 21528 in proportion to base rate revenues collected for 1999 and 2000.

(b) Each rate class should be "mapped" into the appropriate TC classes. Once each TC class' base revenues have been determined, specific numerical allocators should be developed that will establish the specific total dollar amounts of the excess mitigation credit to be allocated to each TC class.

(c) If after 2004, CPL is found to have stranded costs, then the portion of the stranded costs equal to the amount of excess mitigation should be allocated using the same allocation factors associated with excess mitigation credits. The balance of any stranded costs would be allocated using the applicable stranded cost allocators.

(d) [Deleted].

(e) The Company is not entitled to receive interest on the amount of excess mitigation credits that are returned to REPs if the 2004 true-up finds CPL to have stranded costs. The Company will receive interest on any stranded costs on a going-forward basis.

4. NEIL Regulatory Account

29. CPL participates in the Nuclear Electric Insurance Limited (NEIL) mutual insurance company, as a member in its own right, based on its interest in the twin units South Texas Project (STP) and, indirectly, as a member of the South Texas Project Nuclear Operating Company (STPNOC).

30. Each year since STP entered commercial operation, CPL has paid ratepayer-funded premiums into the insurance fund and is entitled to receive a share of the underwriting and investment income of NEIL in the form of distributions.

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AEP TEXAS CENTRAL COMPANY'S RESPONSE TO CITIES' SEVENTEENTH REQUEST FOR INFORMATION

Question No. 12:

For each of AEP/TCC's top ten executives, provide the following for the year ended June 30, 2003; (1) amount of base pay; (2) amount of incentive compensation by type; and (3) amount of other incentives (e.g., cars, memberships, etc. by type.) Explain and show how these costs are allocated among AEP/TCC's various functional entities.

Response No. 12:

See Attachment 1 for requested amounts. The payroll and other costs for these employees are allocated to each function based on the work order used when the cost is incurred as explained in the testimony of Sandra S. Bennett. A work order may charge TCC only, or it may perform an allocation between functions based on the activity performed.

Certain portions of the information responsive to this request is HIGHLY SENSITIVE material and is provided pursuant to the Protective Order issued in Docket No. 28840. The documents are available for review in the voluminous room at the Austin offices of American Electric Power Company (AEP), 400 West 15th Street, Suite 610, Austin, Texas 78701, (512) 481-4562, during normal business hours.

Prepared By:	David A. Jolley	Title:	Senior Compensation Consultant
Sponsored By:	David A. Jolley	Title:	Senior Compensation Consultant
	Sandra S. Bennett	Title:	Assistant Controller, Regulatory Accounting

TCC Top Ten Executives

	6/30/2003	Payments Made 6/30/02- 6/30/03			
Name	**Base Salary**	**Annual Incentive**	**Long-Term Incentive**	**Personal Car Allowance**	**Country Club Dues**
Draper Jr.,E L	$1,090,000	$0	$0	$7,200	$0
Shockley III,Thomas V	$665,000	$0	$0	$6,000	$10,201.03
Fayne,Henry W	$500,000	$0	$0	$6,000	$0
Tomasky,Susan	$475,000	$0	$0	$6,000	$0
Hagan,Thomas M	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Powers,Robert P	$415,000	$0	$116,662.22	$6,000	$700
Files,Glenn	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Pena,Armando A	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Verret,Richard P	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Cross,Jeffrey D	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

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AEP TEXAS CENTRAL COMPANY'S RESPONSE TO CITIES' SEVENTEENTH REQUEST FOR INFORMATION

Question No. 13:

For each of AEP's top ten executives, provide the following for the year ended June 30, 2003; (1) amount of base pay; (2) amount of incentive compensation by type; and (3) amount of other incentives (e.g., cars, memberships, etc. by type). Explain and show how these costs are allocated among AEP's various entities.

Response No. 13:

See Attachment for requested amounts. These employees are AEPSC employees, and their costs are allocated using work orders and activity codes, as is discussed in the testimony of Sandra Bennett. A work order may charge one company only, or it may perform an allocation between companies and functions based on the activity performed.

Certain portions of the information responsive to this request is HIGHLY SENSITIVE material and is provided pursuant to the Protective Order issued in Docket No. 28840. The documents are available for review in the voluminous room at the Austin offices of American Electric Power Company (AEP), 400 West 15th Street, Suite 610, Austin, Texas 78701, (512) 481-4562, during normal business hours.

