Q122. WHAT IS THE PROPER RATE TREATMENT FOR THE DEFERRED TAXES SHOWN ON SCHEDULE G-7.4, ADFIT?

A. The total deferred taxes from Schedule G-7.4 are an adjustment to rate base on Schedule B-1. The pre-1971 ITC shown on Schedule G-7.5e is also an adjustment to rate base on Schedule B-1.

Q123. WHY IS THE PRE-1971 ITC A DEDUCTION TO RATE BASE WHILE THE POST-1970 ITC IS NOT DEDUCTED FROM RATE BASE?

A. Use of the pre-1971 ITC for rate purposes was not restricted by the Tax Code. An election was made by the Company to not reduce rate base by the Post-1970 ITC, but to instead amortize these credits to cost of service no more rapidly than ratably. This treatment is in accordance with Section 46(f)(2) of the Tax Code.

Q124. PLEASE DESCRIBE SCHEDULE G-7.4c, ADFIT AND ITC - PLANT ADJUSTMENTS AND ALLOCATIONS.

A. This schedule seeks information on the balance sheet ADFIT and ITC for additions to new generating plant-in-service since the Company's last filing and any plant adjustments to the test year end. There have been no new generating units added to rate base since the Company's last filing or plant adjustments to the test year end.

Q125. PLEASE DESCRIBE SCHEDULE G-7.4d, ADFIT - RATE CASE EXPENSES.

A. This schedule is inapplicable to ETI for this rate case. The Company does not have any ADFIT related to Texas Retail rate case expenses.

Q126. PLEASE DESCRIBE SCHEDULE G-7.5c, ITC UTILIZED – STAND-ALONE BASIS.

A. This schedule shows ITC utilized as if the Company had filed on a stand-alone basis consistent with the limitations included in the Tax Code based on the stand-alone methodology.

Q127. PLEASE DESCRIBE SCHEDULE G-7.5e, FERC ACCOUNT 255 BALANCE.

A. This schedule shows the FERC account balance for Account 255, Accumulated Deferred ITC.

Q128. PLEASE DESCRIBE SCHEDULE G-7.6, ANALYSIS OF TEST YEAR FIT AND REQUESTED FIT - TAX METHOD 2.

A. Schedule G-7.6 calculates FIT for the test year and requested FIT using Tax Method 2. Included with this schedule are supporting explanations and calculations. This method of calculating FIT expense determines the components of FIT separately. These components include the taxes payable currently, the deferred taxes, and the amortization of ITC.

Company witnesses Roberts and LeBlanc co-sponsor Schedules G-7.6 and G-7.6a.

Q129. PLEASE DESCRIBE SCHEDULE G-7.6a, ANALYSIS OF DEFERRED FIT.

A. This schedule is an analysis of the deferred FIT expense as shown on Schedule G-7.6. Workpapers supporting the calculation(s) are included in WP/G-7.6.

Q130. PLEASE DESCRIBE SCHEDULE G-7.7, ANALYSIS OF ADDITIONAL DEPRECIATION REQUESTED.

A. This schedule requests support for any requested adjustment to return for additional depreciation. ETI is not requesting an adjustment to return for additional depreciation expense.

Q131. PLEASE DESCRIBE SCHEDULE G-7.8, ANALYSIS OF TEST YEAR FIT AND REQUESTED FIT - TAX METHOD 1.

A. This schedule represents what is known as the Method 1 calculation of test year and requested FIT. This is sometimes described as the "return method" for computing FIT. Company witnesses Roberts and LeBlanc co-sponsor Schedule G-7.8.

Return is the total amount shown on Schedule B-1, line 21. Regulated interest expense is defined as the weighted cost of debt

(Schedule K-1, Line 3, column 6) multiplied by the requested rate base (Schedule B-1, line 19). Interest expense is subtracted from return to arrive at the taxable amount of return before adjustments.

Also subtracted is the amortization of taxes in excess of the statutory 35% rate and other items that, before adoption of SFAS 109, were called permanent and flow-through differences. The most significant of these differences is AFUDC, which for many years was recorded on a net of tax basis for both the interest and equity components of AFUDC.

Q132. WHAT IS THE RESULT OF THE TAX METHOD 1 CALCULATIONS?

A. The result of the above calculation equals the taxable component of return. This taxable return is multiplied by the tax factor 0.5384615 (Tax Rate *divided by* One *minus* the Tax Rate, (which is .35/1-.35)), resulting in the total FIT amount before adjustments.

From this amount is subtracted the ITC amortization and amortization of excess deferred taxes to determine total FIT (Method 1).

Q133. DOES THE AMOUNT COMPUTED UNDER METHOD 1 DIFFER FROM THE AMOUNT SHOWN ON SCHEDULE G-7.6, ANALYSIS OF TEST YEAR FIT AND REQUESTED FIT - TAX METHOD 2, AT REQUESTED RATES?

A. No, it is the same amount. The two calculations result in the same amount of FIT expense.

Q134. PLEASE DESCRIBE SCHEDULE G-7.9, AMORTIZATION OF PROTECTED AND UNPROTECTED EXCESS DEFERRED TAXES.

A. This schedule summarizes the amortization of protected and unprotected excess deferred FIT. Schedules G-7.9 through G.7-9c are sponsored by Company witness Roberts.

Q135. PLEASE DESCRIBE SCHEDULE G-7.9a.

A. This schedule reflects the amount of protected excess deferred FIT included in the test year and the unamortized balance of protected excess deferred FIT as of March 31, 2013.

Q136. PLEASE DESCRIBE SCHEDULE G-7.9b.

A. Schedule G-7.9b provides a reconciliation of excess deferred FIT as of March 30, 2013.

Q137. WHAT INFORMATION IS PROVIDED IN SCHEDULE G-7.9c?

A. The Company's unprotected excess deferred FIT was fully amortized at the end of July 1991.

Q138. PLEASE DESCRIBE SCHEDULE G-7.10, EFFECTS OF ACCOUNTING ORDER DEFERRALS.

A. This schedule lists and explains all effects on requested FIT and ADFIT of the Company's deferred accounting approved by the Commission in previous dockets. These are no accounting order deferrals remaining on ETI's books.

Q139. PLEASE DESCRIBE SCHEDULE G-7.11, EFFECTS OF POST-TEST YEAR ADJUSTMENTS.

A. Schedule G-7.11 is not currently applicable to the Company.

Q140. SCHEDULES G-7.12 AND G-7.12a RELATE TO DEFERRED FIT THAT IS PART OF A RATE MODERATION PLAN. DOES THE COMPANY HAVE A RATE MODERATION PLAN?

A. No.

Q141. PLEASE DESCRIBE SCHEDULE G-7.13, LIST OF FIT TESTIMONY.

A. Schedule G-7.13 simply provides page references to Company witness testimony supporting FIT and ADFIT.

7. <u>Outside Services Schedule</u>

Q142. PLEASE DESCRIBE SCHEDULE G-8.

A. This schedule presents information on all outside services employed during the test year that appear in the FERC 900 series accounts. The information is shown as follows: column (a) is the FERC account; column (b) is the vendor sorted by category; column (c) is the purpose of the service; column (d) indicates whether the service is recurring or non-recurring; and column (e) is the amount. Items of a non-recurring nature are removed or normalized in the requested cost of service.

8. Taxes Other Than Income Tax Schedules

Q143. PLEASE DESCRIBE SCHEDULE G-9.