Prepared By:	David A. Jolley	Title:	Senior Compensation Consultant
Sponsored By:	David A. Jolley	Title:	Senior Compensation Consultant
	Sandra S. Bennett	Title:	Assistant Controller, Regulatory Accounting

Cities 17th, Question 13
AEP Top Ten Executives

	6/30/2003	Payments Made 6/30/02- 6/30/03			
Name	**Base Salary**	**Annual Incentive**	**Long-Term Incentive**	**Personal Car Allowance**	**Country Club Dues**
Draper Jr.,E L	$1,090,000	$0	$0	$7,200	$0
Shockley III,Thomas V	$665,000	$0	$0	$6,000	$10,201.03
Fayne,Henry W	$500,000	$0	$0	$6,000	$0
Tomasky,Susan	$475,000	$0	$0	$6,000	$0
Pena,Armando A	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Cross,Jeffrey D	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Buonaiuto,Joseph M	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Hargus,Wendy G	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Assante,Leonard V	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED
Berkemeyer,Thomas G	REDACTED	REDACTED	REDACTED	REDACTED	REDACTED

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AEP TEXAS CENTRAL COMPANY'S RESPONSE TO CITIES' SEVENTEENTH REQUEST FOR INFORMATION

Question No. 14:

Referring to Company's response to Staff's First Request, Question No. BA 1-5, provide the monthly revenues, expenses and investment related to third-party contracts for transmission services for the months July 2002 to date. Provide information by FERC accounts.

Response No. 14:

A spreadsheet containing the monthly revenues and expenses for third-party contracts for transmission services, by project descriptions from July 2002 through November 2003, including FERC accounts, is attached. The investment amount is zero.

Prepared By:	Larry C. Foust	Title:	Issues Manager
Sponsored By:	Randall W. Hamlett	Title:	Manager, Regulatory Accounting Services
	J. Calvin Crowder	Title:	Managing Director, External Affairs

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CITIES' 17th, Q. # 14
Attachment

Monthly Revenue and Expenses for Third Party Transmission Construction Services
July 2002 - November 2003

	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Total	FERC Account
Sharyland																			
Revenue			$200,000.00 [1]					$113,117.13		$176,907.92		$46,580.74		$17,040.86	$15,611.14	$820,796.80 [2]		$1,390,054.59	4170001
Expense	$5,513.34	$4,387 87	$4,113.21	$3,755.62	$3,946.29	$7,300.75	$21,165.51	$21,892.27	$121,294.97	$15,367.39	$49,689.74	$14,445.93	$6,610.75	$14,329.54	$16,583.62	$7,782.20	$13,149.18	$331,328.18	4171013
Magic Valley																			
Revenue				$170,000.00			$121,284.00											$291,284.00	4170001
Expense	$36,889.19	$9,387.86	$16,808.22	$292,301.10	$136,521.20	-$12,285.89	$1,011.04	$9,972.58	$424.70	$345.35	$6,313.57	-$2,527.26	$96.03	$4,390 68	$1,814.06	$157.74	$0 59	$501,620.76	4171013
LCRA:																			
Coleto Creek																			
Revenue	$1,377,790 30	$3,662,138 58	$9,577,763.09	$1,094,760.32	$170,914.44	$6,635,728.65	-$8,315,858.29	$1,376,744.52		$72,008.64	$164,527.55	$267,985.66		$711,022.87	$50,306.98	$39,812.66	$887,241.69	$17,772,887.66	4170001
Expense	$1,295,622.29	$3,438,777 36	$1,182,718.94	$1,028,473.63	$158,209.36	$6,466,475.96		$1,286,218.81		$63,234.49	$270,510.29	$135,636.71		$665,363 58	$45,438.96	$37,379.40	$834,747.39	$16,908,807.17	4171013
Corpus Christi																			
Revenue	$854,674.09	$366,867.04	$3,997,968.58	$1,791,494.46	$8,990,323.21	$5,858,921.65		$2,941,326.90		$1,204,675 55	$1,512,123.60	$2,017,301 88		$2,255,529.28	$42,862.76	$290,644.30	$60,228 80	$32,184,942 10	4170001
Expense	$790,164.04	$323,837.02	$3,763,055.77	$1,711,186.58	$8,486,767.97	$5,517,117.48	-$47,439.91	$2,807,504.25		$1,132,352.00	$1,408,809.46	$1,888,148.14		$2,116,706.45	$38,296.13	$269,147.29	$54,722 96	$30,260,375.63	4171013
Del Rio																			
Revenue									$409,706.21	$6,159 65	$9,115.69	$9,247.52	$36,775.93	$15,452.58	$90,717.85	$82,181.84	$100,632.89	$759,990.16	4170001
Expense									$359,432.61	$5,052 16	$7,307.91	$8,058.35	$31,134.48	$12,613.85	$88,819.48	$73,836.00	$89,863.75	$676,118.59	4171013
Rockport/Fulton																			
Revenue										$37,253.95	$2,787.17	$2,571.28	$7,340.24	$4,174.88		$4,769.91		$58,897.43	4170001
Expense										$31,112.62	$2,231.14	$2,332.47	$5,870.44	$3,856.93		$4,318.98		$49,722.58	4171013
Airline 69kv Loop																			
Revenue										$83,089.01	$30,459.05	$15,667.08		$6,425.34	$11,967.79	$4,016.48	$4,760.46	$156,385 21	4170001
Expense										$66,653.22	$26,875.37	$12,980.87	$14.97	$5,913.33	$10,663.99	$3,582.04	$4,046.60	$130,730 39	4171013
N Pharr/Harlingen																			
Revenue											$112,486.39	$23,773.86	$38,564.59	$30,302.35	$6,031.04	$122,031.17		$333,189 40	4170001
Expense											$95,308.82	$21,921.49	$34,178.91	$5,473.59	$26,522 78	$103,663.31		$287,068.90	4171013
Rincon/Rockport																			
Revenue											$74,775.77	$5,987.32	$59,154.41	$35,111.79		$225,507.78		$400,537.07	4170001
Expense											$59,823.19	$5,253.73	$53,171.32	$52,194 88	-$21,921.49	$194,235.84		$342,757.47	4171013
Rio Grande 69kv to 138kv																			
Revenue											$76,708.25	$10,454.83	$14,595.00	$7,541.19		$33,078.99		$142,378.26	4170001
Expense											$60,635.77	$9,796.17	$11,412.30	$6,503.89		$27,864.00		$116,212.13	4171013