A. This schedule shows the amount of taxes other than income taxes for the three most recent calendar years, the test year expense, adjustments to the test year and the total adjusted tax amount.

Q144. PLEASE DESCRIBE SCHEDULE G-9.1.

A. Schedule G-9.1 reflects the ad valorem taxes assessed and the related plant balances for the last three calendar years and the test year.

9. Factoring Expense Schedule

Q145. PLEASE DESCRIBE SCHEDULE G-10.

A. This schedule is not applicable to ETI because the Company does not factor accounts receivable.

10. Deferred Expense Information Schedule

Q146. PLEASE DESCRIBE SCHEDULE G-11.

A. Schedule G-11 includes information concerning all amortization expense either included in the test year or requested by the Company in this rate filing. The information is categorized by:

- authorizing docket;
- original amount to be amortized;
- deferral period;
- date amortization began;
- total amortization taken as of the beginning of the test year;
- amortization expense for the test year;
- amortization expense included in requested cost of service; and
- unamortized amount as of the end of the test year.

11. Below the Line Expenses Schedule

Q147. PLEASE DESCRIBE SCHEDULE G-12.

A. Schedule G-12 presents a complete analysis of all expenses charged "below the line" during the test year. Verification that "below the line" expenses have been eliminated from the filing has been provided in the workpapers (WP/G-12) for this schedule. The starting point for the Company's cost of service is net utility operating income. None of the items recorded below the line are included in the calculation of net utility operating income and none of the items recorded below the line are included in any adjustment that would include these amounts in cost of service.

12. Non-Recurring Expense Schedule

Q148. PLEASE DESCRIBE SCHEDULE G-13.

A. Schedule G-13 describes any nonrecurring extraordinary expenses the Company is requesting in this filing.

13. Rate Case Expense Schedules

Q149. PLEASE DESCRIBE SCHEDULE G-14.

A. Schedule G-14 details the various expenses charged to FERC Account 928, Regulatory Expense, during the test year, the Company's adjustments to the test year amounts, and the Company's request for each item.

Q150. PLEASE DESCRIBE SCHEDULE G-14.1.

A. Schedule G-14.1 provides information concerning estimated rate case expenses for this case, detailed by each type of expense. I discuss the Company's rate case expense estimate further below.

Q151. PLEASE DESCRIBE SCHEDULE G-14.2.

A. Schedule G-14.2 provides information concerning rate case expenses related to previous rate applications which were not previously considered by the Commission.

14. Monthly O&M Schedules

Q152. PLEASE DESCRIBE SCHEDULE G-15.

A. Schedule G-15 includes the O&M expense for the test year. The schedule provides O&M expense by month, by account, and the total booked for the test year. This schedule also includes total adjusted O&M expenses claimed, including subtotals by functional classification. The Company has also detailed the amount of O&M expense by account that was the result of a transaction with an affiliate and presents this information in the Schedule G-6 series of Schedules.

G. Schedule H – Engineering Information

Q153. PLEASE DESCRIBE SCHEDULES H-1 THROUGH H-1.2d.

A. Schedules H-1 through H-1.2d provide detailed information related to the production plant O&M expenses for all power generating stations. Schedules H-1 through H-1.2d are co-sponsored by Company witness Gerard L. Fontenot.

Q154. PLEASE DESCRIBE SCHEDULE H-2.

A. Schedule H-2 provides the information in Schedule H-1 adjusted for known and measurable changes. This schedule is co-sponsored by Company witness Fontenot.

Q155. PLEASE DESCRIBE SCHEDULE H-3.

A. Schedule H-3 is the summary of production O&M expenses incurred for the years 2008 through 2012.

Q156. PLEASE DESCRIBE SCHEDULE H-5.1.

A. Schedule H-5.1 describes the criteria used to determine which unit improvements, modifications, and repairs become capitalized costs. The instructions for Schedule H-5.1 require that workpapers be provided for the retirement units and expense item information (Retirement Catalog). ETI maintains a Retirement Catalog for capitalized units, which is provided in WP/H-5.1.

Q157. PLEASE DESCRIBE SCHEDULE H-10.

A. This schedule notes that the most recent River Bend Station Decommissioning Cost Study, dated November 2009, was filed with the PUC on December 30, 2009 in Docket No. 37744 as Exhibit WAC-1 to the testimony of Company witness William A. Cloutier.

H. Schedule J – Financial Statements

Q158. PLEASE DESCRIBE SCHEDULE J.

A. This schedule provides the financial statements considered necessary for presentation of the Company's financial position in accordance with generally accepted accounting practices. The statements provided are the Income Statement, Balance Sheet, Retained Earnings, and Statement of Cash Flows for both the test year and twelve months immediately preceding the test year. Also included are the footnotes to the financial statements.

Q159. PLEASE DESCRIBE SCHEDULE J-1.

A. This schedule provides a reconciliation of the balance sheet and the income statement presented on a total Company basis in Schedule J to the same information on a total electric basis.

Q160. PLEASE DESCRIBE SCHEDULE J-2.

A. This schedule provides the consolidated financial statements, including the footnotes, for Entergy Corporation, the parent of ETI.

I. <u>Schedule K – Financial Information</u>

Q161. WOULD YOU PLEASE EXPLAIN SCHEDULE K-1.

A. Schedule K-1 of the RFP shows the overall rate of return on invested capital of the Company. Schedules K-1 through K-6 are co-sponsored by Company witness Chris E. Barrilleaux. Column (4) of Schedule K-1 shows that the Company's capitalization percentages are 51.41% debt and 48.59% common equity. The component cost rates shown in Column (5) are calculated in supporting Schedules K-2 and K-3. The required cost of common equity requested by the Company in this filing is discussed in the testimony of Company witness Samuel C. Hadaway. The cost of equity reflected in Schedule K-1 is 10.4%.

The component cost rates in Column (5) of Schedule K-1 are then applied to the capitalization percentages shown in Column (4) to obtain the overall weighted cost of capital of 8.5133% shown in Column (6). The net original cost rate base of $1,633,805,549 on line 5 is multiplied by the overall rate of return to obtain the requested dollar return on rate base of $139,091,000 on line 7 of Schedule K-1.

The capital amount for common equity reflects the common equity balance as of March 31, 2013.

Q162. PLEASE DISCUSS SUPPORTING SCHEDULE K-2.

A. Schedule K-2 is not currently applicable to the Company because it has no preferred stock.

Q163. PLEASE DISCUSS SCHEDULE K-3.

A. The adjusted overall cost of long-term debt of 6.73% is calculated in Schedule K-3 of the RFP. Details of the sinking fund requirements for long-term debt are also provided in Schedule K-3.

Q164. PLEASE DISCUSS SCHEDULE K-4.

A. This schedule shows a listing of notes outstanding at the end of the test year, and at the end of each quarter for the past two years.

Q165. PLEASE DISCUSS SCHEDULE K-5.

A. Schedule K-5 is a summary of security issuance restrictions that apply to the issuance of preferred stock and long-term debt as of the end of the test year, the most recent fiscal year and projections for three fiscal years. The Mortgage Indenture coverage calculation and the Articles of Incorporation calculation provide the restrictions on the amount of securities that can be issued under each test. The projections of each financial test provided for three fiscal years are sponsored by Company witness Barrilleaux.

Q166. PLEASE DESCRIBE SCHEDULE K-6.