Notes:

[1] Deferred revenues
[2] Includes $810,608.59 of deferred revenues.

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CENTRAL COMPANY FOR	§	**OF**
	§	
AUTHORITY TO CHANGE RATES	§	**ADMINISTRATIVE HEARINGS**

AEP TEXAS CENTRAL COMPANY'S RESPONSE TO CITIES' SEVENTEENTH REQUEST FOR INFORMATION

Question No. 15:

Referring to Company's response to Staff's First Request, Question No. BA 1-9, provide all information used for each company in the peer group for the years 2001 and 2002. Include copies of the source documents relied on. If the information provided is for AEP and not AEP/TCC, provide AEP/TCC information.

Response No. 15:

Attachment 1 below provides the source data for each company in the peer group for 2001 and 2002, with those companies being holding companies with transmission net plant assets equal to or greater than $1 billion. Attachment 2 below provides the summary results of the analysis. In both attachments, TCC data is provided in addition to the holding company data. It should be noted, however, that the other companies, due to their much greater size and asset base, do not provide a reasonable basis for comparability to TCC by itself. The analysis in Attachment 2 provides the two-year average capital dollars per MWh which is a two-year average of 2001 - 2002 Capital Additions divided by the 2002 Total MWhs Transmitted. The source of the data for all companies is FERC Form 1 which was obtained from an electronic download from POWERdat, an online data system offered by Platt's. Please note that ERCOT Wheeling for Others is not included in the MWH Transmitted since it is not reported on the FERC Form 1.

Prepared By: Mark A. Bailey Title: VP, Asset Management
Sponsored By: Mark A. Bailey Title: VP, Asset Management