A. Schedule K-6 contains thirteen specific ratios for the fiscal years 2008 through 2012 and the test year, as well as three projected fiscal years. I co-sponsor the projected ratios along with Company witness Barrilleaux.

J. Schedule M – Nuclear Plant Decommissioning

Q167. PLEASE DESCRIBE SCHEDULE M-1.

A. Schedule M-1 provides general information, decommissioning cost, and funding for each decommissioning fund the Company has established.

Q168. PLEASE DESCRIBE SCHEDULE M-2.

A. Schedule M-2 provides the accumulated fund balance on each decommissioning funding plan established by the Company. The decommissioning funding plan provides the actual and projected annual contributions, administrative fees, earnings on the funds, tax payments, decommissioning outlays, and accumulated fund balances by year.

Q169. WHAT IS THE COMPANY PROPOSING BASED ON THE M-2 INFORMATION?

A. As described in Adjustment AJ16M, the Company is proposing to update the revenue requirement based on the latest information available. This calculation is further explained in the direct testimony of Company witnesses LeBlanc, Monique C. Hoffmeister and Kenneth F. Gallagher.

K. Schedule P – Class Cost of Service Analysis

Q170. PLEASE DESCRIBE SCHEDULE P-10.

A. Schedule P-10 provides adjusted O&M payroll by account for the test year. The information is categorized by Company, affiliates, and total.

L. Schedule S – Test Year Review

Q171. PLEASE DESCRIBE SCHEDULE S.

A. Schedule S consists of a report by ETI's independent certified public accountants ("CPAs"), Deloitte & Touche, on a review covering the test year which complies with applicable standards established by the American Institute of CPAs and with the procedures detailed in the RFP.

Q172. PLEASE DESCRIBE THE SCHEDULE S-1 SERIES.

A. Schedules S, S-1a, and S-1b include a description summarizing the independent accountants' scope of review procedures and materiality considerations applied to each of the required minimum procedures listed in the RFP instructions for Schedule S.

Q173. PLEASE DESCRIBE SCHEDULE S-2.

A. Schedule S-2 indicates that there were no material errors, exceptions, or omissions noted by Deloitte & Touche during the course of the test year review.

Q174. PLEASE DESCRIBE THE SCHEDULE S-3 SERIES.

A. Schedules S-3 and S-3a indicate there were no communications by the independent accountants on reportable conditions required by Statement on Auditing Standards No. 60, Communication of Internal Control Structure Related Matters Noted in an Audit.

Q175. PLEASE DESCRIBE SCHEDULE S-4.

A. Schedule S-4 requires a copy of adjusting journal entries resulting from the most recent annual audit provided by Deloitte & Touche to ETI for posting to ETI's books. There were no such entries for ETI as the result of the most recent audit.

Q176. PLEASE DESCRIBE SCHEDULE S-5.

A. Schedule S-5 includes a copy of all potential or passed adjusting journal entries identified during the course of the most recent annual audit that were not posted to ETI's books.

Q177. PLEASE DESCRIBE SCHEDULE S-6.

A. Schedule S-6 requires the name and telephone number of a contact person through whom arrangements can be made to review Deloitte & Touche's workpapers for the test year review and the most recent annual audit. This schedule also specifies a location in Austin, Texas, where the workpapers will be made available for review.

VI. RATE CASE EXPENSES

Q178. WHAT IS THE COMPANY'S ESTIMATE OF RATE CASE EXPENSES ASSOCIATED WITH THIS PROCEEDING?

A. Schedule G-14.1 reflects the estimated rate case expenses that the Company will incur in connection with this rate proceeding as well as those expenses incurred subsequent to September 30, 2012 in support of Docket No. 39896. Total estimated expenses, including expenses billed to ETI by certain Cities in the Company's service territory, are $9,374,854 as shown on page 1. The estimated expenses are based on the assumption the case is litigated and reflect estimated expenses to obtain a final order from the PUC. The Company will collect actual expenses related to this case and submit the expense amounts, along with supporting testimony, in accordance with the procedural schedule ultimately adopted by the Administrative Law Judge.

Q179. ARE COSTS OF ESI INCLUDED IN RATE CASE EXPENSE?

A. Yes. ETI uses the services of ESI in preparing rate filings. Employees of ESI, such as myself, are required and needed to provide support or testimony in this proceeding.

Q180. PLEASE DESCRIBE THE PROCEDURE FOR REVIEWING THE COMPANY'S ACTUAL RATE CASE EXPENSES.

A. There are a number of consultants and outside lawyers involved in preparing this rate case. The consultants have been retained by ESI or the Company or have been retained by legal counsel representing the Company to provide specialized work needed to support the rate filing.

When billings are received from the consultants or through legal counsel, the appropriate personnel review the charges and approve them for payment. The bill is then forwarded to Accounts Payable for payment. Accounts Payable personnel review each bill submitted for payment to determine that proper approval has been made.

Q181. HOW DOES THE COMPANY PROPOSE TO RECOVER RATE CASE EXPENSES?

A. The Company proposes that it be permitted to recover these costs over a three-year period through a separate rider as was ordered in Docket No. 40295. The Company is not asking for a return on the unamortized balance as is consistent with the same Final Order. The Company, however, is seeking to recover expenses such as ESI depreciation expense, which was disallowed in Docket No. 40295 because the Company is appealing that disallowance (among other things), and is thereby preserving its right to collect ESI depreciation expense attributable to the rate case.

VII. CONCLUSION

Q182. PLEASE STATE YOUR CONCLUSIONS.

A. The Company's requested cost of service and rate base are an accurate reflection of the Company's reasonable and necessary costs as appropriately adjusted and presented in accordance with the PUC's Substantive Rules. Additionally, the adjustments contained in the Company's filing are appropriate and reflect the regulatory treatment intended.

Q183. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY?

A. Yes.

Entergy Texas, Inc.
Listing of Rate Filing Package Schedules Sponsored Or Co-Sponsored By Michael P. Considine

Line No.	Schedule Description		Sponsor	Co-Sponsor
1	A-4	Detail TYE Trial Balance	X	
2	B-1	Rate Base & Return-Total Co		X
3	B-1.2	% Of Plant In Service	X	
4	B-1.3	Penalties Or Fines	X	
5	B-1.4	Post Test Year Adjustments	X	
6	B-2	Accumulated Provision Balances	X	
7	B-2.1	Accumulated Provision Policies	X	
8	C-1	Original Cost of Utility Plan	X	
9	C-2	Detail Of Orig Cost Of Util Plant	X	
10	C-3	Monthly Detail Of Util Plt In Svc	X	
11	C-4.1	CWIP By Functional Group	X	
12	C-4.2	CWIP Allowed In Rate Base	X	
13	C-5	AFUDC or IDC	X	
14	C-6	Nuclear Fuel		X
15	C-6.1	Nuclear Fuel in Process		X
16	D	Narrative-Accum Depr Sect As Spcfd	X	
17	D-1	Accum Dpr By Funct Grp/Prim A/C	X	
18	D-2	Accum Dpr BookingMethods	X	
19	D-3	Plant Held For Future Use	X	
20	D-4	Depreciation Expense	X	
21	D-5	Depreciation Rate Study	X	
22	D-6	Retirement Data for All Generating Units		X
23	D-7	Summary Of Book Salvage	X	
24	D-8	Service Lives	X	
25	E-1	Monthly Blnces-Short Term Assets	X	
26	E-1.1	Detail Of Short Term Assets	X	
27	E-1.2	Obsolete Assets	X	
28	E-1.3	Short Term Assets Policies	X	
29	E-2.2	Fossil Fuel Inventory Evaluation		X
30	E-2.3	Fossil Fuel Inventories		X

Entergy Texas, Inc.
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Line No.	Schedule	Description	Sponsor	Co-Sponsor
31	E-2.4	Fossil Fuel Inventory Levels		X
32	E-4	Working Cash Allowance		X
33	E-5	Prepaymnts + Matrls & Supplies	X	
34	E-6	Customer Deposits	X	
35	G-1	Payroll Information	X	
36	G-1.1	Regular * Overtime Payroll	X	
37	G-1.2	Regular Payroll By Category	X	
38	G-1.3	Payroll Capitalized vs. Expenses	X	
39	G-1.4	Payroll By Company	X	
40	G-1.6	Payments Oth Than Standard Pay		X
41	G-2.1	Pension Expense		X
42	G-2.2	Postretirement Benefits Excl Pens	X	
43	G-3	Bad Debt Expense	X	
44	G-4	Summ Of Adtsng, Contrbtns, Dues	X	
45	G-4.1	Summary Of Advertising Expense	X	
46	G-4.1a	Summ Of Inform/;instruct Advtsng	X	
47	G-4.1b	Advtsng Summ-Promote/Rtn Use	X	
48	G-4.1c	Summ Of General Advtsng Exp	X	
49	G-4.1d	Capitalized Advertising	X	
50	G-4.2	Summ-Contrbtn & Donation Exp	X	
51	G-4.2a	Summ-Educat Contrbtns/Dontns	X	
52	G-4.2b	Summ-Commun Svc Contr/Dontns	X	
53	G-4.2c	Summ-Econ Dvlpmnt Contr/Dontns	X	
54	G-4.3	Summary-Membership Dues Exp	X	
55	G-4.3a	Summary-Industry Organztn Dues	X	
56	G-4.3b	Summ-Business/Economic Dues	X	
57	G-4.3c	Summary-Professional Dues	X	
58	G-4.3d	Summ-Socl/Recrtnl/Fratnl/Relgs Exp	X	
59	G-4.3e	Summ-Political Organztns Exp	X	
60	G-5	Summ-Exclsns From Test Yr Exp	X	

Entergy Texas, Inc.
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Line No.	Schedule Description		Sponsor	Co-Sponsor
61	G-5.1	Analysis Of Legislative Advocacy	X	
62	G-5.1a	Payments To Registrd Lobbyists	X	
63	G-5.1b	Payments For Monitoring Legislatn	X	
64	G-5.2	Summary Of Penalities & Fines	X	
65	G-5.3	Other Exclusions	X	
66	G-5.4	Analysis Of Prior Rt Case Exclsns	X	
67	G-5.5	Comprsn-Pr Rt Cse Excl To Currnt	X	
68	G-7.1	Recon-Test Yr Bk Net Inc & Tax Net Inc		X
69	G-7.2	Plant Adjustments	X	
70	G-7.4	ADFIT		X
71	G-7.4b	Adjustments to ADFIT		X
72	G-7.4c	ADFIT & ITC-Plt Adjstmnts & Alloc		X
73	G-7.4d	ADFIT-Rate Case Expense		X
74	G-7.5c	ITC Utilized-Stand Alone Basis		X
75	G-7.5e	FERC A/C 255 Balance		X
76	G-7.6	Analys-TY & Rqstd FIT-Tx Meth 2		X
77	G-7.6a	Analysis Of Deferred FIT		X
78	G-7.7	Analysis Of Addtnl Deprec Rqstd	X	
79	G-7.8	Analys-TV & Rqstd FIT-Tx Meth 1		X
80	G-7.10	Effects Of Acctng Order Deferrals		X
81	G-7.11	Effct-Post TY Adjust-FIT & ADFIT	X	
82	G-7.12	Effcts-Rt Modrtn Plan-FIT & ADFIT	X	
83	G-7.12a	Trtmnt=FIT/ADFIT in Rt Modrtn Pln	X	
84	G-7.13	List of FIT/ADFIT Testimony		X
85	G-8	Outside Svcs Emp-FERC 900 Exp	X	
86	G-9	Taxes Oth Than Inc Taxes (UR	X	
87	G-9.1	Ad Valorem Txs & Plt Balances	X	
88	G-10	Factoring Expense (UR)	X	
89	G-11	Def Expenses From Prior Dckts	X	
90	G-12	Below The Line Expenses	X	

Entergy Texas, Inc.
Listing of Rate Filing Package Schedules Sponsored Or Co-Sponsored By Michael P. Considine

Line No.	Schedule Description		Sponsor	Co-Sponsor
91	G-13	Nonrecurring Or Extrdnry Exp	X	
92	G-14	Regulatory Commission Exp	X	
93	G-14.1	Rate Case Expenses	X	
94	G-14.2	Rate Case Exp-Pr Rate Applctns	X	
95	G-15	Monthly O&M Expense	X	
96	H-1	Summ Of Test Yr Prod O&M Exp		X
97	H-1.2	Fossil Co-Wide O&M Exp Summ		X
98	H-1.2a	Nat Gas Plt O&M Summary		X
99	H-1.2a1	Natural Gas (Steam Genrtn)		X
100	H-1.2a2	Natural Gas (Combustn Turbine)		X
101	H-1.2b	Coal Plant O&M Summary		X
102	H-1.2c	Lignite Plant O&M Summary		X
103	H-1.2d	Oth Plant O&M Summary		X
104	H-2	Summ-Adjstd TY Prod O&M Exp		X
105	H-3	Summary-Act. Prod. O&M Exp Incurred		X
106	H-5.1	Prod Plt Capital Cost Methodology	X	
107	H-10	Nucl Decommiss Cost Studies	X	
108	J	Financial Statements	X	
109	J-1	Reconciliation-Total Co To Total Elec	X	
110	J-2	Consolidated Finance Statements	X	
111	K-1	Weighted Avg Cost Of Capital		X
112	K-2	Wghtd Avg Cost Of Preferred Stock		X
113	K-3	Wghtd Avg Cost Of Debt		X
114	K-4	Notes Payable		X
115	K-5	Security Issuance Restrictions		X
116	K-6	Financial Ratios		X
117	M-1	Decommissioning Information		X
118	M-2	Decommissioning Funding Plan		X
119	P-10	Payroll Expense Distribution	X	
120	S	Test Yr Review As Specfd	X	

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Line No.	Schedule Description		Sponsor	Co-Sponsor
121	S-1	Scope Of Review	X	
122	S-2	Errors/Excptns Noted-Indp Accnts	X	
123	S-3	Communictns From Indept Accnts	X	
124	S-4	Adjusting Journal Entries	X	
125	S-5	Passed Adjstng Journal	X	
126	S-6	Workpaper Review-Indep Acctnts	X	

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ENTERGY TEXAS, INC. Electric Service SCHEDULE RCE-3	Sheet No.: 85 Effective Date: Proposed Revision: 0 Supersedes: New Schedule Schedule Consists of: One Sheet

RATE CASE EXPENSE RIDER 3

I. APPLICATION N

This Rate Case Expense Rider ("Rider RCE" or the "Rider") is applicable under the regular terms and conditions of Entergy Texas, Inc. ("Company") to all electric service billed under all of the Company's Rate Schedules* and all associated Riders*, whether metered or unmetered service, and subject to the jurisdiction of the Public Utility Commission of Texas ("PUCT").