Transmission Benchmarking Data
2001 - 2002

Holding Company	Year	Tran O&M: Tot $	FERC Acct 565 $	Adj Trans O&M $	CAP ADDS $	Trans Net Book $	Retail Sales MWh	Requirements Sales MWh	Non-Requirement Sale MWh	Wheeling Received MWh	(less) Ener for Pump MWh	Total MWh Transmitted
AEP	2001	268,257,744	155,884,694	112,373,050	298,027,674	3,584,742,639	158,838,745	14,777,176	97,163,481	37,509,248	784,044	309,072,694
AEP	2002	209,544,895	97,967,832	111,577,063	146,447,669	3,614,366,841	137,697,119	12,623,303	109,567,333	46,475,827	721,844	307,085,426
I	2001	136,756,712	443,761	136,312,951	52,702,796	1,160,144,144	37,186,824	1,665,135	496,925	11,613,045	0	50,961,929
I	2002	146,786,703	461,923	146,324,780	58,269,986	1,179,685,498	37,262,557	480,760	17,720	11,163,635	0	48,924,672
G	2001	91,277,965	18,185,378	73,092,587	148,620,717	2,290,540,084	99,958,326	5,708,682	22,646,422	25,048,629	0	153,362,059
G	2002	91,482,594	19,066,030	72,416,564	172,960,196	1,814,076,277	101,633,594	5,320,793	23,548,265	24,901,374	0	155,404,026
B	2001	86,276,993	1,536,067	84,740,926	106,146,213	1,750,784,843	113,497,062	1,940,959	817,787	62,205,231	0	178,461,039
B	2002	70,439,172	1,624,726	68,814,446	98,630,110	1,769,166,327	120,748,129	1,797,476	886,877	71,156,010	0	194,588,492
A	2001	204,193,208	142,989,537	61,203,671	51,627,762	1,151,904,159	104,105,929	5,435,551	41,273,956	6,073,878	536,927	157,426,241
A	2002	201,375,959	140,121,081	61,254,878	45,366,936	1,155,745,538	105,404,885	5,219,919	40,723,522	6,359,965	537,835	158,246,126
F	2001	43,471,904	13,783,837	29,688,067	122,692,370	1,348,788,337	90,495,128	973,982	2,018,889	10,008,035	0	103,496,034
F	2002	49,687,450	17,672,795	32,014,655	100,910,139	1,393,116,718	95,542,625	1,260,474	1,801,549	10,230,388	0	108,835,036
H	2001	286,144,138	195,186,134	90,958,004	134,924,570	2,469,995,192	57,027,590	1,041,459	7,626,664	39,050,610	0	104,746,323
H	2002	256,835,038	171,715,549	85,119,489	68,604,842	2,108,135,649	52,696,524	57,874	6,389,391	39,103,617	0	98,247,406
D	2001	123,213,192	94,737,373	28,475,819	65,866,466	1,427,646,495	47,708,462	202,258	22,648,640	17,535,183	0	88,094,543
D	2002	102,418,626	76,949,453	25,469,173	70,826,751	1,452,078,125	47,029,924	198,901	30,334,565	9,183,345	0	86,746,735
C	2001	82,886,767	35,899,341	46,987,426	49,670,218	1,178,972,143	75,911,626	14,014,756	3,616,521	5,192,246	0	98,735,149
C	2002	85,212,743	31,728,824	53,483,919	102,294,436	1,232,399,389	79,290,067	13,933,074	5,342,880	6,493,849	0	105,059,870
J	2001	105,481,639	3,628,812	101,852,827	140,165,659	1,496,360,865	46,818,999	236,325	1,944,522	18,326,050	1,453,191	68,779,087
J	2002	106,518,205	3,818,212	102,699,993	186,529,493	1,602,055,959	78,293,912	61,751	1,479,210	16,481,018	1,199,655	97,515,546
L	2001	125,187,402	1,683,578	123,503,824	503,153,931	3,103,578,986	145,344,856	15,068,369	37,543,934	10,704,278	761,997	209,423,434
L	2002	140,179,295	854,403	139,324,892	401,033,744	3,401,482,867	151,885,028	15,327,953	38,151,340	14,535,351	964,407	220,864,079
K	2001	151,231,411	10,963,598	140,267,813	108,153,529	2,065,277,791	52,033,674	0	70,344	10,798,556	126,758	63,029,332
K	2002	127,226,964	5,600,443	121,626,521	145,105,242	2,143,541,866	54,391,384	0	31,474	10,609,189	124,014	65,156,061
M	2001	290,666,202	240,956,796	49,709,406	218,472,466	1,217,922,843	103,673,931	1,521,232	2,664,408	0	0	107,859,571
M	2002	304,184,201	252,903,513	51,280,688	222,017,050	1,395,344,660	97,132,558	3,571	0	0	0	97,136,129
E	2001	220,305,587	125,723,436	94,582,151	219,455,089	1,705,412,371	80,079,214	21,691,659	25,131,001	13,147,538	378,988	140,428,400
E	2002	197,976,744	89,446,649	108,530,095	67,332,863	1,714,127,453	81,340,807	20,801,908	58,306,643	5,492,674	252,471	166,194,503
AEP TCC	2001	90,559,430	81,091,118	9,468,312	83,704,628	437,847,797	20,153,162	717,892	3,227,720	0	0	24,098,774
AEP TCC	2002	72,944,041	60,152,888	12,791,153	36,099,283	463,691,694	1,423,663	97,081	20,289,842	0	0	21,810,586