II. GENERAL PROVISIONS

The Rider RCE rate below is to recover costs incurred by the Company and certain municipalities resulting from the base rate case filing in PUCT Docket No. 39896 subsequent to September 30, 2012 per PUCT Docket No. 40295, and the estimated rate case expenses the Company and certain municipalities will incur as a result of its September 2013 base rate case filing.

III. RATE

All electric service accounts billed in accordance with Company's Rate Schedules* and associated Riders* will also be billed the following amount during the Recovery Period:

Rate Class	Rate Schedule	Rate Adjustment
Residential Service	RS, RS-TOD	$0.000288 per kWh
Small General Service	SGS, UMS, TSS	$0.000295 per kWh
General Service	GS, GS-TOD	$0.000205 per kWh
Large General Service	LGS, LGS-TOD	$0.000141 per kWh
Large Industrial Power Service	LIPS, LIPS-TOD, IS	$0.04052 per kW
Lighting	SHL, LS-E, ALS, RLU	$0.000491 per kWh

Amounts billed pursuant to this Rider RCE are not subject to Rider IHE but are subject to State and Local sales tax.

IV. RECOVERY PERIOD

Rider RCE will be billed beginning with the effective date of this Rider and will terminate in the month in which the approved amount has been billed.

*Excluding Schedules CGS, EAPS, MVDRR, MVLMR, SQF, LQF, and SMS.

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DOCKET NO. 41791

APPLICATION OF ENTERGY	§	PUBLIC UTILITY COMMISSION
TEXAS, INC. FOR AUTHORITY	§	
TO CHANGE RATES AND	§	OF TEXAS
RECONCILE FUEL COSTS	§	

DIRECT TESTIMONY

OF

MICHELLE P. BOURG

ON BEHALF OF

ENTERGY TEXAS, INC.

SEPTEMBER 2013

ENTERGY TEXAS, INC.
DIRECT TESTIMONY OF MICHELLE P. BOURG
2013 RATE CASE

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I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michelle P. Bourg. My business address is 639 Loyola Avenue, New Orleans, Louisiana 71113.

Q2. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Entergy Services, Inc. ("ESI") as Director, Performance Management.

Q3. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from Louisiana State University in 2002 with a Bachelor of Science in Electrical Engineering. I earned a Master of Business Administration from Tulane University in 2013. I am a registered professional engineer in the state of Louisiana and am an active member of the Institute of Electrical and Electronics Engineers.

In 2002, I began working for ESI's Transmission organization as a planning engineer in the Transmission Operational Planning department and, in April 2006, became the department's Manager, Transmission Planning. In September 2009, I accepted the position of Manager, Performance Management in ESI's Utility Operations department and, in December 2010, assumed my current position as Director, Performance Management. As the Director, Performance Management, I am responsible for developing, refining, and overseeing the performance reporting processes and benchmarking activities for the Utility and Energy Delivery businesses.

Q4. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Entergy Texas, Inc. ("ETI" or "the Company").

II. PURPOSE OF TESTIMONY

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony provides a benchmarking analysis of the 2010, 2011, and 2012 non-production operations and maintenance ("O&M") expenses of ETI as compared to the electric utility industry. The analysis supports the conclusion that ETI's O&M policies and practices result in reasonable levels of O&M expenditures, and further supports the reasonableness of ETI's test year O&M costs applicable to this docket.

Q6. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. In Section III, I provide an analysis of non-production O&M expenses of the Company as compared to the electric industry.

Q7. DO YOU SPONSOR ANY EXHIBITS?

A. Yes, I sponsor the exhibits listed in the table of contents to my testimony.

III. NON-PRODUCTION O&M BENCHMARKING

Q8. WOULD YOU BRIEFLY DESCRIBE THE PURPOSE OF A BENCHMARKING ANALYSIS?

A. Yes. The purpose of a benchmarking analysis is to compare a measurable operating characteristic of one company to that experienced by a peer group. The operating characteristic can be a physical unit such as expressed by the capacity factor of a generating unit; it can be a measure of the efficiency of the inputs to a process to obtain output, such as the number of employees per unit of output, or as was done here, a measure of cost efficiency of a company, such as the dollars of a particular expense or group of expenses per unit of output, such as mega-watt hour ("MWh") sold.

Just because a benchmark calculation can be made does not mean that the results can or should be relied on in isolation to draw a valid conclusion. For example, the capacity factor of a generating unit will depend on a number of factors not captured by such an analysis, such as the fuel source of the unit or the alternatives available. Nonetheless, viewed in combination with the other evidence provided by the Company in this case, my benchmarking analysis clearly supports the reasonableness of ETI's non-production O&M costs.

In this case, I have presented a benchmarking analysis of how ETI compares to the peer group in terms of the cost per MWh sold to customers as well as per customer for non-production O&M costs. These analyses support the testimony of other witnesses in this case to show that, overall, and taking into account other factors, such as cost control measures and trends, the Company's costs are reasonable.

Q9. HOW DID YOU SELECT THE COMPANIES YOU USED TO REPRESENT THE ELECTRIC UTILITY INDUSTRY, THE PEER GROUP, FOR THE PURPOSE OF ANALYZING NON-PRODUCTION O&M COSTS?

A. I began with all investor-owned electric utilities contained in a database maintained by SNL Financial. SNL Financial collects, standardizes and disseminates corporate, financial and market data for the banking, financial and energy industries. I then removed all companies that had one or more of the following characteristics:

1. Companies that had no retail sales;
2. Companies that had negative or zero administrative and general, distribution or transmission O&M expenses; and
3. Companies with fewer than 20,000 customers.

After making these eliminations, one-hundred six (106) electric operating companies remained, including ETI, for the years 2010, 2011 and 2012.

Q10. ETI PREVIOUSLY FILED A BENCHMARK ANALYSIS FOR THE YEAR 2010 IN WHICH THERE WERE ONE-HUNDRED SIXTEEN (116) COMPANIES REFLECTED IN THE PEER GROUP. WHY HAS THE NUMBER OF COMPANIES CHANGED IN THIS ANALYSIS?

A. Primarily as a result of mergers and other combinations the number of reporting companies that meet the selection criteria has declined over the 2010-2012 period of analysis. Also, in this case, it was decided to rely on a peer group consisting of the same number of companies in each of the three years to provide a consistent comparison group over time.

Q11. WHAT IS THE SOURCE OF THE DATA CONTAINED IN THE DATABASE?

A. The data contained in the database is obtained from each company's annual FERC Form No. 1 filing.

Q12. IN YOUR OPINION, IS IT APPROPRIATE TO COMPARE ETI TO ANY PARTICULAR COMPANY IN THE COMPARISON GROUP?

A. No. In my opinion, the proper comparison is to the group or industry average. Individual companies are likely to have abnormalities reflected in certain years. It would be impossible to eliminate such abnormalities and such eliminations would have to be based on judgment. A comparison to industry averages, especially when the size of the group is as large as I have used, will "smooth out" these abnormalities.

Q13. PLEASE DISCUSS THE ANALYSIS OF NON-PRODUCTION EXPENSES THAT YOU PERFORMED.

A. In performing this analysis, I used all of the companies that met the selection criteria. I developed the total non-production O&M expenses for ETI and each of the comparison companies, and divided that by MWh of sales to ultimate customers. Thus, the O&M costs are expressed in terms of costs per MWh sold. The results of this analysis are summarized in the following table.

TABLE 1
Non-Production O&M
(Dollars Per MWh of Sales)

Year	Weighted Industry Average	ETI	ETI as a % of Industry Average	Rank Among Peer Group
2010	$18.50	$9.69	52%	12
2011	$19.23	$9.72	51%	9
2012	$19.64	$10.75	55%	9

ETI's non-production costs per MWh sold are below the industry average. Its rank is in or near the top decile of the companies analyzed.

Q14. DID YOU ALSO PERFORM AN ANALYSIS OF PARTICULAR SUB-COMPONENTS OF NON-PRODUCTION O&M COSTS?

A. Yes. I performed additional analyses of non-production O&M costs for the following sub-components:

1. Distribution O&M;
2. Transmission O&M;

3. Customer Accounts, Service and Informational, and Sales Expense O&M; and,

4. Administrative and General O&M.

Each of these was analyzed in the same manner as non-production O&M. The O&M costs for ETI and each company in the comparison group were determined and then divided by its sales (MWh) to arrive at a cost per MWh sold. A summary of the results of these analyses is presented in the following tables.

TABLE 2
Distribution O&M
(Dollars Per MWh of Sales)

Year	Weighted Industry Average	ETI	ETI as a % of Industry Average	Rank Among Peer Group
2010	$3.91	$1.85	47%	10
2011	$4.26	$1.88	44%	7
2012	$4.20	$1.87	45%	9

As may be seen, ETI's rank among the peer group is in the top decile.

TABLE 3
Transmission O&M
(Dollars Per MWh of Sales)

Year	Weighted Industry Average	ETI	ETI as a % of Industry Average	Rank Among Peer Group
2010	$3.26	$1.09	33%	24
2011	$3.20	$1.57	49%	40
2012	$3.32	$1.61	48%	37

As may be seen, transmission costs per MWh are well under the industry average.

TABLE 4
Customer Accounts, Service and Informational, and Sales Expense O&M
(Dollars Per MWh of Sales)

Year	Weighted Industry Average	ETI	ETI as a % of Industry Average	Rank Among Peer Group
2010	$4.17	$1.69	41%	19
2011	$4.52	$1.83	40%	16
2012	$4.59	$1.81	39%	18

As may be seen, again, the customer and sales costs per MWh reside in the first quartile.

TABLE 5
Administrative and General O&M
(Dollars Per MWh of Sales)

Year	Weighted Industry Average	ETI	ETI as a % of Industry Average	Rank Among Peer Group
2010	$7.10	$5.06	71%	32
2011	$7.18	$4.44	62%	20
2012	$7.45	$5.45	73%	32

ETI's administrative and general costs expressed on a per MWh sold basis are lower than the electric utility industry average and reside either in the first quartile or in the top of the second quartile. The details for ETI and each of the comparison group companies are contained in Exhibits MPB-1 through MPB-15.

Q15. DID YOU ALSO ANALYZE THE EFFECT OF ELIMINATING CERTAIN ADMINISTRATIVE AND GENERAL ("A&G") EXPENSE ACCOUNTS?

A. Yes. I have removed from the total A&G O&M expenses, the amounts associated with the following accounts:

1. Property Insurance (Account 924);
2. Injuries and Damages (Account 925);
3. Employee Pensions and Benefits (Account 926); and,
4. Regulatory Commission Expenses (Account 928).

In each case, the expenses tend to be volatile and reflect circumstances unique to each company. For example, Property Insurance and Injuries and Damages reflect the effect of storms and damage claims generally outside the control of the company. Employee Pensions and Benefits vary with many variables such as the health of the employees and retirees, and Regulatory Commission expenses reflect the effect of fees and/or consulting costs billed to the company by a regulatory authority.

The analysis of A&G costs per MWh sold, after removal of the costs associated with Account Nos. 924, 925, 926, and 928 is shown in the following table:

TABLE 6 Administrative and General O&M Excluding Account Nos. 924, 925, 926, and 928 (Dollars Per MWh of Sales)				
Year	Weighted Industry Average	ETI	ETI as a % of Industry Average	Rank Among Peer Group
2010	$3.96	$2.41	61%	22
2011	$3.92	$2.34	60%	22
2012	$3.89	$2.63	68%	28

Again, this subset of ETI's administrative and general costs expressed on a per MWh sold basis are lower than the electric utility industry average and reside in the first quartile or in the top of the second quartile. The detailed analysis of adjusted A&G O&M is contained in Exhibit MPB-16 through Exhibit MPB-18.

Q16. DID YOU ANALYZE THE O&M EXPENSE CATEGORIES ON A BASIS OTHER THAN PER MWH SOLD?

A. Yes. I also analyzed the same O&M categories of Total Non-Production O&M, Distribution O&M, Transmission O&M, Customer Accounts, Service and Informational, and Sales Expense O&M, and A&G O&M on a per customer basis. I should note that I do not believe that per customer benchmarking analyses are as useful as per MWh analyses in drawing conclusions concerning ETI's efficiency. O&M costs are not generally caused by the number of customers nor, for the most part, are such costs billed to customers on a per customer basis. Customers do not pay the same charge as any other customer just because they are a customer.

You pay for how much you use. However, I do recognize that certain ESI billing methods are appropriately based on the number of customers; therefore, I have analyzed the O&M costs on this basis as well. The results of these analyses are summarized in the following tables:

TABLE 7
Total Non-Production O&M
(Dollars Per Customer)

Year	Weighted Industry Average	ETI	ETI as a % of Industry Average	Rank Among Peer Group
2010	$441.27	$384.11	87%	30
2011	$454.03	$398.15	88%	32
2012	$467.01	$422.06	90%	39

TABLE 8
Distribution O&M
(Dollars Per Customer)

Year	Weighted Industry Average	ETI	ETI as a % of Industry Average	Rank Among Peer Group
2010	$93.24	$73.23	79%	29
2011	$100.60	$76.87	76%	32
2012	$99.91	$73.52	74%	26

TABLE 9
Transmission O&M
(Dollars Per Customer)

Year	Weighted Industry Average	ETI	ETI as a % of Industry Average	Rank Among Peer Group
2010	$77.73	$43.24	56%	38
2011	$75.51	$64.21	85%	56
2012	$78.98	$63.35	80%	57

TABLE 10
Customer Accounts, Service and Informational, and Sales Expense O&M
(Dollars Per Customer)

Year	Weighted Industry Average	ETI	ETI as a % of Industry Average	Rank Among Peer Group
2010	$99.49	$66.85	67%	35
2011	$106.70	$75.12	70%	38
2012	$109.21	$71.11	65%	38

TABLE 11
Administrative and General O&M
(Dollars Per Customer)

Year	Weighted Industry Average	ETI	ETI as a % of Industry Average	Rank Among Peer Group
2010	$169.22	$200.79	119%	67
2011	$169.65	$181.68	107%	57
2012	$177.16	$213.85	121%	69

TABLE 12
Administrative and General O&M
Excluding Account Nos. 924, 925, 926, and 928
(Dollars Per Customer)

Year	Weighted Industry Average	ETI	ETI as a % of Industry Average	Rank Among Peer Group
2010	$94.34	$95.41	101%	56
2011	$92.52	$95.97	104%	52
2012	$92.49	$103.35	112%	64

As mentioned previously, ETI's costs expressed on a per MWh sold basis were consistently lower than the electric utility industry average. ETI's costs expressed on a per customer basis, however, are higher relative to the industry average than when such costs are expressed on a per MWh sold basis, though they still remain below or near industry average. This difference between the results of the two metrics is because ETI's MWh sales per customer are greater (approximately 60%) than the industry average, which is a function of customer-usage – not any action on the part of the Company. Thus, while ETI's customers consume more energy than the industry average, they do so at a much lower than industry average cost for the non-production functions.