Note 1 Analysis is for holding companies with transmission net plant assets greater than or equal to $1 Billion

2 *The FERC Form 1 source data was obtained from electronic download from PowerDat*

Transmission Benchmarking Analysis
2001 - 2002 Average Capital $/MWh

Holding Company	2Y Cap$/MWh
A	0.31
B	0.53
C	0.72
AEP	0.72
D	0.79
E	0.86
F	1.03
G	1.03
H	1.04
I	1.13
J	1.68
K	1.94
L	2.05
M	2.27
AEP/TCC	2.75

Note: 1. Analysis is for holding companies with transmission net plant assets greater than or equal to $1 Billion dollars

2. The two-year average capital dollars per MWh (2Y Cap$/MWh) calculation is a 2-year average of 2001-2002 Capital Additions divided by the 2002 Total MWh's

3. ERCOT Wheeling for Others is not included in the MWh Transmitted since it is not reported on FERC Form 1

SOAH DOCKET NO. 473-04-1033
PUC DOCKET NO. 28840

	§	
APPLICATION OF AEP TEXAS	§	BEFORE THE STATE OFFICE
	§	
CENTRAL COMPANY FOR	§	OF
	§	
AUTHORITY TO CHANGE RATES	§	ADMINISTRATIVE HEARINGS

AEP TEXAS CENTRAL COMPANY'S RESPONSE TO CITIES' SEVENTEENTH REQUEST FOR INFORMATION

Question No. 16:

Referring to Company's response to Staff's First Request, Question No. BA 1-10, provide all information used for each company in the peer group for the years 2001 and 2002. Include copies of the source documents relied on. If the information provided is for AEP and not AEP/TCC, provide AEP/TCC information.

Response No. 16:

Attachment 1 below provides the source data for each company in the peer group for 2001 and 2002, with those companies being holding companies with transmission net plant assets equal to or greater than $1 billion. Attachment 2 below provides the summary results of the analysis. In both attachments. TCC data is provided in addition to the holding company data. It should be noted, however, that the other companies, due to their much greater size and asset base, do not provide a reasonable basis for comparability to TCC by itself. The analysis in Attachment 2 provides the total expenditures per MWh which is a two-year average of 2001 - 2002 Capital Additions plus 2002 O&M (adjusted to exclude FERC Account 565) divided by the 2002 Total MWhs Transmitted. The source of the data for all companies is FERC Form 1 which was obtained from an electronic download from POWERdat, an online data system offered by Platt's. Please note that ERCOT Wheeling for Others is not included in the MWH Transmitted since it is not reported on the FERC Form 1.

Prepared By:	Mark A. Bailey	Title:	VP, Asset Management
Sponsored By:	Mark A. Bailey	Title:	VP, Asset Management

Transmission Benchmarking Data
2001 - 2002

Holding Company	Year	Tran O&M: Tot $	FERC Acct 565 $	Adj Trans O&M $	CAP ADDS $	Trans Net Book $	Retail Sales MWh	Requirements Sales MWh	Non-Requirement Sale MWh	Wheeling Received MWh	(less) Ener for Pump MWh	Total MWh Transmitted
AEP	2001	268,257,744	155,884,694	112,373,050	298,027,674	3,584,742,639	158 838,745	14,777,176	97,163,481	37,509,248	784,044	309,072,694
AEP	2002	209,544,895	97,967,832	111,577,063	146,447,669	3,614,366,841	137,697,119	12,623,303	109,567,333	46,475,827	721,844	307,085,426
I	2001	136,756,712	443,761	136,312,951	52,702,796	1,160,144,144	37,186,824	1,665,135	496,925	11,613,045	0	50,961,929
I	2002	146,786,703	461,923	146,324,780	58,269,986	1,179,685,498	37,262,557	480,760	17,720	11,163,635	0	48,924 672
G	2001	91,277,965	18,185,378	73,092,587	148,620,717	2,290,540,084	99,958,326	5,708,682	22,646,422	25,048,629	0	153,362,059
G	2002	91,482,594	19,066,030	72,416,564	172,960,196	1,814,076,277	101,633,594	5,320,793	23,548,265	24,901,374	0	155,404,026
B	2001	86,276,993	1,536,067	84,740,926	106,146,213	1,750,784,843	113,497,062	1,940,959	817,787	62,205,231	0	178,461,039
B	2002	70,439,172	1,624,726	68,814,446	98,630,110	1,769,166,327	120,748,129	1,797,476	886,877	71,156,010	0	194,588,492
A	2001	204,193,208	142,989,537	61,203,671	51,627,762	1,151,904,159	104,105,929	5,435,551	41,273,956	6,073,878	536,927	157,426,241
A	2002	201,375,959	140,121,081	61,254,878	45,366,936	1,155,745,538	105,404,885	5,219,919	40,723,522	6,359,965	537,835	158,246,126
F	2001	43,471,904	13,783,837	29,688,067	122,692,370	1,348,788,337	90,495,128	973,982	2,018,889	10,008,035	0	103,496,034
F	2002	49,687,450	17,672,795	32,014,655	100,910,139	1,393,116,718	95,542,625	1,260,474	1,801,549	10,230,388	0	108,835,036
H	2001	286,144,138	195,186,134	90,958,004	134,924,570	2,469,995,192	57,027,590	1,041,459	7,626,664	39,050,610	0	104,746,323
H	2002	256,835,038	171,715,549	85,119,489	68,604,842	2,108,135,649	52,696,524	57,874	6,389,391	39,103,617	0	98,247,406
D	2001	123,213,192	94,737,373	28,475,819	65,866,466	1,427,646,495	47,708,462	202,258	22,648,640	17,535,183	0	88,094,543
D	2002	102,418,626	76,949,453	25,469,173	70,826,751	1,452,078,125	47,029,924	198,901	30,334,565	9,183,345	0	86,746,735
C	2001	82,886,767	35,899,341	46,987,426	49,670,218	1,178,972,143	75,911,626	14,014,756	3,616,521	5,192,246	0	98,735,149
C	2002	85,212,743	31,728,824	53,483,919	102,294,436	1,232,399,389	79,290,067	13,933,074	5,342,880	6,493,849	0	105,059,870
J	2001	105,481,639	3,628,812	101,852,827	140,165,659	1,496,360,865	46,818,999	236,325	1,944,522	18,326,050	1,453,191	68,779,087
J	2002	106,518,205	3,818,212	102,699,993	186,529,493	1,602,055,959	78,293,912	61,751	1,479,210	16,481,018	1,199,655	97,515,546
L	2001	125,187,402	1,683,578	123,503,824	503,153,931	3,103,578,986	145,344,856	15,068,369	37,543,934	10,704,278	761,997	209,423,434
L	2002	140,179,295	854,403	139,324,892	401,033,744	3,401,482,867	151,885,028	15,327,953	38,151,340	14,535,351	964,407	220,864,079
K	2001	151,231,411	10,963,598	140,267,813	108,153,529	2,065,277,791	52,033,674	0	70,344	10,798,556	126,758	63,029,332
K	2002	127,226,964	5,600,443	121,626,521	145,105,242	2,143,541,866	54,391,384	0	31,474	10,609,189	124,014	65,156,061
M	2001	290,666,202	240,956,796	49,709,406	218,472,466	1,217,922,843	103,673,931	1,521,232	2,664,408	0	0	107,859,571
M	2002	304,184,201	252,903,513	51,280,688	222,017,050	1,395,344,660	97,132,558	3,571	0	0	0	97,136,129
E	2001	220,305,587	125,723,436	94,582,151	219,455,089	1,705,412,371	80,079,214	21,691,659	25,131,001	13,147,538	378,988	140,428,400
E	2002	197,976,744	89,446,649	108,530,095	67,332,863	1,714,127,453	81,340,807	20,801,908	58,306,643	5,492,674	252,471	166,194,503
AEP TCC	2001	90,559,430	81,091,118	9,468,312	83,704,628	437,847,797	20,153,162	717,892	3,227,720	0	0	24,098,774
AEP TCC	2002	72,944,041	60,152,888	12,791,153	36,099,283	463,691,694	1,423,663	97,081	20,289,842	0	0	21,810,586

Note 1 Analysis is for holding companies with transmission net plant assets greater than or equal to $1 Billion