In my opinion, although some costs can be allocated properly on a per customer basis, I believe that from the perspective of overall O&M costs, sales are a more significant cost driver of the delivered cost of electricity than the number of customers. The detailed results of these per customer based analyses, however, are contained in Exhibits MPB-19 through MPB-36.

Q17. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

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TOTAL NON-PRODUCTION O&M PER MWH
($/MWh)
2010

Rank	Company	Total Non-Prod O&M ($000)	Total Sales (000 MWh)	Total O&M Per MWh
1	Kingsport Power Company	$ 7,752	2,240	$ 3.46
2	Toledo Edison Company	$ 57,903	10,334	$ 5.60
3	Ohio Edison Company	$ 136,362	24,155	$ 5.65
4	Cleveland Electric Illuminating Company	$ 119,736	18,870	$ 6.35
5	Wheeling Power Co	$ 14,817	2,304	$ 6.43
6	Pennsylvania Power Company	$ 33,985	4,502	$ 7.55
7	Entergy Louisiana, LLC	$ 256,693	30,648	$ 8.38
8	Florida Power & Light Company	$ 947,659	105,003	$ 9.03
9	Oncor Electric Delivery Company LLC	$ 1,008,829	109,323	$ 9.23
10	Potomac Edison Company	$ 107,791	11,670	$ 9.24
11	Entergy Gulf States Louisiana, L.L.C.	$ 185,876	19,823	$ 9.38
12	***Entergy Texas, Inc.***	***$ 156,333***	***16,141***	***$ 9.69***
13	West Penn Power Company	$ 213,840	20,040	$ 10.67
14	Kentucky Utilities Company	$ 213,174	19,936	$ 10.69
15	Nevada Power Company	$ 233,791	20,873	$ 11.20
16	Midwest Energy, Inc.	$ 15,659	1,366	$ 11.46
17	South Carolina Electric & Gas Co.	$ 264,721	22,922	$ 11.55
18	Entergy Mississippi, Inc.	$ 160,421	13,743	$ 11.67
19	Georgia Power Company	$ 1,021,198	87,160	$ 11.72
20	Indianapolis Power & Light Company	$ 173,322	14,609	$ 11.86
21	Southwestern Public Service Company	$ 220,680	18,575	$ 11.88
22	Southwestern Electric Power Company	$ 213,751	17,813	$ 12.00
23	Oklahoma Gas and Electric Company	$ 316,971	26,167	$ 12.11
24	Louisville Gas and Electric Company	$ 150,266	12,338	$ 12.18
25	Duquesne Light Company	$ 171,836	14,090	$ 12.20
26	Duke Energy Carolinas, LLC	$ 1,008,010	79,553	$ 12.67
27	Potomac Electric Power Company	$ 350,546	27,665	$ 12.67
28	Virginia Electric and Power Company	$ 1,043,370	81,226	$ 12.85
29	Baltimore Gas and Electric Company	$ 438,662	32,864	$ 13.35
30	Public Service Company of Oklahoma	$ 239,383	17,917	$ 13.36
31	Cleco Power LLC	$ 120,347	8,992	$ 13.38
32	Ohio Power Company	$ 351,446	26,200	$ 13.41
33	Entergy Arkansas, Inc.	$ 296,370	22,003	$ 13.47
34	Monongahela Power Company	$ 146,185	10,676	$ 13.69
35	Tampa Electric Company	$ 264,365	19,213	$ 13.76
36	Northern Indiana Public Service Co.	$ 223,143	16,191	$ 13.78
37	Union Electric Company	$ 530,352	38,427	$ 13.80
38	Southern Indiana Gas and Electric Company, Inc.	$ 78,284	5,617	$ 13.94
39	Duke Energy Indiana, Inc.	$ 398,452	28,259	$ 14.10
40	PacifiCorp	$ 771,950	53,016	$ 14.56
41	MDU Resources Group, Inc.	$ 40,637	2,786	$ 14.59
42	Alabama Power Company	$ 817,848	55,974	$ 14.61
43	UNS Electric, Inc.	$ 27,355	1,857	$ 14.73
44	Gulf Power Company	$ 167,537	11,359	$ 14.75
45	Mississippi Power Company	$ 143,605	9,723	$ 14.77
46	Jersey Central Power & Light Company	$ 329,433	22,132	$ 14.89
47	Delmarva Power & Light Company	$ 194,128	12,857	$ 15.10
48	MidAmerican Energy Company	$ 329,598	21,710	$ 15.18
49	Sierra Pacific Power Company	$ 125,301	8,097	$ 15.47
50	Tucson Electric Power Company	$ 144,408	9,292	$ 15.54
51	PPL Electric Utilities Corporation	$ 575,681	36,998	$ 15.56

TOTAL NON-PRODUCTION O&M PER MWH
($/MWh)
2010

Rank	Company	Total Non-Prod O&M ($000)	Total Sales (000 MWh)	Total O&M Per MWh
52	KCP&L Greater Missouri Operations Company	$ 132,423	8,339	$ 15.88
53	Public Service Company of Colorado	$ 451,858	28,299	$ 15.97
54	Entergy New Orleans, Inc.	$ 81,729	5,072	$ 16.11
55	Empire District Electric Company	$ 79,382	4,839	$ 16.41
56	Arizona Public Service Company	$ 455,713	27,709	$ 16.45
57	ALLETE (Minnesota Power)	$ 145,725	8,721	$ 16.71
58	Duke Energy Kentucky, Inc.	$ 69,526	4,117	$ 16.89
59	Kansas City Power & Light Company	$ 262,938	15,467	$ 17.00
60	Northern States Power Company - MN	$ 648,424	35,868	$ 18.08
61	Pennsylvania Electric Company	$ 262,657	14,116	$ 18.61
62	Idaho Power Co.	$ 252,642	13,513	$ 18.70
63	Avista Corporation	$ 167,498	8,856	$ 18.91
64	Portland General Electric Company	$ 338,807	17,683	$ 19.16
65	NorthWestern Energy Division	$ 139,183	7,247	$ 19.21
66	Otter Tail Power Company	$ 82,010	4,263	$ 19.24
67	Atlantic City Electric Company	$ 197,004	10,185	$ 19.34
68	Puget Sound Energy, Inc.	$ 405,817	20,901	$ 19.42
69	Dayton Power and Light Company	$ 281,261	14,277	$ 19.70
70	Northern States Power Company - WI	$ 128,851	6,318	$ 20.39
71	El Paso Electric Company	$ 162,345	7,434	$ 21.84
72	PECO Energy Company	$ 864,661	39,310	$ 22.00
73	Kansas Gas and Electric Company	$ 222,110	10,067	$ 22.06
74	Consumers Energy Company	$ 763,573	33,290	$ 22.94
75	Black Hills Colorado Electric Utility Company, LP	$ 40,194	1,742	$ 23.07
76	Westar Energy (KPL)	$ 230,809	9,966	$ 23.16
77	Public Service Company of New Mexico	$ 214,218	9,091	$ 23.56
78	Interstate Power and Light Company	$ 365,243	15,283	$ 23.90
79	Wisconsin Power and Light Company	$ 247,685	10,130	$ 24.45
80	Rochester Gas and Electric Corp	$ 190,301	7,284	$ 26.13
81	Wisconsin Electric Power Company	$ 729,157	27,366	$ 26.64
82	Green Mountain Power Corporation	$ 52,497	1,913	$ 27.44
83	Wisconsin Public Service Corp	$ 297,686	10,795	$ 27.58
84	Rockland Electric Company	$ 47,275	1,679	$ 28.16
85	Detroit Edison Company	$ 1,216,160	42,831	$ 28.39
86	Pacific Gas and Electric Company	$ 2,434,056	84,064	$ 28.95
87	Madison Gas and Electric Company	$ 96,581	3,332	$ 28.99
88	Metropolitan Edison Company	$ 408,582	13,996	$ 29.19
89	New York State Electric & Gas Corp	$ 444,869	15,069	$ 29.52
90	Public Service Electric and Gas Company	$ 808,481	26,613	$ 30.38
91	Commonwealth Edison Company	$ 1,419,665	43,610	$ 32.55
92	NSTAR Electric Company	$ 724,137	21,654	$ 33.44
93	Black Hills Power, Inc.	$ 58,036	1,655	$ 35.07
94	Orange and Rockland Utilities, Inc.	$ 164,376	4,074	$ 40.35
95	Upper Peninsula Power Company	$ 35,732	798	$ 44.77
96	Public Service Company of New Hampshire	$ 246,093	5,420	$ 45.41
97	Unitil Energy Systems, Inc.	$ 39,262	839	$ 46.80
98	Southern California Edison Co.	$ 2,646,977	53,606	$ 49.38
99	United Illuminating Company	$ 302,191	5,735	$ 52.70
100	Central Hudson Gas & Electric Corp	$ 183,457	3,237	$ 56.67
101	Western Massachusetts Electric Company	$ 118,793	1,842	$ 64.51
102	Connecticut Light and Power Company	$ 632,098	9,639	$ 65.58
103	San Diego Gas & Electric Co.	$ 747,997	11,402	$ 65.60

TOTAL NON-PRODUCTION O&M PER MWH
($/MWh)
2010

Rank	Company	Total Non-Prod O&M ($000)	Total Sales (000 MWh)	Total O&M Per MWh
104	Fitchburg Gas and Electric Light Company	$ 17,987	249	$ 72.26
105	Consolidated Edison Company of New York, Inc.	$ 1,907,648	24,142	$ 79.02
106	Golden State Water Company	$ 10,933	132	$ 82.72
	Totals & Weighted Average	$ 39,235,075	2,120,332	$ 18.50
	Arithmetic Average	$ 370,142	20,003	$ 22.04

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TOTAL NON-PRODUCTION O&M PER MWH
($/MWh)
2011

Rank	Company	Total Non-Prod O&M ($000)	Total Sales (000 MWh)	Total O&M Per MWh
1	Kingsport Power Company	$ 9,158	2,137	$ 4.29
2	Wheeling Power Company	$ 10,760	2,269	$ 4.74
3	Cleveland Electric Illuminating Company	$ 146,584	18,916	$ 7.75
4	Toledo Edison Company	$ 87,915	10,437	$ 8.42
5	Entergy Louisiana, LLC	$ 281,839	31,744	$ 8.88
6	West Penn Power Company	$ 188,715	20,104	$ 9.39
7	Entergy Gulf States Louisiana, L.L.C.	$ 191,510	19,885	$ 9.63
8	Oncor Electric Delivery Company LLC	$ 1,097,489	113,837	$ 9.64
9	***Entergy Texas, Inc.***	***$ 163,914***	***16,863***	***$ 9.72***
10	Ohio Edison Company	$ 243,365	24,656	$ 9.87
11	Florida Power & Light Company	$ 1,027,638	103,558	$ 9.92
12	Potomac Edison Company	$ 104,224	10,416	$ 10.01
13	Pennsylvania Power Company	$ 50,492	4,586	$ 11.01
14	Virginia Electric and Power Company	$ 882,221	78,500	$ 11.24
15	Kentucky Utilities Company	$ 221,591	19,256	$ 11.51
16	Southwestern Electric Power Company	$ 219,943	18,679	$ 11.78
17	South Carolina Electric & Gas Co.	$ 262,731	22,151	$ 11.86
18	Entergy Mississippi, Inc.	$ 161,779	13,574	$ 11.92
19	Midwest Energy, Inc.	$ 17,778	1,465	$ 12.14
20	Duke Energy Carolinas, LLC	$ 943,589	76,216	$ 12.38
21	Public Service Company of Oklahoma	$ 225,434	18,197	$ 12.39
22	Indianapolis Power & Light Company	$ 177,728	14,229	$ 12.49
23	Tampa Electric Company	$ 232,060	18,564	$ 12.50
24	Georgia Power Company	$ 1,057,616	84,300	$ 12.55
25	Duquesne Light Company	$ 177,240	14,027	$ 12.64
26	Alabama Power Company	$ 700,021	54,704	$ 12.80
27	Southwestern Public Service Company	$ 243,104	18,631	$ 13.05
28	Pennsylvania Electric Company	$ 185,097	14,134	$ 13.10
29	Nevada Power Company	$ 271,888	20,755	$ 13.10
30	Oklahoma Gas and Electric Company	$ 355,814	27,055	$ 13.15
31	MidAmerican Energy Company	$ 297,896	21,873	$ 13.62
32	Ohio Power Company	$ 599,591	43,492	$ 13.79
33	Cleco Power LLC	$ 125,518	9,028	$ 13.90
34	Entergy Arkansas, Inc.	$ 304,719	21,584	$ 14.12
35	Southern Indiana Gas and Electric Company, Inc.	$ 79,937	5,595	$ 14.29
36	Metropolitan Edison Company	$ 199,639	13,970	$ 14.29
37	Louisville Gas and Electric Company	$ 166,439	11,641	$ 14.30
38	PacifiCorp	$ 777,931	54,307	$ 14.32
39	Northern Indiana Public Service Company	$ 243,551	16,836	$ 14.47
40	Mississippi Power Company	$ 142,711	9,658	$ 14.78
41	Tucson Electric Power Company	$ 138,921	9,332	$ 14.89
42	Duke Energy Indiana, Inc.	$ 416,328	27,810	$ 14.97
43	Potomac Electric Power Company	$ 409,569	26,895	$ 15.23
44	MDU Resources Group, Inc.	$ 44,302	2,879	$ 15.39
45	Baltimore Gas and Electric Company	$ 493,751	31,809	$ 15.52
46	Union Electric Company	$ 584,527	37,428	$ 15.62
47	Delmarva Power & Light Company	$ 199,304	12,691	$ 15.70
48	Public Service Company of Colorado	$ 452,343	28,486	$ 15.88
49	PPL Electric Utilities Corporation	$ 587,297	36,942	$ 15.90
50	UNS Electric, Inc.	$ 29,521	1,853	$ 15.93
51	ALLETE (Minnesota Power)	$ 149,453	9,289	$ 16.09