2 The FERC Form 1 source data was obtained from electronic download from PowerDat

Transmission Benchmarking Analysis
2001 - 2002 Average Capital & 2002 O&M $/ MWh

Holding Company	Total Exp $/MWh
A	0.69
B	0.88
D	1.08
AEP	1.09
C	1.23
F	1.32
G	1.50
E	1.52
H	1.90
L	2.68
J	2.73
M	2.80
K	3.81
I	4.12
AEP/TCC	3.33

Note: 1. Analysis is for holding companies with transmission net plant assets greater than or equal to $1 Billion

2. The total dollar per MWh (Total$/MWh) calculation is a 2-year average of 2001-2002 Capital Additions & Adj O&M divided by the 2002 Total MWh's

3. ERCOT Wheeling for Others is not included in the MWh Transmitted since it is not reported on FERC Form 1

SOAH DOCKET NO. 473-04-1033
PUC DOCKET NO. 28840

APPLICATION OF AEP TEXAS	§	BEFORE THE STATE OFFICE
CENTRAL COMPANY FOR	§	OF
AUTHORITY TO CHANGE RATES	§	ADMINISTRATIVE HEARINGS

AEP TEXAS CENTRAL COMPANY'S RESPONSE TO CITIES' SEVENTEENTH REQUEST FOR INFORMATION

Question No. 20:

Referring to Company's response to Staff's First Request, Question No. BA 1-11, provide a list of each initiative which reduced AEP/TCC's overhead costs. For each initiative, provide the expected AEP/TCC savings for 2002, 2003 and 2004.

Response No. 20:

Refer to Mark A. Bailey's testimony, page 26 line 9 through page 27 line 22, for the AEP merger savings initiatives. The expected savings from these merger initiatives were not projected for the individual AEP operating companies. However, as noted in the testimony of David G. Carpenter (pp. 20-34), merger savings were achieved on an overall AEP basis, and those savings are reflected in lower overhead costs for all AEP business units.

Prepared By:	Albert M. Yockey	Title:	Manager, Transmission Strategic Issues
Sponsored By:	Mark A. Bailey	Title:	VP, Asset Management

SOAH DOCKET NO. 473-04-1033
PUC DOCKET NO. 28840

APPLICATION OF AEP TEXAS	§	**BEFORE THE STATE OFFICE**
	§	
CENTRAL COMPANY FOR	§	**OF**
	§	
AUTHORITY TO CHANGE RATES	§	**ADMINISTRATIVE HEARINGS**

AEP TEXAS CENTRAL COMPANY'S RESPONSE TO CITIES' SEVENTEENTH REQUEST FOR INFORMATION

Question No. 21:

Referring to Company's response to Staff's First Request, Question No. BA 1-11, provide a list of each initiative which directly reduced AEP/TCC's costs. For each initiative, provide the expected AEP/TCC savings for 2002, 2003 and 2004.

Response No. 21:

Refer to Mark A. Bailey's testimony, page 26 line 9 through page 27 line 22, for the AEP merger savings initiatives. The expected savings from these merger initiatives were not projected for the individual AEP operating companies. However, as noted in the testimony of David G. Carpenter (pp. 20-34), merger savings were achieved on an overall AEP basis, and those savings are reflected in lower direct costs for all AEP business units.

Prepared By:	Albert M. Yockey	Title:	Manager, Transmission Strategic Issues
Sponsored By:	Mark A. Bailey	Title:	VP, Asset Management

SOAH DOCKET NO. 473-04-1033
PUC DOCKET NO. 28840

APPLICATION OF AEP TEXAS	§	BEFORE THE STATE OFFICE
CENTRAL COMPANY FOR	§	OF
AUTHORITY TO CHANGE RATES	§	ADMINISTRATIVE HEARINGS

AEP TEXAS CENTRAL COMPANY'S RESPONSE TO CITIES' SEVENTEENTH REQUEST FOR INFORMATION

Question No. 22:

Referring to Company's response to Cities 2-3, Attachment 2, page 3 of 18, provide a reconciliation between the $53,381,226 of distribution O&M for YE 6/03 and the distribution O&M of $187,297,480 shown in Schedule I-A-1.

Response No. 22:

Please see the attached reconciliation.

Prepared By:	Susan C. Franke	Title:	Senior Accounting Consultant
Sponsored By:	Randall W. Hamlett	Title:	Manager, Regulatory Accounting Services